CHESAPEAKE ENERGY CORP
Form 10-Q
May 11, 2009
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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, 2009

¨ **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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ¨ 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 7, 2009, there were 626,171,207 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, 2009	December 31, 2008 (Adjusted)
	($ in millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 83	$ 1,749
Accounts receivable	1,185	1,324
Short-term derivative instruments	1,446	1,082
Other	139	137
Total Current Assets	2,853	4,292
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full-cost accounting:		
Evaluated natural gas and oil properties	32,861	28,965
Unevaluated properties	9,542	11,379
Less: accumulated depreciation, depletion and amortization of natural gas and oil properties	(21,909)	(11,866)
Total natural gas and oil properties, at cost based on full-cost accounting	20,494	28,478
Other property and equipment:		
Natural gas gathering systems and treating plants	3,129	2,717
Buildings and land	1,582	1,513
Drilling rigs and equipment	516	430
Natural gas compressors	191	184
Other	499	482
Less: accumulated depreciation and amortization of other property and equipment	(555)	(496)
Total Other Property and Equipment	5,362	4,830
Total Property and Equipment	25,856	33,308
OTHER ASSETS:		
Investments	378	444
Long-term derivative instruments	275	261
Other assets	299	288
Total Other Assets	952	993
TOTAL ASSETS	$ 29,661	$ 38,593

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(Unaudited)

LIABILITIES AND STOCKHOLDERS EQUITY	March 31, 2009	December 31, 2008 (Adjusted)
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$ 1,424	$ 1,611
Short-term derivative instruments	107	66
Accrued liabilities	826	880
Deferred income taxes	491	358
Income taxes payable	16	108
Revenues and royalties due others	343	431
Accrued interest	155	167
Total Current Liabilities	3,362	3,621
LONG-TERM LIABILITIES:		
Long-term debt, net	12,933	13,175
Deferred income tax liabilities	800	4,200
Asset retirement obligations	275	269
Long-term derivative instruments	271	111
Revenues and royalties due others	54	49
Other liabilities	148	151
Total Long-Term Liabilities	14,481	17,955
CONTINGENCIES AND COMMITMENTS (Note 3)		
STOCKHOLDERS EQUITY:		
Preferred Stock, $0.01 par value, 20,000,000 shares authorized:		
4.50% cumulative convertible preferred stock, 2,558,900 shares issued and outstanding as of March 31, 2009 and December 31, 2008, entitled in liquidation to $256 million	256	256
5.00% cumulative convertible preferred stock (series 2005B), 2,095,615 shares issued and outstanding as of March 31, 2009 and December 31, 2008, entitled in liquidation to $209 million	209	209
6.25% mandatory convertible preferred stock, 143,768 shares issued and outstanding as of March 31, 2009 and December 31, 2008, entitled in liquidation to $36 million	36	36
4.125% cumulative convertible preferred stock, 0 and 3,033 shares issued and outstanding as of March 31, 2009 and December 31, 2008, respectively, entitled in liquidation to $0 and $3 million		3
5.00% cumulative convertible preferred stock (series 2005), 5,000 shares issued and outstanding as of March 31, 2009 and December 31, 2008, entitled in liquidation to $1 million	1	1
Common Stock, $0.01 par value, 750,000,000 shares authorized, 625,455,108 and 607,953,437 shares issued at March 31, 2009 and December 31, 2008, respectively	6	6
Paid-in capital	11,910	11,680
Retained earnings (deficit)	(1,171)	4,569
Accumulated other comprehensive income (loss), net of tax of ($355) million and ($163) million, respectively	582	267
Less: treasury stock, at cost; 719,546 and 657,276 common shares as of March 31, 2009 and December 31, 2008, respectively	(11)	(10)
Total Stockholders Equity	11,818	17,017

TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 29,661	$ 38,593

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, 2009	Three Months Ended March 31, 2008 (Adjusted)
	($ in millions except per share data)	
REVENUES:		
Natural gas and oil sales	$ 1,397	$ 773
Natural gas and oil marketing sales	552	796
Service operations revenue	46	42
Total Revenues	1,995	1,611
OPERATING COSTS:		
Production expenses	238	201
Production taxes	23	75
General and administrative expenses	90	79
Natural gas and oil marketing expenses	523	774
Service operations expense	40	35
Natural gas and oil depreciation, depletion and amortization	447	515
Depreciation and amortization of other assets	57	36
Impairment of natural gas and oil properties and other assets	9,630	
Total Operating Costs	11,048	1,715
INCOME (LOSS) FROM OPERATIONS	(9,053)	(104)
OTHER INCOME (EXPENSE):		
Other income (expense)	8	(9)
Interest expense	14	(99)
Impairment of investments	(153)	
Total Other Income (Expense)	(131)	(108)
INCOME (LOSS) BEFORE INCOME TAXES	(9,184)	(212)
INCOME TAX EXPENSE (BENEFIT):		
Current		
Deferred	(3,444)	(82)
Total Income Tax Expense (Benefit)	(3,444)	(82)
NET INCOME (LOSS)	(5,740)	(130)
PREFERRED STOCK DIVIDENDS	(6)	(12)
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$ (5,746)	$ (142)
EARNINGS (LOSS) PER COMMON SHARE:		

Basic	$ (9.63)	$ (0.29)
Assuming dilution	$ (9.63)	$ (0.29)
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.075	$ 0.0675
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):		
Basic	597	493
Assuming dilution	597	493

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, 2009	Three Months Ended March 31, 2008 (Adjusted)
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME (LOSS)	$ (5,740)	$ (130)
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	504	551
Deferred income taxes	(3,444)	(82)
Unrealized (gains) losses on derivatives	(145)	1,145
Realized (gains) losses on financing derivatives	(19)	(12)
Stock-based compensation	34	29
Loss from equity investments	1	
Impairments	9,783	
Other	25	31
Change in assets and liabilities	262	(17)
Cash provided by operating activities	1,261	1,515
CASH FLOWS FROM INVESTING ACTIVITIES:		
Exploration and development of natural gas and oil properties	(1,347)	(1,406)
Acquisitions of natural gas and oil companies, proved and unproved properties and leasehold, net of cash acquired	(413)	(1,021)
Divestitures of proved and unproved properties and leasehold		243
Additions to other property and equipment	(667)	(551)
Additions to investments	(8)	(9)
Proceeds from sale of drilling rigs and equipment		34
Proceeds from sale of compressors	68	17
Sale of other assets		1
Cash used in investing activities	(2,367)	(2,692)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from credit facility borrowings	1,575	2,591
Payments on credit facility borrowings	(3,120)	(1,377)
Proceeds from issuance of senior notes, net of offering costs	1,346	
Cash paid for common stock dividends	(44)	(33)
Cash paid for preferred stock dividends	(6)	(12)
Derivative settlements	1	(33)
Net increase (decrease) in outstanding payments in excess of cash balance	(287)	44
Excess tax benefit from stock-based compensation		11
Cash paid for repurchase of treasury stock	(1)	
Cash received from exercise of stock options	1	4
Other financing costs	(25)	(18)
Cash provided by (used in) financing activities	(560)	1,177

Net increase (decrease) in cash and cash equivalents		(1,666)		
Cash and cash equivalents, beginning of period		1,749		1
Cash and cash equivalents, end of period	$	83	$	1

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, 2009	Three Months Ended March 31, 2008 (Adjusted)
	($ in millions)	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:		
Interest, net of capitalized interest	$ 25	$ 114
Income taxes, net of refunds received	$ 114	$ 4
SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:		

As of March 31, 2009 and 2008, dividends payable on our common and preferred stock were $51 million and $53 million, respectively.

For the three months ended March 31, 2009 and 2008, natural gas and oil properties were adjusted by a nominal amount and $13 million, respectively, for net income tax liabilities related to acquisitions.

For the three months ended March 31, 2009 and 2008, natural gas and oil properties were adjusted by ($62) million and ($6) million, respectively, as a result of an increase (decrease) in accrued exploration and development costs.

For the three months ended March 31, 2009 and 2008, other property and equipment were adjusted by $13 million and $8 million, respectively, as a result of an increase (decrease) in accrued costs.

We recorded non-cash asset additions to natural gas and oil properties of $2 million and $3 million for the three months ended March 31, 2009 and 2008, respectively, for asset retirement obligations.

On March 31, 2009, we converted all of our outstanding 4.125% cumulative convertible preferred stock (3,033 shares) into 182,887 shares of common stock at a conversion price of $16.584 per share.

For the three months ended March 31, 2009, we issued 14,360,642 shares of common stock, valued at $240 million, for the purchase of leasehold and unproved properties pursuant to an acquisition shelf registration statement.

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, 2009	Three Months Ended March 31, 2008 (Adjusted)
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning of period	$ 505	$ 960
Exchange of common stock for 3,033 and 0 shares of 4.125% preferred stock	(3)	
Balance, end of period	502	960
COMMON STOCK:		
Balance, beginning of period	6	5
Exchange of 182,887 and 0 shares of common stock for preferred stock		
Balance, end of period	6	5
PAID-IN CAPITAL:		
Balance, beginning of period	11,680	7,532
Issuance of common stock for the purchase of leasehold and unproved properties	232	
Stock-based compensation	53	34
Exercise of stock options	1	4
Dividends on common stock	(45)	
Dividends on preferred stock	(6)	
Exchange of 182,887 and 0 shares of common stock for preferred stock	3	
Tax benefit (reduction in tax benefit) from exercise of stock options and restricted stock	(8)	11
Balance, end of period	11,910	7,581
RETAINED EARNINGS (DEFICIT):		
Balance, beginning of period	4,569	4,144
Net income (loss)	(5,740)	(130)
Dividends on common stock		(33)
Dividends on preferred stock		(12)
Balance, end of period	(1,171)	3,969
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	267	(11)
Hedging activity	266	(533)
Marketable securities activity	49	1
Balance, end of period	582	(543)
TREASURY STOCK COMMON:		
Balance, beginning of period	(10)	(6)
Purchase of 64,242 shares for company benefit plans	(1)	

Release of 1,972 and 1,098 shares for company benefit plans		
Balance, end of period	(11)	(6)
TOTAL STOCKHOLDERS EQUITY	$ 11,818	$ 11,966

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, 2009	Three Months Ended March 31, 2008 (Adjusted)
	($ in millions)	
Net income (loss)	$ (5,740)	$ (130)
Other comprehensive income (loss), net of income tax:		
Change in fair value of derivative instruments, net of income taxes of $296 million and ($303) million	484	(492)
Reclassification of (gain) loss on settled contracts, net of income taxes of ($112) million and ($51) million	(184)	(82)
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of ($21) million and $25 million	(34)	41
Unrealized (gain) loss on marketable securities, net of income taxes of $4 million and $1 million	6	1
Reclassification of loss on marketable securities, net of income taxes of $26 million and $0	43	
Comprehensive income (loss)	$ (5,425)	$ (662)

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, 2008 (2008 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, 2009 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, 2009 (the Current Quarter) and the three months ended March 31, 2008 (the Prior Quarter).

Change in Accounting Principle

On January 1, 2009, we adopted and applied retrospectively FASB Staff Position No. APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion*. As a result, our prior year condensed consolidated financial statements have been retrospectively adjusted. See Note 6 for additional information on the application of this accounting principle.

Natural Gas and Oil Properties Ceiling Test

We review the carrying value of our natural gas and oil properties under the full-cost accounting rules of the Securities and Exchange Commission on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. As of March 31, 2009, capitalized costs of natural gas and oil properties exceeded the estimated present value of future net revenues from our proved reserves, net of related income tax considerations, resulting in a write-down in the carrying value of natural gas and oil properties of $9.6 billion. In calculating future net revenues, current prices and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. Based on spot prices for natural gas and oil as of March 31, 2009, these cash flow hedges increased the full-cost ceiling by $1.651 billion, thereby reducing the ceiling test write-down by the same amount. Our qualifying cash flow hedges as of March 31, 2009, which consisted of swaps and collars, covered 292 bcfe, 78 bcfe and 11 bcfe in 2009, 2010 and 2011, respectively. Our natural gas and oil hedging activities are discussed in Note 2 of these condensed consolidated financial statements. Further decreases in market prices from March 31, 2009 levels, as well as changes in production rates, levels of reserves, the evaluation of costs excluded from amortization, future development costs and service costs could result in future ceiling test impairments.

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 2008 Form 10-K.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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. 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. As of March 31, 2009, our natural gas and oil derivative instruments were comprised of the following:

For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays a floating market price to the counterparty.

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.

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.

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

Basis protection swaps are arrangements that guarantee a price differential to NYMEX 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.

All of our derivative instruments are net settled based on the difference between the fixed-price payment and the floating-price payment, resulting in a net amount due to or from the counterparty.

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.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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, 2009	2008
	($ in millions)	
Natural gas and oil sales	$ 778	$ 1,690
Realized gains (losses) on natural gas and oil derivatives	519	215
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	46	(1,067)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	54	(65)
Total natural gas and oil sales	$ 1,397	$ 773

The estimated fair values of our natural gas and oil derivative instruments as of March 31, 2009 and December 31, 2008 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	March 31, 2009	December 31, 2008
	($ in millions)	
Derivative assets (liabilities)[(a)]:		
Fixed-price natural gas swaps	$ 905	$ 863
Fixed-price natural gas collars	789	402
Fixed-price natural gas knockout swaps	40	141
Natural gas call options	(178)	(178)
Natural gas put options	(79)	(39)
Natural gas basis protection swaps	(29)	93
Fixed-price oil swaps	13	31
Fixed-price oil knockout swaps	42	19
Fixed-price oil cap-swaps	2	3
Oil call options	(24)	(35)
Fixed-price oil collars		5
Estimated fair value	$ 1,481	$ 1,305

(a) After adjusting for $558 million and $736 million of unrealized premiums, the value to be realized for these derivatives as of March 31, 2009 and December 31, 2008 was $2.039 billion and $2.041 billion, respectively.

The fair values shown above have the following associated volumes as of March 31, 2009 and December 31, 2008:

	March 31, 2009	December 31, 2008
Natural Gas and Oil Volume Hedged:		
Natural Gas (bbtu)		
Fixed-price natural gas swaps	328,175	466,800
Fixed-price natural gas collars	384,265	457,715
Fixed-price natural gas knockout swaps	98,670	532,660
Natural gas call options	609,470	551,555
Natural gas put options	64,000	73,000
Natural gas basis protection swaps	188,764	219,487
Total gas volume	1,673,344	2,301,217
Oil (mbbls)		
Fixed-price oil swaps	(369)	(310)
Fixed-price oil knockout swaps	9,512	12,248
Fixed-price oil cap-swaps	182	362
Oil call options	18,095	19,355
Fixed-price oil collars		730
Total oil volume	27,420	32,385

To mitigate our exposure to the fluctuation in prices of diesel fuel, we have entered into diesel swaps from April 2009 to March 2010 for a total of 41,475,000 gallons with an average fixed price of $1.60 per gallon. The fair value of these swaps as of March 31, 2009 was a liability of $3 million.

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 or 1.5 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 any additional 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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 fair value of outstanding transactions, per annum exposure fees and the scheduled maturity dates are shown below.

	Secured Hedging Facilities[a]					
	#1	#2	#3	#4	#5	#6
	($ in millions)					
Fair value of outstanding transactions, as of March 31, 2009	$ 165	$ 584	$ 76	$ (3)	$ 98	$ 136
Per annum exposure fee	1%	1%	0.8%	0.8%	0.8%	0.8%
Scheduled maturity date	2010	2013	2020	2012	2012	2012

(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.

Interest Rate Derivatives

We use interest rate derivatives to mitigate our exposure to volatility in interest rates related to our senior notes and credit facility. 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 $7 million and a nominal amount in the Current Quarter and the Prior Quarter, respectively. Unrealized gains (losses) included in interest expense were $45 million and ($13) million in the Current Quarter and the Prior Quarter, respectively.

As of March 31, 2009, the following interest rate derivatives were outstanding:

	Notional Amount ($ in millions)	Weighted Average Fixed Rate	Weighted Average Floating Rate[b]	Fair Value Hedge	Net Premiums ($ in millions)	Fair Value ($ in millions)
Fixed to Floating Interest Rate:						
Swaps						
January 2008 November 2020	$ 500	6.875%	6 mL plus 230 bp	Yes	$	$ 66
April 2008 August 2015	$ 250	6.50%	6 mL plus 240 bp	No	$	$ 20
Call Options						
May 2009 August 2009	$ 750	6.75%	6 mL plus 233 bp	No	$ 9	$ (77)

Floating to Fixed Interest Rate:											
Swaps											
August 2007	July 2012	$	1,375	4.20%	1 - 6 mL	No	$		$	(47)
Collars[(a)]											
August 2007	August 2010	$	250	4.52%	6 mL	No	$		$	(10)
Swaption											
August 2009		$	500	2.56%	1 mL	No	$	5	$	(12)
							$	14	$	(60)

(a) The collars have ceiling and floor fixed interest rates of 5.37% and 4.52%, respectively.

(b) Month LIBOR has been abbreviated mL and basis points has been abbreviated bp .

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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(Unaudited)

In the Current Quarter, we closed interest rate derivatives for gains totaling $12 million of which $7 million was recognized in interest expense. The remaining $5 million was from interest rate derivatives 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 ranging from eight to nine years.

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 ($796 million at March 31, 2009) using an exchange rate of $1.3261 to 1.00. The fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as a liability of $74 million at March 31, 2009.

Disclosures About Derivative Instruments and Hedging Activities

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. The following table sets forth the fair value of each classification of derivative instrument as of March 31, 2009:

	March 31, 2009 Balance Sheet Location		Fair Value ($ in millions)
ASSET DERIVATIVES:			
Derivatives designated as hedging instruments under SFAS 133:			
Interest rate contracts	Long-term derivative instruments	$	66
Commodity contracts	Short-term derivative instruments		958
Commodity contracts	Long-term derivative instruments		138
Total		$	1,162
Derivatives not designated as hedging instruments under SFAS 133:			
Interest rate contracts	Long-term derivative instruments	$	20
Commodity contracts	Short-term derivative instruments		658
Commodity contracts	Long-term derivative instruments		138
Total		$	816
LIABILITY DERIVATIVES:			
Derivatives designated as hedging instruments under SFAS 133:			
Foreign exchange contracts	Long-term derivative instruments		74

Commodity contracts	Short-term derivative instruments		8
Total		$	82
Derivatives not designated as hedging instruments under SFAS 133:			
Interest rate contracts	Short-term derivative instruments	$	96
Interest rate contracts	Long-term derivative instruments		50
Commodity contracts	Short-term derivative instruments		173
Commodity contracts	Long-term derivative instruments		234
Total		$	553

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

A consolidated summary of the effect of derivative instruments on the condensed consolidated statement of operations for the three months ended March 31, 2009 is provided below, separating fair value, cash flow and non-qualifying hedges (as defined by SFAS 133).

The following table presents the gain (loss) recognized in net income (loss) for instruments designated as fair value hedges:

Fair Value Derivatives	Location of Gain (Loss)	Gain (Loss) ($ in millions)
Interest rate contracts	Interest expense[(a)]	$ 8

The following table presents the pre-tax gain (loss) recognized in, and reclassified from, accumulated other comprehensive income (AOCI) and recognized in net income (loss), including any hedge ineffectiveness, for derivative instruments classified as cash flow hedges:

Cash Flow Derivatives	Gain (Loss) Recognized in AOCI (Effective Portion)	Location of Gain (Loss) Reclassified from AOCI (Effective Portion)	Gain (Loss) Reclassified from AOCI (Effective Portion)	Location of Gain (Loss) Recognized (Ineffective Portion)	Gain (Loss) Recognized (Ineffective Portion)[(b)]
Commodity contracts	$ 682	Natural gas and oil sales	$ 296	Natural gas and oil sales	$ 54
Foreign exchange contracts	43	Other income		Other income	
Total	$ 725		$ 296		$ 54

Based upon the market prices at March 31, 2009, we expect to transfer approximately $640 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to net income (loss) during the next 12 months in the related month of production. All transactions hedged as of March 31, 2009 are expected to mature by December 31, 2022.

The following table presents the gain (loss) recognized in net income (loss) for derivatives not designated under SFAS 133:

Non SFAS 133 Derivatives	Location of Gain (Loss)	Gain (Loss) ($ in millions)
Commodity contracts	Natural gas and oil sales	$ 269
Interest rate contracts	Interest expense	44
	Total	$ 313

(a) Interest expense on the hedged item for the current period was $13 million, which is included in the line Interest expense on the condensed consolidated statement of operations.

(b) The amount of gain (loss) recognized in net income (loss) represents the ineffective portion of the hedging relationships and none related to the amount excluded from the assessment of hedge effectiveness.

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, and we attempt to limit our exposure to non-performance by any single counterparty. On March 31, 2009, our commodity and interest rate derivative instruments were spread among 15 counterparties.

On September 15, 2008, Lehman Brothers Holdings Inc. (Lehman) filed for protection under Chapter 11 of the federal Bankruptcy Code in the United States Bankruptcy Court in the Southern District of New York. Chesapeake and its subsidiaries had certain business relationships with Lehman and its subsidiaries.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Lehman Brothers Commercial Bank (LBCB), a subsidiary of Lehman, had $75 million of the $3.5 billion in commitments under our revolving bank credit facility. Although LBCB, to date, has not filed for bankruptcy (to our knowledge), LBCB had not funded approximately $13 million of its share of our borrowings under the credit facility as of March 31, 2009 and we have no reason to expect that LBCB will fund borrowings in the future. The loss of up to $75 million in borrowing capacity is not material to us.

Chesapeake was a counterparty with Lehman Brothers Commodity Services Inc. (LBCS), a subsidiary of Lehman, in financial transactions. Specifically, we utilized LBCS as a counterparty to hedge a portion of our natural gas and oil production. The obligations of LBCS are guaranteed by Lehman, and the Lehman bankruptcy filing resulted in an event of default under our ISDA agreement with LBCS allowing us to terminate the ISDA on September 18, 2008, and cancel the outstanding transactions. The potential loss associated with the termination of such transactions is not material to us.

Chesapeake will continue to closely monitor the Lehman bankruptcy situation and will assert its rights under the various contractual relationships. We believe the Lehman bankruptcy and its potential impact on subsidiaries of Lehman will not have a material adverse effect on Chesapeake or its subsidiaries individually or collectively.

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 monitor the creditworthiness of all our counterparties. 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. During the Current Quarter, we recognized an $8 million bad debt expense related potentially to uncollectible receivables.

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 filed in 2003 in the Circuit Court for Roane County, West Virginia 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, 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. 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. The defendants appealed the judgment and on May 22, 2008, the West Virginia Supreme Court of Appeals refused to hear the appeal. On October 22, 2008, the parties in the *Tawney* matter entered into a settlement agreement providing for the establishment of a settlement fund of $380 million. The Circuit Court for Roane County, West Virginia approved the settlement following a fairness hearing on November 22, 2008, and entered an order to discharge the judgment on January 21, 2009. Chesapeake s share of the settlement fund was approximately $41 million, which amount had previously been fully reserved. The Circuit Court retains continuing jurisdiction over the case during the claims administration process in which the settlement amount is distributed to the members of the plaintiff class.

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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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 expires on December 31, 2013 unless extended. The agreement contains a cap on cash salary and bonus compensation for the next five years at 2008 levels. 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. The agreement also provides for a one-time $75 million well cost incentive award with a five-year clawback. The well cost incentive award was fully applied against Mr. McClendon s obligations under the Founder Well Participation Program as of March 31, 2009. 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, 2009.

Rig Leases

In a series of transactions in 2006, 2007 and 2008, our drilling subsidiaries sold 83 drilling rigs and related equipment for $677 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 lease payments of approximately $95 million annually. The lease obligations are guaranteed by Chesapeake and its other material restricted 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 can exercise an early purchase option after six or seven years 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 lease equal to the fair market rental value of the rigs as determined at the time of renewal. As of March 31, 2009, Chesapeake s drilling subsidiaries had committed to acquire 11 rigs by the end of 2009 and had incurred costs of $68 million as of that date. The total remaining cost of the rigs is estimated to be approximately $83 million. Our intent is to sell and lease back those rigs as they are delivered if acceptable leasing arrangements are available to us. Commitments related to rig lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of March 31, 2009, the minimum aggregate future rig lease payments were approximately $597 million.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Compressor Leases

In a series of transactions in 2007, 2008 and 2009, our compression subsidiary sold a significant portion of its compressor fleet, consisting of 1,685 compressors, for $372 million and entered into a master lease agreement. The term of the agreement varies by buyer ranging from seven to ten years for aggregate lease payments of approximately $46 million annually. The lease obligations are guaranteed by Chesapeake and its other material restricted 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 leases, we can exercise an early purchase option after five 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. As of March 31, 2009, 466 new compressors are on order for approximately $179 million and our intent is to sell and lease back those compressors as they are delivered if acceptable leasing arrangements are available to us. Commitments related to compressor lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of March 31, 2009, the minimum aggregate future compressor lease payments were approximately $379 million.

Transportation Contracts

Chesapeake has various firm pipeline transportation service agreements with expiration dates ranging from 2009 to 2099. 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. The aggregate amounts of such required demand payments as of March 31, 2009, excluding demand charges for pipeline projects that are currently seeking regulatory approval, were as follows ($ in millions):

2009	$ 170
2010	219
2011	193
2012	184
2013	166
After 2013	885
Total	$ 1,817

Drilling Contracts

Currently, Chesapeake has contracts with various drilling contractors to lease approximately 32 rigs with terms of one to three years. These commitments are not recorded in the accompanying consolidated balance sheets. As of March 31, 2009, the aggregate drilling rig commitment was approximately $235 million.

Natural Gas and Oil Purchase Obligations

Our midstream 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 purchasers of our volumetric production payment transactions (VPPs) that we will purchase natural gas and oil associated with the VPPs. Our VPP purchase commitments extend over 11 to 15 year terms based on market prices at the time of production. As of March 31, 2009, we were obligated to purchase 438 bcfe under the terms of the VPPs. We resell the natural gas and oil we purchase at market prices.

Other Commitments

We own a 49% interest in Mountain Drilling Company, a company that specializes in hydraulic drilling rigs which are designed for drilling in urban areas. Due to a meaningful decline in the overall activity in the drilling market and poor operating performance of Mountain Drilling Company, we determined that an impairment had occurred and we fully impaired our investment at March 31, 2009. Chesapeake has an agreement to lend Mountain Drilling Company up to $19 million through December 31, 2009. At March 31, 2009, Mountain Drilling owed Chesapeake $19 million under this agreement.

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(Unaudited)

We invested in Ventura Refining and Transmission LLC in early 2007. We have an agreement to guarantee various commitments for Ventura, up to $70 million, to support its operating activities. As of March 31, 2009, we had $3 million of outstanding performance guarantees. Due to worsening economic conditions, the lack of third party credit available to Ventura, and poor operating performance in the second half of 2008, management determined that an impairment had occurred and we wrote off our investment at December 31, 2008.

4. Net Income Per Share

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

For the Current Quarter and the Prior Quarter, there was no difference between basic 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 for the Current Quarter do not include the effect of (i) outstanding stock options to purchase 1.2 million shares of common stock at a weighted average exercise price of $8.15, (ii) 2.1 million shares of unvested restricted stock at a weighted average grant-date fair value of $35.95, (iii) the assumed conversion of 4.125% convertible preferred stock convertible into 180,854 common shares prior to conversion and (iv) the assumed conversion of the following outstanding preferred stock:

5.00% (Series 2005) convertible preferred stock convertible into 19,443 common shares,

5.00% (Series 2005B) convertible preferred stock convertible into 5,367,289 common shares,

4.50% preferred stock convertible into 5,795,396 common shares, and

6.25% mandatory convertible preferred stock convertible into 1,237,770 common shares.

As a result of the Prior Quarter s net loss to common shareholders, diluted shares for the Prior Quarter 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.

5. Stockholders Equity, Restricted Stock and Stock Options

Common Stock

The following is a summary of the changes in our common shares issued for the three months ended March 31, 2009 and 2008:

	2009	2008
	(in thousands)	
Shares issued at January 1	607,953	511,648
Stock option exercises	100	621
Restricted stock issuances (net of forfeitures)	2,858	2,296
Preferred stock conversions/exchanges	183	
Common stock issued for the purchase of leasehold and unproved properties	14,361	
Shares issued at March 31	625,455	514,565

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Preferred Shares

The following is a summary of the changes in our preferred shares outstanding for the three months ended March 31, 2009 and 2008:

	4.125%	5.00% (2005)	4.50%	5.00% (2005B)	6.25%
			(in thousands)		
Shares outstanding at January 1, 2009	3	5	2,559	2,096	144
Conversion/exchange of preferred for common stock	(3)				
Shares outstanding at March 31, 2009		5	2,559	2,096	144
Shares outstanding at January 1, 2008 and March 31, 2008	3	5	3,450	5,750	144

On March 31, 2009, we converted all of our outstanding 4.125% cumulative convertible preferred stock (3,033 shares) into 182,887 shares of common stock pursuant to the company s mandatory conversion rights.

Dividends

Dividends declared on our common stock and preferred stock are reflected as adjustments to retained earnings to the extent a surplus of retained earnings will exist after giving effect to the dividends. To the extent retained earnings are insufficient to fund the distributions, such payments constitute a return of contributed capital rather than earnings and are accounted for as a reduction to paid-in capital.

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, 2009	2008
	($ in millions)	
Natural gas and oil properties	$ 29	$ 26
General and administrative expenses	19	19
Production expenses	9	7
Natural gas and oil marketing expenses	4	2
Service operations expense	2	1
Total	$ 63	$ 55

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, 2009	21,622,202	$ 38.85
Granted	3,823,904	$ 17.25
Vested	(2,013,143)	$ 31.63
Forfeited	(242,745)	$ 35.83
Unvested shares as of March 31, 2009	23,190,218	$ 35.95

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The aggregate intrinsic value of restricted stock vested during the Current Quarter was approximately $34 million based on the stock price at the time of vesting.

As of March 31, 2009, there was $635 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 2.65 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, we recognized a reduction in tax benefits related to restricted stock of $8 million. During the Prior Quarter, we recognized excess tax benefits related to restricted stock of $6 million. The reduction in tax benefits and the excess tax benefits 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 are currently fully vested.

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, 2009	2,802,421	$ 8.13	3.59	$ 23
Exercised	(100,188)	$ 7.43		$ 1
Forfeited		$		
Expired		$		
Outstanding at March 31, 2009	2,702,233	$ 8.15	3.41	$ 24
Exercisable at March 31, 2009	2,702,233	$ 8.15	3.41	$ 24

(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, 2009, 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 a nominal amount and $5 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

6. Senior Notes and Revolving Bank Credit Facilities

Our total debt consisted of the following as of March 31, 2009 and December 31, 2008:

	March 31, 2009	December 31, 2008 (Adjusted)
	($ 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
9.5% Senior Notes due 2015	1,425	
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]	796	835
6.5% Senior Notes due 2017	1,100	1,100
6.25% Senior Notes due 2018	600	600
7.25% Senior Notes due 2018	800	800
6.875% Senior Notes due 2020	500	500
2.75% Contingent Convertible Senior Notes due 2035[b]	451	451
2.5% Contingent Convertible Senior Notes due 2037[b]	1,378	1,378
2.25% Contingent Convertible Senior Notes due 2038[b]	1,126	1,126
Revolving bank credit facility	2,225	3,474
Midstream revolving bank credit facility	164	460
Discount on senior notes[c]	(1,129)	(1,094)
Interest rate derivatives[d]	163	211
Total notes payable and long-term debt	$ 12,933	$ 13,175

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.3261 to 1.00 and $1.3919 to 1.00 as of March 31, 2009 and December 31, 2008, respectively. See Note 2 for information on our related cross currency swap.

(b) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. 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 when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the first quarter of 2009, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes during the specified period and, as a result, the holders do not have the option to convert their notes into cash and common stock in the second quarter of 2009 under this provision. The notes are also convertible, at the holder s option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. In general, upon conversion of a contingent 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. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years, 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. The optional repurchase dates, the common stock price conversion threshold amounts and the ending date of the first six-month period contingent interest may be payable for the contingent convertible senior notes are as follows:

Contingent Convertible Senior Notes	**Repurchase Dates**	**Common Stock Price Conversion Thresholds**	**Contingent Interest First Payable (if applicable)**
2.75% due 2035	November 15, 2015, 2020, 2025, 2030	$ 48.81	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 64.47	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 107.36	June 14, 2019

(c) Discount at December 31, 2008 is adjusted for the retrospective application of FSP APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion*. Included in this discount is $988 million and $1.009 billion, respectively, associated with the liability component of our contingent convertible senior notes.

(d) 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 contingent convertible senior notes, 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 subsidiaries ability to incur certain secured indebtedness; enter into sale/leaseback transactions; and consolidate, merge or transfer assets.

Chesapeake Energy Corporation is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. As of September 30, 2008, our obligations under our outstanding senior notes and contingent convertible notes were fully and unconditionally guaranteed, jointly and severally, by all of our wholly-owned restricted subsidiaries, other than minor subsidiaries, on a senior unsecured basis. In October 2008, we restructured our non-Appalachian midstream operations. As a result, beginning in the fourth quarter of 2008, our wholly-owned midstream subsidiaries having significant assets and operations do not guarantee our outstanding senior notes.

On January 1, 2009, the company adopted and applied retrospectively FASB Staff Position No. APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)*. We have three debt issuances affected by this change: our 2.75% Contingent Convertible Senior Notes due 2035, our 2.5% Contingent Convertible Senior Notes due 2037 and our 2.25% Contingent Convertible Senior Notes due 2038. FSP APB 14-1 requires the company to account for the liability and equity components of its convertible debt instruments separately and to reflect interest expense at the interest rate of similar nonconvertible debt at the time of issuance (6.86%, 8.0% and 8.0%, respectively). The allocation to the equity component of the convertible notes was $845 million (net of tax) at both March 31, 2009 and December 31, 2008. The accretion of the resulting discount on the debt is recognized as a part of interest expense, thereby increasing the amount of interest expense required to be recognized with respect to such instruments. Given the increase in our overall effective interest rate after adoption of FSP APB 14-1, we also capitalized additional interest which largely offset the increase in interest expense. Additionally, debt issuance costs are required to be allocated in proportion to the liability and equity components and accounted for as debt issuance costs and equity issuance costs, respectively. The applicable nonconvertible debt rates for the issuances are 6.86%, 8.0% and 8.0%, respectively.

The following table summarizes the effect of the change in accounting principle related to our convertible notes on the condensed consolidated balance sheet as of December 31, 2008 ($ in millions):

	December 31, 2008		
	Previously Reported	Adjustment	Adjusted
Unevaluated properties	$ 11,216	$ 163	$ 11,379
Other long-term assets	1,007	(14)	993
Long-term debt, net	14,184	(1,009)	13,175
Deferred income tax liability	3,763	437	4,200
Paid-in-capital	10,835	845	11,680
Retained earnings	4,694	(125)	4,569

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The following table summarizes the effect of the change in accounting principle related to our convertible notes on the condensed consolidated statement of operations for the three months ended March 31, 2008 ($ in millions, except per share data):

	Three Months Ended March 31, 2008		
	Previously Reported	Adjustment	Adjusted
Depreciation and amortization of other assets	36		36
Interest expense	101	(2)	99
Income tax expense (benefit)	(82)		(82)
Net income	(132)	2	(130)
Weighted average common and common equivalent shares outstanding assuming dilution (in millions)	493		493
Earnings per common share:			
Basic	$ (0.29)		$ (0.29)
Diluted	$ (0.29)		$ (0.29)

The following table summarizes the effect of the change in accounting principle related to our convertible notes on the condensed consolidated statement of cash flows for the three months ended March 31, 2008 ($ in millions):

	Three Months Ended March 31, 2008		
	Previously Reported	Adjustment	Adjusted
Cash flows from operating activities	$ 1,498	$ 17	$ 1,515
Cash flows from investing activities	$ (2,675)	$ (17)	$ (2,692)
Cash flows from financing activities	$ 1,177	$	$ 1,177

We have a $3.5 billion syndicated revolving bank credit facility which matures in November 2012. As of March 31, 2009, we had $2.225 billion in outstanding borrowings under this facility and utilized approximately $7 million of the facility for various letters of credit. The terms of the credit facility agreement summarized below reflect amendments effected on March 31, 2009.

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%, both of which are subject to a margin that varies from 0.00% to 0.75% (0.00% prior to the March 31, 2009 amendment) per annum according to our senior unsecured long-term debt ratings, or (ii) the London Interbank Offered Rate (LIBOR), plus a margin that varies from 1.50% to 2.25% (0.75% to 1.50% prior to the March 31, 2009 amendment) 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 of 0.50% (which varied according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum, prior to the March 31, 2009 amendment). 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. Pursuant to the March 31, 2009 amendment of the credit facility, the effects of ceiling test write-downs are excluded from the calculation of total capitalization for purposes of the consolidated indebtedness to total capitalization ratio. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.42 to 1 and our indebtedness to EBITDA ratio was 2.91 to 1 at March 31, 2009. 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 restricted subsidiaries.

We also have a secured revolving bank credit facility for our midstream operations, organized under an unrestricted subsidiary, Chesapeake Midstream Partners, L.P. (CMP) and its operating subsidiary, Chesapeake Midstream Operating, L.L.C. (CMO). CMO is the borrower under the facility, which matures in October 2013, has current availability of $460 million and may be expanded up to $750 million at CMO s option, subject to additional bank participation. CMO is utilizing the facility to fund capital expenditures associated with building additional natural gas gathering and other systems associated with our drilling program and for general corporate purposes related to our midstream operations. As of March 31, 2009, we had $164 million in outstanding borrowings under the midstream credit facility.

Borrowings under the midstream credit facility are secured by all of the assets of the midstream companies organized under CMP and bear interest at our option at either (i) the greater of the reference rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50%, and the one month London Interbank Offered Rate plus 1.50%, all of which would be subject to a margin that varies from 0.75% to 1.50% per annum according to the most recent indebtedness to EBITDA ratio (as defined) or (ii) the LIBOR plus a margin that varies from 1.75% to 2.50% per annum according to the most recent indebtedness to EBITDA ratio (as defined). The unused portion of the facility is subject to a commitment fee that varies from 0.30% to 0.45% per annum according the most recent indebtedness to EBITDA ratio (as defined). Interest is payable quarterly or, if LIBOR applies, it may be paid at more frequent intervals.

The midstream credit facility agreement contains various covenants and restrictive provisions which limit the ability of CMP and its subsidiaries to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires maintenance of an indebtedness to EBITDA ratio (as defined) not to exceed 3.50 to 1, and an EBITDA (as defined) to interest expense coverage ratio of not less than 2.50 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 0.83 to 1 and our EBITDA to interest expense coverage ratio was 10.98 to 1 at March 31, 2009. If CMP or its subsidiaries should fail to perform their obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the midstream facility could be declared immediately due and payable. The midstream credit facility agreement also has cross default provisions that apply to other indebtedness CMP and its subsidiaries may have with an outstanding principal amount in excess of $15 million.

Our revolving bank credit facility and the midstream credit facility do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates in our revolving bank credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, neither of our credit facilities 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.

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 midstream 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 midstream 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.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Management evaluates the performance of our segments based upon income (loss) before income taxes. Revenues from the midstream segment s sale of natural gas and oil related to Chesapeake s ownership interests are reflected as exploration and production revenues. Such amounts totaled $671 million and $1.289 billion 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	Midstream	Other Operations	Intercompany Eliminations	Consolidated Total
			($ in millions)		
For the Three Months Ended March 31, 2009:					
Revenues	$ 1,397	$ 1,223	$ 154	$ (779)	$ 1,995
Intersegment revenues		(671)	(108)	779	
Total revenues	$ 1,397	$ 552	$ 46	$	$ 1,995
Income (loss) before income taxes	$ (9,193)	$ 18	$ (20)	$ 11	$ (9,184)
For the Three Months Ended March 31, 2008 (Adjusted):					
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	$ (226)	$ 15	$ 20	$ (21)	$ (212)
As of March 31, 2009:					
Total assets	$ 25,698	$ 5,714	$ 773	$ (2,524)	$ 29,661
As of December 31, 2008 (Adjusted):					
Total assets	$ 35,192	$ 3,416	$ 688	$ (703)	$ 38,593

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

8. Investments

At March 31, 2009, investments accounted for under the equity method totaled $352 million and investments accounted for under the cost method totaled $26 million. Following is a summary of our investments:

	Approximate % Owned	Accounting Method	Carrying Value March 31, 2009	Carrying Value December 31, 2008
			($ in millions)	
Frac Tech Services, Ltd.[a]	20%	Equity	$ 223	$ 223
Chaparral Energy, Inc.[b][c]	32%	Equity	101	152
DHS Drilling Company[b]	47%	Equity		19
Sierra Mid-Con, L.P.	50%	Equity	12	12
Gastar Exploration Ltd.[b]	17%	Cost	20	11
Mountain Drilling Company[b]	49%	Equity		9
Other			22	18
			$ 378	$ 444

(a) The carrying value of our investment in Frac Tech is in excess of our underlying equity in net assets by approximately $165 million as of March 31, 2009. This excess amount is attributed to certain intangibles associated with the specialty services provided by Frac Tech and is being amortized over the estimated life of the intangibles.

(b) Our investees have been impacted by the dramatic slowing of the worldwide economy and the tightening of the credit markets in the fourth quarter of 2008 and into 2009. The economic weakness has resulted in significantly reduced oil and natural gas prices leading to a meaningful decline in the overall level of activity in the markets served by our investees. Associated with the weakness in performance of certain of the investees, as well as an evaluation of their financial condition and near-term prospects, we recognized during the Current Quarter that an other than temporary impairment had occurred on March 31, 2009 on the following investments: Chaparral Energy of $51 million, DHS Drilling Company of $19 million, Gastar Exploration Ltd. of $70 million and Mountain Drilling Company of $9 million. We will continue to monitor the performance of our investments, and it is reasonably possible that we may experience additional impairments, although we do not believe that our exposure to future charges would be material to our consolidated results of operations.

(c) The carrying value of our investment in Chaparral is in excess of our underlying equity in net assets by approximately $55 million as of March 31, 2009. This excess is attributed to the natural gas and oil reserves held by Chaparral and is being amortized over the estimated life of these reserves based on a unit of production rate.

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. Our nonfinancial assets and liabilities became subject to the statement effective January 1, 2009. This statement establishes a framework for measuring fair value of assets and liabilities and expands disclosures about fair value measurements.

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 estimate 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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, 2009.

	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, net	$	$ 910	$ 434	$ 1,344
Investments	$ 20	$	$	$ 20
Other long-term assets	$ 19	$	$	$ 19
Long-term debt	$	$	$ (1,460)	$ (1,460)
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 obligations under 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. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives.

Level 3 Fair Value Measurements

Derivatives. The fair value of our derivative instruments, excluding natural gas swaps, have been established utilizing established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives.

Debt. The fair value of our long-term debt is based on the face amount 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.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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, 2009	$ 292	$ (1,470)	$ (1,178)
Total gains or losses (realized/unrealized):			
Included in earnings[(a)]	(68)	10	(58)
Included in other comprehensive income (loss)	172		172
Purchases, issuances and settlements	38		38
Transfers in and out of Level 3			
Balance of Level 3 as of March 31, 2009	$ 434	$ (1,460)	$ (1,026)

(a)

	Natural Gas and Oil Sales	Interest Expense
	($ in millions)	
Total gains and (losses) related to derivatives included in earnings for the period	$ (66)	$ (1)
Change in unrealized gains or (losses) relating to assets still held at reporting date	$ 103	$ 5

10. Condensed Consolidating Financial Information

Chesapeake Energy Corporation is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. As of September 30, 2008, our obligations under our outstanding senior notes and contingent convertible notes listed in Note 6 were fully and unconditionally guaranteed, jointly and severally, by all of our wholly-owned subsidiaries, other than minor subsidiaries, on a senior unsecured basis. Since October 2008, following the restructuring of our non-Appalachian midstream operations, certain of our wholly-owned subsidiaries having significant assets and operations have not guaranteed our outstanding notes. The midstream revolving credit facility referred to in Note 6 contains a covenant restricting Chesapeake Midstream Partners, L.P., the parent of our midstream subsidiaries, from paying dividends or distributions or making loans to Chesapeake.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Set forth below are condensed consolidating financial statements for Chesapeake Energy Corporation (the parent) on a stand-alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries as of March 31, 2009 and December 31, 2008 and for the three months ended March 31, 2009 and 2008. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had the subsidiaries operated as independent entities.

CONDENSED CONSOLIDATING BALANCE SHEET

AS OF MARCH 31, 2009

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 83	$	$	$ 83
Other current assets	14	2,670	116	(30)	2,770
Total Current Assets	14	2,753	116	(30)	2,853
PROPERTY AND EQUIPMENT:					
Total natural gas and oil properties, at cost based on full-cost accounting, net		20,490	4		20,494
Other property and equipment, net		2,535	2,827		5,362
Total Property and Equipment		23,025	2,831		25,856
Other assets	244	694	14		952
Investments in subsidiaries and intercompany advance	3,195	142		(3,337)	
TOTAL ASSETS	$ 3,453	$ 26,614	$ 2,961	$ (3,367)	$ 29,661
CURRENT LIABILITIES:					
Current liabilities	$ 258	$ 2,865	$ 271	$ (32)	$ 3,362
Intercompany payable (receivable) from parent	(19,829)	17,481	2,268	80	
Total Current Liabilities	(19,571)	20,346	2,539	48	3,362
Long-term debt, net	10,544	2,225	164		12,933
Deferred income tax liability	536	232	110	(78)	800
Other liabilities	126	616	6		748
Total Long-Term Liabilities	11,206	3,073	280	(78)	14,481
Total Stockholders Equity	11,818	3,195	142	(3,337)	11,818

TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$	3,453	$	26,614	$	2,961	$	(3,367)	$	29,661

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING BALANCE SHEET

AS OF DECEMBER 31, 2008

Adjusted

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 1,749	$	$	$ 1,749
Other current assets	13	2,372	189	(31)	2,543
Total Current Assets	13	4,121	189	(31)	4,292
PROPERTY AND EQUIPMENT:					
Total natural gas and oil properties, at cost based on full-cost accounting, net		28,463	15		28,478
Other property and equipment, net		1,918	2,912		4,830
Total Property and Equipment		30,381	2,927		33,308
Other assets	140	838	15		993
Investments in subsidiaries and intercompany advance	8,455	140		(8,595)	
TOTAL ASSETS	$ 8,608	$ 35,480	$ 3,131	$ (8,626)	$ 38,593
CURRENT LIABILITIES:					
Current liabilities	$ 257	$ 3,322	$ 133	$ (91)	$ 3,621
Intercompany payable (receivable) from parent	(18,272)	16,047	2,165	60	
Total Current Liabilities	(18,015)	19,369	2,298	(31)	3,621
Long-term debt, net	9,241	3,474	460		13,175
Deferred income tax liability	439	3,534	227		4,200
Other liabilities	(74)	648	6		580
Total Long-Term Liabilities	9,606	7,656	693		17,955
Total Stockholders Equity	17,017	8,455	140	(8,595)	17,017
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 8,608	$ 35,480	$ 3,131	$ (8,626)	$ 38,593

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
For the Three Months Ended March 31, 2009:					
REVENUES:					
Natural gas and oil sales	$	$ 1,397	$	$	$ 1,397
Natural gas and oil marketing sales		489	110	(47)	552
Service operations revenue		46			46
Total Revenues		1,932	110	(47)	1,995
OPERATING COSTS:					
Production expenses		238			238
Production taxes		23			23
General and administrative expenses		85	5		90
Natural gas and oil marketing expenses		469	48	6	523
Service operations expense		40			40
Natural gas and oil depreciation, depletion and amortization		447			447
Depreciation and amortization of other assets	(1)	37	20	1	57
Impairment of natural gas and oil properties and other assets		9,626	4		9,630
Total Operating Costs	(1)	10,965	77	7	11,048
INCOME (LOSS) FROM OPERATIONS	1	(9,033)	33	(54)	(9,053)
OTHER INCOME (EXPENSE):					
Other income (expense)	162	5	3	(162)	8
Interest expense	(127)	(18)	(3)	162	14
Impairment of investments		(153)			(153)
Equity in net earnings of subsidiary	(5,763)	(14)		5,777	
Total Other Income (Expense)	(5,728)	(180)		5,777	(131)
INCOME (LOSS) BEFORE INCOME TAXES	(5,727)	(9,213)	33	5,723	(9,184)
INCOME TAX EXPENSE (BENEFIT)	13	(3,450)	13	(20)	(3,444)
NET INCOME (LOSS)	$ (5,740)	$ (5,763)	$ 20	$ 5,743	$ (5,740)

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
For the Three Months Ended March 31, 2008:					
REVENUES:					
Natural gas and oil sales	$	$ 773	$	$	$ 773
Natural gas and oil marketing sales		758	69	(31)	796
Service operations revenue		41	7	(6)	42
Total Revenues		1,572	76	(37)	1,611
OPERATING COSTS:					
Production expenses		201			201
Production taxes		75			75
General and administrative expenses		76	3		79
Natural gas and oil marketing expenses		747	30	(3)	774
Service operations expense		35	3	(3)	35
Natural gas and oil depreciation, depletion and amortization		515			515
Depreciation and amortization of other assets	4	27	11	(6)	36
Total Operating Costs	4	1,676	47	(12)	1,715
INCOME (LOSS) FROM OPERATIONS	(4)	(104)	29	(25)	(104)
OTHER INCOME (EXPENSE):					
Other income (expense)	164	(42)	(1)	(130)	(9)
Interest expense	(99)	(129)	(1)	130	(99)
Equity in net earnings of subsidiary	(168)	2		166	
Total Other Income (Expense)	(103)	(169)	(2)	166	(108)
INCOME (LOSS) BEFORE INCOME TAXES	(107)	(273)	27	141	(212)
INCOME TAX EXPENSE (BENEFIT)	23	(105)	10	(10)	(82)
NET INCOME (LOSS)	$ (130)	$ (168)	$ 17	$ 151	$ (130)

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
For the Three Months Ended March 31, 2009:					
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 1,141	$ 120	$	$ 1,261
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(1,766)	6		(1,760)
Divestitures of proved and unproved natural gas and oil properties					
Additions to other property and equipment		(278)	(389)		(667)
Other investing activities		59	1		60
Cash used in investing activities		(1,985)	(382)		(2,367)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facility borrowings		1,301	274		1,575
Payments on credit facility borrowings		(2,550)	(570)		(3,120)
Proceeds from issuance of senior notes, net of offering costs	1,346				1,346
Other financing activities	(72)	(289)			(361)
Intercompany advances, net	(1,274)	716	558		
Cash provided by financing activities		(822)	262		(560)
Net increase (decrease) in cash and cash equivalents		(1,666)			(1,666)
Cash and cash equivalents, beginning of period		1,749			1,749
Cash and cash equivalents, end of period	$	$ 83	$	$	$ 83

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
For the Three Months Ended March 31, 2008:					
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 1,474	$ 41	$	$ 1,515
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(2,424)	(3)		(2,427)
Divestitures of proved and unproved natural gas and oil properties		243			243
Additions to other property and equipment		(273)	(278)		(551)
Other investing activities		43			43

Cash used in investing activities		(2,411)	(281)		(2,692)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facility borrowings		2,591			2,591
Payments on credit facility borrowings		(1,377)			(1,377)
Proceeds from issuance of senior notes, net of offering costs					
Proceeds from issuance of common stock, net of offering costs					
Other financing activities	(47)	10			(37)
Intercompany advances, net		(240)	240		
Cash provided by financing activities	(47)	984	240		1,177
Net increase (decrease) in cash and cash equivalents	(47)	47			
Cash and cash equivalents, beginning of period		1			1
Cash and cash equivalents, end of period	$ (47)	$ 48	$	$	$ 1

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

11. 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 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. We adopted this statement in the Current Quarter. This statement had no financial impact on our condensed consolidated financial statements. See Note 2 for additional information on the adoption of SFAS No. 161.

On December 31, 2008, the Securities and Exchange Commission (SEC) adopted major revisions to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new disclosure requirements also require companies to report the independence and qualifications of the person primarily responsible for the preparation or audit of reserve estimates, and to file reports when a third party is relied upon to prepare or audit reserves estimates. The new rules also require that oil and gas reserves be reported and the full-cost ceiling value calculated using an average price based upon the prior 12-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. We are in the process of assessing the impact of these new requirements on our financial position, results of operations and financial disclosures.

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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, 2009 (the Current Quarter) and the three months ended March 31, 2008 (the Prior Quarter):

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008 (Adjusted)
Net Production:		
Natural gas (mmcf)	195,749	187,772
Oil (mbbls)	2,874	2,746
Natural gas equivalent (mmcfe)	212,993	204,248
Natural Gas and Oil Sales ($ in millions):		
Natural gas sales	$ 674	$ 1,432
Natural gas derivatives realized gains (losses)	510	268
Natural gas derivatives unrealized gains (losses)	68	(1,002)
Total natural gas sales	1,252	698
Oil sales	104	258
Oil derivatives realized gains (losses)	9	(53)
Oil derivatives unrealized gains (losses)	32	(130)
Total oil sales	145	75
Total natural gas and oil sales	$ 1,397	$ 773
Average Sales Price (excluding all gains (losses) on derivatives):		
Natural gas ($ per mcf)	$ 3.44	$ 7.63
Oil ($ per bbl)	$ 35.99	$ 94.14
Natural gas equivalent ($ per mcfe)	$ 3.65	$ 8.28
Average Sales Price (excluding unrealized gains (losses) on derivatives):		
Natural gas ($ per mcf)	$ 6.05	$ 9.05
Oil ($ per bbl)	$ 39.12	$ 74.73
Natural gas equivalent ($ per mcfe)	$ 6.09	$ 9.33
Other Operating Income[(a)] ($ in millions):		
Natural gas and oil marketing	$ 29	$ 22
Service operations	$ 6	$ 7
Other Operating Income[(a)] ($ per mcfe):		
Natural gas and oil marketing	$ 0.14	$ 0.11
Service operations	$ 0.03	$ 0.03
Expenses ($ per mcfe):		
Production expenses	$ 1.12	$ 0.98
Production taxes	$ 0.11	$ 0.37
General and administrative expenses	$ 0.42	$ 0.39
Natural gas and oil depreciation, depletion and amortization	$ 2.10	$ 2.52
Depreciation and amortization of other assets	$ 0.27	$ 0.18
Interest expense[(b)]	$ 0.14	$ 0.42
Interest Expense ($ in millions):		
Interest expense	$ 38	$ 86
Interest rate derivatives realized (gains) losses	(7)	

Interest rate derivatives unrealized (gains) losses		(45)		13
Total interest expense	$	(14)	$	99
Net Wells Drilled		264		448
Net Producing Wells as of the End of the Period		22,691		21,471

(a) Includes revenue and operating costs and excludes depreciation and amortization of other assets.

(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.

We are the largest independent producer of natural gas in the United States. We own interests in approximately 43,200 producing oil and natural gas 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., primarily in the Big 4 natural gas shale plays: the Barnett Shale in the Fort Worth Basin of north-central Texas, the Haynesville Shale in the Ark-La-Tex area of northwestern Louisiana and East Texas, the Fayetteville Shale in the Arkoma Basin of central Arkansas and the Marcellus Shale in the northern Appalachian Basin of West Virginia, Pennsylvania and New York. We also have substantial operations in various other plays, both conventional and unconventional, in the Mid-Continent, Appalachian Basin, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast and Ark-La-Tex regions of the United States.

During the Current Quarter, Chesapeake continued the industry s most active drilling program drilling 307 gross (237 net) operated wells and participating in another 219 gross (27 net) wells operated by other companies. The company s drilling success rate was 98% for company-operated wells and 99% for non-operated wells. Also during the Current Quarter, we invested $1.020 billion in operated wells (using an average of 113 operated rigs) and $166 million in non-operated wells (using an average of 58 non-operated rigs) for total drilling, completing and equipping costs of $1.186 billion. At May 7, 2009, we were using 94 operated drilling rigs, reflecting the company s decreased drilling activity in response to low natural gas and oil prices.

On April 16, 2009, we announced that we had elected to curtail approximately 400 million cubic feet (mmcf) per day of our gross operated natural gas production due to continued low wellhead prices. The reduction included the approximate 200 mmcf per day curtailment of natural gas production previously announced on March 2, 2009. Prices remain very volatile, and we will restore production from time to time, or curtail production further, based on market conditions. Our strong financial condition, the availability of substantial drilling credits as a result of the 2008 joint ventures, and our extensive natural gas hedging positions provide us with the operational and financial flexibility to curtail production during periods of unusually low prices. The company will monitor market conditions to determine an appropriate time to resume full production.

Chesapeake began 2009 with estimated proved reserves of 12.051 tcfe and ended the Current Quarter with 11.851 tcfe, a decrease of 200 bcfe, or 2%. During the Current Quarter, we replaced 213 bcfe of production with an internally estimated 13 bcfe of new proved reserves, for a reserve replacement rate of 6%. The quarter s reserve movement includes 427 bcfe of extensions, 9 bcfe of acquisitions, 397 bcfe of positive performance revisions and 820 bcfe of downward revisions resulting from natural gas price decreases between December 31, 2008 and March 31, 2009. Based on our current drilling schedule and budget, we expect that virtually all of the proved undeveloped reserves added in 2009 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 $13.3 billion in new leasehold (net of proceeds from divestitures) and 3-D seismic acquisitions and now owns the largest combined inventories of onshore leasehold (15.2 million net acres) and 3-D seismic (22.3 million acres) in the U.S. On this leasehold, the company has approximately 36,000 net drillsites representing more than a 10-year inventory of drilling projects.

Our total debt as a percentage of total capitalization (total capitalization is the sum of total debt less cash on hand and stockholders equity) was 52% as of March 31, 2009 and 40% as of December 31, 2008. The increase in this percentage is primarily the result of the reduction of equity as the result of the Current Quarter $5.7 billion net loss. The average maturity of our long-term debt is over seven years with an average coupon interest rate of approximately 6.1%. No scheduled principal payments are required under our senior notes until 2013 when $864 million is due.

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Business Strategy

Our exploration, development and acquisition activities require us to make substantial capital expenditures. Through the middle of 2008, we increased our capital expenditure budget for 2008 and 2009 several times in response to higher leasehold acquisition costs and in order to accelerate leasehold acquisition and drilling primarily in the Haynesville, Barnett and Marcellus Shale plays. During the second half of 2008 and again in 2009, in response to a significant decrease in natural gas prices, deteriorating global economic conditions and outlook and concerns about an oversupply of natural gas in the U.S. market, and in recognition of the substantial reduction in capital requirements resulting from our joint ventures with Plains Exploration & Production Company (PXP), BP America (BP) and StatoilHydro U.S.A. (StatoilHydro), we significantly reduced our planned capital expenditures through year-end 2010. We further believe our innovative joint ventures will create a significant cost advantage that will allow us to drive down finding costs in our joint venture plays. Our current budgeted capital expenditures are $4.350 billion to $4.975 billion in 2009 and $4.050 billion to $4.675 billion in 2010. We anticipate directing approximately 80% of our gross drilling capital expenditures during 2009 and 2010 to our Big 4 shale plays.

During each of 2009 and 2010, we anticipate our exploration and development costs will be up to 40% lower than 2008 costs as a result of lower service costs and the benefit of using approximately $2.4 billion of joint venture drilling credits in three of our Big 4 shale plays. The following table provides information about the joint venture drilling credits:

	Shale Play		
	Haynesville[(a)]	**Fayetteville**	**Marcellus**
	($ in millions)		
Joint venture with	PXP	BP	StatoilHydro
Closing date	July 1, 2008	September 19, 2008	November 24, 2008
Cash proceeds at closing	$ 1,650	$ 1,100	$ 1,250
Total drilling credit	$ 1,650	$ 800	$ 2,125
Drilling credit billed as of March 31, 2009	$ 158	$ 371	$ 11
Remaining drilling credit as of March 31, 2009	$ 1,492	$ 429	$ 2,114

(a) Chesapeake and PXP amended their joint venture in February 2009 to provide PXP a one-time option in June 2010 to reduce its obligation to fund our drilling and completion costs by $800 million in exchange for assigning us 50% of PXP s interest in the Haynesville joint venture properties.

Cash flow from operations is our primary source of liquidity used to fund capital expenditures. Our $3.5 billion revolving bank credit facility and our $460 million midstream revolving bank credit facility provide us with additional liquidity. In February 2009, we issued $1.425 billion principal amount of our 9.5% senior notes due 2015. Net proceeds of $1.346 billion were used to repay outstanding indebtedness under our revolving bank credit facility, which we may reborrow from time to time to fund drilling and leasehold acquisition initiatives and for general corporate purposes. At March 31, 2009, we had borrowings of $2.225 billion and letters of credit of $7 million outstanding under our revolving bank credit facility and we had borrowings of $164 million under the midstream credit facility.

During 2009 and 2010, we plan to increase our liquidity, reduce our borrowings under our revolving bank credit facility and also strengthen our balance sheet through asset monetizations and the growth of our proved reserve base. Transactions we expect to complete in 2009 include the following:

- We are currently documenting our fifth volumetric production payment transaction (VPP) involving certain of our South Texas assets. We anticipate proceeds of approximately $475 million and expect to complete the transaction in the 2009 second quarter.

- We plan to sell certain non-Haynesville Shale producing assets in Louisiana in a sixth VPP in the second half of 2009 for approximately $250 million.

We are in due diligence with a private equity investor to sell a 50% minority interest in our Barnett Shale and Mid-Continent natural gas gathering and processing assets in our midstream business, Chesapeake Midstream Partners. We anticipate proceeds of more than $550 million and expect to complete the transaction in the 2009 third quarter

We anticipate selling approximately $300 million of mature producing assets late in the 2009 second quarter and another $200 million in the second half of 2009.

We are currently in discussions with several companies about a possible Barnett Shale joint venture transaction and anticipate completing a transaction by year-end 2009 for proceeds of approximately $200 million to $300 million.

We believe that our anticipated internally generated cash flow, cash resources, expected asset monetization transactions and other sources of liquidity will allow us to fully fund our capital expenditure requirements in 2009. Further deterioration of the economy, continued low natural gas and oil prices and other factors, however, could require us to further curtail our spending.

Liquidity and Capital Resources

Sources and Uses of Funds

Cash flow from operations is a significant source of liquidity used to fund capital expenditures. Our joint venture drilling credits also provide an additional source of liquidity that have reduced and will continue to reduce our capital expenditures. Cash provided by operating activities was $1.261 billion in the Current Quarter compared to $1.515 billion in the Prior Quarter. The $254 million decrease in the Current Quarter was primarily due to lower natural gas and oil prices. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding non-cash items such as ceiling test write-downs, 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. To mitigate the risk of declines in natural gas and oil prices and to provide more predictable future cash flow from operations, we currently have hedged through swaps and collars 82% of our expected remaining natural gas and oil production in 2009 and 24% of our expected natural gas and oil production in 2010 at average prices of $7.56 per mcfe and $9.45 per mcfe, respectively. Our natural gas and oil hedges as of March 31, 2009 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, 2009, we had a net natural gas and oil derivative asset of $1.481 billion.

Our $3.5 billion bank credit facility, our $460 million midstream credit facility and cash and cash equivalents are other sources of liquidity. At May 7, 2009, there was $1.268 billion of borrowing capacity available under the revolving bank credit facility and $220 million of borrowing capacity under the midstream credit facility. We use the facilities and cash on hand to fund daily operating activities and acquisitions as needed. We borrowed $1.575 billion and repaid $3.120 billion in the Current Quarter, and we borrowed $2.591 billion and repaid $1.377 billion in the Prior Quarter.

On February 2, 2009, we completed a public offering of $1.0 billion aggregate principal amount of senior notes due 2015, which have a stated coupon rate of 9.5% per annum. The senior notes were priced at 95.071% of par to yield 10.625%. On February 17, 2009, we completed an offering of an additional $425 million aggregate principal amount of the 9.5% Senior Notes due 2015. The additional senior notes were priced at 97.75% of par plus accrued interest from February 2 to February 17, 2009 to yield 10.0% per annum. Net proceeds of $1.346 billion from these two offerings were used to repay outstanding indebtedness under our revolving bank credit facility, which we may reborrow from time to time to fund drilling and leasehold acquisition initiatives and for general corporate purposes.

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 and our other investing activities for the Current Quarter and the Prior Quarter. 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, changes in 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 $44 million and $33 million in the Current Quarter and the Prior Quarter, respectively. The board of directors increased the quarterly dividend on common stock from $0.0675 to $0.075 per share beginning with the dividend paid in July 2008. Dividends paid on our preferred stock decreased to $6 million in the Current Quarter from $12 million in the Prior Quarter as a result of conversions and exchanges of preferred stock into common stock during 2008 and 2009. We received $1 million and $4 million from the exercise of employee and director stock options in the Current Quarter and the Prior Quarter.

In the Current Quarter and Prior Quarter, we received $1 million and paid $33 million, respectively, to settle a portion of the derivative liabilities assumed in our November 2005 acquisition of Columbia Natural Resources, LLC.

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SFAS 123(R) 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 $0 and $11 million, respectively.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists decreased $287 million in the Current Quarter and increased $44 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.

Our accounts receivable are primarily from purchasers of natural gas and oil ($475 million at March 31, 2009) and exploration and production companies which own interests in properties we operate ($476 million at March 31, 2009). 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 or parental guarantees for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. During the Current Quarter, we recognized an $8 million bad debt expense related to potentially uncollectible receivables.

Investing Activities

Cash used in investing activities decreased to $2.367 billion during the Current Quarter, compared to $2.692 billion during the Prior Quarter. We have been reducing our drilling program since the third quarter of 2008 and our leasehold and property acquisitions expenditures in the Current Quarter were 72% lower than in the Prior Quarter. The following table shows our cash used in (provided by) investing activities during these periods:

	Three Months Ended March 31,	
	2009	2008
	($ in millions)	
Natural Gas and Oil Investing Activities:		
Exploration and development of natural gas and oil properties	$ 1,272	$ 1,322
Acquisition of leasehold and unproved properties	257	860
Acquisitions of natural gas and oil companies and proved properties, net of cash acquired	3	64
Geological and geophysical costs	74	84
Interest capitalized on unproved properties	154	97
Divestitures of proved and unproved properties and leasehold		(243)
Total natural gas and oil investing activities	1,760	2,184
Other Investing Activities:		
Additions to other property and equipment	667	551
Proceeds from sale of compressors	(68)	(17)
Proceeds from sale of drilling rigs and equipment		(34)
Additions to investments	8	9
Sale of other assets		(1)
Total other investing activities	607	508
Total cash used in investing activities	$ 2,367	$ 2,692

Due to current general economic conditions, decreases in natural gas prices and concerns about an oversupply of natural gas in the U.S. market, we and other exploration and production companies have significantly decreased budgets for natural gas and oil investing activities in 2009. In connection with our reduced budget for acquisitions, we are using our common stock for some or all of the consideration for certain transactions. In December 2008, we registered 25 million shares of common stock that we may offer and issue to acquire assets (including mineral interests), businesses or securities of other companies. As of May 8, 2009, we had issued approximately 17.5 million shares of common stock for leasehold acquisitions and anticipate we may issue the remaining shares over the course of 2009.

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Bank Credit Facilities

We have a $3.5 billion syndicated revolving bank credit facility that matures in November 2012. As of March 31, 2009, we had $2.225 billion in outstanding borrowings under this facility and had utilized approximately $7 million of the facility for various letters of credit. The terms of the credit facility agreement summarized below reflect amendments effected on March 31, 2009.

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%, both of which are subject to a margin that varies from 0.00% to 0.75% (0.00% prior to the March 31, 2009 amendment) per annum according to our senior unsecured long-term debt ratings, or (ii) the London Interbank Offered Rate (LIBOR), plus a margin that varies from 1.50% to 2.25% (0.75% to 1.50% prior to the March 31, 2009 amendment) 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 of 0.50% (which varied according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum, prior to the March 31, 2009 amendment). 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. Pursuant to the March 31, 2009 amendment of the credit facility, the effects of ceiling test write-downs are excluded from the calculation of total capitalization for purposes of the consolidated indebtedness to total capitalization ratio. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.42 to 1 and our indebtedness to EBITDA ratio was 2.91 to 1 at March 31, 2009. 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 of the company and its restricted subsidiaries that we may have with an outstanding principal amount in excess of $75 million.

We also have a secured revolving bank credit facility for our midstream operations, organized under an unrestricted subsidiary, Chesapeake Midstream Partners, L.P. (CMP) and its operating subsidiary, Chesapeake Midstream Operating, L.L.C. (CMO). The facility matures in October 2013, has initial availability of $460 million and may be expanded up to $750 million at CMO s option, subject to additional bank participation. CMO is utilizing the facility to fund capital expenditures associated with building additional natural gas gathering and other systems associated with our drilling program and for general corporate purposes related to our midstream operations. As of March 31, 2009, we had $164 million in outstanding borrowings under the midstream credit facility.

Borrowings under the midstream credit facility are secured by all of the assets of the midstream companies organized under CMP and bear interest at our option at either (i) the greater of the reference rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50%, and the one month London Interbank Offered Rate plus 1.50%, all of which would be subject to a margin that varies from 0.75% to 1.50% per annum according to the most recent indebtedness to EBITDA ratio (as defined) or (ii) the LIBOR plus a margin that varies from 1.75% to 2.50% per annum according to the most recent indebtedness to EBITDA ratio (as defined). The unused portion of the facility is subject to a commitment fee that varies from 0.30% to 0.45% per annum according the most recent indebtedness to EBITDA ratio (as defined). Interest is payable quarterly or, if LIBOR applies, it may be paid at more frequent intervals.

The midstream credit facility agreement contains various covenants and restrictive provisions which limit the ability of CMP and its subsidiaries to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires maintenance of an indebtedness to EBITDA ratio (as defined) not to exceed 3.50 to 1, and an EBITDA (as defined) to interest expense coverage ratio of not less than 2.50 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 0.83 to 1 and our EBITDA to interest expense coverage ratio was 10.98 to 1 at March 31, 2009. If CMP or its subsidiaries should fail to perform their obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the midstream facility could be declared immediately due and payable. The midstream credit facility agreement also has cross default provisions that apply to other indebtedness of CMP and its subsidiaries may have with an outstanding principal amount in excess of $15 million.

Hedging Facilities

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 or 1.5 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 any additional 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

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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 fair value of outstanding transactions, per annum exposure fees and the scheduled maturity dates are shown below.

	Secured Hedging Facilities[(a)]					
	#1	#2	#3	#4	#5	#6
	($ in millions)					
Fair value of outstanding transactions, as of March 31, 2009	$ 165	$ 584	$ 76	$ (3)	$ 98	$ 136
Per annum exposure fee	1%	1%	0.8%	0.8%	0.8%	0.8%
Scheduled maturity date	2010	2013	2020	2012	2012	2012

(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.

The facilities in general do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates under our revolving bank credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, neither of our credit facilities nor the secured hedging facilities 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, 2009, senior notes represented approximately $10.5 billion of our total debt and consisted of the following ($ 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
9.5% Senior Notes due 2015	1,425
6.625% Senior Notes due 2016	600
6.875% Senior Notes due 2016	670
6.25% Euro-denominated Senior Notes due 2017[(a)]	796
6.5% Senior Notes due 2017	1,100
6.25% Senior Notes due 2018	600
7.25% Senior Notes due 2018	800
6.875% Senior Notes due 2020	500
2.75% Contingent Convertible Senior Notes due 2035[(b)]	451
2.5% Contingent Convertible Senior Notes due 2037[(b)]	1,378
2.25% Contingent Convertible Senior Notes due 2038[(b)]	1,126
Discount on senior notes	(1,129)
Interest rate derivatives[(c)]	163
	$ 10,544

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.3261 to 1.00 as of March 31, 2009. See Note 2 of our condensed consolidated financial statements included in this report for information on our related cross currency swap.

(b) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. 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 when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the first quarter of 2009, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes during the specified period and, as a result, the holders do not have the option to convert their notes into cash and common stock in the second quarter of 2009 under this provision. The notes are also convertible, at the holder s option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. In general, upon conversion of a contingent 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. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years, 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. The optional repurchase dates, the common stock price conversion threshold amounts and the ending date of the first six-month period contingent interest may be payable for the contingent convertible senior notes are as follows:

Contingent Convertible Senior Notes	Repurchase Dates	Common Stock Price Conversion Thresholds	Contingent Interest First Payable (if applicable)
2.75% due 2035	November 15, 2015, 2020, 2025, 2030	$ 48.81	May 14, 2016

2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$	64.47	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$	107.36	June 14, 2019

(c) See Note 2 of our condensed consolidated financial statements included in this report for discussion related to these instruments.

As of March 31, 2009 and currently, debt ratings for the senior notes are Ba3 by Moody s Investor Service (stable outlook), BB by Standard & Poor s Ratings Services (stable outlook) and BB by Fitch Ratings (negative outlook).

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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. We may redeem the senior notes, other than the contingent convertible senior notes, at any time at specified make-whole 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. The debt incurrence covenants do not presently restrict our ability to borrow under or expand our secured credit facility. As of March 31, 2009, we estimate that secured commercial bank indebtedness of approximately $5.6 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, 2009. These include commitments related to drilling rig and compressor leases, transportation and drilling contracts, natural gas and oil purchase obligations and lending and guarantee agreements. These commitments are discussed in Note 3 of our condensed consolidated financial statements included in this report.

Results of Operations Three Months Ended March 31, 2009 vs. March 31, 2008

General. For the Current Quarter, Chesapeake had a net loss of $5.740 billion, or $9.63 per diluted common share, on total revenues of $1.995 billion. This compares to a net loss of $130 million, or $0.29 per diluted common share, on total revenues of $1.611 billion during the Prior Quarter. The Current Quarter loss was due to a non-cash impairment expense of approximately $6.0 billion, net of tax, as a result of a 36% decrease in NYMEX natural gas prices from $5.71 per mcf at December 31, 2008 to $3.63 per mcf at March 31, 2009. The Prior Quarter loss was 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 $1.397 billion compared to $773 million in the Prior Quarter. In the Current Quarter, Chesapeake produced 213.0 bcfe at a weighted average price of $6.09 per mcfe, compared to 204.2 bcfe produced in the Prior Quarter at a weighted average price of $9.33 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on natural gas and oil derivatives of $101 million and ($1.132) billion in the Current Quarter and Prior Quarter, respectively). In the Current Quarter, the decrease in prices resulted in a decrease in revenue of $690 million and increased production resulted in an $81 million increase, for a net decrease in revenues of $609 million (excluding unrealized gains or losses on natural gas and oil derivatives). 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 $6.05, compared to $9.05 in the Prior Quarter (weighted average prices for both quarters exclude the effect of unrealized gains or losses on derivatives). Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $39.12 and $74.73 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 $519 million, or $2.44 per mcfe, in the Current Quarter and an increase of $214 million, or $1.05 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 flows. Assuming the Current Quarter production levels, a change of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $20 million and $19 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.

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

	For the Three Months Ended March 31,			
	2009		2008	
	Mmcfe	Percent	Mmcfe	Percent
Barnett Shale	57,661	27%	37,973	19%
Haynesville Shale	6,585	3	182	
Fayetteville Shale[(a)]	18,194	9	11,111	5
Marcellus Shale	657		303	
Mid-Continent[(a)(b)]	75,265	35	94,463	46
Appalachian Basin	8,466	4	7,584	4
Permian and Delaware Basins	19,412	9	20,118	10
South Texas/Gulf Coast/Ark-La-Tex	26,753	13	32,514	16
Total production	212,993	100%	204,248	100%

(a) The Current Quarter was impacted by the sale of an estimated 4.6 bcf and 3.5 bcf of production in the BP Arkoma and BP Fayetteville divestitures, respectively.

(b) The Current Quarter was impacted by the sale of 4.0 bcf, 3.9 bcf and 5.4 bcfe of production in VPP transactions that closed on May 1, 2008, August 1, 2008 and December 31, 2008, respectively.

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

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 $552 million in natural gas and oil marketing sales in the Current Quarter, with corresponding natural gas and oil marketing expenses of $523 million, for a net margin before depreciation of $29 million. This compares to sales of $796 million, expenses of $774 million and a net margin before depreciation of $22 million in the Prior Quarter. In the Current Quarter, Chesapeake realized an increase in natural gas and oil marketing net margin primarily due to an increase in the gathering rates charged to third parties.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. Chesapeake recognized $46 million in service operations revenue in the Current Quarter with corresponding service operations expense of $40 million, for a net margin before depreciation of $6 million. This compares to revenue of $42 million, expenses of $35 million and a net margin before depreciation of $7 million in the Prior Quarter. The decrease in margins during the Current Quarter was the result of increased expenses associated with the leasing cost of the numerous rigs we have sold and leased back in the past three years and reduced drilling rig rates.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $238 million in the Current Quarter compared to $201 million in the Prior Quarter. On a unit-of-production basis, production expenses were $1.12 per mcfe in the Current Quarter compared to $0.98 per mcfe in the Prior Quarter. The increase in the Current Quarter was primarily due to higher ad valorem taxes and personnel costs. We expect that production expenses for 2009 will range from $1.10 to $1.20 per mcfe produced.

Production Taxes. Production taxes were $23 million in the Current Quarter compared to $75 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.11 per mcfe in the Current Quarter compared to $0.37 per mcfe in the Prior Quarter. The $52 million decrease in production taxes in the Current Quarter is due to a decrease in the average realized sales price of natural gas and oil of $4.63 per mcfe (excluding gains or losses on derivatives), which was partially offset by an increase in production of 9 bcfe.

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 2009 to range from $0.20 to $0.25 per mcfe based on NYMEX prices ranging from $5.00 to $6.00 per mcf of natural gas and oil prices of $48.27 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 $90 million in the Current Quarter and $79 million in the Prior Quarter. General and administrative expenses were $0.42 and $0.39 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 for both the Current Quarter and the Prior Quarter. We anticipate that general and administrative expenses for 2009 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 5 of our condensed consolidated financial statements included in Part I of this report provides additional detail on the accounting for and reporting of our restricted stock and stock options.

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 exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $93 million and $84 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 $447 million and $515 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 $2.10 and $2.52 in the Current Quarter and in the Prior Quarter, respectively. The $0.42 decrease in the average DD&A rate is due primarily to the reduction of our natural gas and oil full-cost pool resulting from divestitures in 2008, the utilization of joint venture drilling credits in the Current Quarter, and the impairment of natural gas and oil properties in 2008 and the additions of reserves through our exploration activities. We expect the DD&A rate for 2009 to be between $1.50 and $1.70 per mcfe produced which is significantly lower than our Current Quarter rate as a result of the Current Quarter impairment of natural gas and oil properties.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $57 million in the Current Quarter and $36 million in the Prior Quarter. Depreciation and amortization of other assets was $0.27 and $0.18 per mcfe for the Current Quarter and the Prior Quarter, respectively. The increase in the Current Quarter is a result of the significant increase in the investment in our gathering systems, buildings and rigs. 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 lives of the assets, which range from two to ten 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 2009 depreciation and amortization of other assets to be between $0.25 and $0.30 per mcfe produced.

Impairment of Natural Gas and Oil Properties and Other Assets. We account for our natural gas and oil properties using the full-cost method of accounting, which limits the amount of costs we can capitalize and requires us to write off these costs if the carrying value of natural gas and oil assets in the evaluated portion of our full-cost pool exceeds the sum of the present value of expected future net cash flows of proved reserves, using a 10% pre-tax discount rate based on constant pricing and cost assumptions, and the present value of certain natural gas and oil hedges.

We reported a non-cash impairment charge of $9.6 billion for the Current Quarter due to a 36% decrease in NYMEX natural gas prices from $5.71 per mcf at December 31, 2008 to $3.63 per mcf at March 31, 2009. Included in this write-down was the impairment of approximately $1.9 billion of unevaluated leasehold. In connection with our scaled-back drilling program, lower natural gas prices and our more focused development efforts in the Big 4 natural gas shale plays, we determined that certain of our unevaluated leasehold positions would likely not be developed and would be allowed to expire. Accordingly, the carrying costs of the impaired leasehold were transferred to the amortization base of our full-cost pool during the Current Quarter and were consequently included in our ceiling test impairment during the Current Quarter.

Additionally, we recognized a $22 million charge for a deposit on canceled contracts that we do not anticipate being refunded.

Impairment of Investments. In the Current Quarter, we recorded a $153 million impairment of certain investments. Each of our investees has been impacted by the dramatic slowing of the worldwide economy and the freezing of the credit markets in the fourth quarter of 2008 and into 2009. The economic weakness has resulted in significantly reduced natural gas and oil prices leading to a meaningful decline in the overall level of activity in the markets served by our investees. Associated with the weakness in performance of certain of the investees, as well as an evaluation of their financial condition and near-term prospects, we recognized that an other than temporary impairment had occurred on the following investments: Gastar Exploration Ltd., $70 million; Chaparral Energy, Inc., $51 million; DHS Drilling Company, $19 million; and Mountain Drilling Company, $9 million. Additionally we recognized approximately $4 million of impairment charges related to other investments.

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Other Income (Expense). Interest and other income (expense) was $8 million in the Current Quarter compared to ($9) million in the Prior Quarter. The Current Quarter consisted of $3 million of interest income, a ($1) million loss related to our equity in the net losses of certain investments, a $1 million gain on sale of assets and $5 million of miscellaneous income. The Prior Quarter income consisted of $2 million of interest income, a ($12) million loss related to our equity in the net losses of certain investments and $1 million of miscellaneous income.

Interest Expense. Interest expense decreased to ($14) million in the Current Quarter compared to $99 million in the Prior Quarter as follows:

	Three Months Ended March 31,	
	2009	2008
	($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 194	$ 180
Capitalized interest	(161)	(103)
Realized (gain) loss on interest rate derivatives	(7)	
Unrealized (gain) loss on interest rate derivatives	(45)	13
Amortization of loan discount and other	5	9
Total interest expense	$ (14)	$ 99
Average long-term borrowings	$ 10,802	$ 8,974

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.14 per mcfe in the Current Quarter compared to $0.42 in the Prior Quarter. The decrease in interest expense per mcfe is primarily due to an increase in capitalized interest and increased production volumes. Capitalized interest increased by $58 million as a result of a significant increase in unevaluated properties, the base on which interest is capitalized in the Current Quarter compared to the Prior Quarter. We expect interest expense for 2009 to be between $0.30 and $0.35 per mcfe produced (before considering the effect of interest rate derivatives).

Income Tax Expense (Benefit). Chesapeake recorded a deferred income tax benefit of $3.444 billion in the Current Quarter, compared to a deferred income tax benefit of $82 million in the Prior Quarter. Of the $3.362 billion increase in income tax benefit recorded in the Current Quarter, $3.454 billion was the result of the decrease in net income before income taxes which was offset by $92 million due to a decrease in the effective tax rate. Our effective income tax rate was 37.5% in the Current Quarter and 38.5% in the Prior Quarter. Our effective tax rate fluctuates as a result of the impact of state income taxes and permanent differences.

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, 2008 (2008 Form 10-K).

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 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. We adopted this statement in the Current Quarter. This statement had no financial impact on our condensed consolidated financial statements. See Note 2 of our condensed consolidated financial statements included in this report for additional information on the adoption of SFAS No. 161.

On December 31, 2008, the Securities and Exchange Commission (SEC) adopted major revisions to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new disclosure requirements also

require companies to report the independence and qualifications of the person primarily responsible for the preparation or audit of reserve estimates, and to file reports when a third party is relied upon to prepare or audit reserves estimates. The new rules also require that oil and gas reserves be reported and the full-cost ceiling value calculated using an average price based upon the prior 12-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. We are in the process of assessing the impact of these new requirements on our financial position, results of operations and financial disclosures.

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 estimates of natural gas and oil reserves, expected natural gas and oil production and future expenses, assumptions regarding future natural gas and oil prices, planned capital expenditures, and anticipated asset acquisitions and sales, as well as statements concerning anticipated cash flow and liquidity, business strategy and other plans and objectives for future operations. Disclosures 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 2008 Form 10-K. They include:

- the volatility of natural gas and oil prices,
- the limitations our level of indebtedness may have on our financial flexibility,
- impacts the current financial crisis may have on our business and financial condition,
- declines in the values of our natural gas and oil properties resulting in ceiling test write-downs,
- the availability of capital on an economic basis, including planned asset monetization transactions, to fund reserve replacement costs,
- our ability to replace reserves and sustain production,
- uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and the timing of development expenditures,
- exploration and development drilling that does not result in commercially productive reserves,
- leasehold terms expiring before production can be established,
- hedging activities resulting in lower prices realized on natural gas and oil sales and the need to secure hedging liabilities,

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

the negative effect lower natural gas and oil prices could have on our ability to borrow,

drilling and operating risks, including potential environmental liabilities,

transportation capacity constraints and interruptions that could adversely affect our cash flow,

adverse effects of governmental and environmental 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.

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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. 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.

Our general strategy for attempting to mitigate exposure to adverse natural gas price changes is to hedge into strengthening gas futures markets when prices allow us to generate high cash margins and when we view prices to be in the upper range of our predicted most likely future price range. Information we consider in forming an opinion about future prices includes general economic conditions, industrial output levels and expectations, producer breakeven cost structures, liquefied natural gas import trends, gas storage inventory levels, industry decline rates for base production and weather trends.

We use a wide range of instruments to achieve our risk management objectives, including swaps, swaps with imbedded puts (knockouts), various collar arrangements, and options (puts or calls). All of these are more fully described below. We typically use swaps or knockouts for much of the volume of gas we are hedging. Swaps are used when the price level is acceptable, and we are not paid a sufficient premium for selling an additional put (the knockouts) that could cause the swap to become ineffective if the NYMEX future price closes below some lower threshold on the settlement date, typically the last trading date of the production month. We do use the knockouts when we are able to obtain a premium for the put that increases our swap pricing when we think the put level is more likely than not to be reached. We also sell calls, taking advantage of the volatility counterparties are willing to pay us, for some smaller portion of our predicted volumes when the absolute price level and the call premium are attractive to us, meaning that we believe it to be more likely than not that the future gas price will not exceed the call strike plus the premium we receive.

The volume of the potential hedging we may enter into is determined by reviewing the company s estimated future production levels, which are derived from extensive examination of existing producing reserve estimates, coupled with our estimates of likely production (risked) from new drilling. These are updated at least every month and adjusted if necessary to actual results and activity levels. We do not hedge more volumes than we expect to produce, and if production estimates are lowered for future periods and hedges are already executed for some volume above the new predicted volumes, the hedges are reversed. The actual price level we decide on with a counterparty is derived from market discovery and bidding and the reference NYMEX price as reflected in current NYMEX trading. Settlement dates of these contracts follow the future NYMEX month and the posted penultimate or last trading day of that contract, which is all standardized in the industry and set by NYMEX.

If our view of future market conditions changes, and prices have fallen to levels we believe are unsustainable, we may close a position by doing a cash settlement with our counterparty, or by entering into a new swap that effectively reverses the position (a counter-swap). The factors we consider in closing a position before the settlement date are identical to those we reviewed when deciding to enter into the original hedge position.

As of March 31, 2009, our natural gas and oil derivative instruments were comprised of the following:

For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays a floating market price to the counterparty.

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.

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.

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

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.

All of our derivative instruments are net settled based on the difference between the fixed-price payment and the floating-price payment, resulting in a net amount due to or from the counterparty.

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.

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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, the Prior Quarter are presented below.

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
	($ in millions)	
Natural gas and oil sales	$ 778	$ 1,690
Realized gains (losses) on natural gas and oil derivatives	519	215
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	46	(1,067)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	54	(65)
Total natural gas and oil sales	$ 1,397	$ 773

As of March 31, 2009, we had the following open natural gas and oil derivative instruments (including 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 31, 2009:

	Volume	Weighted Average Fixed Price to be Received per mmbtu	Weighted Average Put Fixed Price per mmbtu	Weighted Average Call Fixed Price per mmbtu	Weighted Average Differential per mmbtu	SFAS 133 Hedge	Net Premiums ($ in millions)	Fair Value at March 31, 2009 ($ in millions)
Natural Gas (bbtu):								
Swaps:								
Q2 2009	57,518	$ 7.85	$	$	$	Yes	$	$ 226
Q3 2009	57,614	8.06				Yes		216
Q4 2009	99,694	7.57				Yes		238
Q1 2010	14,893	9.98				Yes		62
Q2-Q4 2010	40,905	8.89				Yes		117
2011	10,950	8.59				Yes		20
CNR Swaps[(b)]:								
Q2 2009	4,550	5.18				Yes		6
Q3 2009	4,600	5.18				Yes		5
Q4 2009	4,600	5.18				Yes		1
Other Swaps[(a)]:								
Q2 2009	3,640	10.67				No		25
Q3 2009	3,680	10.77				No		24
Q4 2009	3,680	11.15				No		23
Q1 2010	3,600	11.35				No		
Q2-Q4 2010	24,750	9.89				No		(2)
2011	4,500	8.73				No		(1)
Counter Swaps								

Q2 2009	(3,640)	(9.26)	No	(20)
Q3 2009	(3,680)	(9.26)	No	(19)
Q4 2009	(3,680)	(9.26)	No	(16)

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	Volume	Weighted Average Fixed Price to be Received per mmbtu	Weighted Average Put Fixed Price per mmbtu	Weighted Average Call Fixed Price per mmbtu	Weighted Average Differential per mmbtu	SFAS 133 Hedge	Net Premiums ($ in millions)	Fair Value at March 31, 2009 ($ in millions)
Collars:								
Q2 2009	20,020	$	$ 7.16	$ 8.07	$	Yes	$	$ 64
Q3 2009	23,280		7.20	8.10		Yes		70
Q4 2009	17,220		7.36	8.24		Yes		44
Q1 2010	22,500		6.00	8.00		Yes		15
CNR Collars[(b)]:								
Q2 2009	910		4.50	6.00		Yes		1
Q3 2009	920		4.50	6.00		Yes		1
Q4 2009	920		4.50	6.00		Yes		
Other Collars[(c)]:								
Q2 2009	81,135		5.24/6.99	9.18		No	3	206
Q3 2009	85,060		5.24/6.98	9.16		No	3	199
Q4 2009	44,860		5.39/7.28	9.49		No	3	97
Q1 2010	17,100		5.18/7.05	9.49		No	5	19
Q2-Q4 2010	30,170		5.29/7.33	10.21		No	16	44
2011	18,250		6.00/7.80	11.13		No	14	26
2012 2017	21,920		6.00/7.30	12.00		No	1	3
Knockout Swaps:								
Q4 2009	5,490	10.17	6.33			No		3
Q1 2010	11,700	10.71	6.33			No		9
Q2-Q4 2010	57,830	9.85	6.16			No		23
2011	23,650	9.86	6.29			No		5
Call Options:								
Q2 2009	18,315			8.86		No	27	
Q3 2009	27,160			8.83		No	27	(1)
Q4 2009	28,980			9.03		No	27	(4)
Q1 2010	57,150			10.93		No	42	(6)
Q2-Q4 2010	174,625			10.71		No	125	(19)
2011	116,800			10.70		No	78	(39)
2012 2020	186,440			11.71		No	122	(109)
Put Options:								
Q2 2009	9,100		5.75			No	1	(17)
Q3 2009	9,200		5.75			No	1	(16)
Q4 2009	9,200		5.75			No	1	(12)
Q1 2010	9,000		5.75			No	1	(8)
Q2-Q4 2010	27,500		5.75			No	2	(26)
Basis Protection Swaps:								
(Mid-Continent):								
Q2 2009	16,457				(1.38)	No		(7)
Q3 2009	16,821				(1.37)	No		(12)
Q4 2009	16,953				(1.36)	No		(6)
2011	45,090				(0.82)	No	(3)	(1)
2012 2018	57,961				(0.90)	No	(3)	(8)
Basis Protection Swaps:								
(Appalachian Basin):								
Q2 2009	4,178				0.28	No		
Q3 2009	4,448				0.27	No		1
Q4 2009	4,438				0.27	No		1
Q1 2010	2,293				0.26	No		
Q2-Q4 2010	7,905				0.26	No		1
2011	12,086				0.25	No		2
2012 2022	134				0.11	No		

Total Natural Gas	493	1,448

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	Volume	Weighted Average Fixed Price to be Received per bbl	Weighted Average Put Fixed Price per bbl	Weighted Average Call Fixed Price per bbl	Weighted Average Differential per bbl	SFAS 133 Hedge	Net Premiums ($ in millions)	Fair Value at March 31, 2009 ($ in millions)
Oil (mbbls):								
Other Swaps:								
Q2 2009	910	$ 86.25	$	$	$	No	$	$ 31
Counter Swaps:								
Q2 2009	(819)	67.00				No		(12)
Q3 2009	(230)	69.10				No		(3)
Q4 2009	(230)	69.10				No		(3)
Cap Swaps:								
Q2 2009	182	67.50	50.00			No		2
Knockout Swaps:								
Q2 2009	364	84.52	59.75			No		1
Q3 2009	1,288	85.73	59.93			No		6
Q4 2009	1,288	85.71	58.51			No		4
Q1 2010	1,170	90.25	60.00			No		5
Q2-Q4 2010	3,575	90.25	60.00			No		11
2011	1,095	104.75	60.00			No		9
2012	732	109.50	60.00			No		6
Call Options:								
Q2 2009	1,274			101.79		No	1	
Q3 2009	1,288			101.79		No	1	(1)
Q4 2009	1,288			101.79		No	1	(2)
Q1 2010	1,710			107.86		No	(3)	(2)
Q2-Q4 2010	5,225			107.86		No	(8)	(12)
2011	3,650			185.00		No	36	(3)
2012	3,660			185.00		No	37	(4)
Total Oil							65	33
Total Natural Gas and Oil							$ 558	$ 1,481

(a) This includes options to extend an existing swap for an additional 12 months, one for 40,000 mmbtu/day at $11.35/mmbtu and the other at 50,000 mmbtu/day at $8.73/mmbtu, callable by the counterparty in December 2009 and March 2010, respectively.

(b) 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 ($27 million liability remaining as of March 31, 2009). The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our 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.

(c) Included in Other Collars for 2009, 2010, 2011 and 2012-2017 are 81,445 bbtu, 25,370 bbtu, 3,650 bbtu and 21,920 bbtu of collars which include written put options with weighted average prices of $5.28, $5.24, $6.00 and $6.00, respectively which limit the counterpary s exposure.

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To mitigate our exposure to the fluctuation in prices of diesel fuel, we have entered into diesel swaps from April 2009 to March 2010 for a total of 41,475,000 gallons with an average fixed price of $1.60 per gallon. The fair value of these swaps as of March 31, 2009 was a liability of $3 million.

We have established the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors.

Based upon the market prices at March 31, 2009, we expect to transfer approximately $640 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to earnings during the next 12 months in the related month of production. All transactions hedged as of March 31, 2009 are expected to mature by December 31, 2022.

Additional information concerning the fair value of our natural gas and oil derivative instruments is as follows:

	2009 ($ in millions)
Fair value of contracts outstanding, as of January 1	$ 1,306
Change in fair value of contracts	1,030
Fair value of contracts when entered into	(77)
Contracts realized or otherwise settled	(519)
Fair value of contracts when closed	(259)
Fair value of contracts outstanding, as of March 31	$ 1,481

The change in the fair value of our derivative instruments since January 1, 2009 resulted from new contracts entered into, the settlement of derivatives for a realized gain (loss), as well as a decrease 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.

Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates.

	Years of Maturity						
	2009	2010	2011	2012	2013	Thereafter	Total
Liabilities:							
Long-term debt fixed rate[a]	$	$	$	$	$ 864	$ 10,646	$ 11,510
Average interest rate					7.6%	6.0%	6.1%
Long-term debt variable rate	$	$	$	$ 2,225	$ 164	$	$ 2,389
Average interest rate				1.5%	2.8%		1.6%

(a) This amount does not include the discount included in long-term debt of ($1.129) billion and interest rate derivatives of $163 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 facilities. 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.

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Interest Rate Derivatives

We use interest rate derivatives to mitigate our exposure to volatility in interest rates related to our senior notes and credit facilities. 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 $7 million and a nominal amount in the Current Quarter and the Prior Quarter, respectively. Unrealized gains (losses) included in interest expense were $45 million and ($13) million in the Current Quarter and the Prior Quarter, respectively.

As of March 31, 2009, the following interest rate derivatives were outstanding:

	Notional Amount ($ in millions)	Weighted Average Fixed Rate	Weighted Average Floating Rate(b)	Fair Value Hedge	Net Premiums ($ in millions)	Fair Value ($ in millions)
Fixed to Floating Interest Rate:						
Swaps						
January 2008 November 2020	$ 500	6.875%	6 mL plus 230 bp	Yes	$	$ 66
April 2008 August 2015	$ 250	6.50%	6 mL plus 240 bp	No	$	$ 20
Call Options						
May 2009 August 2009	$ 750	6.75%	6 mL plus 233 bp	No	$ 9	$ (77)
Floating to Fixed Interest Rate:						
Swaps						
August 2007 July 2012	$ 1,375	4.20%	1 - 6 mL	No	$	$ (47)
Collars(a)						
August 2007 August 2010	$ 250	4.52%	6 mL	No	$	$ (10)
Swaption						
August 2009	$ 500	2.56%	1 mL	No	$ 5	$ (12)
					$ 14	$ (60)

(a) The collars have ceiling and floor fixed interest rates of 5.37% and 4.52%, respectively.

(b) Month LIBOR has been abbreviated mL and basis points has been abbreviated bp .

In the Current Quarter, we closed interest rate derivatives for gains totaling $12 million of which $7 million was recognized in interest expense. The remaining $5 million was from interest rate derivatives 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 ranging from eight to nine years.

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 ($796 million at March 31, 2009) using an exchange rate of $1.3261 to 1.00. The fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as a liability of $74 million at March 31, 2009.

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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*

On February 25, 2009, a putative class action was filed in the U.S. District Court for the Southern District of New York against the company and certain of its officers and directors along with certain underwriters of the company s July 2008 common stock offering. The complaint alleges that the registration statement for the offering contained material misstatements and omissions and seeks damages under Sections 11, 12 and 15 of the Securities Act of 1933 of an unspecified amount and rescission. A derivative action was also filed in the District Court of Oklahoma County, Oklahoma on March 10, 2009 against the company s directors and certain of its officers alleging breaches of fiduciary duties relating to the disclosure matters alleged in securities case. Two additional derivative actions were filed in the District Court of Oklahoma County, Oklahoma on April 28 and May 7, 2009 against the company s directors alleging breaches of fiduciary duties relating to executive compensation of the company s CEO and alleged insider trading, among other things, and seeking unspecified damages, equitable relief and disgorgement. Chesapeake is named as a nominal defendant in these derivative actions. On March 26, 2009, a shareholder filed a petition in the District Court of Oklahoma County, Oklahoma seeking to compel inspection of company books and records relating an executive compensation matter. It is inherently difficult to predict the outcome of litigation, and these cases are all in preliminary stages.

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 2008 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 incidental to its business 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 2008 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, 2009:

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, 2009 through January 31, 2009	692,779	$ 17.24		
February 1, 2009 through February 28, 2009	19,535	15.92		
March 1, 2009 through March 31, 2009	10,941	17.16		
Total	723,255	$ 17.20		

(a) Includes the surrender to the company of 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 deferred compensation 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.

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On March 31, 2009, we converted all outstanding shares of our 4.125% Cumulative Convertible Preferred Stock into Chesapeake common stock. On the conversion date, 3,033 shares of the convertible preferred stock were converted into 182,887 shares of common stock, plus the right to receive cash in lieu of fractional shares. The shares of common stock issued in the conversion were issued pursuant to the terms of the Certificate of Designation for the convertible preferred stock without any investment decision required of the holders and thus did not constitute a sale within the meaning of the Securities Act of 1933, as amended. Further, since the shares of common stock were issued solely pursuant to the terms of conversion of the convertible preferred stock and no commission or other remuneration was paid or given directly or indirectly for soliciting the conversion, the common shares are securities included in the exemption from registration provided by Section 3(a)(9) of the Securities Act.

Certain of our employees have purchased shares of our common stock in the 401(k) plan maintained by the company which were not registered under the Securities Act of 1933. These include 252,301 shares in the Chesapeake 401(k) plan which exceeded the number of shares previously registered under Form S-8 registration statements for the plan. Plan participants purchased the shares at prices ranging from $10.319 to $20.01 per share between November 2008 and February 2009. All such shares were acquired by the trustee of the plan on behalf of participants through open market purchases, and the company received no proceeds from these transactions. We filed a registration statement on Form S-8 to increase the shares of Chesapeake common stock registered for the Chesapeake 401(k) plan on February 25, 2009.

ITEM 3. ***Defaults Upon Senior Securities***

Not applicable.

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

Not applicable.

ITEM 5. ***Other Information***

Not applicable.

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ITEM 6. ***Exhibits***

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

Exhibit Number	Exhibit Description	Incorporated by Reference 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	
3.1.3	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B).	10-Q	001-13726	3.1.4	11/10/2008	
3.1.4	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended.	S-8	333-151762	4.1.6	06/18/2008	
3.1.5	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock.	10-Q	001-13726	3.1.6	08/11/2008	
3.1.6	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	11/17/2008	
4.4.1	Fourth Amendment dated as of March 31, 2009 to Seventh Amended and Restated Credit Agreement, dated as of November 2, 2007, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., as Co-Borrowers, Union Bank of California, N.A., as Administrative Agent, The Royal Bank of Scotland, as Syndication Agent, and Bank of America, N.A., SunTrust Bank and BNP Paribas, as Co-Documentation Agents, and the several lenders from time to time parties thereto.					X
4.18	Indenture dated as of February 2, 2009 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company N.A., as Trustee, with respect to the 9.50% senior notes due 2015.	8-K	001-13726	4.1	02/03/2009	
4.18.1	First Supplemental Indenture dated as of February 10, 2009 to Indenture dated as of February 2, 2009 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company N.A., as Trustee, with respect to the 9.50% senior notes due 2015.	8-K	001-13726	4.2	02/17/2009	
4.18.2	Second Supplemental Indenture dated as of March 31, 2009 to Indenture dated as of February 2, 2009 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company N.A., as Trustee, with respect to the 9.50% senior notes due 2015.					X
10.2.1	Employment Agreement dated as of March 1, 2009 between Aubrey K. McClendon and Chesapeake Energy Corporation.					X
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

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
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 requirement 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 11, 2009

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INDEX TO EXHIBITS

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3.1.3	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B).	10-Q	001-13726	3.1.4	11/10/2008	
3.1.4	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended.	S-8	333-151762	4.1.6	06/18/2008	
3.1.5	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock.	10-Q	001-13726	3.1.6	08/11/2008	
3.1.6	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	11/17/2008	
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4.18	Indenture dated as of February 2, 2009 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company N.A., as Trustee, with respect to the 9.50% senior notes due 2015.	8-K	001-13726	4.1	02/03/2009	
4.18.1	First Supplemental Indenture dated as of February 10, 2009 to Indenture dated as of February 2, 2009 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company N.A., as Trustee, with respect to the 9.50% senior notes due 2015.	8-K	001-13726	4.2	02/17/2009	
4.18.2	Second Supplemental Indenture dated as of March 31, 2009 to Indenture dated as of February 2, 2009 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company N.A., as Trustee, with respect to the 9.50% senior notes due 2015.					X
10.2.1	Employment Agreement dated as of March 1, 2009 between Aubrey K. McClendon and Chesapeake Energy Corporation.					X
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

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
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