CHESAPEAKE ENERGY CORP
Form 10-Q
May 12, 2008
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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, 2008

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

Commission File No. 1-13726

Chesapeake Energy Corporation

(Exact name of registrant as specified in its charter)

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

(405) 848-8000

Registrant s telephone number, including area code

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer , accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

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 8, 2008, there were 540,394,957 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, 2008	December 31, 2007
	($ in millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 1	$ 1
Accounts receivable	1,278	1,074
Short-term derivative instruments	3	203
Deferred income taxes	520	1
Inventory	107	87
Other	37	30
Total Current Assets	1,946	1,396
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full-cost accounting:		
Evaluated natural gas and oil properties	29,317	27,656
Unevaluated properties	6,205	5,641
Less: accumulated depreciation, depletion and amortization of natural gas and oil properties	(7,623)	(7,112)
Total natural gas and oil properties, at cost based on full-cost accounting	27,899	26,185
Other property and equipment:		
Natural gas gathering systems and treating plants	1,453	1,135
Buildings and land	954	816
Drilling rigs and equipment	125	106
Natural gas compressors	68	63
Other	351	327
Less: accumulated depreciation and amortization of other property and equipment	(331)	(295)
Total Other Property and Equipment	2,620	2,152
Total Property and Equipment	30,519	28,337
OTHER ASSETS:		
Investments	603	612
Long-term derivative instruments	22	4
Other assets	372	385
Total Other Assets	997	1,001
TOTAL ASSETS	$ 33,462	$ 30,734

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(Unaudited)

	March 31, 2008	December 31, 2007
	($ in millions)	
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 1,478	$ 1,262
Accrued liabilities	710	717
Short-term derivative instruments	1,342	174
Revenues and royalties due others	566	433
Accrued interest	124	175
Total Current Liabilities	4,220	2,761
LONG-TERM LIABILITIES:		
Long-term debt, net	12,250	10,950
Deferred income tax liability	4,076	3,966
Asset retirement obligation	243	236
Long-term derivative instruments	916	408
Revenues and royalties due others	44	42
Other liabilities	243	241
Total Long-Term Liabilities	17,772	15,843
CONTINGENCIES AND COMMITMENTS (Note 3)		
STOCKHOLDERS EQUITY:		
Preferred Stock, $.01 par value, 20,000,000 shares authorized:		
5.00% cumulative convertible preferred stock (series 2005B), 5,750,000 shares issued and outstanding as of March 31, 2008 and December 31, 2007, entitled in liquidation to $575 million	575	575
4.50% cumulative convertible preferred stock, 3,450,000 shares issued and outstanding as of March 31, 2008 and December 31, 2007, entitled in liquidation to $345 million	345	345
6.25% mandatory convertible preferred stock, 143,768 shares issued and outstanding as of March 31, 2008 and December 31, 2007, respectively, entitled in liquidation to $36 million	36	36
4.125% cumulative convertible preferred stock, 3,062 shares issued and outstanding as of March 31, 2008 and December 31, 2007, respectively, entitled in liquidation to $3 million	3	3
5.00% cumulative convertible preferred stock (series 2005), 5,000 shares issued and outstanding as of March 31, 2008 and December 31, 2007, entitled in liquidation to $1 million	1	1
Common Stock, $.01 par value, 750,000,000 shares authorized, 514,564,549 and 511,648,217 shares issued at March 31, 2008 and December 31, 2007, respectively	5	5
Paid-in capital	7,081	7,032
Retained earnings	3,973	4,150
Accumulated other comprehensive income (loss), net of tax of $335 million and $6 million, respectively	(543)	(11)
Less: treasury stock, at cost; 499,723 and 500,821 common shares as of March 31, 2008 and December 31, 2007, respectively	(6)	(6)
Total Stockholders Equity	11,470	12,130
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 33,462	$ 30,734

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,	
	2008	2007
	($ in millions except per share data)	
REVENUES:		
Natural gas and oil sales	$ 773	$ 1,125
Natural gas and oil marketing sales	796	422
Service operations revenue	42	33
Total Revenues	1,611	1,580
OPERATING COSTS:		
Production expenses	201	142
Production taxes	75	42
General and administrative expenses	79	52
Natural gas and oil marketing expenses	774	407
Service operations expense	35	22
Natural gas and oil depreciation, depletion and amortization	515	393
Depreciation and amortization of other assets	36	36
Total Operating Costs	1,715	1,094
INCOME (LOSS) FROM OPERATIONS	(104)	486
OTHER INCOME (EXPENSE):		
Interest and other income	(9)	9
Interest expense	(101)	(79)
Total Other Income (Expense)	(110)	(70)
INCOME (LOSS) BEFORE INCOME TAXES	(214)	416
INCOME TAX EXPENSE (BENEFIT):		
Current		
Deferred	(82)	158
Total Income Tax Expense (Benefit)	(82)	158
NET INCOME (LOSS)	(132)	258
PREFERRED STOCK DIVIDENDS	(11)	(26)
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$ (143)	$ 232
EARNINGS (LOSS) PER COMMON SHARE:		
Basic	$ (0.29)	$ 0.51
Assuming dilution	$ (0.29)	$ 0.50

CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.0675	$ 0.06
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):		
Basic	493	451
Assuming dilution	493	516

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,	
	2008	2007
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME (LOSS)	$ (132)	$ 258
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	553	431
Deferred income taxes	(86)	153
Unrealized losses on derivatives	1,145	311
Realized gains on financing derivatives	(12)	(42)
Stock-based compensation	29	14
Other	14	(1)
Change in assets and liabilities	(13)	(147)
Cash provided by operating activities	1,498	977
CASH FLOWS FROM INVESTING ACTIVITIES:		
Exploration and development of natural gas and oil properties	(1,406)	(1,251)
Acquisitions of natural gas and oil companies, proved and unproved properties and leasehold, net of cash acquired	(1,004)	(419)
Divestitures of proved and unproved properties and leasehold	243	
Additions to other property and equipment	(551)	(212)
Additions to investments	(9)	(17)
Proceeds from sale of drilling rigs and equipment	34	30
Proceeds from sale of compressors	17	
Deposits for acquisitions		(7)
Sale of non-natural gas and oil assets	1	7
Cash used in investing activities	(2,675)	(1,869)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings	2,591	1,833
Payments on long-term borrowings	(1,377)	(858)
Cash paid for common stock dividends	(33)	(27)
Cash paid for preferred stock dividends	(12)	(26)
Derivative settlements	(33)	(22)
Net increase (decrease) in outstanding payments in excess of cash balance	44	(8)
Cash received from exercise of stock options	4	3
Excess tax benefit from stock-based compensation	11	4
Other financing costs	(18)	(6)
Cash provided by financing activities	1,177	893
Net increase (decrease) in cash and cash equivalents		1
Cash and cash equivalents, beginning of period	1	3

Cash and cash equivalents, end of period	$ 1	$ 4

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,	
	2008	2007
	($ in millions)	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:		
Interest, net of capitalized interest	$ 131	$ 104
Income taxes, net of refunds received	$ 4	$ 5
SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:		

Accrued dividends payable on our common and preferred stock was $53 million on both March 31, 2008 and 2007.

For the three months ended March 31, 2008 and 2007, natural gas and oil properties were adjusted by $13 million and $7 million, respectively, for income tax liabilities related to acquisitions.

For the three months ended March 31, 2008 and 2007, natural gas and oil properties were adjusted by ($6) million and $22 million, respectively, as a result of an increase (decrease) in accrued exploration and development costs.

We recorded non-cash asset additions to net natural gas and oil properties of $3 million and $5 million for the three months ended March 31, 2008 and 2007, respectively, for asset retirement obligations.

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,	
	2008	2007
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning of period	$ 960	$ 1,958
Balance, end of period	960	1,958
COMMON STOCK:		
Balance, beginning of period	5	5
Balance, end of period	5	5
PAID-IN CAPITAL:		
Balance, beginning of period	7,032	5,873
Stock-based compensation	34	15
Exercise of stock options	4	3
Tax benefit from exercise of stock options and restricted stock	11	4
Balance, end of period	7,081	5,895
RETAINED EARNINGS:		
Balance, beginning of period	4,150	2,913
Net income (loss)	(132)	258
Dividends on common stock	(33)	(27)
Dividends on preferred stock	(12)	(26)
Adoption of FIN 48		(4)
Balance, end of period	3,973	3,114
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(11)	528
Hedging activity	(533)	(407)
Marketable securities activity	1	2
Balance, end of period	(543)	123
TREASURY STOCK COMMON:		
Balance, beginning of period	(6)	(26)
Release of 1,098 and 260,447 shares for company benefit plans		8
Balance, end of period	(6)	(18)
TOTAL STOCKHOLDERS EQUITY	$ 11,470	$ 11,077

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 (LOSS)

(Unaudited)

	Three Months Ended March 31,	
	2008	2007
	($ in millions)	
Net income (loss)	$ (132)	$ 258
Other comprehensive income (loss), net of income tax:		
Change in fair value of derivative instruments, net of income taxes of ($303) million and ($132) million	(492)	(213)
Reclassification of gain on settled contracts, net of income taxes of ($51) million and ($138) million	(82)	(228)
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of $25 million and $20 million	41	34
Unrealized gain on marketable securities, net of income taxes of $1 million and $1 million	1	2
Comprehensive income (loss)	$ (664)	$ (147)

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 annual report on Form 10-K for the year ended December 31, 2007 (2007 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, 2008 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, 2008 (the Current Quarter) and the three months ended March 31, 2007 (the Prior Quarter).

Income Taxes

Chesapeake adopted the provisions of FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109* on January 1, 2007. As of March 31, 2008, the amount of unrecognized tax benefits related to AMT liabilities associated with uncertain tax positions was $136 million. These AMT liabilities can be utilized as credits against future regular tax liabilities. The uncertain tax positions identified would not have an effect on the effective tax rate. At March 31, 2008, we had a liability of $7 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 U.S. federal, state and local income tax examinations by tax authorities for years prior to 2004. In March 2008, the IRS commenced an examination of Chesapeake s U.S. income tax returns for 2005 and 2006 which we expect will be completed in 2009. We do not anticipate that the outcome of this examination 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, natural gas and oil 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 2007 Form 10-K.

2. Financial Instruments and Hedging Activities

Natural Gas and Oil Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for natural gas and oil. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of March 31, 2008, our natural gas and oil derivative instruments were comprised of swaps, basis protection swaps, knockout swaps, cap-swaps, call options and collars. These instruments allow us to predict with greater certainty the effective natural gas and oil 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.

Basis protection swaps are arrangements that guarantee a price differential for natural gas or oil from a specified delivery point. For Mid-Continent basis protection swaps, which typically 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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

For 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.

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 natural gas and oil prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to natural gas and oil sales in the month of related production.

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

	Three Months Ended March 31,	
	2008	2007
	($ in millions)	
Natural gas and oil sales	$ 1,691	$ 1,001
Realized gains (losses) on natural gas and oil derivatives	214	433
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(1,067)	(255)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(65)	(54)
Total natural gas and oil sales	$ 773	$ 1,125

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The estimated fair values of our natural gas and oil derivative instruments as of March 31, 2008 and December 31, 2007 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	March 31, 2008	December 31, 2007
	($ in millions)	
Derivative assets (liabilities):		
Fixed-price natural gas swaps	$ (862)	$ (54)
Natural gas basis protection swaps	137	151
Fixed-price natural gas knockout swaps	(462)	108
Natural gas call options[(a)]	(515)	(230)
Fixed-price natural gas collars[(b)]	(64)	4
Fixed-price oil swaps	(97)	(110)
Fixed-price oil cap-swaps	(18)	(17)
Fixed-price oil knockout swaps	(217)	(125)
Oil call options[(c)]	(134)	(96)
Estimated fair value	$ (2,232)	$ (369)

(a) After adjusting for $339 million and $255 million of unrealized premiums, the cumulative unrealized gain (loss) related to these call options as of March 31, 2008 and December 31, 2007 was ($176) million and $25 million, respectively.

(b) After adjusting for $8 million of unrealized discount, the cumulative unrealized loss related to these collars as of December 31, 2007 was ($4) million. The unrealized premiums at March 31, 2008 were nominal.

(c) After adjusting for $29 million of unrealized premiums, the cumulative unrealized loss related to these call options as of March 31, 2008 and December 31, 2007 was $105 million and $67 million, respectively.

Since 2006, Chesapeake has lifted a portion of its 2008 through 2022 hedges and as a result had approximately $52 million of deferred hedging gains as of March 31, 2008. These gains have been recorded in accumulated other comprehensive income or as an unrealized gain in natural gas and oil sales. For amounts originally recorded in other comprehensive income, the gain will be recognized in natural gas and oil sales in the month of the hedged production.

Based upon the market prices at March 31, 2008, we expect to transfer approximately $311 million (net of income taxes) of the loss 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, 2008 are expected to mature by December 31, 2022.

We have six secured hedging facilities, each of which permits us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to a stated maximum value. Outstanding transactions under each facility are collateralized by certain of our natural gas and oil properties that do not secure any of our other obligations. The value of reserve collateral pledged to each facility is required to be at least 1.3 times the fair value of transactions outstanding under each facility. In addition, we may pledge collateral from our revolving bank credit facility, from time to time, to these facilities to meet our collateral coverage requirements. The hedging facilities are subject to a 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 natural gas and oil production volumes that we are permitted to hedge under all of our agreements at any one time. The stated maximum capacity under each facility, per annum exposure fees, scheduled maturity dates and the fair value of outstanding transactions are shown below.

	Secured Hedging Facilities [a]					
	#1	#2	#3	#4	#5	#6
	($ in millions)					
Stated maximum value of transactions under facility	$ 750	$ 500	$ 500	$ 250	$ 500	$ 500
Per annum exposure fee	1%	1%	0.8%	0.8%	0.8%	0.8%
Scheduled maturity date	2010	2010	2020	2012	2012	2012
Fair value of outstanding transactions, as of March 31, 2008	$ (90)	$ (764)	$ (421)	$ (76)	$ (76)	$ (147)

(a) Chesapeake Exploration, L.L.C. is the named party to the facilities numbered 1 3 and Chesapeake Energy Corporation is the named party to the facilities numbered 4 6.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 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.

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 a nominal amount and ($2) million in the Current Quarter and the Prior Quarter, respectively. Unrealized gains (losses) included in interest expense were ($13) million and ($1) million in the Current Quarter and the Prior Quarter, respectively.

As of March 31, 2008, the following interest rate derivatives were outstanding:

		Notional Amount ($ in millions)	Weighted Average Fixed Rate	Weighted Average Floating Rate	Weighted Average Cap/Floor Rate	Fair Value Hedge	Net Premiums ($ in millions)	Fair Value ($ in millions)
Fixed to Floating Swaps:								
January 2008	November 2020	$ 800	7.195%	6 month LIBOR plus 328 basis points		Yes	$	$ (8)
January 2008	January 2018	$ 250	6.25%	6 month LIBOR plus 190 basis points		No		5
Floating to Fixed Swaps:								
August 2007	August 2010	$ 825	4.737%	3 month LIBOR		No		(32)
Call Options:								
January 2008	July 2010	$ 500	6.563%			No	5	(11)
Collars:								
August 2007	August 2010	$ 800			5.37% 4.52%	No		(34)
							$ 5	$ (80)

In the Current Quarter, we sold call options on two of our interest rate swaps and received $5 million in premiums. Three options were exercised in the Current Quarter resulting in the termination of three interest rate swaps.

In the Current Quarter, we closed 17 interest rate swaps for gains totaling $48 million. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to interest expense over the remaining term of the related senior notes.

Foreign Currency Derivatives

On December 6, 2006, we issued 600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties pay Chesapeake 19 million and Chesapeake pays the counterparties $30 million, which yields 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 ($948 million at March 31, 2008) using an exchange rate of $1.5805 to 1.00. The fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as an asset of $80 million at March 31, 2008.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 natural gas and oil price and interest rate volatility. These arrangements expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with investment-grade rated counterparties deemed by management to be competent and competitive market makers. Recently there have been concerns about the ability of certain investment banks to continue to meet their financial obligations. A notable example is our counterparty, Bear Stearns, which faced a liquidity crisis in early March 2008. The Bear Stearns parent and JPMorgan Chase & Co. (JPM) entered into an agreement as of March 16, 2008 for JPM to acquire Bear Stearns, and JPM unconditionally guaranteed payment of Bear Stearns liabilities for the period specified in the guaranty, including liabilities that might arise under our derivative contracts with Bear Stearns affiliates. We monitor our counterparties and do not believe a failure by an investment bank counterparty would have a material negative impact on our liquidity.

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 natural gas and oil and exploration and production companies which own interests in properties we operate. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

3. Contingencies and Commitments

Litigation

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

On January 27, 2007, the Circuit Court jury returned a verdict against the defendants of $404 million, consisting of $134 million in compensatory damages and $270 million in punitive damages. Most of the damages awarded by the jury relate to issues not yet addressed by the West Virginia Supreme Court of Appeals, although in June 2006 that Court ruled against the defendants on two certified questions regarding the deductibility of post-production expenses. The jury found fraudulent conduct by the defendants with respect to the sales prices used to calculate royalty payments and with respect to the failure of CNR to disclose post-production deductions. On June 28, 2007, the Circuit Court sustained the jury verdict for punitive damages, and on September 27, 2007, it denied all post-trial motions. Subsequently defendants filed an irrevocable letter of credit in the amount of $50 million in order to stay the judgment pending appeal. On January 24, 2008, the defendants filed their initial Petition for Appeal in the West Virginia Supreme Court of Appeals, and on April 14, 2008, the plaintiffs filed a response, a cross petition and other motions.

Chesapeake and NiSource maintain CNR acted in good faith and paid royalties in accordance with lease terms and West Virginia law. 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.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2008. 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 upon the happening of certain events following a change of control. The agreement further provides that any stock-based awards held by the chief executive officer and deferred compensation will immediately become 100% vested upon termination of employment without cause, 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 or death and, in the event of a change of control, a payment in the amount of two times the executive officer s base compensation. These executive officers are entitled to continue to receive compensation and benefits for 180 days following termination of employment as a result of incapacity. 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 natural gas and oil 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, 2008.

Rig Leases

In a series of transactions in 2006, 2007 and 2008, our drilling subsidiaries sold 80 drilling rigs and related equipment for $647 million and entered into a master lease agreement under which we agreed to lease the rigs from the buyer for initial terms of seven to ten years for rental payments of approximately $90 million annually. The lease obligations are guaranteed by Chesapeake and its other material subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss 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 rig lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of March 31, 2008, the minimum aggregate future rig lease payments were approximately $650 million.

Compressor Leases

In 2007 and 2008, our wholly-owned subsidiary, MidCon Compression, L.L.C., sold a significant portion of its existing compressor fleet, consisting of 1,239 compressors, for $205 million and entered into a master lease agreement. The term of the agreement varies by buyer ranging from seven to ten years for aggregate rental payments of approximately $25 million annually. MidCon s lease obligations are guaranteed by Chesapeake and its other material subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss will be amortized to natural gas and oil marketing expenses over the lease term. Under the

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

leases, we can exercise an early purchase option after six to nine years or we can purchase the compressors at expiration of the lease for the fair market value at the time. In addition, we have the option to renew the lease for negotiated new terms at the expiration of the lease. Through 2009, approximately 480 new compressors are on order for approximately $190 million and will be sold and leased back as the compressors are delivered. Commitments related to compressor lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of March 31, 2008, the minimum aggregate future compressor lease payments were approximately $225 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, 2008, the aggregate amount of such required demand payments was approximately $521 million (excluding demand charges for pipeline projects that are currently seeking regulatory approval).

Drilling Contracts

Currently, Chesapeake has contracts with various drilling contractors to lease approximately 35 rigs with terms of one to three years. As of March 31, 2008, the aggregate drilling rig commitment was approximately $190 million.

As of March 31, 2008, Chesapeake s service operations subsidiaries have contracted to acquire three rigs to be constructed during 2008. The total remaining cost of the rigs is estimated to be approximately $15 million.

Gas Purchase Obligations

Our marketing segment regularly commits to purchase natural gas from other owners in our properties and such commitments typically are short term in nature. We have also committed to purchase natural gas associated with the volumetric production payment transaction we closed on December 31, 2007. The purchase commitment extends over a 15 year term based on market prices at the time of production, and the purchased natural gas will be resold. As of March 31, 2008, we were obligated to purchase 202,993 mmcfe under the terms of the volumetric production payment.

Other Commitments

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, 2008, Mountain Drilling owed Chesapeake $20 million under this agreement.

Chesapeake has an agreement to lend Ventura Refining and Transmission LLC, of which Chesapeake is a 25% equity owner, up to $31 million through January 31, 2017. At March 31, 2008, there was $26 million outstanding under this agreement. Additionally, we have agreed to guarantee up to $70 million in commitments for Ventura to support its operating activities. As of March 31, 2008, we had guaranteed $61 million.

On March 28, 2008, we entered into an agreement to purchase a 460,000 square foot office building in downtown Fort Worth, Texas from Pier 1 Imports, Inc. for $104 million to house our Barnett Shale district headquarters. As part of the transaction, Pier 1 Imports will enter into a lease agreement to rent approximately 250,000 square feet for a primary term of seven years beginning on the closing date, with one three-year renewal option, and a right to terminate the lease at the end of the fifth lease year. The transaction is expected to close in the second quarter of 2008.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Net Income (Loss) 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. For the Current Quarter, there was no difference between actual weighted average shares outstanding, which are used in computing basic EPS, and diluted weighted average shares, which are used in computing EPS assuming dilution.

As a result of the Current Quarter s net loss to common shareholders, diluted shares do not include the effect of (i) outstanding stock options to purchase 2.6 million shares of common stock at a weighted average exercise price of $7.71, (ii) 5.3 million shares of unvested restricted stock at a weighted average grant-date fair value of $34.07 and (iii) the assumed conversion of the following outstanding preferred stock:

4.125% preferred stock convertible into 184,200 common shares,

5.00% (Series 2005) convertible preferred stock convertible into 19,432 common shares,

5.00% (Series 2005B) convertible preferred stock convertible into 14,719,425 common shares,

4.50% preferred stock convertible into 7,810,800 common shares, and

6.25% mandatory convertible preferred stock convertible into 1,031,175 common shares.

A reconciliation for the three months ended March 31, 2007 is 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% 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

5. Stockholders Equity, Restricted Stock and Stock Options

The following is a summary of the changes in our common shares outstanding for the three months ended March 31, 2008 and 2007:

	2008	2007
	(in thousands)	
Shares outstanding at January 1	511,648	458,601
Stock option exercises	621	532
Restricted stock issuances net of terminations and vesting	2,296	2,253
Shares outstanding at March 31	514,565	461,386

There were no changes in our preferred shares outstanding in the Current Quarter.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Stock-Based Compensation

Chesapeake s stock-based compensation programs consist of restricted stock and stock options issued to employees and non-employee directors. To the extent compensation cost relates to employees directly involved in natural gas and oil exploration and development activities, such amounts are capitalized to natural gas and oil properties. Amounts not capitalized are recognized as general and administrative expenses, production expenses, natural gas and oil marketing expenses or service operations expense. We recorded the following stock-based compensation during the Current Quarter and the Prior Quarter:

	Three Months Ended March 31,	
	2008	2007
	($ in millions)	
Natural gas and oil properties	$ 26	$ 9
General and administrative expenses	19	10
Production expenses	7	3
Natural gas and oil marketing expenses	2	1
Service operations expense	1	
Total	$ 55	$ 23

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

A summary of the changes in unvested shares of restricted stock during the Current Quarter is presented below:

	Number of Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2008	19,688,759	$ 32.42
Granted	3,046,950	$ 40.14
Vested	(1,507,561)	$ 24.66
Forfeited	(306,006)	$ 34.58
Unvested shares as of March 31, 2008	20,922,142	$ 34.07

The aggregate intrinsic value of restricted stock vested during the Current Quarter was approximately $61 million based on the stock price at the time of vesting.

As of March 31, 2008, there was $633 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 3.07 years.

The vesting of certain restricted stock grants results in state and federal income tax benefits related to the difference between the market price of the common stock at the date of vesting and the date of grant. During the Current Quarter and the Prior Quarter, we recognized excess tax benefits related to restricted stock of $6 million and $1 million, respectively, which were recorded as adjustments to additional paid-in capital

and deferred income taxes.

Stock Options. Prior to 2006, we granted stock options under several stock compensation plans. Outstanding options expire ten years from the date of grant and vest over a four-year period.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2008	4,445,455	$ 7.55		$ 141
Exercised	(624,674)	$ 6.52		$ 23
Forfeited	(1,000)	$ 15.48		
Outstanding at March 31, 2008	3,819,781	$ 7.71	4.21	$ 147
Exercisable at March 31, 2008	3,813,781	$ 7.70	4.20	$ 147

(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, 2008, unrecognized compensation cost related to unvested stock options was not significant.

During the Current Quarter and the Prior Quarter, we recognized excess tax benefits related to stock options of $5 million and $3 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes.

6. Senior Notes and Revolving Bank Credit Facility

Our long-term debt consisted of the following as of March 31, 2008 and December 31, 2007:

	March 31, 2008	December 31, 2007
	($ 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
6.375% Senior Notes due 2015	600	600
7.75% Senior Notes due 2015	300	300
6.625% Senior Notes due 2016	600	600
6.875% Senior Notes due 2016	670	670
6.25% Euro-denominated Senior Notes due 2017[(a)]	948	876
6.5% Senior Notes due 2017	1,100	1,100
6.25% Senior Notes due 2018	600	600
6.875% Senior Notes due 2020	500	500
2.75% Contingent Convertible Senior Notes due 2035[(b)]	690	690
2.5% Contingent Convertible Senior Notes due 2037[(b)]	1,650	1,650

Revolving bank credit facility	3,164	1,950
Discount on senior notes	(102)	(105)
Impact of interest rate derivatives[c]	66	55
Total notes payable and long-term debt	$ 12,250	$ 10,950

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.5805 to 1.00 and $1.4603 to 1.00 as of March 31, 2008 and December 31, 2007, 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, in cash, all or a portion of these notes on November 15, 2015, 2020, 2025 and 2030 at 100% of the principal amount of the notes. The holders of the 2.5% Contingent Convertible Senior Notes due 2037 may require us to repurchase, in cash, all or a portion of these notes on May 15, 2017, 2022, 2027 and 2032 at 100% of the principal amount of the 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. One such triggering circumstance is that the price of our common stock exceeds a threshold amount during a specified period. At May 9, 2008, that threshold amount was $48.831 for the 2.75% Contingent Convertible Senior Notes and $64.477 for the 2.5% Contingent Convertible Senior Notes. If the price of our common stock remains at current trading levels (closing price on May 9, 2008 of $56.67), or continues to increase, it is likely that holders of our 2.75% Contingent Convertible Senior Notes will have the option to convert their notes into cash and common stock in the third quarter of 2008. However, we believe the trading prices of the notes will remain above the respective conversion trigger prices such that holders would realize greater value by selling their notes in the open market as opposed to converting them into cash and common stock. 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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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convertible senior notes, beginning with the six-month interest period ending May 14, 2016 with respect to the 2.75% Contingent Convertible Senior Notes due 2035 and November 14, 2017 with respect to the 2.5% Contingent Convertible Senior Notes due 2037, under certain conditions. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash.

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

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

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

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

We have a $3.5 billion syndicated revolving bank credit facility which matures in November 2012. As of March 31, 2008, we had $3.164 billion in outstanding borrowings under our facility and utilized approximately $4 million of the facility for various letters of credit. Borrowings under our facility are secured by certain producing natural gas and oil properties and bear interest at our option 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), plus a margin that varies from 0.75% to 1.50% per annum 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 0.20% 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 0.70 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.75 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.52 to 1 and our indebtedness to EBITDA ratio was 2.23 to 1 at March 31, 2008. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $75 million.

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 operational segment and natural gas and oil 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 natural gas and oil. The marketing segment is responsible for gathering, processing, compressing, transporting and selling natural gas and oil primarily from Chesapeake-operated wells. We also have drilling rig and trucking operations which are responsible for providing drilling rigs primarily used on Chesapeake-operated wells and trucking services utilized in the transportation of drilling rigs on both Chesapeake-operated wells and wells operated by third parties.

Management evaluates the performance of our segments based upon income before income taxes. Revenues from the marketing segment s sale of natural gas and oil related to Chesapeake s ownership interests are reflected as exploration and production revenues. Such amounts totaled $1.289 billion and $705 million for the Current Quarter and the Prior Quarter. 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	Intercompany Eliminations	Consolidated Total
			($ in millions)		
For the Three Months Ended March 31, 2008:					
Revenues	$ 773	$ 2,085	$ 149	$ (1,396)	$ 1,611
Intersegment revenues		(1,289)	(107)	1,396	
Total revenues	$ 773	$ 796	$ 42	$	$ 1,611
Income (loss) before income taxes	$ (228)	$ 15	$ 20	$ (21)	$ (214)
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
As of March 31, 2008:					
Total assets	$ 31,583	$ 2,285	$ 505	$ (911)	$ 33,462
As of December 31, 2007:					
Total assets	$ 29,317	$ 1,759	$ 487	$ (829)	$ 30,734

8. Divestitures

In the Current Quarter, we sold non-core natural gas and oil assets in the Rocky Mountains and in the Arkoma Basin Woodford Shale play for proceeds of $243 million.

9. Fair Value Measurements

Effective January 1, 2008, we adopted Statement of Financial Accounting Standards No. 157, *Fair Value Measurements* for our financial assets and liabilities measured on a recurring basis. This statement establishes a framework for measuring fair value of assets and liabilities and expands disclosures about fair value measurements. In February 2008, the FASB issued FSP 157-2, which delayed the effective date of SFAS No. 157 by one year for nonfinancial assets and liabilities.

SFAS 157 defines fair value as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To quantify an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

directly or indirectly. Level 3 inputs are unobservable inputs for the financial asset or liability and have the lowest priority. Chesapeake uses appropriate valuation techniques based on available inputs, including counterparty quotes, to measure the fair values of its assets and liabilities. Counterparty quotes are generally assessed as a Level 3 input.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of March 31, 2008.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
Financial Assets (Liabilities):				
Derivatives	$	$ (789)	$ (1,443)	$ (2,232)
Investments	$ 44	$	$	$ 44
Other long-term assets	$ 19	$	$	$ 19
Long-term debt	$	$	$ (1,740)	$ (1,740)
Other long-term liabilities	$ (19)	$	$	$ (19)

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Level 1 Fair Value Measurements

Investments. The fair value of Chesapeake s investment in Gastar Exploration Ltd. common stock is based on a quoted market price.

Other Long-Term Assets and Liabilities. The fair value of other long-term assets and liabilities, consisting of our Deferred Compensation Plan, is based on quoted market prices.

Level 2 Fair Value Measurements

Derivatives. The fair values of our natural gas swaps are measured internally using established index prices and other sources. These values are based upon, among other things, futures prices and time to maturity.

Level 3 Fair Value Measurements

Derivatives. The fair values of our derivatives, excluding natural gas swaps, are based on estimates provided by our respective counterparties and reviewed internally using established index prices and other sources. These values are based upon, among other things, futures prices, interest rate curves and time to maturity.

Debt. The fair value of our long-term debt is based on face value of the debt along with the value of the related interest rate swaps. The interest rate swap values are based on estimates provided by our respective counterparties and reviewed internally for reasonableness using future interest rate curves and time to maturity.

A reconciliation of Chesapeake s assets and liabilities classified as Level 3 measurements is presented below.

	Derivatives	Debt	Total
		($ in millions)	
Balance of Level 3 as of January 1, 2008	$ (340)	$ (2,404)	$ (2,744)
Total gains or losses (realized/unrealized):			
Included in earnings(a)	(1,053)	(36)	(1,089)
Included in other comprehensive income (loss)	(32)		(32)
Purchases, issuances and settlements	(18)	700(b)	682
Transfers in and out of Level 3			
Balance of Level 3 as of March 31, 2008	$ (1,443)	$ (1,740)	$ (3,183)

(a)

	Natural Gas and Oil Revenue	Interest Expense
	($ in millions)	
Total gains and losses included in earnings for the period (above)	$ (1,112)	$ 59
Change in unrealized gains or losses relating to assets still held at reporting date	$ (1,060)	$ 59

(b) Amount represents debt no longer recorded at fair value due to the closing of the related interest rate swap in the Current Quarter.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Recently Issued and Proposed Accounting Standards

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

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. 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. Since we have not elected to adopt the fair value option for eligible items, SFAS No. 159 has not had an impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of Accounting Research Bulletin No. 51*. This statement requires an entity to separately disclose non-controlling interests as a separate component of equity in the balance sheet and clearly identify on the face of the income statement net income related to non-controlling interests. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations*. This statement requires assets acquired and liabilities assumed to be measured at fair value as of the acquisition date, acquisition-related costs incurred prior to the acquisition to be expensed and contractual contingencies to be recognized at fair value as of the acquisition date. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*. This Statement changes the disclosure requirements for derivative instruments and hedging activities. The Statement requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We are currently assessing the impact that adoption of this statement will have on our financial position, results of operations or cash flows.

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

11. Subsequent Events

On April 2, 2008, we completed a public offering of 23 million shares of common stock at $45.75 per share. Net proceeds of approximately $1.011 billion were used to repay outstanding borrowings under our revolving bank credit facility, which may be reborrowed to fund our recently announced drilling and land acquisition initiatives and for other general corporate purposes.

Subsequent to March 31, 2008, a holder of our 5.0% (Series 2005B) cumulative convertible preferred stock exchanged 1,689,300 shares for 4,845,266 shares of common stock in two privately negotiated exchanges.

On May 1, 2008, we sold certain Chesapeake-operated long-lived producing assets in Texas, Oklahoma and Kansas in a volumetric production payment transaction for proceeds of approximately $623 million. These assets had estimated proved reserves of approximately 94 bcfe and current net production of approximately 47 mmcfe

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

per day. Chesapeake retained drilling rights on the properties below currently producing intervals. For accounting purposes, the transaction will be treated as a sale and the company s proved reserves will be reduced accordingly.

On May 1, 2008, we announced our intention to sell all of our Arkoma Basin Woodford Shale properties in Hughes, Pittsburg, Coal and Atoka counties in Oklahoma. The properties consist of approximately 85,000 net acres and 40 mmcfe per day of current production. We expect to receive proceeds of over $1.2 billion from the sale of the properties and anticipate completing a transaction in mid-2008.

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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, natural gas and oil sales, average sales prices received, other operating income and expenses for the three months ended March 31, 2008 (the Current Quarter) and the three months ended March 31, 2007 (the Prior Quarter):

	Three Months Ended March 31,	
	2008	**2007**
Net Production:		
Natural gas (mmcf)	187,772	140,792
Oil (mbbls)	2,746	2,143
Natural gas equivalent (mmcfe)	204,248	153,650
Natural Gas and Oil Sales ($ in millions):		
Natural gas sales	$ 1,432	$ 888
Natural gas derivatives realized gains (losses)	268	415
Natural gas derivatives unrealized gains (losses)	(1,002)	(297)
Total natural gas sales	698	1,006
Oil sales	258	113
Oil derivatives realized gains (losses)	(53)	18
Oil derivatives unrealized gains (losses)	(130)	(12)
Total oil sales	75	119
Total natural gas and oil sales	$ 773	$ 1,125
Average Sales Price (excluding all gains (losses) on derivatives):		
Natural gas ($ per mcf)	$ 7.63	$ 6.31
Oil ($ per bbl)	$ 94.14	$ 52.80
Natural gas equivalent ($ per mcfe)	$ 8.28	$ 6.52
Average Sales Price (excluding unrealized gains (losses) on derivatives):		
Natural gas ($ per mcf)	$ 9.05	$ 9.26
Oil ($ per bbl)	$ 74.73	$ 61.13
Natural gas equivalent ($ per mcfe)	$ 9.33	$ 9.33
Other Operating Income[(a)] ($ in millions):		
Natural gas and oil marketing	$ 22	$ 15
Service operations	$ 7	$ 11
Other Operating Income ($ per mcfe):		
Natural gas and oil marketing	$ 0.11	$ 0.10
Service operations	$ 0.03	$ 0.08
Expenses ($ per mcfe):		
Production expenses	$ 0.98	$ 0.93
Production taxes	$ 0.37	$ 0.27
General and administrative expenses	$ 0.39	$ 0.34

Natural gas and oil depreciation, depletion and amortization		$ 2.52	$ 2.56
Depreciation and amortization of other assets		$ 0.18	$ 0.23
Interest expense[(b)]		$ 0.43	$ 0.50
Interest Expense ($ in millions):			
Interest expense		$ 88	$ 76
Interest rate derivatives	realized (gains) losses		2
Interest rate derivatives	unrealized (gains) losses	13	1
Total interest expense		$ 101	$ 79
Net Wells Drilled		448	461
Net Producing Wells as of the End of the Period		21,840	19,623

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

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We are the third largest producer of natural gas in the United States (second among independents). We own interests in approximately 39,200 producing natural gas and oil wells that are currently producing approximately 2.3 bcfe per day, 92% of which is natural gas. Our strategy is focused on discovering, acquiring and developing conventional and unconventional natural gas reserves onshore in the U.S., east of the Rocky Mountains.

Our most important operating area has historically been the *Mid-Continent region* of Oklahoma, Arkansas, southwestern Kansas and the Texas Panhandle. At March 31, 2008, 47% of our estimated proved natural gas and oil reserves were located in the Mid-Continent region. During the past five years, we have also built significant positions in various conventional and unconventional plays in the *Fort Worth Basin* in north-central Texas; the *Appalachian Basin*, principally in West Virginia, eastern Kentucky, eastern Ohio, Pennsylvania and southern New York; the *Permian and Delaware Basins* of West Texas and eastern New Mexico; the *Ark-La-Tex* area of East Texas and northern Louisiana; and the *South Texas and Texas Gulf Coast regions*. We have established a top-three position in nearly every major unconventional play onshore in the U.S. east of the Rockies, including the Barnett Shale, the Arkansas Fayetteville Shale, the Louisiana Haynesville Shale, the Appalachian Basin Devonian and Marcellus Shales, the Delaware Basin Barnett and Woodford Shales in West Texas, and the Alabama Conasauga and Chattanooga Shales.

Natural gas and oil production for the Current Quarter was 204.2 bcfe, an increase of 50.5 bcfe, or 33% over the 153.7 bcfe produced in the Prior Quarter. The Current Quarter marked the 27th consecutive quarter we have increased our production. During these 27 quarters, Chesapeake s U.S. production has increased 467% for an average compound quarterly growth rate of 6.6% and an average compound annual growth rate of 29.2%.

During the Current Quarter, Chesapeake continued the industry s most active drilling program and drilled 478 gross (400 net) operated wells and participated in another 422 gross (48 net) wells operated by other companies. The company s drilling success rate was 100% for company-operated wells and 98% for non-operated wells. Also during the Current Quarter, we invested $1.182 billion in operated wells (using an average of 140 operated rigs) and $192 million in non-operated wells (using an average of 93 non-operated rigs). Total costs incurred in natural gas and oil acquisition, exploration and development activities during the Current Quarter, including seismic, unproved properties, leasehold, capitalized interest and internal costs, non-cash tax basis step-up and asset retirement obligations, were $2.2 billion.

Chesapeake began 2008 with estimated proved reserves of 10.879 tcfe and ended the Current Quarter with 11.480 tcfe, an increase of 601 bcfe, or 6%. During the Current Quarter, we replaced 204 bcfe of production with an internally estimated 805 bcfe of new proved reserves, for a reserve replacement rate of 395%. Reserve replacement through the drillbit was 798 bcfe, or 391% of production (including 365 bcfe of positive performance revisions and 112 bcfe of positive revisions resulting from natural gas and oil price increases between December 31, 2007 and March 31, 2008). Reserve replacement through the acquisition of proved reserves was 39 bcfe. During the Current Quarter, we divested 32 bcfe of estimated proved reserves. Based on our current drilling schedule and budget, we expect that virtually all of the proved undeveloped reserves added in 2008 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.

Since 2000, Chesapeake has invested $10.3 billion in new leasehold and 3-D seismic acquisitions and now owns what we believe are the largest combined inventories of onshore leasehold (13.9 million net acres) and 3-D seismic (20.0 million acres) in the U.S. On this leasehold, the company has approximately 33,700 net drillsites representing more than a 10-year inventory of drilling projects.

As of March 31, 2008, the company s debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders equity) was 52% compared to 47% as of December 31, 2007. The average maturity of our long-term debt is over eight years with an average interest rate of approximately 5.8%.

Liquidity and Capital Resources

During March 2008, we announced three new unconventional natural gas discoveries the Haynesville Shale in Louisiana and the Colony Granite Wash and Mountain Front Granite Wash in Oklahoma and five new unconventional oil projects. We are increasing the drilling and leasehold acquisition activities in these new plays as well as in our existing plays in the Barnett Shale in North Texas, the Fayetteville Shale in Arkansas and the Marcellus and Lower Huron Shales in Appalachia. In order to exploit these new discoveries and to increase the pace of drilling and leasehold acquisition in our existing plays, we have increased our budgeted exploration and production capital expenditures, net of estimated proceeds from planned sales of natural gas and oil leasehold and producing properties, to $5.3 billion in 2008 and $6.8 billion in 2009.

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We had previously planned to fund our 2008 and 2009 capital expenditures through cash flow from operations, borrowings under our revolving credit facility and from asset monetizations. Our previously announced asset monetizations remain on track, and on May 1, 2008, we announced a new planned transaction to sell leasehold for anticipated proceeds of over $1.2 billion in mid-2008. Considering the increasing number of opportunities available, however, we expect to fund some or all of our additional capital expenditures through public capital market transactions. In addition, we will continue to evaluate alternative natural gas and oil monetizations and financing opportunities, including transactions involving our undeveloped acreage and non-strategic assets. We believe the various sources of cash available to us will provide us with sufficient liquidity to execute our business strategy and fund our budgeted capital expenditure requirements for the foreseeable future.

On April 2, 2008, we completed a public offering of 23 million shares of common stock at $45.75 per share. Net proceeds of approximately $1.011 billion were used to repay outstanding borrowings under our revolving bank credit facility, which may be reborrowed from time to time to fund our recently announced drilling and land acquisition initiatives and for other general corporate purposes.

Sources and Uses of Funds

Cash flow from operations is our primary source of liquidity to meet operating expenses and fund capital expenditures (other than for acquisitions outside our budgeted leasehold and property acquisitions). Cash provided by operating activities was $1.498 billion in the Current Quarter compared to $977 million in the Prior Quarter. The $521 million increase in the Current Quarter was primarily due to higher volumes of natural gas and oil production. Changes in cash flow from operations are largely due to the same factors that affect our net income excluding non-cash items, such as depreciation, depletion and amortization, deferred income taxes and unrealized gains and (losses) on derivatives. See the discussion below under *Results of Operations*.

Changes in market prices for natural gas and oil directly impact the level of our cash flow from operations. While a decline in natural gas or oil prices would affect the amount of cash flow that would be generated from operations, we currently have natural gas and oil hedges in place covering 74% of our expected remaining natural gas production in 2008 and 72% of our expected remaining oil production in 2008, thereby minimizing the commodity price risk associated with a substantial portion of our 2008 cash flow. Our natural gas and oil hedges as of March 31, 2008 are detailed in Item 3 of Part I of this report. Depending on changes in natural gas and oil futures markets and management s view of underlying natural gas and oil supply and demand trends, we may increase or decrease our current hedging positions.

As of March 31, 2008, we had a net natural gas and oil derivative liability of $2.232 billion as a result of significant increases in natural gas and oil prices since December 31, 2007. We satisfy commodity derivative liabilities from a portion of the proceeds of natural gas and oil production sold at market prices during the period of contract settlement (which will occur through 2022). The remaining proceeds, representing the derivative contract price, are included in our budget estimates. We have arrangements with our hedging counterparties that allow us to minimize the potential liquidity impact of significant mark-to-market fluctuations in the value of our natural gas and oil hedges by making collateral allocations from our bank credit facility or directly pledging natural gas and oil properties, rather than posting cash or letters of credit with the counterparties.

Our $3.5 billion bank credit facility is another source of liquidity. At May 8, 2008, there was $501 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 $2.591 billion and repaid $1.377 billion in the Current Quarter, and we borrowed $1.833 billion and repaid $858 million in the Prior Quarter.

Our primary use of funds is for capital expenditures related to exploration, development and acquisition of natural gas and oil properties. We refer you to the table under *Investing Activities* below, which sets forth the components of our natural gas and oil investing activities for the Current Quarter and the Prior Quarter. Our drilling, land and seismic capital expenditures are currently budgeted at $5.3 billion in 2008. We believe this level of exploration and development will enable us to increase our total production by 21% in 2008 (inclusive of acquisitions completed or scheduled to close in 2008 through the filing date of this report but without regard to any additional acquisitions that may be completed in 2008).

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

We paid dividends on our common stock of $33 million and $27 million in the Current Quarter and the Prior Quarter, respectively. The board of directors increased the quarterly dividend on common stock from $0.06 to $0.0675 per share beginning with the dividend paid in July 2007. We paid dividends on our preferred stock of $12 million and $26 million in the Current Quarter and the Prior Quarter, respectively. We received $4 million and $3 million from the exercise of employee and director stock options in the Current Quarter and the Prior Quarter, respectively.

In the Current Quarter and Prior Quarter, we paid $33 million and $22 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 $11 million and $4 million, respectively.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists increased $44 million in the Current Quarter and decreased $8 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.

Credit Risk

A significant portion of our liquidity is concentrated in derivative instruments that enable us to hedge a portion of our exposure to natural gas and oil prices and interest rate volatility. These arrangements expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with investment grade rated counterparties deemed by management to be competent and competitive market makers. Recently there have been concerns about the ability of certain investment banks to continue to meet their financial obligations. A notable example is our counterparty, Bear Stearns, which faced a liquidity crisis in early March 2008. The Bear Stearns parent and JPMorgan Chase & Co. (JPM) entered into an agreement as of March 16, 2008 for JPM to acquire Bear Stearns, and JPM unconditionally guaranteed payment of Bear Stearns liabilities for the period specified in the guaranty, including liabilities that might arise under our derivative contracts with Bear Stearns affiliates. As of March 31, 2008, we recorded a liability of $30 million for our hedging contracts with Bear Stearns affiliates. Should settlements of these contracts result in amounts being owed to us, we believe they would be covered by the JPM guaranty. We monitor our counterparties and do not believe a failure by an investment bank counterparty would have a material negative impact on our liquidity.

Our accounts receivable are primarily from purchasers of natural gas and oil ($1.024 billion at March 31, 2008) and exploration and production companies which own interests in properties we operate ($170 million at March 31, 2008). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

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Investing Activities

Cash used in investing activities increased to $2.675 billion during the Current Quarter, compared to $1.869 billion during the Prior Quarter. Over the past year, we have continued our active drilling program and shifted our acquisition strategy from significant stock and asset acquisitions to targeted leasehold and property acquisitions needed for planned natural gas and oil development. Our investing activities during the Current Quarter and the Prior Quarter reflect our increasing focus on converting our resource inventory into production, redeploying our capital by selling natural gas and oil properties with lower rates of return and increasing our investment in properties with higher return potential, and investing in drilling rigs, midstream systems, compressors and other property and equipment to support our natural gas and oil exploration, development and production activities. The following table shows our cash used in (provided by) investing activities during these periods:

	Three Months Ended March 31,	
	2008	2007
	($ in millions)	
Natural Gas and Oil Investing Activities:		
Exploration and development of natural gas and oil properties	$ 1,322	$ 1,053
Acquisitions of natural gas and oil companies and proved properties, net of cash acquired	64	162
Acquisition of leasehold and unproved properties	860	344
Geological and geophysical costs	84	50
Interest on leasehold and unproved properties	80	61
Deposits for acquisitions		7
Divestitures of proved and unproved properties and leasehold	(243)	
Total natural gas and oil investing activities	2,167	1,677
Other Investing Activities:		
Additions to other property and equipment	551	212
Proceeds from sale of drilling rigs and equipment	(34)	(30)
Proceeds from sale of compressors	(17)	
Additions to investments	9	17
Sale of non-natural gas and oil assets	(1)	(7)
Total other investing activities	508	192
Total cash used in investing activities	$ 2,675	$ 1,869

Bank Credit and Hedging Facilities

We have a $3.5 billion syndicated revolving bank credit facility that matures in November 2012. As of March 31, 2008, we had $3.164 billion in outstanding borrowings under this facility and had utilized approximately $4 million of the facility for various letters of credit. Borrowings under the facility are secured by certain producing natural gas and oil properties and bear interest at our option 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), plus a margin that varies from 0.75% 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 0.20% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals. Our subsidiaries, Chesapeake Exploration, L.L.C. and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility and Chesapeake and all its other wholly-owned subsidiaries except minor subsidiaries are guarantors.

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 0.70 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.75 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.52 to 1 and our indebtedness to EBITDA ratio was 2.23 to 1 at March 31, 2008. 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 six secured hedging facilities, each of which permits us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to a stated maximum value. Outstanding transactions under each facility are collateralized by certain of our natural gas and oil properties that do not secure any of our other obligations. The value of reserve collateral pledged to each facility is required to be at least 1.3 times the fair value of transactions outstanding under each facility. In addition, we may pledge collateral from our revolving bank credit facility, from time to time, to these facilities to meet our collateral coverage requirements. The hedging facilities are subject to an annual 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 natural gas and oil production volumes that we are permitted to hedge under all of our agreements at any one time. The stated maximum capacity under each facility, per annum exposure fees, scheduled maturity dates and the fair value of outstanding transactions are shown below.

	Secured Hedging Facilities [(a)]					
	#1	#2	#3	#4	#5	#6
	($ in millions)					
Stated maximum value of transactions under facility	$ 750	$ 500	$ 500	$ 250	$ 500	$ 500
Per annum exposure fee	1%	1%	0.8%	0.8%	0.8%	0.8%
Scheduled maturity date	2010	2010	2020	2012	2012	2012
Fair value of outstanding transactions, as of March 31, 2008	$ (90)	$ (764)	$ (421)	$ (76)	$ (76)	$ (147)

(a) Chesapeake Exploration, L.L.C. is the named party to the facilities numbered 1 3 and Chesapeake Energy Corporation is the named party to the facilities numbered 4 6.

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.

Senior Note Obligations

In addition to outstanding revolving bank credit facility borrowings discussed above, as of March 31, 2008, senior notes represented approximately $9.1 billion of our long-term debt and consisted of the following ($ 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
6.375% Senior Notes due 2015	600
7.75% Senior Notes due 2015	300
6.625% Senior Notes due 2016	600
6.875% Senior Notes due 2016	670
6.25% Euro-denominated Senior Notes due 2017 [(a)]	948
6.5% Senior Notes due 2017	1,100
6.25% Senior Notes due 2018	600
6.875% Senior Notes due 2020	500
2.75% Contingent Convertible Senior Notes due 2035	690
2.5% Contingent Convertible Senior Notes due 2037	1,650
Discount on senior notes	(102)
Impact of interest rate derivatives	66
	$ 9,086

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.5805 to 1.00 as of March 31, 2008. See Note 2 of our accompanying condensed consolidated financial statements for information on our related cross currency swap.

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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, in cash, all or a portion of these notes on November 15, 2015, 2020, 2025 and 2030 at 100% of the principal amount of the notes. The holders of the 2.5% Contingent Convertible Senior Notes due 2037 may require us to repurchase, in cash, all or a portion of these notes on May 15, 2017, 2022, 2027 and 2032 at 100% of the principal amount of the 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. One such triggering circumstance is that the price of our common stock exceeds a threshold amount during a specified period. At May 9, 2008, that threshold amount was $48.831 for the 2.75% Contingent Convertible Senior Notes and $64.477 for the 2.5% Contingent Convertible Senior Notes. If the price of our common stock remains at current trading levels (closing price on May 9, 2008 of $56.67), or continues to increase, it is likely that holders of our 2.75% Contingent Convertible Senior Notes will have the option to convert their notes into cash and common stock in the third quarter of 2008. However, we believe the trading prices of the notes will remain above the respective trigger conversion prices such that holders would realize greater value by selling their notes in the open market as opposed to converting them into cash and common stock. 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.

As of March 31, 2008 and currently, debt ratings for the senior notes are Ba3 by Moody s Investor Service (negative outlook), BB by Standard & Poor s Ratings Services (positive outlook) and BB by Fitch Ratings (negative 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 to 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, 2008, we estimate that secured commercial bank indebtedness of approximately $5.5 billion could have been incurred under the most restrictive indenture covenant.

Other Contractual Obligations

Chesapeake has various financial obligations which are not recorded as liabilities in its condensed consolidated balance sheet at March 31, 2008. These include commitments related to drilling rig and compressor leases, transportation and drilling contracts and lending and guarantee agreements. These commitments are discussed in Note 3 of our condensed consolidated financial statements included in Part 1 of this report.

Union Contract

As a result of the CNR acquisition, we assumed a collective bargaining agreement with the United Steel Workers of America (USWA) which expired effective December 1, 2006, covering approximately 135 of our field employees in West Virginia and Kentucky. We continued to operate under the terms of the collective bargaining agreement while negotiating with the USWA. Contract negotiations began in October 2006 and have been mediated by the Federal Mediation and Conciliation Service. On May 4, 2007, we presented the USWA leadership our last, best and final offer . On December 7, 2007, the USWA membership voted to reject our offer. The company declared impasse and, effective February 1, 2008 we implemented the terms of our offer with certain minor clarifications. On March 12, 2008, the USWA filed an Unfair Labor Practice Charge with the National Labor Relations Board (NLRB). We have responded to the charge and are awaiting the outcome from the NLRB. There have been no strikes, work stoppages or slowdowns since the expiration of the contract, although no assurances can be given that such actions will not occur.

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Results of Operations Three Months Ended March 31, 2008 vs. March 31, 2007

General. For the Current Quarter, Chesapeake had a net loss of $132 million, or $0.29 per diluted common share, on total revenues of $1.611 billion. This compares to net income of $258 million, or $0.50 per diluted common share, on total revenues of $1.580 billion during the Prior Quarter. The Current Quarter loss is due to an unrealized non-cash after-tax mark-to-market loss of $704 million related to future period natural gas and oil and interest rate hedges resulting primarily from higher natural gas and oil prices as of March 31, 2008 compared to December 31, 2007.

Natural Gas and Oil Sales. During the Current Quarter, natural gas and oil sales were $773 million compared to $1.125 billion in the Prior Quarter. In the Current Quarter, Chesapeake produced 204.2 bcfe compared to 153.7 bcfe produced in the Prior Quarter at weighted average prices for both quarters of $9.33 per mcfe (weighted average prices exclude the effect of unrealized losses on natural gas and oil derivatives of $1.132 billion and $309 million in the Current Quarter and Prior Quarter, respectively). Excluding unrealized gains or losses on natural gas and oil derivatives, increased production volume resulted in a $471 million increase in revenue in the Current Quarter. The increase in production from the Prior Quarter to the Current Quarter was primarily generated from the drillbit.

For the Current Quarter, we realized an average price per mcf of natural gas of $9.05, compared to $9.26 in the Prior Quarter (weighted average prices for both quarters discussed exclude the effect of unrealized gains or losses on derivatives). Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $74.73 and $61.13 in the Current Quarter and Prior Quarter, respectively. Realized gains or losses from our natural gas and oil derivatives resulted in a net increase in natural gas and oil revenues of $214 million, or $1.05 per mcfe, in the Current Quarter and $433 million, or $2.82 per mcfe, in the Prior Quarter.

Changes in natural gas and oil prices have a significant impact on our natural gas and oil revenues and cash flow. Assuming the Current Quarter production levels, a change of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $19 million and $18 million, respectively, and a change of $1.00 per barrel of oil sold would have resulted in an increase or decrease in revenues and cash flow of approximately $3 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,			
	2008		2007	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	105,928	52%	81,705	53%
Barnett Shale	37,973	18	16,155	11
Permian and Delaware Basins	19,796	10	12,706	8
South Texas and Texas Gulf Coast	18,890	9	19,144	13
Ark-La-Tex	13,777	7	12,860	8
Appalachian Basin [(a)]	7,884	4	11,080	7
Total production	204,248	100%	153,650	100%

(a) The Current Quarter results reflect the sale of 55 mmcfe per day of production in a volumetric production payment (VPP) transaction as of December 31, 2007.

Natural gas production represented approximately 92% of our total production volume on a natural gas equivalent basis in both the Current Quarter and the Prior Quarter.

Natural Gas and Oil Marketing Sales and Operating Expenses. Natural gas and oil marketing activities are substantially for third parties who are owners in Chesapeake-operated wells. Chesapeake realized $796 million in natural gas and oil marketing sales in the Current Quarter, with corresponding natural gas and oil marketing expenses of $774 million, for a net margin before depreciation of $22 million. This compares to sales of $422 million, expenses of $407 million and a net margin before depreciation of $15 million in the Prior Quarter. In the Current Quarter, Chesapeake realized an increase in natural gas and oil marketing sales volumes related to the increase in production on Chesapeake-operated wells.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. These operations have grown as a result of assets and businesses we acquired and leased. Chesapeake recognized $42 million in service operations revenue in the Current Quarter with corresponding service operations expense of $35 million, for a net margin before depreciation of $7 million. This compares to revenue of $33 million, expenses of $22 million and a net margin before depreciation of $11 million in the Prior Quarter.

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Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $201 million in the Current Quarter compared to $142 million in the Prior Quarter. On a unit-of-production basis, production expenses were $0.98 per mcfe in the Current Quarter compared to $0.93 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 2008 will range from $0.95 to $1.05 per mcfe produced.

Production Taxes. Production taxes were $75 million in the Current Quarter compared to $42 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.37 per mcfe in the Current Quarter compared to $0.27 per mcfe in the Prior Quarter. The $33 million increase in production taxes in the Current Quarter is due to an increase in production of 51 bcfe and an increase in the realized average sales price of natural gas and oil of $1.76 per mcfe (excluding gains or losses on derivatives).

In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas and oil prices are higher. We expect production taxes for 2008 to range from $0.35 to $0.40 per mcfe based on NYMEX prices ranging from $7.60 to $8.90 per mcf of natural gas and oil prices of $84.48 per barrel.

General and Administrative Expenses. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our natural gas and oil properties, were $79 million in the Current Quarter and $52 million in the Prior Quarter. General and administrative expenses were $0.39 and $0.34 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 $19 million and $10 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 and a higher stock price at the time of new grants. We anticipate that general and administrative expenses for 2008 will be between $0.43 and $0.49 per mcfe produced (including stock-based compensation ranging from $0.10 to $0.12 per mcfe).

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock. Prior to 2004, stock-based compensation awards were only in the form of stock options. Employee stock-based compensation awards generally vest over a period of four or five years. Our non-employee director awards vest over a period of three years.

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

Chesapeake follows the full-cost method of accounting under which all costs associated with natural gas and oil 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 $84 million and $51 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our natural gas and oil property acquisition, exploration and development efforts.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $515 million and $393 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 $2.52 and $2.56 in the Current Quarter and in the Prior Quarter, respectively. The $0.04 decrease in the average DD&A rate is primarily the result of our underlying reserve base growing faster than our capitalized costs and related future development costs. We expect the DD&A rate for 2008 to be between $2.50 and $2.70 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $36 million in the Current Quarter and the Prior Quarter. Depreciation and amortization of other assets was $0.18 and $0.23 per mcfe for the Current Quarter and the Prior Quarter, respectively. The decrease per mcfe in the Current Quarter was primarily due to higher production volume. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful

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lives of the assets, which range from two to seven years. To the extent company-owned drilling rigs and equipment are used to drill our wells, a substantial portion of the depreciation is capitalized in natural gas and oil properties as exploration or development costs. We expect 2008 depreciation and amortization of other assets to be between $0.20 and $0.24 per mcfe produced.

Interest and Other Income. Interest and other income was ($9) million in the Current Quarter compared to $9 million in the Prior Quarter. The Current Quarter income consisted of $2 million of interest income, ($12) million related to losses of equity investees and $1 million of miscellaneous income. The Prior Quarter income consisted of $2 million of interest income, $6 million related to earnings of equity investees and $1 million of miscellaneous income.

Interest Expense. Interest expense increased to $101 million in the Current Quarter compared to $79 million in the Prior Quarter as follows:

	Three Months Ended March 31,	
	2008	2007
	($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 167	$ 135
Capitalized interest	(86)	(64)
Realized (gain) loss on interest rate derivatives		2
Unrealized (gain) loss on interest rate derivatives	13	1
Amortization of loan discount and other	7	5
Total interest expense	$ 101	$ 79
Average long-term borrowings	$ 8,974	$ 7,324

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.43 per mcfe in the Current Quarter compared to $0.50 in the Prior Quarter. The decrease in interest expense per mcfe is due to increased production volumes. We expect interest expense for 2008 to be between $0.50 and $0.55 per mcfe produced (before considering the effect of interest rate derivatives).

Income Tax Expense. Chesapeake recorded an income tax benefit of $82 million in the Current Quarter, compared to income tax expense of $158 million in the Prior Quarter. Of the $240 million decrease in the Current Quarter, $239 million was the result of the decrease in net income before income taxes and $1 million was the result of an increase in the effective tax rate. Our effective income tax rate was 38.5% in the Current Quarter and 38% in the Prior Quarter. Our effective tax rate fluctuates as a result of the impact of state income taxes and permanent differences. Most of our 2007 income tax expense was deferred, and we expect most of our 2008 income tax expense to be deferred.

Critical Accounting Policies

We consider accounting policies related to hedging, natural gas and oil 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, 2007 (2007 Form 10-K).

Effective January 1, 2008, we adopted Statement of Financial Accounting Standards No. 157, *Fair Value Measurements* for our financial assets and liabilities measured on a recurring basis. This statement establishes a framework for measuring fair value of assets and liabilities and expands disclosures about fair value measurements. In February 2008, the FASB issued FSP 157-2, which delayed the effective date of SFAS No. 157 by one year for nonfinancial assets and liabilities.

SFAS 157 defines fair value as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To quantify an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the financial asset or liability and have the lowest priority. Chesapeake uses appropriate valuation techniques based on available inputs, including counterparty quotes to measure the fair values of its assets and liabilities. Counterparty quotes are generally assessed as a Level 3 input.

As of March 31, 2008, we had a net derivative liability of $2.232 billion, of which 65% was based on estimates provided by our respective counterparties and reviewed internally using established indexes and other sources and, as such, are classified as a Level 3 fair value measurement. The accounting applicable to our natural gas and oil derivative contracts is discussed in Note 2 and Note 9 of our condensed consolidated financial statements included in Part 1 of this report.

Recently Issued and Proposed Accounting Standards

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

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. 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. Since we have not elected to adopt the fair value option for eligible items, SFAS No. 159 has not had an impact on our financial position, results of operations or cash flows.

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In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of Accounting Research Bulletin No. 51*. This statement requires an entity to separately disclose non-controlling interests as a separate component of equity in the balance sheet and clearly identify on the face of the income statement net income related to non-controlling interests. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations*. This statement requires assets acquired and liabilities assumed to be measured at fair value as of the acquisition date, acquisition-related costs incurred prior to the acquisition to be expensed and contractual contingencies to be recognized at fair value as of the acquisition date. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*. This Statement changes the disclosure requirements for derivative instruments and hedging activities. The Statement requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We are currently assessing the impact that adoption of this statement will have on our financial position, results of operations or cash flows.

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

Forward-Looking Statements

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements give our current expectations or forecasts of future events. They include statements regarding natural gas and oil reserve estimates, planned capital expenditures, the drilling of natural gas and oil wells and future acquisitions, expected natural gas and oil 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 2007 Form 10-K and include:

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

the strength and financial resources of our competitors,

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

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

unsuccessful exploration and development drilling,

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

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

lower natural gas and oil 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***

Natural Gas and Oil Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for natural gas and oil. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of March 31, 2008, our natural gas and oil derivative instruments were comprised of swaps, basis protection swaps, knockout swaps, cap-swaps, call options and collars. These instruments allow us to predict with greater certainty the effective natural gas and oil 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.

Basis protection swaps are arrangements that guarantee a price differential for natural gas or oil from a specified delivery point. For Mid-Continent basis protection swaps, which typically 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 typically 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 knockout swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty s exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.

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

For 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.

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 natural gas and oil prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to natural gas and oil sales in the month of related production.

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

	Three Months Ended March 31,	
	2008	2007
	($ in millions)	
Natural gas and oil sales	$ 1,691	$ 1,001
Realized gains (losses) on natural gas and oil derivatives	214	433
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(1,067)	(255)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(65)	(54)
Total natural gas and oil sales	$ 773	$ 1,125

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As of March 31, 2008, we had the following open natural gas and oil derivative instruments (excluding derivatives assumed through our acquisition of CNR in November 2005) designed to hedge a portion of our natural gas and oil production for periods after March 2008:

	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, 2008 ($ in millions)
Natural Gas (bbtu):								
Swaps:								
2Q 2008	67,455	$ 8.18	$	$	$	Yes	$	$ (123)
3Q 2008	71,763	8.43				Yes		(133)
4Q 2008	64,102	9.03				Yes		(108)
1Q 2009	27,699	9.84				Yes		(33)
Q2 Q4 2009	80,439	8.58				Yes		(56)
2010	21,974	8.66				Yes		(13)
2011 2020	100,455	8.06				Yes		(78)
Basis Protection Swaps (Mid-Continent):								
2Q 2008	29,655				(0.33)	No		27
3Q 2008	40,440				(0.52)	No		25
4Q 2008	40,010				(0.48)	No		38
Q1 2009	34,530				(0.51)	No		23
Q2 Q4 2009	71,240				(0.39)	No		46
2010	13,000				(1.03)	No		
2011 2018	76,180				(0.93)	No		(16)
Basis Protection Swaps (Appalachian Basin):								
2Q 2008	5,783				0.33	No		(1)
3Q 2008	5,763				0.33	No		
4Q 2008	5,840				0.33	No		
Q1 2009	3,849				0.29	No		(1)
Q2 Q4 2009	13,064				0.28	No		(2)
2010	10,199				0.26	No		(1)
2011	12,086				0.25	No		(1)
2012 2022	134				0.11	No		
Other Swaps:								
2Q 2008	6,050	8.47				No		(8)
3Q 2008	4,600	8.73				No		(7)
4Q 2008	4,600	8.73				No		(9)
Q1 2009[(a)]	22,750	8.73				No		(33)
2010[(a)]	18,250	8.73				No		(19)
Knockout Swaps:								
2Q 2008	60,380	9.15	6.21			No		(49)
3Q 2008	62,560	9.32	6.21			No		(63)
4Q 2008	63,810	9.98	6.23			No		(57)
Q1 2009	71,100	10.15	6.23			No		(92)
Q2 Q4 2009	209,000	9.12	6.09			No		(156)
2010	109,500	9.51	6.13			No		(45)
Call Options:								
2Q 2008	27,050			10.12		No	21	(15)
3Q 2008	32,200			10.25		No	21	(33)

4Q 2008	43,760		10.06	No	21	(61)
Q1 2009	51,300		11.19	No	32	(77)
Q2 Q4 2009	146,670		11.21	No	90	(107)
2010	156,950		10.68	No	94	(143)
2011	83,950		10.27	No	53	(68)
2012	14,640		11.50	No	7	(11)
Collars:						
2Q 2008	2,730	7.50	9.68	Yes		(2)
3Q 2008	2,760	7.50	9.68	Yes		(3)
4Q 2008	2,760	7.50	9.68	Yes		(5)

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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, 2008 ($ in millions)
Other Collars:								
2Q 2008	8,190	$	$ 8.53	$ 10.00	$	No	$ 5	$ (3)
3Q 2008	8,280		8.53	10.00		No	5	(7)
4Q 2008	6,450		8.50	10.00		No	5	(8)
Q1 2009	11,250		5.70/8.14	10.82		No	(4)	(17)
Q2 Q4 2009	34,375		5.70/8.14	10.82		No	(11)	(6)
Total Natural Gas							339	(1,511)
Oil (mbbls):								
Swaps:								
2Q 2008	865	71.29				Yes		(32)
3Q 2008	935	72.17				Yes		(31)
4Q 2008	598	64.60				Yes		(19)
Q1 2009	135	68.02				Yes		(4)
Q2 Q4 2009	412	67.77				Yes		(11)
Knockout Swaps:								
2Q 2008	758	80.22	56.58			No		(15)
3Q 2008	828	81.64	56.83			No		(15)
4Q 2008	1,012	81.50	57.41			No		(17)
Q1 2009	1,935	83.41	57.74			No		(29)
Q2 Q4 2009	5,913	85.54	58.21			No		(89)
2010	4,015	87.34	60.00			No		(50)
2011	365	98.25	60.00			No		(2)
Cap-Swaps:								
2Q 2008	273	77.60	55.00			No		(6)
3Q 2008	276	77.60	55.00			No		(6)
4Q 2008	276	77.60	55.00			No		(6)
Call Options:								
2Q 2008	637			83.57		No	2	(11)
3Q 2008	644			83.57		No	2	(11)
4Q 2008	828			81.67		No	3	(16)
Q1 2009	630			82.14		No	3	(13)
Q2 Q4 2009	1,925			82.14		No	9	(40)
2010	2,555			96.43		No	10	(43)
Other Collars:								
2010	730		90.00/80.00	136.40		No		
Total Oil							29	(466)
Total Natural Gas and Oil							$ 368	$ (1,977)

(a) These include options to extend an existing swap for an additional 12 months at 50,000 mmbtu/day at $8.73/mmbtu. The options are callable by the counterparty in March 2009 and March 2010.

Since 2006, Chesapeake has lifted a portion of its 2008 through 2022 hedges and had approximately $52 million of deferred hedging gains as of March 31, 2008. These gains have been recorded in accumulated other comprehensive income or as an unrealized gain in natural gas and oil sales. For amounts originally recorded in other comprehensive income, the gain will be recognized in natural gas and oil sales in the month of

the hedged production.

We assumed certain liabilities related to open derivative positions in connection with our acquisition of Columbia Natural Resources, LLC in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million. The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair

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value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our natural gas and oil revenues upon settlement. For example, if the fair value of the derivative positions assumed does not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to natural gas and oil 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 natural gas and oil 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, 2008:

	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, 2008 ($ in millions)
Natural Gas (bbtu):						
Swaps:						
2Q 2008	9,555	$ 4.68	$	$	Yes	$ (50)
3Q 2008	9,660	4.68			Yes	(54)
4Q 2008	9,660	4.66			Yes	(57)
Q1 2009	4,500	5.18			Yes	(26)
Q2 Q4 2009	13,750	5.18			Yes	(55)
Collars:						
Q1 2009	900		4.50	6.00	Yes	(4)
Q2 Q4 2009	2,750		4.50	6.00	Yes	(9)
Total Natural Gas						$ (255)

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, 2008.

Based upon the market prices at March 31, 2008, we expect to transfer approximately $311 million (net of income taxes) of the loss 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, 2008 are expected to mature by December 31, 2022.

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

	2008 ($ in millions)
Fair value of contracts outstanding, as of January 1	$ (369)
Change in fair value of contracts	(1,548)
Fair value of contracts when entered into	(109)
Contracts realized or otherwise settled	(214)
Fair value of contracts when closed	8

Fair value of contracts outstanding, as of March 31	$ (2,232)

The change in the fair value of our derivative instruments since January 1, 2008 resulted from new contracts entered into, the settlement of derivatives for a realized gain, as well as an increase in natural gas prices. Derivative instruments reflected as current in the 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 natural gas and oil as of the consolidated balance sheet date. The derivative settlement amounts are not due and payable until the month in which the related underlying hedged transaction occurs.

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Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates. As of March 31, 2008, the fair value of the fixed-rate long-term debt has been estimated based on quoted market prices.

	Years of Maturity						
	2008	2009	2010	2011	2012	Thereafter	Total
	($ in billions)						
Liabilities:							
Long-term debt fixed-rate[(a)]	$	$	$	$	$	$ 9.122	$ 9.122
Average interest rate						5.8%	5.8%
Long-term debt variable rate	$	$	$	$	$ 3.164	$	$ 3.164
Average interest rate					3.7%		3.7%

(a) This amount does not include the discount included in long-term debt of ($102) million and the impact of interest rate derivatives of $66 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 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.

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 a nominal amount and ($2) million in the Current Quarter and the Prior Quarter. Unrealized gains (losses) included in interest expense were ($13) million and ($1) million in the Current Quarter and the Prior Quarter.

As of March 31, 2008, the following interest rate derivatives were outstanding:

		Notional Amount ($ in millions)	Weighted Average Fixed Rate	Weighted Average Floating Rate	Weighted Average Cap/Floor Rate	Fair Value Hedge	Net Premiums ($ in millions)	Fair Value ($ in millions)
Fixed to Floating Swaps:								
January 2008	November 2020	$ 800	7.195%	6 month LIBOR plus 328 basis points		Yes	$	$ (8)
January 2008	January 2018	$ 250	6.25%	6 month LIBOR plus 190 basis points		No		5
Floating to Fixed Swaps:								
August 2007	August 2010	$ 825	4.737%	3 month LIBOR		No		(32)

Call Options:									
January 2008	July 2010	$	500	6.563%			No	5	(11)
Collars:									
August 2007	August 2010	$	800		5.37%	4.52%	No		(34)
								$ 5	$ (80)

In the Current Quarter, we sold call options on two of our interest rate swaps and received $5 million in premiums. Three options were exercised in the Current Quarter resulting in the termination of three interest rate swaps.

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In the Current Quarter, we closed 17 interest rate swaps for a gain totaling $48 million. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to realized interest expense over the remaining term of the related senior notes.

Foreign Currency Derivatives

On December 6, 2006, we issued 600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties pay Chesapeake 19 million and Chesapeake pays the counterparties $30 million, which yields 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 ($948 million at March 31, 2008) using an exchange rate of $1.5805 to 1.00. The fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as an asset of $80 million at March 31, 2008.

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 2007 Form 10-K. 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 2007 Form 10-K. 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, 2008:

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, 2008 through January 31, 2008	430,523	$ 40.260		
February 1, 2008 through February 29, 2008	6,540	45.209		
March 1, 2008 through March 31, 2008	11,965	45.781		
Total	449,028	$ 40.479		

(a) Includes the deemed surrender to the company of 3,749 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 445,279 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:

		Incorporated by Reference				
Exhibit Number	**Exhibit Description**	**Form**	**SEC File Number**	**Exhibit**	**Filing Date**	**Filed Herewith**
3.1.1	Chesapeake s Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	08/09/2006	
3.1.2	Certificate of Designation for Series A Junior Participating Preferred Stock, as amended.	10-Q	001-13726	3.1.2	08/09/2006	
3.1.3	Certificate of Designation of 4.125% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.3	05/08/2007	
3.1.4	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B) as amended.					X
3.1.5	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended.	10-K	001-13726	3.1.5	02/29/2008	
3.1.6	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock.	8-K	001-13726	3.1	09/15/2005	
3.1.7	Certificate of Designation of 6.25% Mandatory Convertible Preferred Stock, as amended.	10-K	001-13726	3.1.7	02/29/2008	
3.2	Chesapeake s Amended and Restated Bylaws.	8-K	001-13726	3.1	06/13/2007	
12	Ratios of Earnings to Fixed Charges and Preferred Dividends.					X
31.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
32.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X

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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 12, 2008

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INDEX TO EXHIBITS

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3.1.3	Certificate of Designation of 4.125% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.3	05/08/2007	
3.1.4	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B) as amended.					X
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