CHESAPEAKE ENERGY CORP
Form 10-Q
August 10, 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 June 30, 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 (State or other jurisdiction of incorporation or organization)	**73-1395733** (I.R.S. Employer Identification No.)
6100 North Western Avenue **Oklahoma City, Oklahoma** (Address of principal executive offices)	**73118** (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 [X] No [ ]

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

Large accelerated filer [X]	Accelerated filer [ ]
Non-accelerated filer [ ] (Do not check if a smaller reporting company)	Smaller reporting company [ ]

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

As of August 6, 2009, there were 641,652,116 shares of our $0.01 par value common stock outstanding.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	June 30, 2009	December 31, 2008 (Adjusted)
	($ in millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 554	$ 1,749
Accounts receivable	1,122	1,324
Short-term derivative instruments	1,133	1,082
Other	139	137
Total Current Assets	2,948	4,292
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full-cost accounting:		
Evaluated natural gas and oil properties	33,886	28,965
Unevaluated properties	9,465	11,379
Less: accumulated depreciation, depletion and amortization of natural gas and oil properties	(22,199)	(11,866)
Total natural gas and oil properties, at cost based on full-cost accounting	21,152	28,478
Other property and equipment:		
Natural gas gathering systems and treating plants	3,256	2,717
Buildings and land	1,618	1,513
Drilling rigs and equipment	556	430
Natural gas compressors	248	184
Other	522	482
Less: accumulated depreciation and amortization of other property and equipment	(616)	(496)
Total Other Property and Equipment	5,584	4,830
Total Property and Equipment	26,736	33,308
OTHER ASSETS:		
Investments	394	444
Long-term derivative instruments	88	261
Other assets	303	288
Total Other Assets	785	993
TOTAL ASSETS	$ 30,469	$ 38,593

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(Unaudited)

	June 30, 2009	December 31, 2008 (Adjusted)
	($ in millions)	
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 971	$ 1,611
Short-term derivative instruments	28	66
Accrued liabilities	983	880
Deferred income taxes	401	358
Income taxes payable		108
Revenues and royalties due others	371	431
Accrued interest	220	167
Total Current Liabilities	2,974	3,621
LONG-TERM LIABILITIES:		
Long-term debt, net	13,568	13,175
Deferred income tax liabilities	906	4,200
Asset retirement obligations	279	269
Long-term derivative instruments	322	111
Other liabilities	418	200
Total Long-Term Liabilities	15,493	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 June 30, 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 June 30, 2009 and December 31, 2008, entitled in liquidation to $209 million	209	209
5.00% cumulative convertible preferred stock (series 2005), 5,000 shares issued and outstanding as of June 30, 2009 and December 31, 2008, entitled in liquidation to $1 million	1	1
6.25% mandatory convertible preferred stock, 0 shares and 143,768 shares issued and outstanding as of June 30, 2009 and December 31, 2008, respectively, entitled in liquidation to $0 and $36 million		36
4.125% cumulative convertible preferred stock, 0 and 3,033 shares issued and outstanding as of June 30, 2009 and December 31, 2008, respectively, entitled in liquidation to $0 and $3 million		3
Common Stock, $0.01 par value, 1,000,000,000 shares and 750,000,000 shares authorized, 630,251,782 and 607,953,437 shares issued at June 30, 2009 and December 31, 2008, respectively	6	6
Paid-in capital	12,032	11,680
Retained earnings (deficit)	(929)	4,569
Accumulated other comprehensive income (loss), net of tax of ($267) million and ($163) million, respectively	438	267
Less: treasury stock, at cost; 718,800 and 657,276 common shares as of June 30, 2009 and December 31, 2008, respectively	(11)	(10)
Total Stockholders Equity	12,002	17,017

TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 30,469	$ 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 June 30, 2009	Three Months Ended June 30, 2008 (Adjusted)	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008 (Adjusted)
	($ in millions except per share data)			
REVENUES:				
Natural gas and oil sales	$ 1,097	$ (1,594)	$ 2,494	$ (821)
Natural gas and oil marketing sales	532	1,099	1,084	1,895
Service operations revenue	44	40	90	82
Total Revenues	1,673	(455)	3,668	1,156
OPERATING COSTS:				
Production expenses	213	219	451	419
Production taxes	24	88	46	163
General and administrative expenses	74	101	164	180
Natural gas and oil marketing expenses	500	1,075	1,023	1,849
Service operations expense	46	32	87	67
Natural gas and oil depreciation, depletion and amortization	295	523	742	1,038
Depreciation and amortization of other assets	58	40	115	76
Impairment of natural gas and oil properties and other assets	5		9,635	
Restructuring costs	34		34	
Total Operating Costs	1,249	2,078	12,297	3,792
INCOME (LOSS) FROM OPERATIONS	424	(2,533)	(8,629)	(2,636)
OTHER INCOME (EXPENSE):				
Other income (expense)	(2)	(1)	5	(11)
Interest expense	(22)	(54)	(8)	(153)
Impairment of investments	(10)		(162)	
Loss on exchanges of Chesapeake debt	(2)		(2)	
Total Other Income (Expense)	(36)	(55)	(167)	(164)
INCOME (LOSS) BEFORE INCOME TAXES	388	(2,588)	(8,796)	(2,800)
INCOME TAX EXPENSE (BENEFIT):				
Current income taxes	1	3	1	3
Deferred income taxes	144	(999)	(3,299)	(1,081)
Total Income Tax Expense (Benefit)	145	(996)	(3,298)	(1,078)
NET INCOME (LOSS)	243	(1,592)	(5,498)	(1,722)
PREFERRED STOCK DIVIDENDS	(6)	(9)	(12)	(21)
LOSS ON CONVERSION/EXCHANGE OF PREFERRED STOCK		(42)		(42)

NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$	237	$	(1,643)	$	(5,510)	$	(1,785)
EARNINGS (LOSS) PER COMMON SHARE:								
Basic	$	0.39	$	(3.16)	$	(9.18)	$	(3.52)
Assuming dilution	$	0.39	$	(3.16)	$	(9.18)	$	(3.52)
CASH DIVIDEND DECLARED PER COMMON SHARE	$	0.075	$	0.075	$	0.15	$	0.1425
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):								
Basic		603		521		600		507
Assuming dilution		610		521		600		507

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Six Months Ended June 30, 2009	2008 (Adjusted)
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME (LOSS)	$ (5,498)	$ (1,722)
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	857	1,119
Deferred income taxes	(3,299)	(1,081)
Impairments	9,792	
Unrealized (gains) losses on derivatives	29	4,538
Realized (gains) losses on financing derivatives	(35)	32
Stock-based compensation	68	61
Interest expense on contingent convertible notes	40	33
Restructuring costs	29	
Loss from equity investments	8	
Loss on exchanges of Chesapeake debt	2	
Other	12	20
Change in assets and liabilities	(7)	(202)
Cash provided by operating activities	1,998	2,798
CASH FLOWS FROM INVESTING ACTIVITIES:		
Exploration and development of natural gas and oil properties	(2,092)	(2,935)
Acquisitions of natural gas and oil companies, proved and unproved properties and leasehold, net of cash acquired	(412)	(2,815)
Interest capitalized on unproved properties	(314)	(244)
Proceeds from sale of volumetric production payments	41	616
Divestitures of proved and unproved properties and leasehold	187	247
Additions to other property and equipment	(980)	(1,229)
Proceeds from (additions to) investments	2	(81)
Proceeds from sale of drilling rigs and equipment		34
Proceeds from sale of compressors	68	51
Deposits made for acquisitions	(9)	(19)
Deposits received for divestitures	8	
Proceeds from sale of other assets	36	2
Cash used in investing activities	(3,465)	(6,373)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from credit facility borrowings	3,363	6,758
Payments on credit facility borrowings	(4,166)	(6,195)
Proceeds from issuance of senior notes, net of offering costs	1,346	2,136
Proceeds from issuance of common stock, net of offering costs		1,011
Cash paid for common stock dividends	(89)	(66)

Cash paid for preferred stock dividends	(12)	(22)
Derivative settlements	9	(93)
Net increase (decrease) in outstanding payments in excess of cash balance	(350)	47
Proceeds from mortgage of building	54	
Proceeds from sale/leaseback of surface land	145	
Excess tax benefit from stock-based compensation		21
Other	(28)	(23)
Cash provided by financing activities	272	3,574
Net decrease in cash and cash equivalents	(1,195)	(1)
Cash and cash equivalents, beginning of period	1,749	1
Cash and cash equivalents, end of period	$ 554	$

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

(Unaudited)

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008 (Adjusted)
	($ in millions)	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:		
Interest, net of $314 million and $244 million of capitalized interest, respectively	$ 2	$ 96
Income taxes, net of refunds received	$ 176	$ 5
SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:		

As of June 30, 2009 and 2008, dividends payable on our common and preferred stock were $51 million and $48 million, respectively.

For the six months ended June 30, 2009 and 2008, natural gas and oil properties were adjusted by a nominal amount and $12 million, respectively, for net income tax liabilities related to acquisitions.

For the six months ended June 30, 2009 and 2008, natural gas and oil properties were adjusted by ($65) million and $33 million, respectively, as a result of an increase (decrease) in accrued exploration and development costs.

For the six months ended June 30, 2009 and 2008, other property and equipment were adjusted by ($12) million and $17 million, respectively, as a result of an increase (decrease) in accrued costs.

We recorded non-cash asset additions (reductions) to natural gas and oil properties of ($2) million and $6 million for the six months ended June 30, 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.

On June 15, 2009, we converted all of our outstanding 6.25% Mandatory Convertible Preferred Stock (143,768 shares) into 1,239,538 shares of common stock.

In June 2009, we privately exchanged approximately $85 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 2,530,650 shares of our common stock.

For the six months ended June 30, 2009, we issued 15,823,838 shares of common stock, valued at $269 million, for the purchase of proved and unproved properties and leasehold pursuant to an acquisition shelf registration statement.

For the six months ended June 30, 2008, holders of our 5.0% (Series 2005B) Cumulative Convertible Preferred Stock exchanged 2,718,500 shares for 7,780,703 shares of common stock in privately negotiated exchanges.

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(Unaudited)

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008 (Adjusted)
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning of period	$ 505	$ 960
Exchange of common stock for 143,768 and 0 shares of 6.25% preferred stock	(36)	
Exchange of common stock for 3,033 and 0 shares of 4.125% preferred stock	(3)	
Exchange of common stock for 0 and 2,718,500 shares of 5.00% preferred stock (series 2005B)		(272)
Balance, end of period	466	688
COMMON STOCK:		
Balance, beginning of period	6	5
Issuance of 15,823,838 and 0 shares of common stock for the purchase of proved and unproved properties and leasehold		
Issuance of 0 and 23,000,000 shares of common stock		
Exchange of 2,530,650 and 0 shares of common stock for convertible notes		
Exchange of 1,422,425 and 7,780,883 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 15,823,838 shares and 0 shares of common stock for the purchase of proved and unproved properties and leasehold	254	
Issuance of 0 and 23,000,000 shares of common stock		1,052
Issuance of 2.25% contingent convertible senior notes due 2038		345
Exchange of 2,530,650 and 0 shares of common stock for convertible notes	54	
Exchange of 1,422,425 and 7,780,883 shares of common stock for preferred stock	39	272
Stock-based compensation	119	82
Exercise of stock options	1	7
Offering expenses		(53)
Dividends on common stock	(91)	
Dividends on preferred stock	(12)	
Tax benefit (reduction in tax benefit) from exercise of stock options and restricted stock	(12)	21
Balance, end of period	12,032	9,258
RETAINED EARNINGS (DEFICIT):		
Balance, beginning of period	4,569	4,145
Net income (loss)	(5,498)	(1,722)
Dividends on common stock		(73)
Dividends on preferred stock		(10)

Balance, end of period	(929)	2,340
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	267	(11)
Hedging activity	110	(1,191)
Investment activity	61	28
Balance, end of period	438	(1,174)
TREASURY STOCK COMMON:		
Balance, beginning of period	(10)	(6)
Purchase of 64,242 and 0 shares for company benefit plans	(1)	
Release of 2,718 and 1,098 shares for company benefit plans		
Balance, end of period	(11)	(6)
TOTAL STOCKHOLDERS EQUITY	$ 12,002	$ 11,111

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 June 30, 2009	Three Months Ended June 30, 2008 (Adjusted)	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008 (Adjusted)
	($ in millions)			
Net income (loss)	$ 243	$ (1,592)	$ (5,498)	$ (1,722)
Other comprehensive income (loss), net of income tax:				
Change in fair value of derivative instruments, net of income taxes of $37 million, ($530) million, $333 million and ($833) million	63	(865)	547	(1,357)
Reclassification of (gain) loss on settled contracts, net of income taxes of ($120) million, $103 million, ($232) million, and $52 million	(197)	167	(381)	85
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of ($13) million, $24 million, ($34) million and $49 million	(22)	39	(56)	80
Unrealized (gain) loss on investments, net of income taxes of $7 million, $16 million, $11 million and $17 million	12	27	18	28
Reclassification of loss on investments, net of income taxes of $0, $0, $26 million and $0			43	
Comprehensive income (loss)	$ 99	$ (2,224)	$ (5,327)	$ (2,886)

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 (SEC). 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. The accompanying consolidated financial statements should be read in conjunction with the consolidated financial statements and the notes thereto for the year ended December 31, 2008 contained in our Current Report on Form 8-K dated June 25, 2009. All material adjustments (consisting solely of normal recurring adjustments) which, in the opinion of management, are necessary for a fair statement of the results for the interim periods have been reflected. The results for the three and six months ended June 30, 2009 are not necessarily indicative of the results to be expected for the full year. This Form 10-Q relates to the three and six months ended June 30, 2009 (the Current Quarter and the Current Period , respectively) and the three and six months ended June 30, 2008 (the Prior Quarter and the Prior Period , respectively). Any material subsequent events have been considered for disclosure through August 10, 2009, the filing date of this Form 10-Q.

Change in Accounting Principle

On January 1, 2009, we adopted and applied retrospectively Financial Accounting Standards Board (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.

Oil and Natural Gas Properties Ceiling Test

We review the carrying value of our natural gas and oil properties under the full-cost accounting rules of the SEC 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 (including the impact of cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. Any excess of the net book value, less deferred income taxes, is written off as an expense. As of June 30, 2009, the present value of our proved reserves was $11.076 billion which exceeded our net capitalized cost and no impairment was necessary.

In calculating future net revenues, prices and costs used are those as of the end of the appropriate quarterly period 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. Our qualifying cash flow hedges as of June 30, 2009, which consisted of swaps and collars, covered 253 bcfe, 74 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. Based on spot prices for natural gas and oil of $3.89 per mcf and $70.00 per barrel, respectively, as of June 30, 2009, these cash flow hedges increased the full-cost ceiling by $1.219 billion, thereby reducing any potential ceiling test write-down by the same amount. Had the effects of our cash flow hedges not been considered in calculating the ceiling limitation, the impairment as of June 30, 2009 would have been approximately $115 million, net of tax.

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.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

2. Financial Instruments and Hedging Activities

Natural Gas and Oil Derivatives

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 June 30, 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. On occasion, we sell an additional put option with the collar and receive a premium to make a three-way collar. This eliminates the counterparty s downside exposure below the second put option.

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 non-Appalachian Basin 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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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.

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 accumulated 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, the Current Period and the Prior Period are presented below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	($ in millions)			
Natural gas and oil sales	$ 717	$ 2,233	$ 1,495	$ 3,925
Realized gains (losses) on natural gas and oil derivatives	597	(423)	1,115	(208)
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(253)	(3,340)	(206)	(4,409)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	36	(64)	90	(129)
Total natural gas and oil sales	$ 1,097	$ (1,594)	$ 2,494	$ (821)

The estimated fair values of our natural gas and oil derivative instruments as of June 30, 2009 and December 31, 2008 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	June 30, 2009	December 31, 2008
	($ in millions)	
Derivative assets (liabilities)[(a)]:		
Fixed-price natural gas swaps	$ 733	$ 863
Fixed-price natural gas collars	492	402
Fixed-price natural gas knockout swaps	47	141
Natural gas call options	(157)	(178)
Natural gas put options	(59)	(39)
Natural gas basis protection swaps	(54)	93
Fixed-price oil swaps	1	31
Fixed-price oil knockout swaps	66	19
Fixed-price oil cap-swaps		3
Oil call options	(71)	(35)

Fixed-price oil collars				5
Estimated fair value	$	998	$	1,305

(a) After adjusting for $488 million and $736 million of unrealized premiums, the value to be realized for these derivatives as of June 30, 2009 and December 31, 2008 was $1.486 billion and $2.041 billion, respectively.

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The volume hedged under natural gas and oil derivative instruments as of June 30, 2009 and December 31, 2008 is summarized below.

	June 30, 2009	December 31, 2008
Natural Gas and Oil Volume Hedged:		
Natural Gas (bbtu)		
Fixed-price natural gas swaps	354,291	466,800
Fixed-price natural gas collars	260,110	457,715
Fixed-price natural gas knockout swaps	98,670	532,660
Natural gas call options	595,525	551,555
Natural gas put options	91,400	73,000
Natural gas basis protection swaps	210,822	219,487
Total natural gas volume	1,610,818	2,301,217
Oil (mbbls)		
Fixed-price oil swaps	(460)	(310)
Fixed-price oil knockout swaps	9,148	12,248
Fixed-price oil cap-swaps		362
Oil call options	14,996	19,355
Fixed-price oil collars		730
Total oil volume	23,684	32,385

To mitigate our exposure to the fluctuation in prices of diesel fuel, we have entered into diesel swaps from July 2009 to March 2010 for a total of 29,025,000 gallons with an average fixed price of $1.58 per gallon. The fair value of these swaps as of June 30, 2009 was an asset of $10 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 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 June 30, 2009	$ 130	$ 370	$ 22	$ (1)	$ 77	$ 84
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.

On June 11, 2009, we entered into a multi-counterparty secured hedging facility with 13 hedge counterparties, one of which is a new counterparty to the company. These 13 hedge counterparties have committed to provide approximately 3.9 tcfe of trading capacity under the terms of the facility. Each of the six counterparties to our existing secured hedging facilities is a party to this new facility. The facility allows us to enter into cash-settled natural gas and oil price and basis hedges with the hedge counterparties. Our obligations under the new facility will be secured by natural gas and oil proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by at least 1.65 times, and guarantees by our subsidiaries that also guarantee our revolving bank credit facility and indentures. The hedge counterparties obligations under the facility will be secured by cash or short-term U.S. Treasury instruments to the extent that any mark-to-market amounts they owe to Chesapeake exceed defined thresholds. The maximum volume-based trading capacity under the facility is governed by the expected production of the pledged reserve collateral and volume-based trading limits are applied separately to price and basis hedges. In addition, there are volume-based sub-limits for natural gas and oil hedges. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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certain collateral coverage and other requirements are met. The facility does not have a maturity date. Counterparties to the agreement have the right to cease trading with the company on a prospective basis as long as obligations associated with any existing trades in the facility continue to be satisfied in accordance with the terms of the agreement.

All existing trades with the hedge counterparties are expected to be novated into the multi-counterparty facility along with any collateral currently pledged under the existing secured hedge facilities. Trades novated into the multi-counterparty facility from the existing secured hedge facilities will continue to be subject to pre-existing exposure fees, if any, but we are not required to pay an exposure fee for any new trades in the multi-counterparty facility. The new multi-counterparty facility will consolidate and replace our six secured hedging facilities described above. As of July 31, 2009, no trades had been transacted or novated or collateral pledged under the multi-counterparty facility.

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 $5 million, $4 million, $12 million and $4 million in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. Unrealized gains (losses) included in interest expense were $42 million, $14 million, $87 million and $1 million in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively.

As of June 30, 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							
April 2009	December 2018	$ 1,750	7.78%	1 6 mL plus 492 bp	Yes	$	$ (62)
April 2008	November 2020	$ 1,000	8.09%	1 6 mL plus 485 bp	No	$ (1)	$ (16)
Call Options							
August 2009	November 2009	$ 500	6.69%	1 6 mL plus 263 bp	No	$	$ (14)
Floating to Fixed Interest Rate:							
Swaps							

August 2007	July 2012	$	1,375	4.20%	1 - 6 mL	No	$		$	(32)
Collars[(a)]										
August 2007	August 2010	$	250	4.52%	6 mL	No	$		$	(9)
Swaption										
August 2009		$	500	2.56%	1 mL	No	$	4	$	(11)
							$	3	$	(144)

(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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(Unaudited)

In the Current Period, we closed interest rate derivatives for gains totaling $30 million, of which $18 million was recognized in interest expense. The remaining $12 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 four to eleven 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 fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as an asset of $7 million at June 30, 2009. The euro-denominated debt in notes payable has been adjusted to $841 million at June 30, 2009 using an exchange rate of $1.4020 to 1.00 with an offsetting entry to other comprehensive income of $34 million related to future interest expense.

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. Pursuant to SFAS 161, the following table sets forth the fair value of each classification of derivative instrument as of June 30, 2009 on a gross basis:

	June 30, 2009		
	Balance Sheet Location		**Fair Value ($ in millions)**
ASSET DERIVATIVES:			
Derivatives designated as hedging instruments under SFAS 133:			
Foreign exchange contracts	Long-term derivative instruments	$	7
Commodity contracts	Short-term derivative instruments		797
Commodity contracts	Long-term derivative instruments		84
Total			888
Derivatives not designated as hedging instruments under SFAS 133:			
Interest rate contracts	Long-term derivative instruments		5
Commodity contracts	Short-term derivative instruments		454
Commodity contracts	Long-term derivative instruments		82
Total			541

LIABILITY DERIVATIVES:

Derivatives designated as hedging instruments under SFAS 133:			
Interest rate contracts	Long-term derivative instruments		62
Commodity contracts	Short-term derivative instruments		3
Total			65
Derivatives not designated as hedging instruments under SFAS 133:			
Interest rate contracts	Short-term derivative instruments		26
Interest rate contracts	Long-term derivative instruments		61
Commodity contracts	Short-term derivative instruments		117
Commodity contracts	Long-term derivative instruments		289
Total			493
Total derivative instruments		$	871

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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 and six months ended June 30, 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)	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
		($ in millions)	
Interest rate contracts	Interest expense[(a)]	$ 10	$ 18

(a) Interest expense on the hedged items for the Current Quarter and the Current Period was $20 million and $33 million, respectively, which is included in interest expense on the condensed consolidated statement of operations.

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 ($ in millions):

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) [(a)]
Three Months Ended June 30, 2009					
Commodity contracts	$ 30	Natural gas and oil sales	$ 317	Natural gas and oil sales	$ 36
Foreign exchange contracts	35	Other income		Other income	
Total	$ 65		$ 317		$ 36
Six Months Ended June 30, 2009					
Commodity contracts	$ 712	Natural gas and oil sales	$ 613	Natural gas and oil sales	$ 90
Foreign exchange contracts	78	Other income		Other income	
Total	$ 790		$ 613		$ 90

(a) The amount of gain (loss) recognized in net income (loss) represents the ineffective portion of all our cash flow derivatives.

Based upon the market prices at June 30, 2009, we expect to transfer approximately $461 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 June 30, 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)**	**Three Months Ended June 30, 2009**	**Six Months Ended June 30, 2009**
		($ in millions)	
Commodity contracts	Natural gas and oil sales	$ 27	$ 296
Interest rate contracts	Interest expense	37	81
	Total	$ 64	$ 377

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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 June 30, 2009, our commodity and interest rate derivative instruments were spread among 14 counterparties. Additionally, our multi-counterparty secured hedging facility described above requires our counterparties to secure their natural gas and oil hedging obligations in excess of defined thresholds. We expect to use the facility for all of our commodity hedging.

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 and the Current Period, we recognized $5 million and $13 million, respectively, of bad debt expense related to potentially uncollectible receivables.

3. Contingencies and Commitments

Litigation

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 the securities case.

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 to compensation of the company s CEO. Chesapeake opposed the petition and a hearing is scheduled for August 20, 2009.

Three derivative actions were filed in the District Court of Oklahoma County, Oklahoma on April 28, May 7, and May 20, 2009 against the company s directors alleging breaches of fiduciary duties relating to compensation of the company s CEO and alleged insider trading, among other things, and seeking unspecified damages, equitable relief and disgorgement. These three derivative actions were consolidated and a Consolidated Derivative Shareholder Petition was filed on June 23, 2009. Chesapeake is named as a nominal defendant.

It is inherently difficult to predict the outcome of litigation, and we are currently unable to estimate the amount of any potential liabilities associated with the foregoing cases, which are all in preliminary stages.

Chesapeake is also involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, claims for underpayment of royalties, property damage claims and contract actions. With regard to the latter, several mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their oil and natural gas interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The company has satisfactorily resolved several of the suits but some remain pending. The remaining leasehold acquisition cases are in various stages of discovery. The company believes that it has substantial defenses to the claims made in all these cases.

The company records an associated liability when a loss is probable and the amount is reasonably estimable. Although the outcome of litigation cannot be predicted with certainty, management is of the opinion that no pending or threatened lawsuit or dispute incidental to its business operations is likely to have a material adverse effect on the

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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company s consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management s estimates.

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 June 30, 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 is being 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 payment equal to the fair market rental value of the rigs as determined at the time of renewal. Commitments related to rig lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of June 30, 2009, the minimum aggregate future rig lease payments were approximately $574 million. As of June 30, 2009, Chesapeake s drilling subsidiaries had committed to acquire seven rigs by the end of 2009 and had incurred costs of $47 million as of that date. The total remaining cost of the rigs is estimated to be approximately $52 million. Our intent is to sell and lease back those rigs as they are delivered if acceptable leasing arrangements are available to us.

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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 is being 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. Commitments related to compressor lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of June 30, 2009, the minimum aggregate future compressor lease payments were approximately $362 million. As of June 30, 2009, 339 new compressors were on order for approximately $129 million and our intent is to sell and lease back those compressors as they are delivered if acceptable leasing arrangements are available to us.

Surface Land Leases

In the Current Quarter, we sold 113 surface land sites in the Barnett Shale area in and around Fort Worth, Texas for approximately $145 million and entered into a 40-year master lease agreement under which we agreed to lease the sites for approximately $15 million to $27 million annually. These lease transactions were recorded as a financing lease and the cash received was recorded with an offsetting long-term liability on the condensed consolidated balance sheet. As of June 30, 2009, the minimum aggregate future surface land site payments were approximately $866 million. Chesapeake has the option to repurchase up to a specified number of sites at any time during the term of the lease.

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 June 30, 2009, excluding demand charges for pipeline projects that are currently seeking regulatory approval, were as follows ($ in millions):

2009	$	110
2010		224
2011		196
2012		185
2013		168
After 2013		891
Total	$	1,774

Drilling Contracts

Currently, Chesapeake has contracts with various drilling contractors to lease approximately 22 rigs with terms of one to three years. These commitments are not recorded in the accompanying condensed consolidated balance sheets. As of June 30, 2009, the aggregate drilling rig commitment was approximately $200 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 are based on market prices at the time of production and extend over 11 to 15 year terms. As of June 30, 2009, we were obligated to purchase 420 bcfe under the terms of the VPPs. We resell the natural gas and oil we purchase at market prices.

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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 June 30, 2009, Mountain Drilling owed Chesapeake $19 million under this agreement.

We invested in Ventura Refining and Transmission LLC in early 2007 in an effort to improve the market for our oil and condensate production in western Oklahoma. 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. During the Current Period, we paid an additional $13 million to fund various costs associated with Ventura s operations. These payments were expensed as incurred.

4. Net Income Per Share

Statement of Financial Accounting Standards No. 128, *Earnings Per Share*, requires presentation of basic and diluted earnings per share, as defined, on the face of the statements of operations for all entities with complex capital structures. SFAS 128 requires a reconciliation of the numerator and denominator of the basic and diluted EPS computations. The following securities were not included in the calculation of diluted earnings per share, as the effect was antidilutive:

	Shares (in millions)	Net Income Adjustments ($ in millions)
Three Months Ended June 30, 2009:		
Common stock equivalent of our preferred stock outstanding:		
5.00% (series 2005B) cumulative convertible preferred stock	5	$ 3
4.50% cumulative convertible preferred stock	6	$ 3

A reconciliation for the Current Quarter is as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
Three Months Ended June 30, 2009:			
Basic EPS:			
Income available to common shareholders	$ 237	603	$ 0.39
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 5.00% (Series 2005) cumulative convertible preferred stock			

Assumed conversion as of the beginning of the period of preferred shares outstanding prior to conversion:				
Common stock equivalent of preferred stock outstanding prior to conversion of 6.25% mandatory convertible preferred stock		1		
Employee stock options		1		
Restricted stock		5		
Diluted EPS income available to common shareholders and assumed conversions	$ 237	610	$	0.39

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For the Current Period, Prior Quarter and Prior Period, 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, diluted shares do not include the effect of the following:

	Shares (in millions)	Net Income Adjustments ($ in millions)
Six Months Ended June 30, 2009:		
Employee stock options	1	$
Restricted stock	4	$
Common stock equivalent of our preferred stock outstanding:		
5.00% (series 2005) cumulative convertible preferred stock		$
5.00% (series 2005B) cumulative convertible preferred stock	5	$ 5
4.50% cumulative convertible preferred stock	6	$ 6
Common stock equivalent of our preferred stock outstanding prior to conversion:		
4.125% cumulative convertible preferred stock		$
6.25% mandatory convertible preferred stock	1	$ 1
Three Months Ended June 30, 2008:		
Employee stock options	2	$
Restricted stock	8	$
2.75% contingent convertible senior notes due 2035	3	$ 3
Common stock equivalent of our preferred stock outstanding:		
4.125% cumulative convertible preferred stock		$
5.00% (series 2005) cumulative convertible preferred stock		$
5.00% (series 2005B) cumulative convertible preferred stock	8	$ 4
4.50% cumulative convertible preferred stock	8	$ 4
6.25% mandatory convertible preferred stock	1	$ 1
Common stock equivalent of our preferred stock outstanding prior to conversion:		
5.00% (series 2005B) cumulative convertible preferred stock	3	$ 43
4.125% cumulative convertible preferred stock		$
Six Months Ended June 30, 2008:		
Employee stock options	2	$
Restricted stock	7	$
2.75% contingent convertible senior notes due 2035	3	$ 3
Common stock equivalent of our preferred stock outstanding:		
4.125% cumulative convertible preferred stock		$
5.00% (series 2005) cumulative convertible preferred stock		$
5.00% (series 2005B) cumulative convertible preferred stock	8	$ 8
4.50% cumulative convertible preferred stock	8	$ 8
6.25% mandatory convertible preferred stock	1	$ 1
Common stock equivalent of our preferred stock outstanding prior to conversion:		
5.00% (series 2005B) cumulative convertible preferred stock	5	$ 47
4.125% cumulative convertible preferred stock		$

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 six months ended June 30, 2009 and 2008:

	2009	2008
	(in thousands)	
Shares issued at January 1	607,953	511,648
Stock option exercises	157	1,213
Restricted stock issuances (net of forfeitures)	2,365	2,136
Convertible note exchanges	2,531	
Preferred stock conversions/exchanges	1,422	7,781
Common stock issued for the purchase of proved and unproved properties and leasehold	15,824	
Common stock issuance		23,000
Shares issued at June 30	630,252	545,778

In June 2009, we privately exchanged approximately $85 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 2,530,650 shares of our common stock.

In the Current Period, we issued 15,823,838 shares of common stock, valued at $269 million, for the purchase of proved and unproved properties and leasehold pursuant to an acquisition shelf registration statement.

Preferred Shares

The following is a summary of the changes in our preferred shares outstanding for the six months ended June 30, 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)				(144)
Shares outstanding at June 30, 2009		5	2,559	2,096	
Shares outstanding at January 1, 2008	3	5	3,450	5,750	144
Conversion/exchange of preferred for common stock				(2,718)	
Shares outstanding at June 30, 2008	3	5	3,450	3,032	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.

On June 15, 2009, we converted all of our outstanding 6.25% Mandatory Convertible Preferred Stock (143,768 shares) into 1,239,538 shares of common stock pursuant to the company s mandatory conversion rights.

For the six months ended June 30, 2008, holders of our 5.0% (Series 2005B) Cumulative Convertible Preferred Stock exchanged 2,718,500 shares for 7,780,703 shares of common stock in privately negotiated exchanges.

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.

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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, the Prior Quarter, the Current Period and the Prior Period:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	($ in millions)			
Natural gas and oil properties	$ 29	$ 26	$ 58	$ 51
General and administrative expenses	19	21	39	40
Production expenses	9	7	17	14
Natural gas and oil marketing expenses	4	2	8	4
Service operations expense	2	1	4	3
Total	$ 63	$ 57	$ 126	$ 112

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 Period is presented below:

	Number of Unvested Restricted Shares (in thousands)	Weighted-Average Grant-Date Fair Value
Unvested shares as of January 1, 2009	21,622	$ 38.85
Granted	4,039	$ 17.47
Vested	(2,751)	$ 32.85
Forfeited	(708)	$ 35.75
Unvested shares as of June 30, 2009	22,202	$ 35.80

The aggregate intrinsic value of restricted stock vested during the Current Period was approximately $50 million based on the stock price at the time of vesting.

As of June 30, 2009, there was $565 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 2.44 years.

The vesting of certain restricted stock grants results in state and federal income tax benefits related to the difference between the market price of the common stock at the date of vesting and the date of grant. During the Current Quarter and the Current Period we recognized a reduction in tax benefits related to restricted stock of $5 million and $13 million, respectively. During the Prior Quarter and the Prior Period we recognized excess tax benefits related to restricted stock of $3 million and $9 million, respectively. The reduction in tax benefits and the excess tax benefits were recorded as adjustments to additional paid-in capital and deferred income taxes.

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(Unaudited)

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 all are currently fully vested.

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

	Number of Shares Underlying Options (in thousands)	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	$ 8.13	3.59	$ 23
Exercised	(157)	$ 7.68		$ 2
Expired		$		
Outstanding at June 30, 2009	2,645	$ 8.15	3.10	$ 31
Exercisable at June 30, 2009	2,645	$ 8.15	3.10	$ 31

(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.

During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized excess tax benefits related to stock options of a nominal amount, $7 million, a nominal amount and $12 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)

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6. Senior Notes and Revolving Bank Credit Facilities

Our total debt consisted of the following:

	June 30, 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]	841	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]	1,041	1,126
Revolving bank credit facility	2,834	3,474
Midstream revolving bank credit facility	297	460
Discount on senior notes[c]	(1,072)	(1,094)
Interest rate derivatives[d]	39	211
Total notes payable and long-term debt	$ 13,568	$ 13,175

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.4020 to 1.00 and $1.3919 to 1.00 as of June 30, 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 second 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 third 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	$ 64.36	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*. Discount at June 30, 2009 and December 31, 2008 included $936 million and $1.009 billion, respectively, associated with the equity component of our contingent convertible senior notes.

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

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

Our outstanding senior notes are unsecured senior obligations of Chesapeake that rank equally in right of payment with all of our existing and future senior indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. We may redeem the senior notes, other than the 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, 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 (Including Partial Cash Settlement)* (FSP APB 14-1). 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 us to account for the liability and equity components of our 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). 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 allocation to the equity component of the convertible notes was $845 million (net of tax) at 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.

The following table summarizes the effect of the change in accounting principle related to our contingent convertible notes on the condensed consolidated balance sheet:

	December 31, 2008		
	Previously Reported	Adjustment ($ in millions)	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 contingent convertible notes on the condensed consolidated statement of operations ($ in millions, except per share data):

	Previously Reported	Adjustment	Adjusted
Three Months Ended June 30, 2008:			
Depreciation and amortization of other assets	$ 40	$	$ 40
Interest expense	$ 63	$ (9)	$ 54
Income tax expense (benefit)	$ (1,000)	$ 4	$ (996)
Net income (loss)	$ (1,597)	$ 5	$ (1,592)
Weighted average common and common equivalent shares outstanding assuming dilution (in millions)	521		521
Earnings (loss) per common share:			
Basic	$ (3.17)	$ 0.01	$ (3.16)
Diluted	$ (3.17)	$ 0.01	$ (3.16)

	Previously Reported	Adjustment	Adjusted
Six Months Ended June 30, 2008:			
Depreciation and amortization of other assets	$ 77	$ (1)	$ 76
Interest expense	$ 163	$ (10)	$ 153
Income tax expense (benefit)	$ (1,082)	$ 4	$ (1,078)
Net income (loss)	$ (1,729)	$ 7	$ (1,722)
Weighted average common and common equivalent shares outstanding assuming dilution (in millions)	507		507
Earnings (loss) per common share:			
Basic	$ (3.54)	$ 0.02	$ (3.52)
Diluted	$ (3.54)	$ 0.02	$ (3.52)

The following table summarizes the effect of the change in accounting principle related to our contingent convertible notes on the condensed consolidated statement of cash flows for the six months ended June 30, 2008 ($ in millions):

	Previously Reported	Adjustment	Adjusted
Six Months Ended June 30, 2008:			
Cash flows provided by operating activities	$ 2,754	$ 44	$ 2,798
Cash flows used in investing activities	$ (6,329)	$ (44)	$ (6,373)
Cash flows provided by financing activities	$ 3,574	$	$ 3,574

We have a $3.5 billion syndicated revolving bank credit facility which matures in November 2012. As of June 30, 2009, we had $2.834 billion in outstanding borrowings under this facility and utilized approximately $10 million of the facility for various letters of credit.

Borrowings under the facility are secured by certain producing natural gas and oil properties and bear interest at our option at either (i) the greater of the reference rate of Union Bank, 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% 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% 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%. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

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The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.70 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.75 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.43 to 1 and our indebtedness to EBITDA ratio was 3.47 to 1 at June 30, 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 Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $75 million.

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

We also have a $460 million syndicated 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 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 June 30, 2009, we had $297 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 LIBOR 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 1.35 to 1 and our EBITDA to interest expense coverage ratio was 12.84 to 1 at June 30, 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 contains 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.

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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.

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 $622 million, $1.787 billion, $1.293 billion and $3.076 billion for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period. 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)		
Three Months Ended June 30, 2009:					
Revenues	$ 1,097	$ 1,154	$ 115	$ (693)	$ 1,673
Intersegment revenues		(622)	(71)	693	
Total revenues	$ 1,097	$ 532	$ 44	$	$ 1,673
Income (loss) before income taxes	$ 408	$ 11	$ (14)	$ (17)	$ 388
Three Months Ended June 30, 2008 (Adjusted):					
Revenues	$ (1,594)	$ 2,886	$ 154	$ (1,901)	$ (455)
Intersegment revenues		(1,787)	(114)	1,901	
Total revenues	$ (1,594)	$ 1,099	$ 40	$	$ (455)
Income (loss) before income taxes	$ (2,605)	$ 15	$ 27	$ (25)	$ (2,588)
Six Months Ended June 30, 2009:					
Revenues	$ 2,494	$ 2,377	$ 269	$ (1,472)	$ 3,668
Intersegment revenues		(1,293)	(179)	1,472	
Total revenues	$ 2,494	$ 1,084	$ 90	$	$ 3,668
Income (loss) before income taxes	$ (8,785)	$ 29	$ (34)	$ (6)	$ (8,796)

Six Months Ended June 30, 2008 (Adjusted):					
Revenues	$ (821)	$ 4,971	$ 303	$ (3,297)	$ 1,156
Intersegment revenues		(3,076)	(221)	3,297	
Total revenues	$ (821)	$ 1,895	$ 82	$	$ 1,156
Income (loss) before income taxes	$ (2,831)	$ 30	$ 47	$ (46)	$ (2,800)
As of June 30, 2009:					
Total assets	$ 26,258	$ 6,052	$ 800	$ (2,641)	$ 30,469
As of December 31, 2008 (Adjusted):					
Total assets	$ 35,192	$ 3,416	$ 688	$ (703)	$ 38,593

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8. Restructuring

In the Current Period, we reorganized our Charleston, West Virginia-based Eastern Division from a regional corporate headquarters to a regional field office consistent with the business model the company uses elsewhere in the country. As a result, we consolidated the management of our Eastern Division land, legal, accounting, information technology, geoscience and engineering departments into our corporate offices in Oklahoma City. The costs of the reorganization include termination benefits, consolidating or closing facilities and relocating employees. In addition, we had certain other workforce reductions that resulted in termination benefits. We expect all costs associated with our reorganization to be paid by year-end 2009.

A summary of Chesapeake s restructuring charges is presented below ($ in millions):

	Restructuring Costs Through June 30, 2009	Restructuring Costs To Be Incurred	Total Restructuring Costs
Restructuring Costs:			
Termination and relocation costs	$ 6	$ 16	$ 22
Acceleration of restricted stock awards	9		9
Other associated costs	3		3
Total Restructuring Costs	$ 18	$ 16	$ 34

9. Investments

At June 30, 2009, investments accounted for under the equity method totaled $379 million and investments accounted for under the cost method totaled $15 million. Following is a summary of our investments:

	Approximate % Owned	Accounting Method	Carrying Value June 30, 2009	Carrying Value December 31, 2008
			($ in millions)	
Frac Tech Services, Ltd.[a]	20%	Equity	$ 217	$ 223
Chaparral Energy, Inc.[b][c]	32%	Equity	126	152
DHS Drilling Company[b]	47%	Equity		19
Sierra Mid-Con, L.P.	50%	Equity	14	12
Gastar Exploration Ltd.[b]	17%	Cost	14	11
Mountain Drilling Company[b]	49%	Equity		9
Other		Cost/Equity	23	18
			$ 394	$ 444

(a) The carrying value of our investment in Frac Tech is in excess of our underlying equity in net assets by approximately $155 million as of June 30, 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 Period 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 condensed 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 $53 million as of June 30, 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.

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10. 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.

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of June 30, 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):				
Cash equivalents	$ 506	$	$	$ 506
Derivatives, net	$	$ 743	$ 128	$ 871
Investments	$ 14	$	$	$ 14
Other long-term assets	$ 23	$	$	$ 23
Long-term debt	$	$	$ (2,529)	$ (2,529)
Other long-term liabilities	$ (23)	$	$	$ (23)

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

Cash Equivalents. The fair value of cash equivalents is based on quoted market prices.

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, oil and diesel 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Level 3 Fair Value Measurements

Derivatives. The fair value of our derivative instruments, excluding natural gas and diesel swaps, have been established utilizing established index prices, volatility curves, discount factors and options pricing models. 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 certain of our long-term debt is based on the face amount of that debt along with the value of the related interest rate swaps. The interest rate swap values are based on estimates provided by our respective counterparties and reviewed internally for reasonableness using future interest rate curves and time to maturity.

A summary of the changes in Chesapeake s assets (liabilities) classified as Level 3 measurements during the Current Period is presented below:

	Derivatives	Debt ($ in millions)	Total
Balance of Level 3 as of January 1, 2009	$ 292	$ (1,470)	$ (1,178)
Total gains (losses) (realized/unrealized):			
Included in earnings[(a)]	416	(59)	357
Included in other comprehensive income (loss)	170		170
Purchases, issuances and settlements	(750)	(1,000)[(b)]	(1,750)
Transfers in and out of Level 3			
Balance of Level 3 as of June 30, 2009	$ 128	$ (2,529)	$ (2,401)

(a)

	Natural Gas and Oil Sales	Interest Expense
	($ in millions)	
Total gains (losses) related to derivatives included in earnings for the period	$ 311	$ 105
Change in unrealized gains (losses) relating to assets still held at reporting date	$ (148)	$ 92

(b) Amount represents additional debt now recorded at fair value as a result of new interest rate swaps entered into in the Current Period.

Fair Value of Other Financial Instruments

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

The carrying values of financial instruments comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term debt and our convertible preferred stock primarily using quoted market prices. Our carrying amounts for such debt, excluding the impact of interest rate derivatives, at June 30, 2009 and December 31, 2008 were $13.5 billion and $13.0 billion, respectively, compared to approximate fair values of $11.8 billion and $10.5 billion, respectively. The carrying amounts for our convertible preferred stock as of June 30, 2009 and December 31, 2008 were $466 million and $505 million, respectively, compared to approximate fair values of $319 million and $294 million, respectively.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

11. 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.

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 June 30, 2009 and December 31, 2008 and for the three and six months ended June 30, 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 JUNE 30, 2009

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 554	$	$	$ 554
Other current assets	9	2,247	175	(37)	2,394
Total Current Assets	9	2,801	175	(37)	2,948
PROPERTY AND EQUIPMENT:					
Total natural gas and oil properties, at cost based on full-cost accounting, net		21,147	5		21,152
Other property and equipment, net		2,717	2,867		5,584
Total Property and Equipment		23,864	2,872		26,736
Other assets	157	616	12		785
Investments in subsidiaries and intercompany advance	4,449	265		(4,714)	
TOTAL ASSETS	$ 4,615	$ 27,546	$ 3,059	$ (4,751)	$ 30,469
CURRENT LIABILITIES:					
Current liabilities	$ 321	$ 2,509	$ 183	$ (39)	$ 2,974
Intercompany payable (receivable) from parent	(18,760)	16,475	2,184	101	

Total Current Liabilities		(18,439)		18,984		2,367		62		2,974
Long-term debt, net		10,436		2,835		297				13,568
Deferred income tax liability		564		320		121		(99)		906
Other liabilities		52		958		9				1,019
Total Long-Term Liabilities		11,052		4,113		427		(99)		15,493
Total Stockholders Equity		12,002		4,449		265		(4,714)		12,002
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$	4,615	$	27,546	$	3,059	$	(4,751)	$	30,469

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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	2,392	169	(31)	2,543
Total Current Assets	13	4,141	169	(31)	4,292
PROPERTY AND EQUIPMENT:					
Total natural gas and oil properties, at cost based on full-cost accounting, net		28,474	4		28,478
Other property and equipment, net		2,481	2,349		4,830
Total Property and Equipment		30,955	2,353		33,308
Other assets	140	838	15		993
Investments in subsidiaries and intercompany advance	8,452	143		(8,595)	
TOTAL ASSETS	$ 8,605	$ 36,077	$ 2,537	$ (8,626)	$ 38,593
CURRENT LIABILITIES:					
Current liabilities	$ 257	$ 3,324	$ 131	$ (91)	$ 3,621
Intercompany payable (receivable) from parent	(18,274)	16,636	1,578	60	
Total Current Liabilities	(18,017)	19,960	1,709	(31)	3,621
Long-term debt, net	9,241	3,474	460		13,175
Deferred income tax liability	438	3,543	219		4,200
Other liabilities	(74)	648	6		580
Total Long-Term Liabilities	9,605	7,665	685		17,955
Total Stockholders Equity	17,017	8,452	143	(8,595)	17,017

TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$	8,605	$	36,077	$	2,537	$	(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
Three Months Ended June 30, 2009:					
REVENUES:					
Natural gas and oil sales	$	$ 1,097	$	$	$ 1,097
Natural gas and oil marketing sales		467	118	(53)	532
Service operations revenue		44			44
Total Revenues		1,608	118	(53)	1,673
OPERATING COSTS:					
Production expenses		213			213
Production taxes		24			24
General and administrative expenses		68	6		74
Natural gas and oil marketing expenses		450	46	4	500
Service operations expense		46			46
Natural gas and oil depreciation, depletion and amortization		295			295
Depreciation and amortization of other assets		36	22		58
Impairment of natural gas and oil properties and other assets		(4)	9		5
Restructuring costs		34			34
Total Operating Costs		1,162	83	4	1,249
INCOME (LOSS) FROM OPERATIONS		446	35	(57)	424
OTHER INCOME (EXPENSE):					
Other income (expense)	175	(1)	(1)	(175)	(2)
Interest expense	(159)	(36)	(2)	175	(22)
Impairment of investments		(10)			(10)
Loss on exchanges of Chesapeake debt	(2)				(2)
Equity in net earnings of subsidiary	235	(16)		(219)	
Total Other Income (Expense)	249	(63)	(3)	(219)	(36)
INCOME (LOSS) BEFORE INCOME TAXES	249	383	32	(276)	388
INCOME TAX EXPENSE (BENEFIT)	6	150	12	(23)	145
NET INCOME (LOSS)	$ 243	$ 233	$ 20	$ (253)	$ 243

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

(Adjusted)

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Three Months Ended June 30, 2008:					
REVENUES:					
Natural gas and oil sales	$	$ (1,594)	$	$	$ (1,594)
Natural gas and oil marketing sales		1,058	78	(37)	1,099
Service operations revenue		40			40
Total Revenues		(496)	78	(37)	(455)
OPERATING COSTS:					
Production expenses		219			219
Production taxes		88			88
General and administrative expenses		98	3		101
Natural gas and oil marketing expenses		1,046	33	(4)	1,075
Service operations expense		32			32
Natural gas and oil depreciation, depletion and amortization		523			523
Depreciation and amortization of other assets		32	11	(3)	40
Total Operating Costs		2,038	47	(7)	2,078
INCOME (LOSS) FROM OPERATIONS		(2,534)	31	(30)	(2,533)
OTHER INCOME (EXPENSE):					
Other income (expense)	175	(1)		(175)	(1)
Interest expense	(167)	(62)		175	(54)
Equity in net earnings of subsidiary	(1,597)	1		1,596	
Total Other Income (Expense)	(1,589)	(62)		1,596	(55)
INCOME (LOSS) BEFORE INCOME TAXES	(1,589)	(2,596)	31	1,566	(2,588)
INCOME TAX EXPENSE (BENEFIT)	3	(1,000)	12	(11)	(996)
NET INCOME (LOSS)	$ (1,592)	$ (1,596)	$ 19	$ 1,577	$ (1,592)

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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
Six Months Ended June 30, 2009:					
REVENUES:					
Natural gas and oil sales	$	$ 2,494	$	$	$ 2,494
Natural gas and oil marketing sales		956	228	(100)	1,084
Service operations revenue		90			90
Total Revenues		3,540	228	(100)	3,668
OPERATING COSTS:					
Production expenses		452	(1)		451
Production taxes		46			46
General and administrative expenses		153	11		164
Natural gas and oil marketing expenses		919	94	10	1,023
Service operations expense		87			87
Natural gas and oil depreciation, depletion and amortization		742			742
Depreciation and amortization of other assets	(1)	74	41	1	115
Impairment of natural gas and oil properties and other assets		9,621	14		9,635
Restructuring costs		34			34
Total Operating Costs	(1)	12,128	159	11	12,297
INCOME (LOSS) FROM OPERATIONS	1	(8,588)	69	(111)	(8,629)
OTHER INCOME (EXPENSE):					
Other income (expense)	337	3	2	(337)	5
Interest expense	(286)	(54)	(5)	337	(8)
Impairment of investments		(162)			(162)
Gain (loss) on debt exchanges or repurchases	(2)				(2)
Equity in net earnings of subsidiary	(5,529)	(28)		5,557	
Total Other Income (Expense)	(5,480)	(241)	(3)	5,557	(167)
INCOME (LOSS) BEFORE INCOME TAXES	(5,479)	(8,829)	66	5,446	(8,796)
INCOME TAX EXPENSE (BENEFIT)	19	(3,300)	25	(42)	(3,298)

NET INCOME (LOSS)	$	(5,498)	$	(5,529)	$	41	$	5,488	$	(5,498)

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

(Adjusted)

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Six Months Ended June 30, 2008:					
REVENUES:					
Natural gas and oil sales	$	$ (821)	$	$	$ (821)
Natural gas and oil marketing sales		1,816	147	(68)	1,895
Service operations revenue		82			82
Total Revenues		1,077	147	(68)	1,156
OPERATING COSTS:					
Production expenses		419			419
Production taxes		163			163
General and administrative expenses		174	6		180
Natural gas and oil marketing expenses		1,793	63	(7)	1,849
Service operations expense		67			67
Natural gas and oil depreciation, depletion and amortization		1,038			1,038
Depreciation and amortization of other assets	1	62	19	(6)	76
Total Operating Costs	1	3,716	88	(13)	3,792
INCOME (LOSS) FROM OPERATIONS	(1)	(2,639)	59	(55)	(2,636)
OTHER INCOME (EXPENSE):					
Other income (expense)	339	(11)		(339)	(11)
Interest expense	(266)	(226)		339	(153)
Equity in net earnings of subsidiary	(1,766)	2		1,764	
Total Other Income (Expense)	(1,693)	(235)		1,764	(164)
INCOME (LOSS) BEFORE INCOME TAXES	(1,694)	(2,874)	59	1,709	(2,800)
INCOME TAX EXPENSE (BENEFIT)	28	(1,106)	23	(23)	(1,078)
NET INCOME (LOSS)	$ (1,722)	$ (1,768)	$ 36	$ 1,732	$ (1,722)

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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
Six Months Ended June 30, 2009:					
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 1,854	$ 144	$	$ 1,998
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(2,825)	7		(2,818)
Divestitures of proved and unproved natural gas and oil properties		228			228
Additions to other property and equipment		(793)	(187)		(980)
Other investing activities		97	8		105
Cash used in investing activities		(3,293)	(172)		(3,465)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facility borrowings		2,825	538		3,363
Payments on credit facility borrowings		(3,466)	(700)		(4,166)
Proceeds from issuance of senior notes, net of offering costs	1,346				1,346
Other financing activities	(102)	(169)			(271)
Intercompany advances, net	(1,244)	1,054	190		
Cash provided by financing activities		244	28		272
Net increase (decrease) in cash and cash equivalents		(1,195)			(1,195)
Cash and cash equivalents, beginning of period		1,749			1,749
Cash and cash equivalents, end of period	$	$ 554	$	$	$ 554

	Parent	(Adjusted) Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Six Months Ended June 30, 2008:					
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 2,712	$ 86	$	$ 2,798
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(5,994)			(5,994)
		863			863

Divestitures of proved and unproved natural gas and oil properties					
Additions to other property and equipment		(790)	(439)		(1,229)
Other investing activities		(13)			(13)
Cash used in investing activities		(5,934)	(439)		(6,373)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facility borrowings		6,758			6,758
Payments on credit facility borrowings		(6,195)			(6,195)
Proceeds from issuance of senior notes, net of offering costs	2,136				2,136
Proceeds from issuance of common stock, net of offering costs	1,011				1,011
Other financing activities	(60)	(76)			(136)
Intercompany advances, net		(353)	353		
Cash provided by financing activities	3,087	134	353		3,574
Net increase (decrease) in cash and cash equivalents	3,087	(3,088)			(1)
Cash and cash equivalents, beginning of period		1			1
Cash and cash equivalents, end of period	$ 3,087	$ (3,087)	$	$	$

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

12. 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.

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.

In April 2009, the FASB issued Staff Position SFAS 107-1 and Accounting Principles Board (APB) Opinion No. 28-1, *Interim Disclosures about Fair Value of Financial Instruments* (FSP 107-1 and APB 28-1). FSP 107-1 amends FASB Statement No. 107, *Disclosures about Fair Values of Financial Instruments*, to require disclosures about fair value of financial instruments in interim financial statements as well as in annual financial statements. APB 28-1 amends APB Opinion No. 28, *Interim Financial Reporting*, to require those disclosures in all interim financial statements. FSP 107-1 and APB 28-1 are effective for interim periods ending after June 15, 2009 and we have adopted them in the Current Quarter.

In April 2009, the FASB issued Staff Position SFAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly* (FSP 157-4). FSP 157-4 provides additional guidance in estimating fair value under SFAS No. 157, *Fair Value Measurements*, when the volume and level of transaction activity for an asset or liability have significantly decreased in relation to normal market activity for the asset or liability. FSP 157-4 also provides additional guidance on circumstances that may indicate a transaction is not orderly. FSP 157-4 is effective for interim periods ending after June 15, 2009, and we have adopted its provisions in the Current Quarter. FSP 157-4 did not have a significant impact on our financial position, results of operations, cash flows or disclosures.

In April 2009, the FASB issued Staff Position SFAS 115-2 and SFAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments* (FSP 115-2). FSP 115-2 provides guidance in determining whether impairments in debt securities are other than temporary, and modifies the presentation and disclosures surrounding such instruments. FSP 115-2 is effective for interim periods ending after June 15, 2009, and we have adopted its provisions in the Current Quarter. FSP 115-2 did not have a significant impact on our financial position, results of operations, cash flows or disclosures.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events*. This statement establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. SFAS 165 requires companies to reflect in their financial statements the effects of subsequent events that provide additional evidence about conditions at the balance-sheet date. Subsequent events that provide evidence about conditions that arose after the balance-sheet date should be disclosed if the financial statements would otherwise be misleading. Disclosures should include the nature of the event and either an estimate of its financial effect or a statement that an estimate cannot be made. SFAS 165 is effective for interim or annual financial periods ending after June 15, 2009. We adopted this statement in the Current Quarter and as the requirements under SFAS 165 are consistent with our current practice, the implementation of this statement did not have a material impact on our consolidated financial statements or our financial disclosures.

In June 2009, the FASB issued SFAS No. 167, *Amendments to FASB Interpretation No. 46(R)*. Among other items, SFAS 167 responds to concerns about the application of certain key provisions of FIN 46(R), including those regarding the transparency of the involvement with variable interest entities. SFAS 167 is effective for calendar year companies beginning on January 1, 2010. We are currently assessing the impact that adoption of SFAS 167 will have on our financial position, results of operations, cash flows or disclosures.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

In June 2009, the FASB issued SFAS No. 168, *The FASB Accounting Standards Codification* ™ *and the Hierarchy of Generally Accepted Accounting Principles*. This standard replaces SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles,* and establishes only two levels of U.S. GAAP, authoritative and nonauthoritative. The FASB Accounting Standards Codification will become the source of authoritative, nongovernmental GAAP, except for rules and interpretive releases of the SEC, which are sources of authoritative GAAP for SEC registrants. This standard is effective for financial statements for interim or annual reporting periods ending after September 15, 2009. We will begin to use the new guidelines and numbering system prescribed by the Codification when referring to GAAP in the third quarter of 2009. As the Codification was not intended to change or alter existing GAAP, it will not have any impact on our consolidated financial statements.

13. Subsequent Events

In December 2008, we filed a Registration Statement on Form S-4 to register 25,000,000 shares of common stock and on July 14, 2009 we registered an additional 1,499,832 shares of common stock to offer and issue in connection with the acquisition of assets, businesses or securities of other companies. As of July 15, 2009, we had issued all of the shares of common stock for proved and unproved properties and leasehold acquisitions.

On August 4, 2009, we sold certain Chesapeake operated long-lived producing assets in South Texas in our fifth volumetric production payment transaction for proceeds of approximately $370 million.

On August 6, 2009, we announced an amendment to our Haynesville Shale joint venture agreement with Plains Exploration & Production Company (PXP). As part of the amendment, PXP has agreed to accelerate the payment of its remaining joint venture drilling carries as of September 30, 2009 in exchange for an approximate 12% reduction in the total amount of drilling carry obligations due to Chesapeake. At the closing, scheduled to occur on September 29, 2009, Chesapeake will receive cash of approximately $1.1 billion instead of an estimated $1.25 billion in remaining carried drilling costs that PXP would have paid over the next three years under the original agreement. In addition, Chesapeake and PXP have agreed to terminate a previous joint venture amendment that granted PXP a one-time option in June 2010 to avoid paying the last $800 million of the drilling carry obligations in exchange for the conveyance of 50% of its Haynesville Shale assets to Chesapeake. After closing the amendment, Chesapeake and PXP will each pay their proportionate working interest costs on future drilling. Furthermore, Chesapeake and PXP have agreed to make several other minor modifications to the agreement.

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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 and six months ended June 30, 2009 (the Current Quarter and the Current Period) and the three and six months ended June 30, 2008 (the Prior Quarter and the Prior Period):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008 (Adjusted)	2009	2008 (Adjusted)
Net Production:				
Natural gas (mmcf)	204,282	194,994	400,031	382,766
Oil (mbbls)	3,152	2,816	6,026	5,562
Natural gas equivalent (mmcfe)	223,194	211,890	436,187	416,138
Natural Gas and Oil Sales ($ in millions):				
Natural gas sales	$ 548	$ 1,896	$ 1,223	$ 3,329
Natural gas derivatives realized gains (losses)	587	(302)	1,096	(34)
Natural gas derivatives unrealized gains (losses)	(192)	(2,526)	(123)	(3,528)
Total natural gas sales	943	(932)	2,196	(233)
Oil sales	169	337	272	596
Oil derivatives realized gains (losses)	10	(121)	19	(174)
Oil derivatives unrealized gains (losses)	(25)	(878)	7	(1,010)
Total oil sales	154	(662)	298	(588)
Total natural gas and oil sales	$ 1,097	$ (1,594)	$ 2,494	$ (821)
Average Sales Price (excluding all gains (losses) on derivatives):				
Natural gas ($ per mcf)	$ 2.68	$ 9.73	$ 3.06	$ 8.70
Oil ($ per bbl)	$ 53.59	$ 119.81	$ 45.19	$ 107.13
Natural gas equivalent ($ per mcfe)	$ 3.21	$ 10.54	$ 3.43	$ 9.43
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Natural gas ($ per mcf)	$ 5.56	$ 8.18	$ 5.80	$ 8.61
Oil ($ per bbl)	$ 56.72	$ 76.96	$ 48.32	$ 75.86
Natural gas equivalent ($ per mcfe)	$ 5.89	$ 8.55	$ 5.98	$ 8.93
Other Operating Income (Loss)[(a)] ($ in millions):				
Natural gas and oil marketing	$ 32	$ 24	$ 61	$ 46
Service operations	$ (2)	$ 8	$ 3	$ 15
Other Operating Income (Loss)[(a)] ($ per mcfe):				
Natural gas and oil marketing	$ 0.14	$ 0.12	$ 0.14	$ 0.11
Service operations	$ (0.01)	$ 0.04	$ 0.01	$ 0.04
Expenses ($ per mcfe):				
Production expenses	$ 0.95	$ 1.03	$ 1.03	$ 1.01
Production taxes	$ 0.11	$ 0.41	$ 0.11	$ 0.39
General and administrative expenses	$ 0.33	$ 0.48	$ 0.38	$ 0.43
Natural gas and oil depreciation, depletion and amortization	$ 1.32	$ 2.47	$ 1.70	$ 2.49
Depreciation and amortization of other assets	$ 0.26	$ 0.19	$ 0.26	$ 0.18
Interest expense[(b)]	$ 0.29	$ 0.32	$ 0.22	$ 0.37

Interest Expense ($ in millions):								
Interest expense	$	69	$	72	$	107	$	158
Interest rate derivatives realized (gains) losses		(5)		(4)		(12)		(4)
Interest rate derivatives unrealized (gains) losses		(42)		(14)		(87)		(1)
Total interest expense	$	22	$	54	$	8	$	153
Net Wells Drilled		212		485		476		933
Net Producing Wells as of the End of the Period		22,626		22,324		22,626		22,324

(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 one of the leading producers of natural gas in the United States. We own interests in approximately 43,300 producing natural gas and oil wells that are currently producing approximately 2.5 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 Period, Chesapeake continued the industry s most active drilling program drilling 580 gross (432 net with an average working interest of 74%) operated wells and participating in another 581 gross (44 net with an average working interest of 8%) wells operated by other companies. The company s drilling success rate was 99% for both company-operated and non-operated wells. Also during the Current Period, we invested $1.509 billion in operated wells (using an average of 104 operated rigs) and $401 million in non-operated wells (using an average of 53 non-operated rigs) for total drilling, completing and equipping costs of $1.910 billion (net of carries). Currently we are using 95 operated drilling rigs, reflecting the company s decreased drilling activity in response to low natural gas and oil prices.

Our total Current Quarter production was 223.2 bcfe, comprised of 204.3 bcf (92% on a natural gas equivalent basis) and 3.152 mmbbls of oil and natural gas liquids (8% on a natural gas equivalent basis). Daily production for the Current Quarter averaged 2.453 bcfe, an increase of 125 mmcfe, or 5%, over the 2.328 bcfe produced per day in the Prior Quarter. Adjusted for our 2009 voluntary production curtailments due to low natural gas and oil prices (which averaged approximately 74 mmcfe per day during the Current Quarter), our three 2008 volumetric production payment sales (which averaged approximately 139 mmcfe per day during the Current Quarter) and the estimated impact from the 2008 sales of Woodford Shale and Fayetteville Shale properties (which would have averaged approximately 81 mmcfe per day during the Current Quarter), our year over year production growth rate would have been 16% after making similar adjustments to prior quarters. We are not currently curtailing production, but may do so again later this summer or fall as market conditions dictate. We also expect that rising pipeline and gathering system pressures during the next few months will likely result in involuntary natural gas production curtailments across the industry.

Chesapeake began 2009 with estimated proved reserves of 12.051 tcfe and ended the Current Period with 12.525 tcfe, an increase of 474 bcfe, or 4%. During the Current Period, we replaced 436 bcfe of production with an internally estimated 910 bcfe of new proved reserves, for a reserve replacement rate of 209%. The Current Period s reserve movement includes 920 bcfe of extensions, 740 bcfe of positive performance revisions, 664 bcfe of downward revisions resulting from natural gas price decreases between December 31, 2008 and June 30, 2009 and 86 bcfe of net divestitures. 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 built the largest combined inventories of onshore leasehold (14.3 million net acres) and 3-D seismic (22.7 million acres) in the U.S. and the largest inventory of U.S. Big 4 Shale play leasehold (2.7 million net acres). On our leasehold, the company has approximately 36,000 net drillsites representing more than a 10-year inventory of drilling projects.

Our high level of hedging at attractive prices should continue to insulate us from potentially soft near-term natural gas prices during the remainder of 2009. We also believe that the remaining joint venture drilling carries of approximately $3.7 billion will result in high returns on invested capital, reduce our capital expenditures and improve our balance sheet.

Our debt, net of cash on hand, as a percentage of total capitalization (total capitalization is the sum of debt, net of cash on hand, and stockholders equity) was 52% as of June 30, 2009 and 40% as of December 31, 2008. The increase in this percentage is primarily due to the reduction of equity as the result of a $5.5 billion net loss caused by impairments of natural gas and oil properties and other assets of $9.6 billion in the Current Period. 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 the first half of 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. (STO), we significantly reduced our planned capital expenditures through year-end 2010. Our current budgeted capital expenditures are $4.700 billion to $5.425 billion in 2009 and $4.350 billion to $4.975 billion in 2010. We anticipate directing approximately 75% of our gross drilling capital expenditures during 2009 and 2010 to our Big 4 shale plays.

Our innovative joint ventures create a significant cost advantage for us that allows us to drive down finding costs in our joint venture plays. During each of 2009 and 2010, we anticipate our exploration and development costs will be significantly lower than 2008 costs as a result of lower service costs and the benefit of using approximately $2.6 billion of joint venture drilling carries in three of our Big 4 shale plays. The following table provides information about the joint venture drilling carries:

	Shale Play			
	Haynesville[(a)]	Fayetteville	Marcellus	Total
	($ in millions)			
Joint venture with	PXP	BP	STO	
Closing date	July 1, 2008	September 19, 2008	November 24, 2008	
Cash proceeds at closing	$ 1,650	$ 1,100	$ 1,250	$ 4,000
Total drilling carry	$ 1,650	$ 800	$ 2,125	$ 4,575
Carries billed as of June 30, 2009	$ 276	$ 536	$ 39	$ 851
Remaining drilling carry as of June 30, 2009	$ 1,374	$ 264	$ 2,086	$ 3,724

(a) On August 6, 2009, we announced an amendment to our Haynesville Shale joint venture agreement with Plains Exploration & Production Company (PXP). As part of the amendment, PXP has agreed to accelerate the payment of its remaining joint venture drilling carries as of September 30, 2009 in exchange for an approximate 12% reduction in the total amount of drilling carry obligations due to Chesapeake. At the closing, scheduled to occur on September 29, 2009, Chesapeake will receive cash of approximately $1.1 billion instead of an estimated $1.25 billion in remaining carried drilling costs that PXP would have paid over the next three years under the original agreement. In addition, Chesapeake and PXP have agreed to terminate a previous joint venture amendment that granted PXP a one-time option in June 2010 to avoid paying the last $800 million of the drilling carry obligations in exchange for the conveyance of 50% of its Haynesville Shale assets to Chesapeake. After the closing of the amendment, Chesapeake and PXP will each pay their proportionate working interest costs on future drilling. Furthermore, Chesapeake and PXP have agreed to make several other minor modifications to the agreement.

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 June 30, 2009, we had borrowings of $2.834 billion and letters of credit of $10 million outstanding under our revolving bank credit facility and we had borrowings of $297 million under the midstream credit facility.

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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 have completed or expect to complete in 2009 include the following:

- In the Current Quarter, we sold producing properties and gathering assets located primarily in Louisiana for $208 million and certain midstream and real estate surface assets for $172 million. In July 2009, we sold producing properties in Central Texas for $75 million. We expect to sell certain other midstream assets in multiple transactions for a total of approximately $70 million in the third quarter of 2009.

- We sold our fifth volumetric production payment transaction (VPP) involving certain of our South Texas assets for proceeds of approximately $371 million on August 4, 2009.

- We plan to sell certain non-Haynesville Shale producing assets in Louisiana in a sixth VPP in the second half of 2009 for approximately $225 million to $250 million.

- We plan to sell to a private equity investor a 50% interest in our Barnett Shale and Mid-Continent natural gas gathering and processing assets in our midstream business subsidiary, Chesapeake Midstream Partners, L.P. We anticipate proceeds of more than $550 million in the 2009 third quarter.

- We continue to have discussions with several companies about a possible joint venture on some or all of our Barnett Shale leasehold in a transaction targeted for completion by year end 2009.

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 carries also provide an additional source of liquidity that have reduced and will continue to reduce our capital expenditures. Cash provided by operating activities was $1.998 billion in the Current Period compared to $2.798 billion in the Prior Period. The $800 million decrease in the Current Period 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 impairments of assets, 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 86% of our expected remaining natural gas and oil production in 2009 and 22% of our expected natural gas and oil production in 2010 at average prices of $7.46 per mcfe and $9.48 per mcfe, respectively. Our natural gas and oil hedges as of June 30, 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 June 30, 2009, we had a net natural gas and oil derivative asset of $998 million.

Our $3.5 billion bank credit facility, our $460 million midstream credit facility and cash and cash equivalents are other sources of liquidity. At August 6, 2009, there was $1.4 billion of borrowing capacity available under the revolving bank credit facility and $92 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 $3.363 billion and repaid $4.166 billion in the Current Period, and we borrowed $6.758 billion and repaid $6.195 billion in the Prior Period.

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.

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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 Period and the Prior Period. 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 $89 million and $66 million in the Current Period and the Prior Period, respectively. Dividends paid on our preferred stock decreased to $12 million in the Current Period from $22 million in the Prior Period as a result of conversions and exchanges of preferred stock into common stock during 2008 and 2009.

In the Current Period and Prior Period, we received $9 million and paid $93 million, respectively, to settle a portion of the derivative liabilities assumed in our November 2005 acquisition of Columbia Natural Resources, LLC.

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 Period and the Prior Period, we reported a tax benefit from stock-based compensation of $0 and $21 million, respectively.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists decreased $350 million in the Current Period and increased $47 million in the Prior Period. All disbursements are funded on the day they are presented to our bank using available cash on hand or draws on our revolving bank credit facility.

In the Current Period, we received net proceeds of $54 million from the mortgage financing of one of our buildings. The interest-only loan has a five-year term at a floating rate of prime plus 275 basis points. At our option, we may prepay in full without penalty beginning in year four. The payment obligation is guaranteed by Chesapeake. Chesapeake is also party to a master lease for the entire building that will come into effect only in the event that a tenant defaults.

In the Current Quarter, we sold 113 surface land sites in the Barnett Shale area in and around Fort Worth, Texas for net proceeds of approximately $145 million and entered into a master lease agreement under which we agreed to lease the sites for 40 years for approximately $15 million to $27 million annually. As of June 30, 2009, the minimum aggregate future surface land site payments were approximately $866 million.

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, and we attempt to limit our exposure to non-performance by any single counterparty. On June 30, 2009, our commodity and interest rate derivative instruments were spread among 14 counterparties. Additionally, our multi-counterparty secured hedging facility requires our counterparties to secure their natural gas and oil hedging obligations in excess of defined thresholds. We expect to use the facility for all of our commodity hedging.

Our accounts receivable are primarily from purchasers of natural gas and oil ($534 million at June 30, 2009) and exploration and production companies which own interests in properties we operate ($452 million at June 30, 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

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the Current Quarter and the Current Period, we recognized $5 million and $13 million, respectively, of bad debt expense related to potentially uncollectible receivables.

Investing Activities

Cash used in investing activities decreased to $3.465 billion during the Current Period, compared to $6.373 billion during the Prior Period. We have been reducing our drilling program since the third quarter of 2008, and our leasehold and property acquisitions expenditures in the Current Period were 86% lower than in the Prior Period. The following table shows our cash used in (provided by) investing activities during these periods:

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Natural Gas and Oil Investing Activities:	($ in millions)	
Exploration and development of natural gas and oil properties	$ 1,995	$ 2,785
Acquisition of leasehold and unproved properties	410	2,645
Acquisitions of natural gas and oil companies and proved properties, net of cash acquired	2	202
Geological and geophysical costs	97	138
Interest capitalized on unproved properties	314	224
Proceeds from sale of volumetric production payment	(41)	(616)
Divestitures of proved and unproved properties and leasehold	(187)	(247)
Deposits for acquisitions	9	19
Deposits for divestitures	(8)	
Total natural gas and oil investing activities	2,591	5,150
Other Investing Activities:		
Additions to other property and equipment	980	1,229
Proceeds from sale of compressors	(68)	(51)
Proceeds from sale of drilling rigs and equipment		(34)
(Proceeds from) additions to investments	(2)	81
Sale of other assets	(36)	(2)
Total other investing activities	874	1,223
Total cash used in investing activities	$ 3,465	$ 6,373

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 have used our common stock for some or all of the consideration for certain transactions. In December 2008, we registered 25 million shares of common stock and on July 14, 2009 we registered an additional 1,499,832 shares of common stock to acquire assets (including mineral interests), businesses or securities of other companies. As of July 15, 2009, we had issued all of the shares of common stock for proved and unproved properties and leasehold acquisitions.

Bank Credit Facilities

We have a $3.5 billion syndicated revolving bank credit facility that matures in November 2012. As of June 30, 2009, we had $2.834 billion in outstanding borrowings under this facility and had utilized approximately $10 million of the facility for various letters of credit.

Borrowings under the facility are secured by certain producing natural gas and oil properties and bear interest at our option at either (i) the greater of the reference rate of Union Bank, 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% 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% 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%. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.70 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.75 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.43 to 1 and our indebtedness to EBITDA ratio was 3.47 to 1 at June 30, 2009. If we

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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 Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $75 million.

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

We also have a $460 million syndicated 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 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 June 30, 2009, we had $297 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 LIBOR 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 1.35 to 1 and our EBITDA to interest expense coverage ratio was 12.84 to 1 at June 30, 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.

Our revolving bank credit facility and midstream credit facility 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 contains 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.

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 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 June 30, 2009	$ 130	$ 370	$ 22	$ (1)	$ 77	$ 84
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.

On June 11, 2009, we entered into a multi-counterparty secured hedging facility with 13 hedge counterparties, one of which is a new counterparty to the company. These 13 hedge counterparties have committed to provide approximately 3.9 tcfe of trading capacity under the terms of the facility. Each of the six counterparties to our existing secured hedge facilities is a party to this new facility. The facility allows us to enter into cash-settled natural gas and oil price and basis hedges with the hedge counterparties. Our obligations under the new facility will be secured by natural gas and oil proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by at least 1.65 times, and guarantees by our subsidiaries that also guarantee our revolving bank credit facility and indentures. The hedge counterparties obligations under the facility will be secured by cash or short-term U.S. Treasury instruments to the extent that any mark-to-market amounts they owe to Chesapeake exceed defined thresholds. The maximum volume-based trading capacity under the facility is governed by the expected production of the pledged reserve collateral and volume-based trading limits are applied separately to price and basis hedges. In addition, there are volume-based sub-limits for natural gas and oil hedges. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that certain collateral coverage and other requirements are met. The facility does not have a maturity date. Counterparties to the agreement have the right to cease trading with the company on a prospective basis as long as obligations associated with any existing trades in the facility continue to be satisfied in accordance with the terms of the agreement.

All existing trades with the hedge counterparties are expected to be novated into the multi-counterparty facility along with any collateral currently pledged under the existing secured hedge facilities. Trades novated into the multi-counterparty facility from the existing secured hedge facilities will continue to be subject to any pre-existing exposure fees, if any, but we are not required to pay an exposure fee for any new trades in the multi-counterparty facility. The new multi-counterparty facility will consolidate and replace our six secured hedge facilities described above. As of July 31, 2009, no trades had been transacted or novated or collateral pledged under the multi-counterparty facility.

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Senior Note Obligations

In addition to outstanding borrowings under our revolving bank credit facility and midstream credit facility discussed above, as of June 30, 2009, senior notes represented approximately $10.4 billion of our total debt and consisted of the following ($ 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)]		841
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)]		1,041
Discount on senior notes[(c)]		(1,072)
Interest rate derivatives[(d)]		39
	$	10,437

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.4020 to 1.00 as of June 30, 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 second 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 third 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	Repurchase Dates	Common Stock Price Conversion	Contingent Interest First Payable

Convertible		Thresholds	(if applicable)
Senior Notes			
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	$ 64.36	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 107.36	June 14, 2019

(c) Included in this discount is $936 million associated with the equity component of our contingent convertible senior notes.

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

As of June 30, 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 revolving bank credit facility. As of June 30, 2009, we estimate that secured commercial bank indebtedness of approximately $5.7 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 June 30, 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 June 30, 2009 vs. June 30, 2008

General. For the Current Quarter, Chesapeake had net income of $243 million, or $0.39 per diluted common share, on total revenues of $1.673 billion. This compares to a net loss of $1.592 billion, or ($3.16) per diluted common share, on total revenues of ($455) million during the Prior Quarter. The Prior Quarter loss was due to an unrealized non-cash after-tax mark-to-market loss of $2.094 billion related to future period natural gas and oil hedges resulting primarily from higher natural gas and oil prices as of June 30, 2008 compared to March 31, 2008.

Natural Gas and Oil Sales. During the Current Quarter, natural gas and oil sales were $1.097 billion compared to ($1.594) billion in the Prior Quarter. In the Current Quarter, Chesapeake produced 223.2 bcfe at a weighted average price of $5.89 per mcfe, compared to 211.9 bcfe produced in the Prior Quarter at a weighted average price of $8.55 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on natural gas and oil derivatives of ($217) million and ($3.404) billion in the Current Quarter and the Prior Quarter, respectively). In the Current Quarter, the decrease in prices resulted in a decrease in revenue of $594 million and increased production resulted in a $97 million increase, for a net decrease in revenues of $497 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 $5.56, compared to $8.18 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 $56.72 and $76.96 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 $597 million, or $2.68 per mcfe, in the Current Quarter and a decrease of $423 million, or $1.99 per mcfe, in the Prior Quarter.

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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 a change of $1.00 per barrel of oil sold would have resulted in an increase or decrease in revenues and cash flow of approximately $3 million without considering the effect of derivative activities.

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

	For the Three Months Ended June 30,			
	2009		2008	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent[(a)(b)]	76,567	34%	94,463	45%
Barnett Shale	59,133	27	43,309	20
South Texas/Gulf Coast/Ark-La-Tex	24,142	11	31,503	15
Permian and Delaware Basins	19,229	9	19,360	9
Fayetteville Shale[(a)]	20,344	9	12,996	6
Haynesville Shale	12,228	5	1,284	1
Appalachian Basin	8,355	4	8,540	4
Marcellus Shale	3,196	1	435	
Total production	223,194	100%	211,890	100%

(a) The Current Quarter was impacted by the sale of an estimated 7 bcf of production in the BP divestitures.

(b) The Current Quarter was impacted by the sale of 13 bcfe of production in VPP transactions that closed in 2008.

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

Natural Gas and Oil Marketing Sales and Operating Expenses. Natural gas and oil marketing activities are substantially for third parties who are owners in Chesapeake-operated wells. Chesapeake realized $532 million in natural gas and oil marketing sales in the Current Quarter, with corresponding natural gas and oil marketing expenses of $500 million, for a net margin before depreciation of $32 million. This compares to sales of $1.099 billion, expenses of $1.075 billion and a net margin before depreciation of $24 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 third-party marketing volumes.

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 $44 million in service operations revenue in the Current Quarter with corresponding service operations expense of $46 million, for a net margin before depreciation of ($2) million. This compares to revenue of $40 million, expenses of $32 million and a net margin before depreciation of $8 million in the Prior Quarter. The decrease in margin during the Current Quarter was the result of both a reduction in drilling rates and certain fixed operating expenses associated with rigs that were not in operation during the Current Quarter.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $213 million in the Current Quarter compared to $219 million in the Prior Quarter. On a unit-of-production basis, production expenses were $0.95 per mcfe in the Current Quarter compared to $1.03 per mcfe in the Prior Quarter. The decrease in the Current Quarter was primarily due to lower service costs in the field as a result of the economic downturn. We expect that production expenses for 2009 will range from $1.10 to $1.20 per mcfe produced.

Production Taxes. Production taxes were $24 million in the Current Quarter compared to $88 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.11 per mcfe in the Current Quarter compared to $0.41 per mcfe in the Prior Quarter. The $64 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 $7.33 per mcfe (excluding gains or losses on derivatives) and additional exemptions, which was partially offset by an increase in production of 11 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 $55.67 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 $74 million in the Current Quarter and $101 million in the Prior Quarter. General and administrative expenses were $0.33 and $0.48 per mcfe for the Current Quarter and Prior Quarter, respectively. The decrease in the Current Quarter is primarily due to a reduction in advertising expense and legal settlements. Included in general and administrative expenses is stock-based compensation of $19 million for the Current Quarter and $21 million 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 $89 million and $83 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 $295 million and $523 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 $1.32 and $2.47 in the Current Quarter and in the Prior Quarter, respectively. The $1.15 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 carries in the Current Quarter, the impairment of natural gas and oil properties in 2008 and 2009 and the addition of reserves through our drilling activities. We expect the DD&A rate for 2009 to be between $1.50 and $1.70 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $58 million in the Current Quarter and $40 million in the Prior Quarter. Depreciation and amortization of other assets was $0.26 and $0.19 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 our investment in gathering systems, buildings and rigs. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 10 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 depreciation and amortization of other assets for 2009 to be between $0.25 and $0.30 per mcfe produced.

Restructuring Costs. In the Current Quarter, we recorded $34 million of restructuring and relocating costs in our Eastern Division and certain other workforce reduction costs. We reorganized our Charleston, West Virginia-based Eastern Division from a regional corporate headquarters to a regional field office consistent with the business model we use elsewhere in the country. As a result, we consolidated the management of our Eastern Division land, legal, accounting, information technology, geoscience and engineering departments into our corporate offices in Oklahoma City. The costs of the restructuring include termination benefits, consolidating or closing facilities and relocating employees. The discussion of restructuring costs in Note 8 of our condensed consolidated financial statements included in Part I of this report provides additional detail on the accounting for and reporting of these costs.

Other Income (Expense). Other income (expense) was ($2) million and ($1) million in the Current Quarter and in the Prior Quarter, respectively. The Current Quarter consisted of $2 million of interest income, a ($7) million loss related to our equity in the net losses of certain investments and $3 million of miscellaneous income. The Prior Quarter income consisted of $2 million of interest income, a ($5) million loss related to our equity in the net losses of certain investments and $2 million of miscellaneous income.

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Interest Expense. Interest expense decreased to $22 million in the Current Quarter compared to $54 million in the Prior Quarter as follows:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008
	($ in millions)	
Interest expense on senior notes and revolving bank credit facilities	$ 213	$ 181
Capitalized interest	(152)	(121)
Realized (gain) loss on interest rate derivatives	(5)	(4)
Unrealized (gain) loss on interest rate derivatives	(42)	(14)
Amortization of loan discount and other	8	12
Total interest expense	$ 22	$ 54
Average long-term borrowings	$ 11,493	$ 10,064

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.29 per mcfe in the Current Quarter compared to $0.32 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 $31 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).

Impairment of Investments. In the Current Quarter, we paid $10 million to fund various costs associated with Ventura Refining and Transmission LLC s operations. These costs were expensed as incurred.

Loss on Exchanges of Chesapeake Debt. In the Current Quarter, we privately exchanged approximately $85 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 2,530,650 shares of our common stock. The difference between the estimated fair market value of the notes exchanged and the fair value of the common stock issued resulted in a Current Quarter loss of $2 million on the cancellation of indebtedness.

Income Tax Expense (Benefit). Chesapeake recorded income tax expense of $145 million in the Current Quarter, compared to an income tax benefit of $996 million in the Prior Quarter. Of the $1.141 billion increase in income tax expense recorded in the Current Quarter, $1.145 billion was the result of the increase in net income before income taxes which was offset by $4 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.

Results of Operations Six Months Ended June 30, 2009 vs. June 30, 2008

General. For the Current Period, Chesapeake had a net loss of $5.498 billion, or $9.18 per diluted common share, on total revenues of $3.668 billion. This compares to a net loss of $1.722 billion, or $3.52 per diluted common share, on total revenues of $1.156 billion during the Prior Period. The Current Period 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 Period loss was due to an unrealized non-cash after-tax mark-to-market loss of $2.791 billion related to future period natural gas and oil hedges resulting primarily from higher natural gas and oil prices as of June 30, 2008 compared to December 31, 2007.

Natural Gas and Oil Sales. During the Current Period, natural gas and oil sales were $2.494 billion compared to ($821) million in the Prior Period. In the Current Period, Chesapeake produced 436.2 bcfe at a weighted average price of $5.98 per mcfe, compared to 416.1 bcfe produced in the Prior Period at a weighted average price of $8.93 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on natural gas and oil derivatives of ($116) million and ($4.538) billion in the Current Period and Prior Period, respectively). In the Current Period, the decrease in prices resulted in a decrease in revenue of $1.285 billion and increased production resulted in a $179 million increase, for a net decrease in revenues of $1.106 billion (excluding unrealized gains or losses on natural gas and oil derivatives). The increase in production from the Prior Period to the Current Period was primarily generated from the drillbit by organic growth.

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For the Current Period, we realized an average price per mcf of natural gas of $5.80, compared to $8.61 in the Prior Period (weighted average prices for both Periods exclude the effect of unrealized gains or losses on derivatives). Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $48.32 and $75.86 in the Current Period and Prior Period, respectively. Realized gains or losses from our natural gas and oil derivatives resulted in a net increase in natural gas and oil revenues of $1.115 billion, or $2.55 per mcfe, in the Current Period and a decrease of $208 million, or $0.50 per mcfe, in the Prior Period.

Changes in natural gas and oil prices have a significant impact on our natural gas and oil revenues and cash flows. Assuming the Current Period production levels, a change of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $40 million and $39 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 $6 million without considering the effect of derivative activities.

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

	For the Six Months Ended June 30,			
	2009		2008	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent[(a)(b)]	151,832	35%	188,931	45%
Barnett Shale	116,794	27	81,282	20
South Texas/Gulf Coast/Ark-La-Tex	50,895	11	64,011	15
Permian and Delaware Basins	38,647	9	39,484	10
Fayetteville Shale[(a)]	38,538	9	24,108	6
Haynesville Shale	18,813	4	1,466	
Appalachian Basin	16,814	4	15,986	4
Marcellus Shale	3,854	1	870	
Total production	436,187	100%	416,138	100%

(a) The Current Period was impacted by the sale of an estimated 15 bcf of production in the BP divestitures.

(b) The Current Period was impacted by the sale of 27 bcfe of production in VPP transactions that closed in 2008.

Natural gas production represented approximately 92% in both the Current Period the Prior Period 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 $1.084 billion in natural gas and oil marketing sales in the Current Period, with corresponding natural gas and oil marketing expenses of $1.023 billion, for a net margin before depreciation of $61 million. This compares to sales of $1.895 billion, expenses of $1.849 billion and a net margin before depreciation of $46 million in the Prior Period. In the Current Period, Chesapeake realized an increase in natural gas and oil marketing net margin primarily due to an increase in third-party marketing volumes.

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 $90 million in service operations revenue in the Current Period with corresponding service operations expense of $87 million, for a net margin before depreciation of $3 million. This compares to revenue of $82 million, expenses of $67 million and a net margin before depreciation of $15 million in the Prior Period. The decrease in margin during the Current Period was the result of both a reduction in drilling rates and certain fixed operating expenses associated with rigs that were not in operation during the Current Period.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $451 million in the Current Period compared to $419 million in the Prior Period. On a unit-of-production basis, production expenses were $1.03 per mcfe in the Current Period compared to $1.01 per mcfe in the Prior Period. The increase in the Current Period 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 $46 million in the Current Period compared to $163 million in the Prior Period. On a unit-of-production basis, production taxes were $0.11 per mcfe in the Current Period compared to $0.39 per mcfe in the Prior Period. The $117 million decrease in production taxes in the Current Period is due to a decrease in the average realized sales price of natural gas and oil of $6.00 per mcfe (excluding gains or losses on derivatives) and additional exemptions, which was partially offset by an increase in production of 20 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 $55.67 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 $164 million in the Current Period and $180 million in the Prior Period. General and administrative expenses were $0.38 and $0.43 per mcfe for the Current Period and Prior Period, respectively. The decrease in the Current Period is primarily due to a reduction in advertising expense and legal settlements. Included in general and administrative expenses is stock-based compensation of $39 million and $40 million for the Current Period and the Prior Period, respectively. 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 $182 million and $167 million of internal costs in the Current Period and the Prior Period, 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 $742 million and $1.038 billion during the Current Period and the Prior Period, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $1.70 and $2.49 in the Current Period and in the Prior Period, respectively. The $0.79 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 carries in the Current Period, the impairment of natural gas and oil properties in 2008 and 2009 and the addition of reserves through our drilling activities. We expect the DD&A rate for 2009 to be between $1.50 and $1.70 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $115 million in the Current Period and $76 million in the Prior Period. Depreciation and amortization of other assets was $0.26 and $0.18 per mcfe for the Current Period and the Prior Period, respectively. The increase in the Current Period is a result of the significant increase in our investment in gathering systems, buildings and rigs. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 10 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 depreciation and amortization of other assets for 2009 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 Period 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

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transferred to the amortization base of our full-cost pool during the Current Period and were consequently included in our ceiling test impairment during the Current Period.

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

Restructuring Costs. In the Current Period, we recorded $34 million of restructuring and relocation costs in our Eastern Division and certain other workforce reduction costs. We reorganized our Charleston, West Virginia-based Eastern Division from a regional corporate headquarters to a regional field office consistent with the business model we use elsewhere in the country. As a result, we consolidated the management of our Eastern Division land, legal, accounting, information technology, geoscience and engineering departments into our corporate offices in Oklahoma City. The costs of the restructuring include termination benefits, consolidating or closing facilities and relocating employees. The discussion of restructuring costs in Note 8 of our condensed consolidated financial statements included in Part I of this report provides additional detail on the accounting for and reporting of these costs.

Other Income (Expense). Other income (expense) was $5 million in the Current Period compared to ($11) million in the Prior Period. The Current Period consisted of $5 million of interest income, an ($8) million loss related to our equity in the net losses of certain investments and $8 million of miscellaneous income. The Prior Period income consisted of $4 million of interest income, a ($17) million loss related to our equity in the net losses of certain investments and $2 million of miscellaneous income.

Interest Expense. Interest expense decreased to $8 million in the Current Period compared to $153 million in the Prior Period as follows:

	Six Months Ended June 30,	
	2009	2008
	($ in millions)	
Interest expense on senior notes and revolving bank credit facilities	$ 407	$ 361
Capitalized interest	(314)	(224)
Realized (gain) loss on interest rate derivatives	(12)	(4)
Unrealized (gain) loss on interest rate derivatives	(87)	(1)
Amortization of loan discount and other	14	21
Total interest expense	$ 8	$ 153
Average long-term borrowings	$ 11,095	$ 9,597

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.22 per mcfe in the Current Period compared to $0.37 in the Prior Period. The decrease in interest expense per mcfe is primarily due to an increase in capitalized interest and increased production volumes. Capitalized interest increased by $90 million as a result of a significant increase in unevaluated properties, the base on which interest is capitalized, in the Current Period compared to the Prior Period. 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).

Impairment of Investments. In the Current Period, we recorded a $162 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; Ventura Refining and Transmission LLC, $13 million; and Mountain Drilling Company, $9 million.

Loss on Exchanges of Chesapeake Debt. In the Current Period, we privately exchanged approximately $85 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 2,530,650 shares of our common stock. The difference between the estimated fair market value of the notes exchanged and the fair value of the common stock issued resulted in a Current Period loss of $2 million on the cancellation of indebtedness.

Income Tax Expense (Benefit). Chesapeake recorded an income tax benefit of $3.298 billion in the Current Period, compared to an income tax benefit of $1.078 billion in the Prior Period. Of the $2.220 billion increase in income tax benefit recorded in the Current Period, $2.308 billion was the result of the decrease in net income before income taxes which was offset by $88 million due to a decrease in the effective tax rate. Our effective income tax rate was 37.5% in the Current Period and 38.5% in the Prior Period. 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.

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.

In April 2009, the FASB issued Staff Position SFAS 107-1 and Accounting Principles Board (APB) Opinion No. 28-1, *Interim Disclosures about Fair Value of Financial Instruments* (FSP 107-1 and APB 28-1). FSP 107-1 amends FASB Statement No. 107, *Disclosures about Fair Values of Financial Instruments*, to require disclosures about fair value of financial instruments in interim financial statements as well as in annual financial statements. APB 28-1 amends APB Opinion No. 28, *Interim Financial Reporting*, to require those disclosures in all interim financial statements. FSP 107-1 and APB 28-1 are effective for interim periods ending after June 15, 2009 and we have adopted them in the Current Quarter.

In April 2009, the FASB issued Staff Position SFAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly* (FSP 157-4). FSP 157-4 provides additional guidance in estimating fair value under SFAS No. 157, *Fair Value Measurements*, when the volume and level of transaction activity for an asset or liability have significantly decreased in relation to normal market activity for the asset or liability. FSP 157-4 also provides additional guidance on circumstances that may indicate a transaction is not orderly. FSP 157-4 is effective for interim periods ending after June 15, 2009, and we have adopted its provisions in the Current Quarter. FSP 157-4 did not have a significant impact on our financial position, results of operations, cash flows or disclosures.

In April 2009, the FASB issued Staff Position SFAS 115-2 and SFAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments* (FSP 115-2). FSP 115-2 provides guidance in determining whether impairments in debt securities are other than temporary, and modifies the presentation and disclosures surrounding such instruments. FSP 115-2 is effective for interim periods ending after June 15, 2009, and we have adopted its provisions in the Current Quarter. FSP 115-2 did not have a significant impact on our financial position, results of operations, cash flows or disclosures.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events*. This statement establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. SFAS 165 requires companies to reflect in their financial statements the effects of subsequent events that provide additional evidence about conditions at the balance-sheet date. Subsequent events that provide evidence about conditions that arose after the balance-sheet date should be disclosed if the financial statements would otherwise be misleading. Disclosures should include the nature of the

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event and either an estimate of its financial effect or a statement that an estimate cannot be made. SFAS 165 is effective for interim or annual financial periods ending after June 15, 2009. We adopted this statement in the Current Quarter and as the requirements under SFAS 165 are consistent with our current practice, the implementation of this statement did not have a material impact on our consolidated financial statements or our financial disclosures.

In June 2009, the FASB issued SFAS No. 167, *Amendments to FASB Interpretation No. 46(R)*. Among other items, SFAS 167 responds to concerns about the application of certain key provisions of FIN 46(R), including those regarding the transparency of the involvement with variable interest entities. SFAS 167 is effective for calendar year companies beginning on January 1, 2010. We are currently assessing the impact that adoption of SFAS 167 will have on our financial position, results of operations, cash flows or disclosures.

In June 2009, the FASB issued SFAS No. 168, *The FASB Accounting Standards Codification* ™ *and the Hierarchy of Generally Accepted Accounting Principles*. This standard replaces SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles,* and establishes only two levels of U.S. GAAP, authoritative and nonauthoritative. The FASB Accounting Standards Codification will become the source of authoritative, nongovernmental GAAP, except for rules and interpretive releases of the SEC, which are sources of authoritative GAAP for SEC registrants. This standard is effective for financial statements for interim or annual reporting periods ending after September 15, 2009. We will begin to use the new guidelines and numbering system prescribed by the Codification when referring to GAAP in the third quarter of 2009. As the Codification was not intended to change or alter existing GAAP, it will not have any impact on our consolidated financial statements.

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 and in Item 1A in Part II of this report. 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 amount and 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,

potential increased operating costs resulting from legislative and regulatory changes such as those proposed with respect to commodity derivatives trading, natural gas and oil tax incentives and deductions, hydraulic fracturing and climate change,

losses possible from pending or future litigation.

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

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

Natural Gas and Oil Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for natural gas and oil. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. 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 and oil price changes is to hedge into strengthening natural gas and oil 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, natural gas and oil 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 described in more detail below. We typically use swaps or knockouts for a large portion of the volume of natural gas and oil we hedge. Swaps are used when the price level is acceptable, and we are not paid a sufficient premium for selling an additional put (a knockout) that could cause the swap to become ineffective if the NYMEX future price closes below some lower threshold on the pricing date. We use 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 not to be reached. We also sell calls, taking advantage of the volatility inherent in the market for some smaller portion of our projected production volumes when the strike price levels and the premiums are attractive to us. In other words, we sell calls when we believe it to be more likely than not that the future natural gas or oil price will not exceed the call strike price 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 and estimates of likely production (risked) from new drilling. Production forecasts 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 production forecasts, the hedges are reversed. The actual fixed hedge price on our derivative instruments is derived from market discovery, bidding and the reference NYMEX price, as reflected in current NYMEX trading. The pricing dates of our derivative contracts follow NYMEX futures, either being the penultimate trading day, last trading day or average of the last three trading days of the month. 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.

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.

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As of June 30, 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. On occasion, we sell an additional put option with the collar and receive a premium to make a three-way collar. This eliminates the counterparty s downside exposure below the second put option.

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 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 non-Appalachian Basin 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.

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

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

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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, the Current Period and the Prior Period are presented below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	($ in millions)			
Natural gas and oil sales	$ 717	$ 2,233	$ 1,495	$ 3,925
Realized gains (losses) on natural gas and oil derivatives	597	(423)	1,115	(208)
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(253)	(3,340)	(206)	(4,409)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	36	(64)	90	(129)
Total natural gas and oil sales	$ 1,097	$ (1,594)	$ 2,494	$ (821)

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As of June 30, 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 June 30, 2009:

	Volume (bbtu)	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 June 30, 2009 ($ in millions)
Natural Gas:								
Swaps[(a)]:								
Q3 2009	77,381	$ 7.45	$	$	$	Yes	$	$ 262
Q4 2009	123,750	7.30				Yes		286
2010	51,627	9.29				Yes		166
2011	10,950	8.59				Yes		18
CNR Swaps[(b)]:								
Q3 2009	4,600	5.18				Yes		6
Q4 2009	4,600	5.18				Yes		1
Other Swaps[(c)]:								
Q3 2009	6,170	8.09				No		25
Q4 2009	5,780	8.61				No		22
2010	36,093	9.17				No		(1)
2011	6,230	8.16				No		
2012-2016	34,470	6.84				No		(16)
Counter Swaps								
Q3 2009	(3,680)	9.26				No		(20)
Q4 2009	(3,680)	9.26				No		(16)
Collars:								
Q3 2009	23,280		7.20	8.10		Yes		76
Q4 2009	17,220		7.36	8.24		Yes		47
2010	22,500		6.00	8.00		Yes		15
CNR Collars[(b)]:								
Q3 2009	920		4.50	6.00		Yes		1
Q4 2009	920		4.50	6.00		Yes		
Other Collars[(d)]:								
Q3 2009	79,400		5.19/6.85	9.06		No	6	201
Q4 2009	34,910		5.40/7.01	9.51		No	6	79
2010	48,090		5.12/7.14	9.73		No	13	59
2011	10,950		6.00/7.57	11.67		No	8	12
2012 2017	21,920		6.00/7.30	12.00		No	1	2
Knockout Swaps:								
Q4 2009	5,490	10.17	6.33			No		3
2010	69,530	9.99	6.19			No		38
2011	23,650	9.86	6.29			No		6
Call Options:								
Q3 2009	8,845			9.94		No	21	
Q4 2009	13,340			10.06		No	21	(2)
2010	270,100			10.20		No	174	(30)
2011	116,800			10.70		No	78	(25)
2012 2020	186,440			11.71		No	122	(100)

Put Options:					
Q3 2009	9,200	4.45	No	6	(6)
Q4 2009	9,200	4.45	No	6	(5)
2010	36,500	5.75	No	3	(28)
2011	36,500	5.75	No	26	(20)

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	Volume (bbtu)	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 June 30, 2009 ($ in millions)
Basis Protection Swaps[e]:								
Non-Appalachian Basin:								
Q3 2009	5,005	$	$	$	$ (2.81)	No	$	$ (13)
Q4 2009	14,591				(1.25)	No		(11)
2010	14,590				(0.33)	No		(1)
2011	56,040				(0.73)	No	(3)	(13)
2012 2018	89,291				(0.70)	No	(3)	(21)
Basis Protection Swaps:								
Appalachian Basin:								
Q3 2009	4,448				0.27	No		1
Q4 2009	4,438				0.27	No		1
2010	10,199				0.26	No		1
2011	12,086				0.25	No		2
2012 2022	134				0.11	No		
Total Natural Gas							485	1,002

	Volume (mbbls)	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 June 30, 2009 ($ in millions)
Oil:								
Counter Swaps:								
Q3 2009	(230)	$ 69.10	$	$	$	No	$	$
Q4 2009	(230)	69.10				No		1
Knockout Swaps:								
Q3 2009	1,288	85.73	52.79			No	(18)	18
Q4 2009	1,288	85.71	52.79			No	(18)	13
2010	4,745	90.25	60.00			No		20
2011	1,095	104.75	60.00			No		9
2012	732	109.50	60.00			No		6
Call Options:								
Q3 2009	1,288			101.79		No	1	(1)
Q4 2009	1,288			101.79		No	1	(3)
2010	5,110			100.71		No	6	(25)
2011	3,650			105.00		No	16	(18)
2012	3,660			105.00		No	15	(24)
Total Oil							3	(4)
Total Natural Gas and Oil							$ 488	$ 998

(a) Included in Swaps are trades for 22,000 bbtu that were novated with the VPP divestiture that closed on August 4, 2009.

(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 ($19 million liability remaining as of June 30, 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,

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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 Swaps are options to extend existing swaps 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. Also included are trades for 45,000 bbtu that were novated with the VPP divestiture that closed on August 4, 2009.

(d) Included in Other Collars for 2009, 2010, 2011 and 2012-2017 are 36,260 bbtu, 29,870 bbtu, 3,650 bbtu and 21,920 bbtu of three-way collars which include written put options with weighted average prices of $5.25, $5.09, $6.00 and $6.00, respectively, which limit the counterparty s exposure.

(e) Included in Non-Appalachian Basin Basis Swaps are trades for 65,600 bbtu that were novated with the VPP divestiture that closed on August 4, 2009.

To mitigate our exposure to the fluctuation in price of diesel fuel, we have entered into diesel swaps from July 2009 to March 2010 for a total of 29,025,000 gallons with an average fixed price of $1.58 per gallon. The fair value of these swaps as of June 30, 2009 was as asset of $10 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. Future risk related to counterparties not being able to meet their obligations has been mitigated under our new secured hedging facility which requires counterparties to post collateral if their obligations to Chesapeake are in excess of defined thresholds. 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.

The table below reconciles the Current Period change in fair value of our natural gas and oil derivatives. Of the $998 million fair value asset, $1.121 billion relates to contracts maturing in the next 12 months, of which we expect to transfer approximately $461 million (net of income taxes) from accumulated other comprehensive income to net income (loss) and $123 million liability relates to contracts maturing after 12 months. All transactions hedged as of June 30, 2009 are expected to mature by December 31, 2022.

	2009 ($ in millions)
Fair value of contracts outstanding, as of January 1	$ 1,305
Change in fair value of contracts	1,117
Fair value of contracts when entered into	(38)
Contracts realized or otherwise settled	(1,057)
Fair value of contracts when closed	(329)
Fair value of contracts outstanding, as of June 30	$ 998

The change in natural gas and oil prices during the Current Period increased our derivative assets by $1.117 billion. This gain is recorded in natural gas and oil sales or in accumulated other comprehensive income. We entered into new contracts for which a premium of $38 million was received, and a liability recorded. We settled and lifted contracts, reducing our assets by $1.057 billion and $329 million, respectively, and the realized gain is recorded in natural gas and oil sales in the month of related production.

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Interest Rate Risk

The table below presents principal cash flows ($ in millions) 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	$ 10,606	$ 11,470
Average interest rate					7.6%	6.0%	6.1%
Long-term debt variable rate	$	$	$	$ 2,834	$ 297	$	$ 3,131
Average interest rate				2.26%	2.89%		2.32%

(a) This amount does not include the discount included in long-term debt of ($1.072) billion and interest rate derivatives of $39 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 fluctuations in earnings or cash flow due to changes in market interest rates. However, changes in interest rates do affect the fair value of our fixed-rate debt.

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 $5 million, $4 million, $12 million and $4 million in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. Unrealized gains (losses) included in interest expense were $42 million, $14 million, $87 million and $1 million in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively.

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As of June 30, 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							
April 2009	December 2018	$ 1,750	7.78%	1 6 mL plus 492 bp	Yes	$	$ (62)
April 2008	November 2020	$ 1,000	8.09%	1 6 mL plus 485 bp	No	$ (1)	$ (16)
Call Options							
August 2009	November 2009	$ 500	6.69%	1 6 mL plus 263 bp	No	$	$ (14)
Floating to Fixed Interest Rate:							
Swaps							
August 2007	July 2012	$ 1,375	4.20%	1 6 mL	No	$	$ (32)
Collars[a]							
August 2007	August 2010	$ 250	4.52%	6 mL	No	$	$ (9)
Swaption							
August 2009		$ 500	2.56%	1 mL	No	$ 4	$ (11)
						$ 3	$ (144)

(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 Period, we closed interest rate derivatives for gains totaling $30 million, of which $18 million was recognized in interest expense. The remaining $12 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 four to eleven 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 fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as an asset of $7 million at June 30, 2009. The euro-denominated debt in notes payable has been adjusted to $841 million at June 30, 2009 using an exchange rate of $1.4020 to 1.00 with an offsetting entry to other comprehensive income of $34 million related to future interest expense.

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***

We refer to you 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.

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 and the following additional risk factor should be considered carefully, together with other information in this report and other reports and materials we file with the Securities and Exchange Commission.

Potential legislative and regulatory actions could increase our costs, reduce our revenue and cash flow from natural gas and oil sales, reduce our liquidity or otherwise alter the way we conduct our business.

The activities of exploration and production companies operating in the United States are subject to extensive federal, state and local regulations. Changes to existing regulations or new regulations such as those described below could, if adopted, have an adverse effect on our business.

Federal budget proposals would potentially increase and accelerate the payment of federal income taxes of independent producers of natural gas and oil. Proposals that would significantly affect us would repeal the expensing of intangible drilling costs, repeal the percentage depletion allowance and increase the amortization period of geological and geophysical expenses. These changes, if enacted, will make it more costly for us to explore for and develop our natural gas and oil resources.

The U.S. Congress is considering measures aimed at increasing the transparency and stability of the over-the-counter (OTC) derivative markets and preventing excessive speculation. We maintain an active price and basis protection hedging program related to the natural gas and oil we produce. Additionally, we have used the OTC market exclusively for our natural gas and oil derivative contracts and rely on our hedging activities to manage the risk of low commodity prices and to predict with greater certainty the cash flow from our hedged production. Proposals being considered would impose clearing and standardization requirements for all OTC derivatives and restrict trading positions in the energy futures markets. Such changes would likely materially reduce our hedging opportunities and could negatively affect our revenues and cash flow during periods of low commodity prices.

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

The following table presents information about repurchases of our common stock during the three months ended June 30, 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)]
April 1, 2009 through April 30, 2009	12,706	$ 19.73		
May 1, 2009 through May 31, 2009	19,320	22.46		
June 1, 2009 through June 30, 2009	211,172	20.22		
Total	243,198	$ 20.37		

(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.

On June 15, 2009, we converted all outstanding shares of our 6.25% Mandatory Convertible Preferred Stock into Chesapeake common stock. On the mandatory conversion date, 143,768 shares of the convertible preferred stock were converted into 1,239,538 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.

On June 19, 2009, Chesapeake entered into two unsolicited transactions with holders of the company s 2.25% Contingent Convertible Senior Notes due 2038, to issue 745,900 and 1,784,750 shares of the company s common stock in exchange for principal amounts of the 2.25% Convertible Notes equaling $25 million and $60.5 million, respectively. The transactions closed on June 24, 2009 and June 25, 2009, respectively, and the $85.5 million principal amount of 2.25% Convertible Notes was retired upon receipt. The issuance of the shares of common stock in these transactions was exempt from registration under the Securities Act pursuant to Section 3(a)(9) under the Securities Act.

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

Not applicable.

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

Seven matters were submitted to a vote of the shareholders at Chesapeake s annual meeting of shareholders held on June 12, 2009: the election of directors for three-year terms expiring in 2012; an amendment to the company s certificate of incorporation to increase the number of authorized shares of common stock; an amendment to the company s Long Term Incentive Plan covering awards of stock-based compensation to its employees, consultants and non-employee directors; the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for the fiscal year ending December 31, 2009; a shareholder proposal regarding annual elections of directors; a shareholder proposal regarding a majority voting standard for director elections; and a shareholder proposal regarding the Company s non-discrimination policy.

In the election of directors, Richard K. Davidson received 387,370,398 votes for election and 137,669,534 votes were withheld from voting for Mr. Davidson; V. Burns Hargis received 442,224,691 votes for election and 82,815,241 votes were withheld from voting for Mr. Hargis; and Charles T. Maxwell received 370,380,745 votes for election and 154,659,187 votes were withheld from voting for Mr. Maxwell. There were no broker non-votes for the election of directors. The other directors whose terms continue after the meeting are Frank Keating, Merrill A.

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Miller, Jr. and Frederick B. Whittemore, whose terms expire in 2010, and Aubrey K. McClendon and Don Nickles, whose terms expire in 2011.

On the proposal for the amendment to the certificate of incorporation, 407,635,861 votes were received for approval of the amendment, 99,106,115 votes were received against approval of the amendment and holders of 18,297,953 shares abstained from voting on this proposal. There were no broker non-votes for this proposal.

On the proposal for an amendment of the Long Term Incentive Plan, 335,614,943 votes were received for approval of the amendment, 61,347,175 votes were received against approval of the amendment and holders of 14,302,702 shares abstained from voting on this proposal. There were 113,775,110 broker non-votes on this proposal.

On the proposal to ratify the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for the fiscal year ending December 31, 2009, 498,582,542 votes were received for approval of the ratification, 10,842,638 votes were received against the ratification and holders of 15,614,750 shares abstained from voting on this proposal. There were no broker non-votes for this proposal.

On the shareholder proposal regarding annual election of directors, 354,708,943 votes were received for proposal, 54,274,038 votes were received against the proposal and holders of 2,281,615 shares abstained from voting on this proposal. There were 113,775,334 broker non-votes on this proposal.

On the shareholder proposal regarding a majority voting standard for director elections, 321,570,201 votes were received for proposal, 87,083,334 votes were received against the proposal and holders of 2,514,060 shares abstained from voting on this proposal. There were 113,872,335 broker non-votes on this proposal.

On the shareholder proposal regarding Company s non-discrimination policy, 157,117,754 votes were received for proposal, 222,531,003 votes were received against the proposal and holders of 31,620,838 shares abstained from voting on this proposal. There were 113,770,335 broker non-votes on this proposal.

ITEM 5. ***Other Information***

Not applicable.

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ITEM 6. ***Exhibits***

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

		Incorporated by Reference					
Exhibit Number	**Exhibit Description**	**Form**	**SEC File Number**	**Exhibit**	**Filing Date**	**Filed Herewith**	**Furnished Herewith**
3.1.1	Chesapeake s Restated Certificate of Incorporation, as amended.					X	
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.	10-K	001-13726	3.1.5	02/29/2008		
3.1.5	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock.	10-Q	001-13726	3.1.6	08/11/2008		
3.2	Chesapeake s Amended and Restated Bylaws.	8-K	001-13726	3.1	11/17/2008		
10.1.14	Chesapeake s Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.1.14	06/17/2009		
12	Ratios of Earnings to Fixed Charges and Preferred Dividends.					X	
31.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
31.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
32.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X	
32.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X	
101.INS	XBRL Instance Document.						X
101.SCH	XBRL Taxonomy Extension Schema Document.						X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.						X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.						X
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.						X

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101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.						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: August 10, 2009

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3.1.5	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock.	10-Q	001-13726	3.1.6	08/11/2008		
3.2	Chesapeake s Amended and Restated Bylaws.	8-K	001-13726	3.1	11/17/2008		
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