CHESAPEAKE ENERGY CORP
Form 10-Q
November 09, 2009
Table of Contents

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 September 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	**73-1395733**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

6100 North Western Avenue	
Oklahoma City, Oklahoma	**73118**
(Address of principal executive offices)	(Zip Code)

(405) 848-8000

(Registrant s telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [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 [ ]   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 November 4, 2009, there were 647,707,733 shares of our $0.01 par value common stock outstanding.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

INDEX TO FORM 10-Q FOR THE QUARTER ENDED SEPTEMBER 30, 2009

PART I.

Financial Information

PART II.

Other Information

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	September 30, 2009	December 31, 2008 (Adjusted)
	($ in millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 520	$ 1,749
Accounts receivable, net	1,298	1,324
Short-term derivative instruments	538	1,082
Other	152	137
Total Current Assets	2,508	4,292
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full-cost accounting:		
Evaluated natural gas and oil properties	33,513	28,965
Unevaluated properties	9,708	11,379
Less: accumulated depreciation, depletion and amortization of natural gas and oil properties	(22,489)	(11,866)
Total natural gas and oil properties, at cost based on full-cost accounting	20,732	28,478
Other property and equipment:		
Natural gas gathering systems and treating plants	3,307	2,717
Buildings and land	1,656	1,513
Drilling rigs and equipment	610	430
Natural gas compressors	301	184
Other	538	482
Less: accumulated depreciation and amortization of other property and equipment	(766)	(496)
Total other property and equipment	5,646	4,830
Total Property and Equipment	26,378	33,308
OTHER ASSETS:		
Investments	422	444
Long-term derivative instruments	89	261
Other assets	322	288
Total Other Assets	833	993
TOTAL ASSETS	$ 29,719	$ 38,593

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(Unaudited)

	September 30, 2009	December 31, 2008 (Adjusted)
	($ in millions)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 932	$ 1,611
Short-term derivative instruments	28	66
Accrued liabilities	838	880
Deferred income taxes	172	358
Income taxes payable	1	108
Revenues and royalties due others	392	431
Accrued interest	151	167
Total Current Liabilities	2,514	3,621
LONG-TERM LIABILITIES:		
Long-term debt, net	12,073	13,175
Deferred income tax liabilities	1,316	4,200
Asset retirement obligations	282	269
Long-term derivative instruments	256	111
Other liabilities	449	200
Total Long-Term Liabilities	14,376	17,955
CONTINGENCIES AND COMMITMENTS (Note 3)		
EQUITY:		
Chesapeake 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 September 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 September 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 September 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 September 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 September 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, 645,273,711 and 607,953,437 shares issued at September 30, 2009 and December 31, 2008, respectively	6	6
Paid-in capital	11,981	11,680
Retained earnings (deficit)	(737)	4,569
	274	267

Accumulated other comprehensive income (loss), net of tax of ($167) million and ($163) million, respectively		
Less: treasury stock, at cost; 766,554 and 657,276 common shares as of September 30, 2009 and December 31, 2008, respectively	(12)	(10)
Total Chesapeake Stockholders Equity	11,978	17,017
Noncontrolling interest	851	
Total Equity	12,829	17,017
TOTAL LIABILITIES AND EQUITY	$ 29,719	$ 38,593

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008 (Adjusted)	2009	2008 (Adjusted)
	($ in millions except per share data)			
REVENUES:				
Natural gas and oil sales	$ 1,187	$ 6,408	$ 3,681	$ 5,587
Marketing, gathering and compression sales	575	1,038	1,660	2,934
Service operations revenue	49	45	139	127
Total Revenues	1,811	7,491	5,480	8,648
OPERATING COSTS:				
Production expenses	218	239	670	658
Production taxes	25	87	71	250
General and administrative expenses	95	108	259	288
Marketing, gathering and compression expenses	546	1,014	1,569	2,864
Service operations expense	49	37	136	104
Natural gas and oil depreciation, depletion and amortization	295	480	1,037	1,518
Depreciation and amortization of other assets	62	48	177	124
Impairment of natural gas and oil properties and other assets	86		9,721	
Loss on sale of other property and equipment	38		38	
Restructuring costs			34	
Total Operating Costs	1,414	2,013	13,712	5,806
INCOME (LOSS) FROM OPERATIONS	397	5,478	(8,232)	2,842
OTHER INCOME (EXPENSE):				
Other income (expense)	(30)	(12)	(25)	(23)
Interest expense	(43)	(34)	(52)	(186)
Impairment of investments			(162)	
Loss on exchanges of Chesapeake debt	(17)	(31)	(19)	(31)
Total Other Income (Expense)	(90)	(77)	(258)	(240)
INCOME (LOSS) BEFORE INCOME TAXES	307	5,401	(8,490)	2,602
INCOME TAX EXPENSE (BENEFIT):				
Current income taxes		193	1	196
Deferred income taxes	115	1,886	(3,185)	806
Total Income Tax Expense (Benefit)	115	2,079	(3,184)	1,002
NET INCOME (LOSS)	192	3,322	(5,306)	1,600
Net income (loss) attributable to noncontrolling interest				

NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	192	3,322	(5,306)	1,600
Preferred stock dividends	(6)	(6)	(18)	(27)
Loss on conversion/exchange of preferred stock		(25)		(67)
NET INCOME (LOSS) AVAILABLE TO CHESAPEAKE COMMON STOCKHOLDERS	$ 186	$ 3,291	$ (5,324)	$ 1,506
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$ 0.30	$ 5.94	$ (8.78)	$ 2.88
Assuming dilution	$ 0.30	$ 5.62	$ (8.78)	$ 2.76
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.075	$ 0.075	$ 0.225	$ 0.2175
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	619	554	606	523
Assuming dilution	626	588	606	557

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30, 2009	2008 (Adjusted)
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME (LOSS)	$ (5,306)	$ 1,600
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	1,214	1,642
Deferred income tax expense (benefit)	(3,185)	806
Impairments	9,883	
Loss on sale of other property and equipment	38	
Unrealized (gains) losses on derivatives	295	(89)
Realized (gains) losses on financing derivatives	(53)	59
Stock-based compensation	104	100
Accretion of discount on contingent convertible notes	60	57
Restructuring costs	12	
Loss from equity investments	32	34
Loss on exchanges of Chesapeake debt	19	31
Other	8	5
Change in assets and liabilities	10	142
Cash provided by operating activities	3,131	4,387
CASH FLOWS FROM INVESTING ACTIVITIES:		
Exploration and development of natural gas and oil properties	(2,767)	(4,621)
Acquisitions of natural gas and oil companies, proved and unproved properties and leasehold, net of cash acquired	(1,371)	(7,691)
Proceeds from sales of volumetric production payments	408	1,210
Proceeds from divestitures of proved and unproved properties and leasehold	1,321	4,666
Additions to other property and equipment	(1,362)	(1,969)
Additions to investments	(40)	(61)
Proceeds from sale of drilling rigs and equipment		46
Proceeds from sale of compressors	68	114
Proceeds from sale of other assets	89	21
Proceeds from sale of investments		2
Cash used in investing activities	(3,654)	(8,283)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from credit facilities borrowings	5,563	12,831
Payments on credit facilities borrowings	(7,866)	(11,307)
Proceeds from issuance of senior notes, net of offering costs	1,346	2,136
Proceeds from issuance of common stock, net of offering costs		2,598
Cash paid to repurchase Chesapeake debt		(312)
Cash paid for common stock dividends	(135)	(106)

Cash paid for preferred stock dividends	(18)	(29)
Proceeds from sale of noncontrolling interest in midstream joint venture	588	
Derivative settlements	19	(146)
Net increase (decrease) in outstanding payments in excess of cash balance	(305)	210
Proceeds from mortgage of building	54	
Proceeds from financing of real estate surface assets	145	
Excess tax benefit from stock-based compensation		42
Other	(97)	(58)
Cash provided (used in) by financing activities	(706)	5,859
Net increase (decrease) in cash and cash equivalents	(1,229)	1,963
Cash and cash equivalents, beginning of period	1,749	1
Cash and cash equivalents, end of period	$ 520	$ 1,964

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

(Unaudited)

	Nine Months Ended September 30,	
	2009	2008 (Adjusted)
	($ in millions)	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:		
Interest, net of $467 million and $390 million of capitalized interest, respectively	$ 111	$ 133
Income taxes, net of refunds received	$ 176	$ 5
SUPPLEMENTAL SCHEDULE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:		

As of September 30, 2009 and 2008, dividends payable on our common and preferred stock were $52 million and $48 million, respectively.

For the nine months ended September 30, 2009 and 2008, natural gas and oil properties were adjusted by a nominal amount and $13 million, respectively, for net income tax liabilities related to acquisitions.

For the nine months ended September 30, 2009 and 2008, natural gas and oil properties were adjusted by ($77) million and ($3) million, respectively, as a result of an increase (decrease) in accrued exploration and development costs.

For the nine months ended September 30, 2009 and 2008, other property and equipment were adjusted by ($31) million and $23 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 ($3) million and $6 million for the nine months ended September 30, 2009 and 2008, respectively, for asset retirement obligations.

We recorded non-cash asset additions to natural gas gathering systems of $3 million and $6 million for the nine months ended September 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.

During the nine months ended September 30, 2009, holders of our 2.25% Contingent Convertible Senior Notes due 2038 exchanged approximately $238 million in aggregate principal amount for an aggregate of 6,707,321 shares of our common stock in privately negotiated exchanges.

During the nine months ended September 30, 2009, we issued 24,822,832 shares of common stock, valued at $429 million, for the purchase of proved and unproved properties and leasehold pursuant to an acquisition shelf registration statement.

During the nine months ended September 30, 2008, holders of our 5.0% Cumulative Convertible Preferred Stock (Series 2005B) exchanged 3,654,385 shares for 10,443,642 shares of common stock in privately negotiated exchanges.

During the nine months ended September 30, 2008, a holder of our 4.5% Cumulative Convertible Preferred Stock exchanged 891,100 shares for 2,227,750 shares of common stock in a privately negotiated exchange.

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY

(Unaudited)

	Nine Months Ended September 30, 2009	Nine Months Ended September 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 29 shares of 4.125% preferred stock	(3)	
Exchange of common stock for 0 and 891,100 shares of 4.50% preferred stock		(89)
Exchange of common stock for 0 and 3,654,385 shares of 5.00% preferred stock (series 2005B)		(366)
Balance, end of period	466	505
COMMON STOCK:		
Balance, beginning of period	6	5
Issuance of 24,822,832 and 0 shares of common stock for the purchase of proved and unproved properties and leasehold		
Issuance of 0 and 51,750,000 shares of common stock		1
Exchange of 6,707,321 and 0 shares of common stock for convertible notes		
Exchange of 1,422,425 and 12,673,135 shares of common stock for preferred stock		
Balance, end of period	6	6
PAID-IN CAPITAL:		
Balance, beginning of period	11,680	7,532
Issuance of 24,822,832 shares and 0 shares of common stock for the purchase of proved and unproved properties and leasehold	420	
Issuance of 0 and 51,750,000 shares of common stock		2,698
Issuance of 2.25% contingent convertible senior notes due 2038		345
Exchange of 6,707,321 and 0 shares of common stock for convertible notes	164	
Exchange of 1,422,425 and 12,673,135 shares of common stock for preferred stock	39	454
Stock-based compensation	140	124
Exercise of stock options	3	8
Offering expenses		(113)
Dividends on common stock	(138)	
Dividends on preferred stock	(17)	
Allocation of joint venture capital to Global Infrastructure Partners	(263)	
Tax benefit (reduction in tax benefit) from exercise of stock-based compensation	(47)	42
Balance, end of period	11,981	11,090
RETAINED EARNINGS (DEFICIT):		
Balance, beginning of period	4,569	4,145
Net income (loss)	(5,306)	1,600
Dividends on common stock		(115)

Dividends on preferred stock		(15)
Balance, end of period	(737)	5,615
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	267	(11)
Hedging activity	(60)	54
Investment activity	67	1
Balance, end of period	274	44
TREASURY STOCK COMMON:		
Balance, beginning of period	(10)	(6)
Purchase of 115,430 and 87,056 shares for company benefit plans	(2)	(3)
Release of 6,152 and 1,098 shares for company benefit plans		
Balance, end of period	(12)	(9)
TOTAL CHESAPEAKE STOCKHOLDERS EQUITY	11,978	17,251
NONCONTROLLING INTEREST:		
Sale of noncontrolling interest in midstream joint venture	588	
Allocation of joint venture capital to Global Infrastructure Partners	263	
Balance, end of period	851	
TOTAL EQUITY	$ 12,829	$ 17,251

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Unaudited)

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008 (Adjusted)	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008 (Adjusted)
	($ in millions)			
Net income (loss)	$ 192	$ 3,322	$ (5,306)	$ 1,600
Other comprehensive income (loss), net of income tax:				
Change in fair value of derivative instruments, net of income taxes of $38 million, $728 million, $372 million and ($105) million	62	1,187	609	(170)
Reclassification of (gain) loss on settled contracts, net of income taxes of ($144) million, $65 million, ($377) million, and $117 million	(236)	104	(617)	189
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of $2 million, ($29) million, ($31) million and $20 million	5	(46)	(52)	34
Unrealized (gain) loss on investments, net of income taxes of $4 million, ($16) million, $14 million and $1 million	6	(27)	24	1
Reclassification of loss on investments, net of income taxes of $0, $0, $26 million and $0			43	
Comprehensive income (loss) attributable to Chesapeake stockholders	29	4,540	(5,299)	1,654
Comprehensive income attributable to noncontrolling interest				
Comprehensive income (loss)	$ 29	$ 4,540	$ (5,299)	$ 1,654

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

7

Table of Contents

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 condensed 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 nine months ended September 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 nine months ended September 30, 2009 (the Current Quarter and the Current Period , respectively) and the three and nine months ended September 30, 2008 (the Prior Quarter and the Prior Period , respectively). Any material subsequent events have been considered for disclosure through November 9, 2009, the filing date of this Form 10-Q.

Change in Accounting Principle

On January 1, 2009, we adopted and applied retrospectively the provisions of Accounting Standards Codification (ASC), 470-20 *Debt with Conversion and Other Options*. 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. Under SEC regulations, the excess above the ceiling is not expensed (or is reduced) if, subsequent to the end of the period, but prior to the release of the financial statements, natural gas and oil prices increase sufficiently such that an excess above the ceiling would have been eliminated (or reduced) if the increased prices were used in the calculations.

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 September 30, 2009, which consisted of swaps and collars, covered 126 bcfe and 74 bcfe in 2009 and 2010, 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 $3.30 per mcf and $70.21 per barrel, respectively, as of September 30, 2009, these cash flow hedges increased the full-cost ceiling by $968 million, thereby reducing any potential ceiling test write-down by the same amount before the effect of income taxes.

As of September 30, 2009, our ceiling test calculation indicated an impairment of our natural gas and oil properties of approximately $1.2 billion, net of tax. Based on natural gas and oil prices at November 4, 2009 of $4.49 per mcf and $80.64 per barrel, respectively, as well as the corresponding adjusted impact from our cash flow hedges of $738 million, we no longer had an impairment. Therefore, we were not required to record a write-down of our natural gas and oil properties under the full-cost method of accounting in the Current Quarter.

As of March 31, 2009, capitalized costs of natural gas and oil properties exceeded the estimated present value of future net revenues from our proved reserves, net of related income tax considerations, resulting in a write-down in the carrying value of natural gas and oil properties of $6.0 billion, net of tax.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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.

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 our risk management objectives. As of September 30, 2009 and December 31, 2008, our natural gas and oil derivative instruments were comprised of the following types of instruments:

Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.

Collars: These instruments 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 put and the call strike price, no payments are due from either party. On occasion, we make a three-way collar by selling an additional put option with the collar in exchange for a more favorable strike price on the collar. This eliminates the counterparty s downside exposure below the second put option.

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.

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.

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 either party.

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 either party.

Basis protection swaps: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas 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 ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

	September 30, 2009		December 31, 2008	
	Volume Hedged	Fair Value ($ in millions)	Volume Hedged	Fair Value ($ in millions)
Natural gas (bbtu):				
Fixed-price natural gas swaps	192,026	$ 344	466,800	$ 863
Fixed-price natural gas collars	127,290	205	457,715	402
Fixed-price natural gas knockout swaps	95,010	53	532,660	141
Natural gas call options	522,165	(125)	551,555	(178)
Natural gas put options	(82,200)	(43)	(73,000)	(39)
Natural gas basis protection swaps	140,328	(45)	219,487	93
Total natural gas	994,619	$ 389	2,155,217	$ 1,282
Oil (mbbls):				
Fixed-price oil swaps	(230)		(310)	31
Fixed-price oil collars			730	5
Fixed-price oil knockout swaps	7,860	50	12,248	19
Fixed-price oil cap-swaps			362	3
Oil call options	11,515	(55)	19,355	(35)
Total oil	19,145	$ (5)	32,385	$ 23
Total estimated fair value[(a)]		$ 384		$ 1,305

(a) After adjusting for $392 million and $736 million of unrealized premiums, the value to be realized for these derivatives as of September 30, 2009 and December 31, 2008 was $776 million and $2.041 billion, respectively.

Pursuant to ASC 815, certain derivatives qualify for designation as cash flow hedges. Following these provisions, 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 as the physical transactions being hedged occur. Any change in fair value resulting from ineffectiveness is currently recognized in natural gas and oil sales as unrealized gains (losses). 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 natural gas and oil sales. Realized gains (losses) are included in natural gas and oil sales in the month of related production.

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. 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 ASC 815. 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.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	($ in millions)			
Natural gas and oil sales	$ 785	$ 2,036	$ 2,280	$ 5,961
Realized gains (losses) on natural gas and oil derivatives	687	(246)	1,802	(454)
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(278)	4,543	(484)	134
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(7)	75	83	(54)
Total natural gas and oil sales	$ 1,187	$ 6,408	$ 3,681	$ 5,587

Based upon the market prices at September 30, 2009, we expect to transfer approximately $340 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 September 30, 2009 are expected to mature by December 31, 2022.

We began 2009 with six secured hedging facilities, each of which permitted 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 of the facilities were collateralized by certain of our natural gas and oil properties that did not secure any of our other obligations. On June 11, 2009, we entered into a multi-counterparty hedge facility with 13 counterparties that have committed to provide approximately 3.9 tcfe of trading capacity and an aggregate mark-to-market capacity of $10.4 billion under the terms of the facility. The new multi-counterparty facility was intended to consolidate and replace the six secured hedge facilities. As of September 30, 2009, there were trades outstanding on three of the six secured hedge facilities with a fair value of $86 million, and trades covering 122.9 bcfe had been novated into the multi-counterparty facility. As of November 6, 2009, all remaining trades had been novated and pledged collateral transferred to the multi-counterparty facility, resulting in 905.7 bcfe hedged and collateral value of approximately $4.1 billion. These trades 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 multi-counterparty facility allows us to enter into cash-settled natural gas and oil price and basis hedges with the counterparties. Our obligations under the multi-counterparty facility are 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 corporate revolving bank credit facility and indentures. The counterparties obligations under the facility must 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.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

To mitigate our exposure to the fluctuation in prices of diesel fuel which is used in our exploration and development activities, we have entered into diesel swaps from October 2009 to March 2010 for a total of 19,800,000 gallons with an average fixed price of $1.58 per gallon. Chesapeake pays the fixed price and receives floating price. The fair value of these swaps as of September 30, 2009 was an asset of $6 million.

Interest Rate Derivatives

To mitigate our exposure to volatility in interest rates related to our senior notes and bank credit facilities, we enter into interest rate derivatives. As of September 30, 2009 and December 31, 2008, our interest rate derivative instruments were comprised of the following types of instruments:

Swaps: Chesapeake enters into fixed-to-floating interest rate swaps (we receive a fixed interest rate and pay a floating market rate) to mitigate our exposure to changes in the fair value of our senior notes. We enter into floating-to-fixed interest rate swaps (we receive a floating market rate and pay a fixed interest rate) to manage our interest rate exposure related to our bank credit facilities borrowings.

Collars: These instruments contain a fixed floor rate (floor) and a ceiling rate (cap). If the floating rate is above the cap, we have a net receivable from the counterparty and if the floating rate is below the floor, we have a net payable to the counterparty. If the floating rate is between the floor and the cap, there is no payment due from either party. Collars are used to manage our interest rate exposure related to our bank credit facilities borrowings.

Call options: Occasionally we sell call options for a premium when we think it is more likely that the option will expire unexercised. The option allows the counterparty to terminate an open swap at a specific date.

Swaptions: Occasionally we sell an option to a counterparty for a premium which allows the counterparty to enter into a swap with us on a specific date.

The notional amount of debt hedged and the estimated fair value of our interest rate derivatives outstanding as of September 30, 2009 and December 31, 2008 are provided below.

	September 30, 2009		December 31, 2008	
	Notional Amount	Fair Value	Notional Amount	Fair Value
	($ in millions)			
Interest rate				
Swaps	$ 3,325	$ (74)	$ 1,575	$ 88
Collars	250	(8)	800	(35)
Call options	250	(9)	750	(105)
Swaptions			750	(10)
Totals	$ 3,825	$ (91)	$ 3,875	$ (62)

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For interest rate derivative instruments designated as fair value hedges (in accordance with ASC 815), 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 currently reported in the condensed consolidated statements of operations as unrealized gains (losses) within interest expense.

Gains or losses from interest rate derivative transactions are reflected as adjustments to interest expense in the condensed consolidated statements of operations. The components of interest expense for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period are presented below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	($ in millions)			
Interest expense on senior notes	$ 195	$ 171	$ 572	$ 472
Interest expense on credit facilities	18	23	47	83
Capitalized interest	(153)	(166)	(467)	(390)
Realized (gains) losses on interest rate derivatives	(7)	5	(19)	1
Unrealized (gains) losses on interest rate derivatives	(20)	(8)	(106)	(9)
Amortization of loan discount and other	10	9	25	29
Total interest expense	$ 43	$ 34	$ 52	$ 186

Our qualifying interest rate swaps are considered 100% effective and therefore no ineffectiveness was recorded for the periods presented above.

Gains and losses related to terminated qualifying interest rate derivative transactions will be amortized as an adjustment to interest expense over the remaining term of the related senior notes. Over the next eleven years we will be realizing $109 million in gains related to such trades.

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 ASC 815. The fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as an asset of $44 million at September 30, 2009. The euro-denominated debt in notes payable has been adjusted to $878 million at September 30, 2009 using an exchange rate of $1.4630 to 1.00.

Additional Disclosures About Derivative Instruments and Hedging Activities

In accordance with ASC 815 and ASC 210, 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. Derivative instruments reflected as current in the condensed consolidated balance sheet represent the estimated fair value of derivatives scheduled to settle over the next twelve months based on market prices/rates as of the balance sheet date. The derivative settlement amounts are not due until the month in which the related underlying hedged transaction occurs.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Pursuant to ASC 815, the following table sets forth the fair value of each classification of derivative instrument as of September 30, 2009 on a gross basis without regard to same-counterparty netting:

	September 30, 2009 Balance Sheet Location	Fair Value ($ in millions)
ASSET DERIVATIVES:		
Derivatives designated as hedging instruments under ASC 815:		
Commodity contracts	Short-term derivative instruments	$ 378
Commodity contracts	Long-term derivative instruments	25
Foreign exchange contracts	Long-term derivative instruments	44
Total		447
Derivatives not designated as hedging instruments under ASC 815:		
Commodity contracts	Short-term derivative instruments	237
Commodity contracts	Long-term derivative instruments	51
Interest rate contracts	Long-term derivative instruments	10
Total		298
LIABILITY DERIVATIVES:		
Derivatives designated as hedging instruments under ASC 815:		
Commodity contracts	Short-term derivative instruments	(5)
Interest rate contracts	Long-term derivative instruments	(30)
Total		(35)
Derivatives not designated as hedging instruments under ASC 815:		
Commodity contracts	Short-term derivative instruments	(73)
Commodity contracts	Long-term derivative instruments	(223)
Interest rate contracts	Short-term derivative instruments	(27)
Interest rate contracts	Long-term derivative instruments	(44)
Total		(367)
Total derivative instruments		$ 343

A consolidated summary of the effect of derivative instruments on the condensed consolidated statements of operations for the three and nine months ended September 30, 2009 is provided below, separating fair value, cash flow and non-qualifying derivatives (as defined by ASC 815).

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

Fair Value Derivatives	Location of Gain (Loss)	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Interest rate contracts	Interest expense[a]	$ 13	$ 31

(a) Interest expense on the hedged items for the Current Quarter and the Current Period was $33 million and $66 million, respectively, which is included in interest expense on the condensed consolidated statement of operations.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 designated as cash flow derivatives ($ in millions):

Cash Flow Derivatives	Location of Gain (Loss)	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Gain (Loss) Recognized in AOCI (Effective Portion)			
Commodity contracts	AOCI	$ 107	$ 819
Foreign exchange contracts	AOCI	1	79
		$ 108	$ 898
Gain (Loss) Reclassified from AOCI (Effective Portion)			
Commodity contracts	Natural gas and oil sales	$ 381	$ 994
Foreign exchange contracts	Other income		
		$ 381	$ 994
Gain (Loss) Recognized (Ineffective Portion)[(a)]			
Commodity contracts	Natural gas and oil sales	$ (7)	$ 83
Foreign exchange contracts	Other income		
		$ (7)	$ 83

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

The following table presents the gain (loss) recognized in net income (loss) for instruments not qualifying as cash flow or fair value derivatives ($ in millions):

Non-Qualifying Derivatives	Location of Gain (Loss)	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Commodity contracts	Natural gas and oil sales	$ 28	$ 324
Interest rate contracts	Interest expense	14	94
	Total	$ 42	$ 418

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 September 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 now use this 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 a nominal amount and $13 million, respectively, of bad debt expense related to potentially uncollectible receivables.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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. Following the appointment of a lead plaintiff and counsel, the plaintiff filed an amended complaint on September 11, 2009 alleging that the registration statement for the offering contained material misstatements and omissions and seeking damages under Sections 11, 12 and 15 of the Securities Act of 1933 of an unspecified amount and rescission. The action was transferred to the U.S. District Court for the Western District of Oklahoma on October 13, 2009. 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. On August 20, 2009, the court denied the inspection demand, dismissed the petition and entered judgment in favor of Chesapeake. The shareholder is appealing the court s ruling.

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. Chesapeake filed a motion to dismiss the petition on August 7, 2009. The court has not set a date to hear the motion.

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 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 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. The agreement contains a cap on cash salary and bonus compensation for the next five years at 2008 levels. 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 the CEO s obligations under the Founder Well Participation Program as of March 31, 2009. The

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

agreements with the chief operating officer, chief financial officer and other executive officers expire on September 30, 2012. The agreements with our COO, CFO and other executive vice presidents contain a cap on cash salary for the three-year term of the agreement. In addition, annual cash bonuses will not exceed the sum of the individual EVP s cash bonus compensation for (a) the last half of 2008 and (b) the first half of 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 receive a lump sum payment equal to 26 weeks of cash salary 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. The agreements also provide for a 2008 incentive award payable in four equal annual installments, the first of which was paid on September 30, 2009. The payment of each installment of the award is subject to the individual s continued employment on the date of payment, except that the unpaid installments of the award would be accelerated and paid in lump sum in the event of a change of control or a termination by the executive for good reason, as defined in the agreements.

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 September 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 September 30, 2009, the minimum aggregate future rig lease payments were approximately $539 million. As of September 30, 2009, Chesapeake s drilling subsidiary had committed to acquire one rig by the end of 2009 and had incurred costs of $9 million as of that date. The total remaining cost of the rig is estimated to be approximately $5 million. Our intent is to sell and lease back owned rigs when acceptable leasing arrangements are available to us.

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 $47 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 marketing, gathering and compression 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 September 30, 2009, the minimum aggregate future

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

compressor lease payments were approximately $355 million. As of September 30, 2009, 218 new compressors were on order for approximately $92 million. Our intent is to sell and lease back owned compressors when acceptable leasing arrangements are available to us.

Real Estate Surface Asset Leases

In April 2009, we financed 113 real estate surface assets 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 September 30, 2009, the minimum aggregate future lease payments were approximately $862 million. Chesapeake has the option to repurchase up to a specified number of assets 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 September 30, 2009, excluding demand charges for pipeline projects that are currently seeking regulatory approval, were as follows ($ in millions):

2009	$	60
2010		231
2011		251
2012		240
2013		222
After 2013		1,278
Total	$	2,282

Drilling Contracts

Currently, Chesapeake has contracts with various drilling contractors to lease approximately 20 rigs with terms of one to three years. These commitments are not recorded in the accompanying condensed consolidated balance sheets. As of September 30, 2009, the aggregate drilling rig commitment was approximately $175 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 September 30, 2009, we were obligated to purchase 468 bcfe under the terms of the VPPs. We resell the natural gas and oil we purchase at market prices.

Other Commitments

In the Current Period, we financed one of our buildings for approximately $54 million with a five-year term loan which has 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.

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 $17 million to fund various costs associated with Ventura s operations. These payments were expensed as incurred.

4. Net Income Per Share

ASC 260, *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. ASC 260 requires a reconciliation of the numerator and denominator of the basic and diluted EPS computations. The following securities and associated adjustments to net income comprised of dividends and loss on conversions/exchanges 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 September 30, 2009:		
Common stock equivalent of our preferred stock outstanding:		
5.00% cumulative convertible preferred stock (series 2005)		$
5.00% cumulative convertible preferred stock (series 2005B)	5	$ 3
4.50% cumulative convertible preferred stock	6	$ 3
Three Months Ended September 30, 2008:		
Common stock equivalent of our preferred stock outstanding prior to conversion:		
5.00% cumulative convertible preferred stock (series 2005B)	1	$ 13
4.50% cumulative convertible preferred stock	1	$ 12
Nine Months Ended September 30, 2009:		
Employee stock options	1	$
Restricted stock	5	$
Common stock equivalent of our preferred stock outstanding:		
5.00% cumulative convertible preferred stock (series 2005)		$
5.00% cumulative convertible preferred stock (series 2005B)	5	$ 8
4.50% cumulative convertible preferred stock	6	$ 9
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
Nine Months Ended September 30, 2008:		
Common stock equivalent of our preferred stock outstanding prior to conversion:		
5.00% cumulative convertible preferred stock (series 2005B)	5	$ 62
4.50% cumulative convertible preferred stock	2	$ 14

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For the Current 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 of the net loss to common stockholders.

Reconciliations for the Current Quarter, Prior Quarter and Prior Period are as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
Three Months Ended September 30, 2009:			
Basic EPS:			
Income available to Chesapeake common stockholders	$ 186	619	$ 0.30
Effect of Dilutive Securities			
Employee stock options		1	
Restricted stock		6	
Diluted EPS income available to Chesapeake common stockholders and assumed conversions	$ 186	626	$ 0.30
Three Months Ended September 30, 2008:			
Basic EPS:			
Income available to Chesapeake common stockholders	$ 3,291	554	$ 5.94
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.50% cumulative convertible preferred stock	3	6	
Common shares assumed issued for 5.00% cumulative convertible preferred stock (series 2005B)	3	5	
Common shares assumed issued for 6.25% mandatory convertible preferred stock		1	
Effect of contingent convertible senior notes outstanding during the period	9	13	
Employee stock options		2	
Restricted stock		7	
Diluted EPS income available to Chesapeake common stockholders and assumed conversions	$ 3,306	588	$ 5.62
Nine Months Ended September 30, 2008:			
Basic EPS:			
Income available to Chesapeake common stockholders	$ 1,506	523	$ 2.88

Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.50% cumulative convertible preferred stock	8	6	
Common shares assumed issued for 5.00% cumulative convertible preferred stock (series 2005B)	8	5	
Common shares assumed issued for 6.25% mandatory convertible preferred stock	2	1	
Effect of contingent convertible senior notes outstanding during the period	12	13	
Employee stock options		2	
Restricted stock		7	
Diluted EPS income available to Chesapeake common stockholders and assumed conversions	$ 1,536	557	$ 2.76

Table of Contents

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 nine months ended September 30, 2009 and 2008:

	2009	2008
	(in thousands)	
Shares issued at January 1	607,953	511,648
Stock option exercises	429	1,473
Restricted stock issuances (net of forfeitures)	3,940	4,352
Convertible note exchanges	6,707	
Preferred stock conversions/exchanges	1,422	12,673
Common stock issued for the purchase of proved and unproved properties and leasehold	24,823	
Common stock issuances		51,750
Shares issued at September 30	645,274	581,896

During the Current Period, holders of our 2.25% Contingent Convertible Senior Notes due 2038 exchanged approximately $238 million in aggregate principal amount for an aggregate of 6,707,321 shares of our common stock in privately negotiated exchanges.

During the Current Period, we issued 24,822,832 shares of common stock, valued at $429 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 nine months ended September 30, 2009 and 2008:

	4.50%	5.00% (2005B)	5.00% (2005)	6.25%	4.125%
			(in thousands)		
Shares outstanding at January 1, 2009	2,559	2,096	5	144	3
Conversion/exchange of preferred for common stock				(144)	(3)
Shares outstanding at September 30, 2009	2,559	2,096	5		
Shares outstanding at January 1, 2008	3,450	5,750	5	144	3
Conversion/exchange of preferred for common stock	(891)	(3,654)			
Shares outstanding at September 30, 2008	2,559	2,096	5	144	3

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.

During the Prior Period, holders of our 5.0% Cumulative Convertible Preferred Stock (Series 2005B) exchanged 3,654,385 shares for 10,443,642 shares of common stock in privately negotiated exchanges.

During the Prior Period, a holder of our 4.50% Cumulative Convertible Preferred Stock exchanged 891,000 shares for 2,227,750 shares of our common stock in a privately negotiated transaction.

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.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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, marketing, gathering and compression expenses, service operations expense or restructuring costs. We recorded the following stock-based compensation during the Current Quarter, the Prior Quarter, the Current Period and the Prior Period:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	($ in millions)			
Natural gas and oil properties	$ 27	$ 30	$ 85	$ 81
General and administrative expenses	22	26	60	66
Production expenses	8	8	26	22
Marketing, gathering and compression expenses	4	3	12	8
Service operations expense	2	2	6	4
Restructuring costs			9	
Total	$ 63	$ 69	$ 198	$ 181

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	7,956	$ 18.61
Vested	(8,944)	$ 36.51
Forfeited	(930)	$ 35.14
Unvested shares as of September 30, 2009	19,704	$ 31.91

The aggregate intrinsic value of restricted stock vested during the Current Period was approximately $186 million based on the stock price at the time of vesting.

As of September 30, 2009, there was $509 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 2.58 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 $36 million and $48 million, respectively. During the Prior Quarter and the Prior Period, we recognized excess tax benefits related to restricted stock of $18 million and $27 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.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(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	(429)	$ 7.36		$ 7
Expired	(11)	$ 6.47		
Outstanding at September 30, 2009	2,362	$ 8.28	2.96	$ 48
Exercisable at September 30, 2009	2,362	$ 8.28	2.96	$ 48

(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 $1 million, $3 million, $1 million and $15 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

6. Senior Notes and Revolving Bank Credit Facilities

Our total debt consisted of the following at September 30, 2009 and December 31, 2008:

	September 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]	878	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]	888	1,126
General corporate revolving bank credit facility	1,618	3,474
CMD revolving bank credit facility		460
CMP revolving bank credit facility	12	
Discount on senior notes[c]	(991)	(1,094)
Interest rate derivatives[d]	80	211
Total notes payable and long-term debt	$ 12,073	$ 13,175

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.4630 to 1.00 and $1.3919 to 1.00 as of September 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 third 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 fourth 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 the provisions of ASC 470-20, *Debt with Conversion and Other Options*. Discount at September 30, 2009 and December 31, 2008 included $859 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.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Senior Notes

Our senior notes are unsecured senior obligations of Chesapeake and 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. Our senior note obligations are guaranteed by certain of our wholly-owned subsidiaries. See Note 13 for condensed consolidating financial information regarding our guarantor and non-guarantor subsidiaries. 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 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.

During the Current Period, holders of our 2.25% Contingent Convertible Senior Notes due 2038 exchanged approximately $238 million in aggregate principal amount for an aggregate of 6,707,321 shares of our common stock in privately negotiated exchanges.

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

On January 1, 2009, we adopted and applied retrospectively the provisions of ASC 470-20, *Debt with Conversion and Other Options*. 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. ASC 470-20 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 ASC 470-20, 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	Adjusted
	($ in millions)		
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

Table of Contents

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 statements of operations ($ in millions, except per share data):

	Previously Reported	Adjustment	Adjusted
Three Months Ended September 30, 2008:			
Depreciation and amortization of other assets	$ 48	$	$ 48
Interest expense	$ 48	$ (14)	$ 34
Income tax expense (benefit)	$ 2,074	$ 5	$ 2,079
Net income (loss)	$ 3,313	$ 9	$ 3,322
Weighted average common and common equivalent shares outstanding assuming dilution (in millions)	588		588
Earnings (loss) per common share:			
Basic	$ 5.93	$ 0.01	$ 5.94
Diluted	$ 5.61	$ 0.01	$ 5.62

	Previously Reported	Adjustment	Adjusted
Nine Months Ended September 30, 2008:			
Depreciation and amortization of other assets	$ 125	$ (1)	$ 124
Interest expense	$ 212	$ (26)	$ 186
Income tax expense (benefit)	$ 991	$ 11	$ 1,002
Net income (loss)	$ 1,584	$ 16	$ 1,600
Weighted average common and common equivalent shares outstanding assuming dilution (in millions)	557		557
Earnings (loss) per common share:			
Basic	$ 2.85	$ 0.03	$ 2.88
Diluted	$ 2.73	$ 0.03	$ 2.76

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 nine months ended September 30, 2008 ($ in millions):

	Previously Reported	Adjustment	Adjusted
Nine Months Ended September 30, 2008:			
Cash flows provided by operating activities	$ 4,305	$ 82	$ 4,387
Cash flows used in investing activities	$ (8,201)	$ (82)	$ (8,283)
Cash flows provided by financing activities	$ 5,859	$	$ 5,859

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Bank Credit Facilities

We utilize three bank credit facilities, described below, as sources of liquidity.

	General Corporate Credit Facility	CMD Credit Facility ($ in millions)	CMP Credit Facility
Borrowing capacity	$ 3,500	$ 250	$ 500
Maturity date	November 2012	September 2012	September 2012
Borrowers	Chesapeake Exploration, L.L.C. and Chesapeake Appalachia, L.L.C.	Chesapeake Midstream Operating, L.L.C. (CMO)	Chesapeake Midstream Partners, L.L.C. (CMP)
Facility structure	Senior secured revolving	Senior secured revolving	Senior secured revolving
Amount outstanding as of September 30, 2009	$ 1,618		$ 12
Letters of credit outstanding as of September 30, 2009	$ 11		

Our credit facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates under our general corporate credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, none of our credit facilities contain provisions which would trigger an acceleration of amounts due under the facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

General Corporate Credit Facility

Our $3.5 billion syndicated revolving bank credit facility is used for general corporate purposes. 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.

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 (excluding discount on senior notes) 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 0.41 to 1 and our indebtedness to EBITDA ratio was 3.48 to 1 at September 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.

The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and all of our other wholly-owned restricted subsidiaries.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CMD Credit Facility

Our Chesapeake Midstream Development, L.P. (CMD) $250 million syndicated revolving bank credit facility is used to fund capital expenditures to build natural gas gathering and other systems for our drilling program and for general corporate purposes associated with our midstream operations. Borrowings under the CMD credit facility are secured by all of the assets of the wholly-owned subsidiaries (the restricted subsidiaries) of CMD, itself a wholly-owned subsidiary of Chesapeake, 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 1.00%, all of which would be subject to a margin that varies from 2.00% to 2.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined) or (ii) the LIBOR plus a margin that varies from 3.00% to 3.75% 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 of 0.50% per annum according to 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 CMD credit facility agreement contains various covenants and restrictive provisions which limit the ability of CMD and its restricted 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 3.00 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 0.01 to 1 and our EBITDA to interest expense coverage ratio was 6.62 to 1 at September 30, 2009. If CMD or its restricted 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 CMD facility could be declared immediately due and payable. The CMD credit facility agreement also has cross default provisions that apply to other indebtedness CMD and its restricted subsidiaries may have with an outstanding principal amount in excess of $15 million.

CMP Credit Facility

Our Chesapeake Midstream Partners, L.L.C. (CMP) $500 million syndicated revolving bank credit facility was established concurrent with the midstream joint venture we formed on September 30, 2009 (see Note 8 for discussion regarding the midstream joint venture). As a result of that transaction, our existing CMD credit facility was amended and restated. Borrowings under the CMP credit facility are secured by all of the assets of the companies organized under CMP, which is 50% owned by Chesapeake and 50% owned by our joint venture partner Global Infrastructure Partners, 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 1.00%, all of which would be subject to a margin that varies from 2.00% to 2.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined) or (ii) the LIBOR plus a margin that varies from 3.00% to 3.75% 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 of 0.50% per annum according to 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 CMP 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 3.00 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 0.09 to 1 and our EBITDA to interest expense coverage ratio was 17.49 to 1 at September 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 CMP facility could be declared immediately due and payable. The CMP 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.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

7. Segment Information

In accordance with ASC 280, *Segment Reporting*, 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 marketing, gathering and compression of 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. Our drilling rig and trucking service operations are presented in Other Operations in the table below.

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 $716 million, $1.591 billion, $2.009 billion and $4.667 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.

	Exploration and Production	Midstream	Other Operations	Intercompany Eliminations	Consolidated Total
			($ in millions)		
Three Months Ended September 30, 2009:					
Revenues	$ 1,187	$ 1,291	$ 69	$ (736)	$ 1,811
Intersegment revenues		(716)	(20)	736	
Total revenues	$ 1,187	$ 575	$ 49	$	$ 1,811
Income (loss) before income taxes	$ 431	$ (111)	$ (19)	$ 6	$ 307
Three Months Ended September 30, 2008 (Adjusted):					
Revenues	$ 6,408	$ 2,629	$ 164	$ (1,710)	$ 7,491
Intersegment revenues		(1,591)	(119)	1,710	
Total revenues	$ 6,408	$ 1,038	$ 45	$	$ 7,491
Income (loss) before income taxes	$ 5,384	$ 19	$ 21	$ (23)	$ 5,401
Nine Months Ended September 30, 2009:					
Revenues	$ 3,681	$ 3,669	$ 338	$ (2,208)	$ 5,480
Intersegment revenues		(2,009)	(199)	2,208	
Total revenues	$ 3,681	$ 1,660	$ 139	$	$ 5,480

Income (loss) before income taxes	$ (8,354)	$ (82)	$ (53)	$ (1)	$ (8,490)
Nine Months Ended September 30, 2008 (Adjusted):					
Revenues	$ 5,587	$ 7,601	$ 467	$ (5,007)	$ 8,648
Intersegment revenues		(4,667)	(340)	5,007	
Total revenues	$ 5,587	$ 2,934	$ 127	$	$ 8,648
Income (loss) before income taxes	$ 2,555	$ 49	$ 67	$ (69)	$ 2,602
As of September 30, 2009:					
Total assets	$ 25,612	$ 7,240	$ 624	$ (3,757)	$ 29,719
As of December 31, 2008 (Adjusted):					
Total assets	$ 35,415	$ 3,416	$ 465	$ (703)	$ 38,593

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

8. Midstream Joint Venture

On September 30, 2009, we formed a joint venture with Global Infrastructure Partners (GIP), a New York-based private equity fund, to own and operate natural gas midstream assets. As part of the transaction, Chesapeake contributed certain natural gas gathering and processing assets to a new entity, Chesapeake Midstream Partners, L.L.C. (CMP), and GIP purchased a 50% interest in CMP. Chesapeake retained the remaining 50% interest in CMP and received a $588 million cash distribution from CMP. The assets we contributed to the joint venture were substantially all of our midstream assets in the Barnett Shale and also the majority of our non-shale midstream assets in the Arkoma, Anadarko, Delaware and Permian Basins. The financial results of CMP will be consolidated and GIP s 50% ownership interest is reflected as a noncontrolling interest as of September 30, 2009 in our consolidated financial statements.

CMP will focus on unregulated business activities in service to both Chesapeake and third-party natural gas producers and its revenues will be generated almost entirely from fixed fee-based arrangements for gathering, compression, dehydration and treating services. CMP has entered into various agreements with Chesapeake, including a long-term gas gathering agreement at rates consistent with current market pricing. CMP will operate the contributed assets. Certain Chesapeake employees will provide services to CMP through an employee secondment agreement. In return for certain cost reimbursements, CMP will utilize various support functions within Chesapeake, including accounting, human resources and information technology.

Subsidiaries of our wholly-owned subsidiary CMD will continue to operate our midstream assets outside of the CMP joint venture. These include natural gas gathering assets in the Fayetteville Shale, Haynesville Shale, Marcellus Shale and other areas in Appalachia.

Concurrent with GIP s funding of its interest in the joint venture, CMP closed a new $500 million secured revolving bank credit facility to partially fund capital expenditures associated with the building of additional natural gas gathering systems and for general corporate purposes. Additionally, we amended and restated the existing midstream lending agreement to reduce the total capacity from $460 million to $250 million, among other changes. This separate secured revolving bank credit facility supports CMD s continuing midstream activities. These facilities are described in Note 6.

In the Current Quarter, we recorded an $82 million impairment of certain of the gathering systems contributed to CMP prior to the formation of the joint venture, and we expensed $4 million of debt issuance costs associated with the portion of our $460 million credit facility that was reduced to $250 million. The combined impairment of $86 million was included in impairment of natural gas and oil properties and other assets on our condensed consolidated statement of operations. Additionally, an estimated post-closing adjustment related to the joint venture transaction was recorded in the Current Quarter and is expected to be finalized by December 31, 2009.

The $851 million noncontrolling interest included in our consolidated equity at September 30, 2009 represents GIP s 50% interest in the net assets of CMP, which were recorded by CMP at Chesapeake s historical cost basis. This noncontrolling interest includes the $588 million GIP contributed in exchange for a 50% ownership interest in CMP plus $263 million of Chesapeake equity allocated to GIP pursuant to ASC 810 in order to properly reflect GIP s 50% interest in the carrying value of CMP s net assets.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

9. Natural Gas and Oil Properties

Volumetric Production Payment

On August 4, 2009, we sold certain Chesapeake-operated long-lived producing assets in South Texas in our fifth volumetric production payment transaction (VPP) for proceeds of $370 million. The assets included proved reserves of approximately 68 bcfe and net production (at the time of sale) of approximately 55 mmcfe per day. For accounting purposes, cash proceeds from this transaction were reflected as a reduction of natural gas and oil properties with no gain or loss recognized and our proved reserves were reduced accordingly.

Joint Ventures

In August 2009, we amended our Haynesville Shale joint venture agreement with Plains Exploration & Production Company (PXP). As part of the amendment, PXP accelerated the payment of its remaining joint venture drilling carries as of September 30, 2009 in exchange for an approximate 10% reduction in the total amount of drilling carry obligations due to Chesapeake and we received cash of $1.1 billion instead of an estimated $1.23 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 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 by conveying 50% of its Haynesville Shale assets to Chesapeake.

During the Current Period, we received the benefit of approximately $959 million in drilling carries associated with the Haynesville ($350 million), Fayetteville ($524 million) and Marcellus ($85 million) joint ventures.

Divestitures

During the Current Period, we sold non-core natural gas and oil assets for proceeds of $278 million.

10. Restructuring

In the Current Period, we restructured 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 virtually all costs associated with our restructuring to be paid by year-end 2009.

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

	Restructuring Costs Through September 30, 2009	Restructuring Costs To Be Incurred	Total Restructuring Costs
Restructuring Costs:			
Termination and relocation costs	$ 20	$ 2	$ 22
Acceleration of restricted stock awards	9		9
Other associated costs	3		3

Total Restructuring Costs	$	32	$	2	$	34

31

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

11. Investments

At September 30, 2009, investments accounted for under the equity method totaled $388 million and investments accounted for under the cost method totaled $34 million. Following is a summary of our investments:

	Approximate % Owned	Accounting Method	Carrying Value September 30, 2009	Carrying Value December 31, 2008
			($ in millions)	
Frac Tech Services, Ltd.[a]	20%	Equity	$ 242	$ 223
Chaparral Energy, Inc.[b][c]	32%	Equity	107	152
DHS Drilling Company[b]	47%	Equity		19
Sierra Mid-Con, L.P.	49%	Equity	14	12
Gastar Exploration Ltd.[b]	17%	Cost	33	11
Mountain Drilling Company[b]	49%	Equity		9
Other		Cost/Equity	26	18
			$ 422	$ 444

(a) The carrying value of our investment in Frac Tech is in excess of our underlying equity in net assets by approximately $145 million as of September 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 have monitored and 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 $46 million as of September 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.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

12. Fair Value Measurements

Effective January 1, 2008, we adopted ASC 820, *Fair Value Measurements and Disclosures* 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 the fair value of assets and liabilities and expands disclosures about fair value measurements.

ASC 820 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 September 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	$ 510	$	$	$ 510
Derivatives, net	$	$ 351	$ (8)	$ 343
Investments	$ 33	$	$	$ 33
Other long-term assets	$ 30	$	$	$ 30
Long-term debt	$	$	$ (2,048)	$ (2,048)
Other long-term liabilities	$ (30)	$	$	$ (30)

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.

Table of Contents

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, oil 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	Total
		($ in millions)	
Balance of Level 3 as of January 1, 2009	$ 292	$ (1,470)	$ (1,178)
Total gains (losses) (realized/unrealized):			
Included in earnings[(a)]	566	(128)	438
Included in other comprehensive income (loss)	123		123
Purchases, issuances and settlements	(989)	(450)[(b)]	(1,439)
Transfers in and out of Level 3			
Balance of Level 3 as of September 30, 2009	$ (8)	$ (2,048)	$ (2,056)

(a)

	Natural Gas and Oil Sales	Interest Expense
	($ in millions)	
Total gains (losses) related to derivatives included in earnings for the period	$ 398	$ 168
Change in unrealized gains (losses) relating to assets still held at reporting date	$ (380)	$ 149

(b) Amount represents a reduction in debt now recorded at fair value as a result of interest rate swaps that were terminated 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 ASC 825, *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 September 30, 2009 and December 31, 2008 were $11.9 billion and $13.0 billion, respectively, compared to approximate fair values of $11.7 billion and $10.5 billion, respectively. The carrying amounts for our convertible preferred stock as of September 30, 2009 and December 31, 2008 were $466 million and $505 million, respectively, compared to approximate fair values of $402 million and $294 million, respectively.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. 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 senior 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 CMD credit facility and the CMP credit facility referred to in Note 6 each contain a covenant restricting the payment of dividends or distributions or the making of 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 September 30, 2009 and December 31, 2008 and for the three and nine months ended September 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 SEPTEMBER 30, 2009

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 363	$ 157	$	$ 520
Other	9	1,831	208	(60)	1,988
Total Current Assets	9	2,194	365	(60)	2,508
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full-cost accounting		20,527	205		20,732
Other property and equipment		2,820	2,826		5,646
Total Property and Equipment		23,347	3,031		26,378
Other assets	201	608	24		833
Investments in subsidiaries and intercompany advance	3,738	244		(3,982)	
TOTAL ASSETS	$ 3,948	$ 26,393	$ 3,420	$ (4,042)	$ 29,719
CURRENT LIABILITIES:					
Current liabilities	$ 211	$ 2,231	$ 133	$ (61)	$ 2,514
Intercompany payable (receivable) from parent	(19,118)	17,091	2,012	15	

Total Current Liabilities	(18,907)	19,322	2,145	(46)	2,514
LONG-TERM LIABILITIES:					
Long-term debt, net	10,443	1,618	12		12,073
Deferred income tax liabilities	311	860	159	(14)	1,316
Other liabilities	123	855	9		987
Total Long-Term Liabilities	10,877	3,333	180	(14)	14,376
EQUITY:					
Chesapeake stockholders equity	11,978	3,738	244	(3,982)	11,978
Noncontrolling interest			851		851
Total Equity	11,978	3,738	1,095	(3,982)	12,829
TOTAL LIABILITIES AND EQUITY	$ 3,948	$ 26,393	$ 3,420	$ (4,042)	$ 29,719

Table of Contents

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	13	2,392	169	(31)	2,543
Total Current Assets	13	4,141	169	(31)	4,292
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full-cost accounting		28,474	4		28,478
Other property and equipment		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 LIABILITIES:					
Long-term debt, net	9,241	3,474	460		13,175
Deferred income tax liabilities	438	3,543	219		4,200
Other liabilities	(74)	648	6		580
Total Long-Term Liabilities	9,605	7,665	685		17,955
EQUITY:					

Chesapeake stockholders equity		17,017		8,452		143		(8,595)		17,017
Noncontrolling interest										
Total 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

36

Table of Contents

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 September 30, 2009:					
REVENUES:					
Natural gas and oil sales	$	$ 1,184	$ 3	$	$ 1,187
Marketing, gathering and compression sales		504	126	(55)	575
Service operations revenue		49			49
Total Revenues		1,737	129	(55)	1,811
OPERATING COSTS:					
Production expenses		217	1		218
Production taxes		25			25
General and administrative expenses		86	9		95
Marketing, gathering and compression expenses		517	54	(25)	546
Service operations expense		49			49
Natural gas and oil depreciation, depletion and amortization		293	2		295
Depreciation and amortization of other assets	1	36	26	(1)	62
Impairment of natural gas and oil properties and other assets			86		86
Loss on sale of other property and equipment			38		38
Restructuring costs					
Total Operating Costs	1	1,223	216	(26)	1,414
INCOME (LOSS) FROM OPERATIONS	(1)	514	(87)	(29)	397
OTHER INCOME (EXPENSE):					
Other income (expense)	175	(30)		(175)	(30)
Interest expense	(161)	(57)		175	(43)
Loss on exchanges of Chesapeake debt	(17)				(17)
Equity in net earnings of subsidiary	195	(72)		(123)	
Total Other Income (Expense)	192	(159)		(123)	(90)
INCOME (LOSS) BEFORE INCOME TAXES	191	355	(87)	(152)	307
INCOME TAX EXPENSE (BENEFIT)	(1)	160	(33)	(11)	115
NET INCOME (LOSS)	192	195	(54)	(141)	192
Net income (loss) attributable to noncontrolling interest					

NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE COMMON STOCKHOLDERS	$	192	$	195	$	(54)	$	(141)	$	192

Table of Contents

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 September 30, 2008:					
REVENUES:					
Natural gas and oil sales	$	$ 6,408	$	$	$ 6,408
Marketing, gathering and compression sales		994	87	(43)	1,038
Service operations revenue		45			45
Total Revenues		7,447	87	(43)	7,491
OPERATING COSTS:					
Production expenses		239			239
Production taxes		87			87
General and administrative expenses		104	4		108
Marketing, gathering and compression expenses		984	34	(4)	1,014
Service operations expense		37			37
Natural gas and oil depreciation, depletion and amortization		480			480
Depreciation and amortization of other assets	(1)	36	12	1	48
Total Operating Costs	(1)	1,967	50	(3)	2,013
INCOME (LOSS) FROM OPERATIONS	1	5,480	37	(40)	5,478
OTHER INCOME (EXPENSE):					
Other income (expense)	186	(19)	7	(186)	(12)
Interest expense	(160)	(60)		186	(34)
Loss on exchanges of Chesapeake debt	(31)				(31)
Equity in net earnings of subsidiary	3,324	2		(3,326)	
Total Other Income (Expense)	3,319	(77)	7	(3,326)	(77)
INCOME (LOSS) BEFORE INCOME TAXES	3,320	5,403	44	(3,366)	5,401
INCOME TAX EXPENSE (BENEFIT)	(2)	2,079	17	(15)	2,079
NET INCOME (LOSS)	3,322	3,324	27	(3,351)	3,322
Net income (loss) attributable to noncontrolling interest					
	$ 3,322	$ 3,324	$ 27	$ (3,351)	$ 3,322

NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE COMMON STOCKHOLDERS

Table of Contents

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
Nine Months Ended September 30, 2009:					
REVENUES:					
Natural gas and oil sales	$	$ 3,678	$ 3	$	$ 3,681
Marketing, gathering and compression sales		1,461	354	(155)	1,660
Service operations revenue		139			139
Total Revenues		5,278	357	(155)	5,480
OPERATING COSTS:					
Production expenses		670			670
Production taxes		71			71
General and administrative expenses		239	20		259
Marketing, gathering and compression expenses		1,436	148	(15)	1,569
Service operations expense		136			136
Natural gas and oil depreciation, depletion and amortization		1,035	2		1,037
Depreciation and amortization of other assets		110	67		177
Impairment of natural gas and oil properties and other assets		9,635	86		9,721
Loss on sale of other property and equipment			38		38
Restructuring costs		34			34
Total Operating Costs		13,366	361	(15)	13,712
INCOME (LOSS) FROM OPERATIONS		(8,088)	(4)	(140)	(8,232)
OTHER INCOME (EXPENSE):					
Other income (expense)	512	(27)	2	(512)	(25)
Interest expense	(447)	(112)	(5)	512	(52)
Impairment of investments		(148)	(14)		(162)
Loss on exchanges of Chesapeake debt	(19)				(19)
Equity in net earnings of subsidiary	(5,335)	(101)		5,436	
Total Other Income (Expense)	(5,289)	(388)	(17)	5,436	(258)
INCOME (LOSS) BEFORE INCOME TAXES	(5,289)	(8,476)	(21)	5,296	(8,490)
INCOME TAX EXPENSE (BENEFIT)	17	(3,141)	(8)	(52)	(3,184)
NET INCOME (LOSS)	(5,306)	(5,335)	(13)	5,348	(5,306)
Net income (loss) attributable to noncontrolling interest					

NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE COMMON STOCKHOLDERS	$	(5,306)	$	(5,335)	$	(13)	$	5,348	$	(5,306)

Table of Contents

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
Nine Months Ended September 30, 2008:					
REVENUES:					
Natural gas and oil sales	$	$ 5,587	$	$	$ 5,587
Marketing, gathering and compression sales		2,810	235	(111)	2,934
Service operations revenue		127			127
Total Revenues		8,524	235	(111)	8,648
OPERATING COSTS:					
Production expenses		658			658
Production taxes		250			250
General and administrative expenses		279	9		288
Marketing, gathering and compression expenses		2,767	97		2,864
Service operations expense		104			104
Natural gas and oil depreciation, depletion and amortization		1,518			1,518
Depreciation and amortization of other assets		92	32		124
Total Operating Costs		5,668	138		5,806
INCOME (LOSS) FROM OPERATIONS		2,856	97	(111)	2,842
OTHER INCOME (EXPENSE):					
Other income (expense)	525	(29)	6	(525)	(23)
Interest expense	(426)	(285)		525	(186)
Loss on exchanges of Chesapeake debt	(31)				(31)
Equity in net earnings of subsidiary	1,558	(5)		(1,553)	
Total Other Income (Expense)	1,626	(319)	6	(1,553)	(240)
INCOME (LOSS) BEFORE INCOME TAXES	1,626	2,537	103	(1,664)	2,602
INCOME TAX EXPENSE (BENEFIT)	26	979	40	(43)	1,002
NET INCOME (LOSS)	1,600	1,558	63	(1,621)	1,600
Net income (loss) attributable to noncontrolling interest					
	$ 1,600	$ 1,558	$ 63	$ (1,621)	$ 1,600

NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE COMMON STOCKHOLDERS

Table of Contents

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
Nine Months Ended September 30, 2009:					
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 3,074	$ 57	$	$ 3,131
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(3,475)	(199)		(3,674)
Proceeds from divestitures of natural gas and oil properties		1,729			1,729
Additions to other property and equipment		(661)	(701)		(1,362)
Other investing activities		(386)	39		(347)
Cash used in investing activities		(2,793)	(861)		(3,654)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		4,894	669		5,563
Payments on credit facilities borrowings		(6,749)	(1,117)		(7,866)
Proceeds from issuance of senior notes, net of offering costs	1,346				1,346
Proceeds from sales of noncontrolling, interest in midstream joint venture			588		588
Other financing activities	(153)	(167)	(17)		(337)
Intercompany advances, net	(1,193)	355	838		
Cash provided by financing activities		(1,667)	961		(706)
Net increase (decrease) in cash and cash equivalents		(1,386)	157		(1,229)
Cash and cash equivalents, beginning of period		1,749			1,749
Cash and cash equivalents, end of period	$	$ 363	$ 157	$	$ 520

	Parent	(Adjusted) Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Nine Months Ended September 30, 2008:					
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 4,234	$ 153	$	$ 4,387
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(11,922)			(11,922)
Proceeds from divestitures of natural gas oil properties		5,858	18		5,876
Additions to other property and equipment		(1,204)	(765)		(1,969)
Other investing activities		(268)			(268)
Cash used in investing activities		(7,536)	(747)		(8,283)

CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		12,831			12,831
Payments on credit facilities borrowings		(11,307)			(11,307)
Proceeds from issuance of senior notes, net of offering costs	2,136				2,136
Proceeds from issuance of common stock, net of offering costs	2,598				2,598
Other financing activities	(405)	6			(399)
Intercompany advances, net	(4,329)	3,735	594		
Cash provided by financing activities		5,265	594		5,859
Net increase (decrease) in cash and cash equivalents		1,963			1,963
Cash and cash equivalents, beginning of period		1			1
Cash and cash equivalents, end of period	$	$ 1,964	$	$	$ 1,964

41

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

14. 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 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 Accounting Standards Update (ASU) 2009-01, *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 has become the single source of authoritative nongovernmental U.S. GAAP, except for rules and interpretive releases of the SEC, which are sources of authoritative U.S. GAAP for SEC registrants. This standard is effective for financial statements for interim or annual reporting periods ended after September 15, 2009. We began to use the new guidelines and numbering system prescribed by the Codification when referring to GAAP in the Current Quarter. As the Codification was not intended to change or alter existing GAAP, it did not have any impact on our consolidated financial statements.

In August 2009, the FASB issued ASU 2009-05, *Fair Value Measurements and Disclosures (Topic 820) Measuring Liabilities at Fair Value*. This update provides clarification for the fair value measurement of liabilities. ASU 2009-05 is effective for the first reporting period beginning after issuance and we have adopted its provisions in the Current Quarter. ASU 2009-05 did not have a significant impact on our financial position, results of operations, cash flows or disclosures.

15. Subsequent Events

Subsequent to September 30, 2009, holders of $125 million of our 2.25% Contingent Convertible Senior Notes due 2038 exchanged their senior notes for 3.5 million shares of common stock in privately negotiated exchanges. The difference between the fair value of the notes that were exchanged and the fair value of the common stock issued will be recorded as a loss on exchange of debt of approximately $21 million.

Table of Contents

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008 (Adjusted)	2009	2008 (Adjusted)
Net Production:				
Natural gas (mmcf)	210,292	196,657	610,323	579,423
Oil (mbbls)	3,027	2,810	9,053	8,372
Natural gas equivalent (mmcfe)	228,454	213,517	664,641	629,655
Natural Gas and Oil Sales ($ in millions):				
Natural gas sales	$ 596	$ 1,717	$ 1,819	$ 5,046
Natural gas derivatives realized gains (losses)	675	(140)	1,771	(174)
Natural gas derivatives unrealized gains (losses)	(275)	3,854	(398)	325
Total natural gas sales	996	5,431	3,192	5,197
Oil sales	189	319	461	915
Oil derivatives realized gains (losses)	12	(106)	31	(280)
Oil derivatives unrealized gains (losses)	(10)	764	(3)	(245)
Total oil sales	191	977	489	390
Total natural gas and oil sales	$ 1,187	$ 6,408	$ 3,681	$ 5,587
Average Sales Price (excluding all gains (losses) on derivatives):				
Natural gas ($ per mcf)	$ 2.84	$ 8.73	$ 2.98	$ 8.71
Oil ($ per bbl)	$ 62.47	$ 113.53	$ 50.97	$ 109.28
Natural gas equivalent ($ per mcfe)	$ 3.44	$ 9.54	$ 3.43	$ 9.47
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Natural gas ($ per mcf)	$ 6.04	$ 8.02	$ 5.88	$ 8.41
Oil ($ per bbl)	$ 66.42	$ 75.74	$ 54.37	$ 75.82
Natural gas equivalent ($ per mcfe)	$ 6.44	$ 8.38	$ 6.14	$ 8.75
Other Operating Income (Loss)[(a)] ($ in millions):				
Marketing, gathering and compression	$ 29	$ 24	$ 91	$ 70
Service operations	$	$ 8	$ 3	$ 23
Other Operating Income (Loss)[(a)] ($ per mcfe):				
Marketing, gathering and compression	$ 0.13	$ 0.11	$ 0.14	$ 0.11
Service operations	$	$ 0.04	$	$ 0.04
Expenses ($ per mcfe):				
Production expenses	$ 0.96	$ 1.12	$ 1.01	$ 1.04
Production taxes	$ 0.11	$ 0.41	$ 0.11	$ 0.40
General and administrative expenses	$ 0.42	$ 0.51	$ 0.39	$ 0.46

Natural gas and oil depreciation, depletion and amortization	$ 1.29	$ 2.25	$ 1.56	$ 2.41
Depreciation and amortization of other assets	$ 0.27	$ 0.22	$ 0.27	$ 0.20
Interest expense[(b)]	$ 0.28	$ 0.20	$ 0.24	$ 0.31
Interest Expense ($ in millions):				
Interest expense	$ 70	$ 37	$ 177	$ 194
Interest rate derivatives realized (gains) losses	(7)	5	(19)	1
Interest rate derivatives unrealized (gains) losses	(20)	(8)	(106)	(9)
Total interest expense	$ 43	$ 34	$ 52	$ 186
Net Wells Drilled	224	455	700	1,388
Net Producing Wells as of the End of the Period	22,749	22,475	22,749	22,475

(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 43,600 producing natural gas and oil wells that are currently producing approximately 2.6 bcfe per day, 93% 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 853 gross operated wells (624 net with an average working interest of 73%) and participating in another 864 gross wells operated by other companies (76 net with an average working interest of 9%). The company s drilling success rate was 99% for company-operated wells and 98% for non-operated wells. Also during the Current Period, we invested $2.211 billion in operated wells (using an average of 102 operated rigs) and $330 million in non-operated wells (using an average of 57 non-operated rigs) for total drilling, completing and equipping costs of $2.541 billion (net of carries).

Our total Current Quarter production was 228.5 bcfe, comprised of 210.3 bcf (92% on a natural gas equivalent basis) and 3.027 mmbbls of oil and natural gas liquids (8% on a natural gas equivalent basis). Daily production for the Current Quarter averaged 2.483 bcfe, an increase of 162 mmcfe, or 7%, over the 2.321 bcfe produced per day in the Prior Quarter. Adjusted for our 2009 voluntary production curtailments due to low natural gas prices and involuntary production curtailments due to pipeline repairs (which together averaged approximately 45 mmcfe per day during the Current Quarter), our 2009 and third and fourth quarter 2008 volumetric production payment transactions (which combined averaged approximately 125 mmcfe per day during the Current Quarter) and the estimated impact from various divestitures (which would have averaged approximately 105 mmcfe per day during the Current Quarter), our year over year production growth rate would have been 14% after making similar adjustments to prior quarters.

Chesapeake began 2009 with estimated proved reserves of 12.051 tcfe and ended the Current Period with 11.994 tcfe, a decrease of 57 bcfe, or 0.5%. During the Current Period, we replaced 665 bcfe of production with an internally estimated 608 bcfe of new proved reserves, for a reserve replacement rate of 91%. The Current Period s reserve movement included 1.455 tcfe of extensions, 1.503 tcfe of positive performance revisions, 2.164 tcfe of downward revisions resulting primarily from a decrease in natural gas prices between December 31, 2008 and September 30, 2009 and 186 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 (14.1 million net acres) and 3-D seismic (23.3 million acres) in the U.S. and the largest inventory of U.S. Big 4 Shale play leasehold (2.8 million net acres). We are currently using 105 operated drilling rigs to further develop our inventory of approximately 36,000 net drillsites, which represents 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 $2.1 billion will enhance 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 equity) was 47% as of September 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 $5.3 billion net loss caused by impairments of natural gas and oil properties and other assets of $9.7 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 6.2%. No scheduled principal payments are required under our senior notes until 2013 when $864 million is due.

Table of Contents

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 innovative 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, net of drilling carries, are $3.525 billion to $3.900 billion in 2009 and $4.625 billion to $5.000 billion in 2010. We anticipate directing approximately 75% of the drilling capital expenditures (before drilling carries) during 2009 and 2010 to our Big 4 shale plays.

During 2009, our exploration and development costs have been significantly lower than 2008 costs as a result of lower service costs and the benefit of approximately $959 million of joint venture drilling carries in three of our Big 4 shale plays. We expect low service costs to continue in 2010, and the remaining approximately $2.1 billion of drilling carries associated with our joint ventures create a significant cost advantage for us that will allow us to continue to drive down finding costs in our joint venture 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 September 30, 2009	$	1,522	$	723	$	85	$	2,330
Remaining drilling carry as of September 30, 2009	$		$	77	$	2,040	$	2,117

(a) In August 2009, we amended our Haynesville Shale joint venture agreement with Plains Exploration & Production Company (PXP). As part of the amendment, PXP accelerated the payment of its remaining joint venture drilling carries as of September 30, 2009 in exchange for an approximate 10% reduction in the total amount of drilling carry obligations due to Chesapeake and we received cash of $1.1 billion instead of an estimated $1.23 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 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 by conveying 50% of its Haynesville Shale assets to Chesapeake.

The joint ventures in three of our shale plays are a complementary part of our business strategy to maximize the value of our leasehold inventory and minimize our investment risk. We have previously announced our efforts to arrange a joint venture for some or all of our Barnett Shale leasehold which, if successful, would enable us to increase our Barnett drilling activity and production. There are other new plays we are identifying and developing which may become additional joint venture opportunities. Our 50/50 joint venture with Global Infrastructure Partners in the Current Quarter is another example of our joining with a strong partner to develop key assets which include all of our midstream assets in the Barnett Shale and other midstream assets in the Mid-Continent. Upon the closing of this transaction, we received proceeds of $588 million. During the Current Period, we sold non-core natural gas and oil assets for proceeds of $278 million, and we expect to close additional sales of non-core properties in the coming months. Over the next two years, we expect to be a net seller of leasehold and producing properties.

Apart from asset monetizations, cash flow from operations is our primary source of liquidity used to fund capital expenditures. Our three revolving bank credit facilities provide us with borrowing capacity of up to $4.25 billion for 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 reborrow from time to time to fund drilling and leasehold acquisition initiatives and for general corporate purposes. At September 30, 2009, we had borrowings of $1.630 billion and letters of credit of $11 million outstanding under our credit facilities.

Table of Contents

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 and 2010. 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. Cash provided by operating activities was $3.131 billion in the Current Period compared to $4.387 billion in the Prior Period. The $1.256 billion decrease in the Current Period was primarily due to lower natural gas 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 75% 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 $7.29 per mcfe and $9.39 per mcfe, respectively. Our natural gas and oil hedges as of September 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 September 30, 2009, we had a net natural gas and oil derivative asset of $384 million.

Our three revolving bank credit facilities, described below under *Bank Credit Facilities*, are other sources of liquidity. At November 4, 2009, there was $2.9 billion of borrowing capacity available under these credit facilities. We use the facilities and cash on hand to fund daily operating activities and capital expenditures as needed. We borrowed $5.563 billion and repaid $7.866 billion in the Current Period, and we borrowed $12.831 billion and repaid $11.307 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 $1.346 billion from these two offerings were used to repay outstanding indebtedness under our general corporate revolving bank credit facility, which we reborrow from time to time to fund drilling and leasehold acquisition initiatives and for general corporate purposes. The following table reflects the proceeds from sales of securities we issued in the Current Period and the Prior Period ($ in millions):

	For the Nine Months Ended September 30,			
	2009		2008	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Senior notes	$ 1,425	$ 1,346	$ 800	$ 787
Contingent convertible senior notes			1,380	1,349
Common stock			2,698	2,598
Total	$ 1,425	$ 1,346	$ 4,878	$ 4,734

Our primary use of funds is for capital expenditures related to exploration, development and acquisition of natural gas and oil properties. As described under *Business Strategy*, our joint venture drilling carries have reduced and will continue to reduce our capital expenditures. 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.

Table of Contents

We paid dividends on our common stock of $135 million and $106 million in the Current Period and the Prior Period, respectively. Dividends paid on our preferred stock decreased to $18 million in the Current Period from $29 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 $19 million and paid $146 million, respectively, to settle a portion of the derivative liabilities assumed in our November 2005 acquisition of Columbia Natural Resources, LLC.

ASC 718 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 $42 million, respectively.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists decreased $305 million in the Current Period and increased $210 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 facilities.

In the Current Period, we formed a joint venture with Global Infrastructure Partners (GIP), a New York-based private equity fund, to own and operate natural gas midstream assets. As part of the transaction, we contributed certain natural gas gathering and processing assets into a new entity, Chesapeake Midstream Partners, L.L.C. (CMP), and GIP purchased a 50% interest in CMP. Chesapeake retained the remaining 50% interest in CMP and received a $588 million cash distribution from CMP. The transaction is discussed in Note 8 of our condensed consolidated financial statements included in this report.

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 the loan in full without penalty beginning in year four.

In the Current Period, we financed 113 real estate surface assets 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 assets for 40 years for approximately $15 million to $27 million annually. As of September 30, 2009, the minimum aggregate future lease payments were approximately $862 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. During the more than 15 years we have engaged in hedging activities, we have experienced a counterparty default only once (Lehman Brothers in September 2008), and the total loss recorded in that instance was immaterial (presently approximately $15 million without giving effect to possible future recoveries or the results of replacement hedges we entered into after the termination of our Lehman hedges pursuant to the terms of the ISDA agreement with Lehman). On September 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 now use this facility for all of our commodity hedging.

Our accounts receivable are primarily from purchasers of natural gas and oil ($476 million at September 30, 2009) and exploration and production companies which own interests in properties we operate ($528 million at September 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 parent guarantees for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. During the Current Quarter and the Current Period, we recognized a nominal amount and $13 million, respectively, of bad debt expense related to potentially uncollectible receivables.

Table of Contents

Investing Activities

Cash used in investing activities decreased to $3.654 billion during the Current Period, compared to $8.283 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 88% lower than in the Prior Period. The following table shows our cash used in (provided by) investing activities during these periods:

	Nine Months Ended September 30,	
	2009	2008
	($ in millions)	
Natural Gas and Oil Investing Activities:		
Exploration and development of natural gas and oil properties	$ 2,647	$ 4,407
Acquisition of leasehold and unproved properties	890	6,933
Acquisitions of natural gas and oil companies and proved properties, net of cash acquired	17	368
Geological and geophysical costs	120	214
Interest capitalized on unproved properties	464	390
Proceeds from sales of volumetric production payments	(408)	(1,210)
Proceeds from divestitures of proved and unproved properties and leasehold	(1,321)	(4,666)
Total natural gas and oil investing activities	2,409	6,436
Other Investing Activities:		
Additions to other property and equipment	1,362	1,969
Proceeds from sales of compressors	(68)	(114)
Proceeds from sales of drilling rigs and equipment		(46)
Additions to investments	40	61
Proceeds from sales of other assets	(89)	(23)
Total other investing activities	1,245	1,847
Total cash used in investing activities	$ 3,654	$ 8,283

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.

Table of Contents

Bank Credit Facilities

We utilize three bank credit facilities, described below, as sources of liquidity.

	General Corporate Credit Facility	CMD Credit Facility ($ in millions)	CMP Credit Facility
Borrowing capacity	$ 3,500	$ 250	$ 500
Maturity date	November 2012	September 2012	September 2012
Borrowers	Chesapeake Exploration, L.L.C. and Chesapeake Appalachia, L.L.C.	Chesapeake Midstream Operating, L.L.C. (CMO)	Chesapeake Midstream Partners, L.L.C. (CMP)
Facility structure	Senior secured revolving	Senior secured revolving	Senior secured revolving
Amount outstanding as of September 30, 2009	$ 1,618		$ 12
Letters of credit outstanding as of September 30, 2009	$ 11		

Our credit facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates under our general corporate credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, none of our credit facilities contain provisions which would trigger an acceleration of amounts due under the facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

General Corporate Credit Facility

Our $3.5 billion syndicated revolving bank credit facility is used for general corporate purposes. 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 (excluding discount on senior notes) 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 0.41 to 1 and our indebtedness to EBITDA ratio was 3.48 to 1 at September 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.

The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and all of our other wholly-owned restricted subsidiaries.

CMD Credit Facility

Our Chesapeake Midstream Development, L.P. (CMD) $250 million syndicated revolving bank credit facility is used to fund capital expenditures to build natural gas gathering and other systems for our drilling program and for general corporate purposes associated with our midstream operations. Borrowings under the CMD credit facility are secured by all of the assets of the wholly-owned subsidiaries (the restricted subsidiaries) of CMD, itself a wholly-owned subsidiary of Chesapeake, 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 1.00%, all of which would be subject to a margin that varies from 2.00% to 2.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined) or (ii) the LIBOR plus a margin that varies from 3.00% to 3.75% 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 of 0.50% per annum according to 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 CMD credit facility agreement contains various covenants and restrictive provisions which limit the ability of CMD and its restricted 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 3.00 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 0.01 to 1 and our EBITDA to interest expense coverage ratio was 6.62 to 1 at September 30, 2009. If CMD or its restricted 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 CMD facility could be declared immediately due and payable. The CMD credit facility agreement also has cross default provisions that apply to other indebtedness of CMD and its restricted subsidiaries may have with an outstanding principal amount in excess of $15 million.

CMP Credit Facility

Our Chesapeake Midstream Partners, L.L.C. (CMP) $500 million syndicated revolving bank credit facility was established concurrent with the midstream joint venture we formed on September 30, 2009 (see Note 8 for discussion regarding the midstream joint venture). As a result of that transaction, our existing CMD credit facility was amended and restated. Borrowings under the CMP credit facility are secured by all of the assets of the midstream companies organized under CMP, which is 50% owned by Chesapeake and 50% owned by our joint venture partner Global Infrastructure Partners, 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 1.00%, all of which would be subject to a margin that varies from 2.00% to 2.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined) or (ii) the LIBOR plus a margin that varies from 3.00% to 3.75% 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 of 0.50% per annum according to 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 CMP 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 3.00 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 0.09 to 1 and our EBITDA to interest expense coverage ratio was 17.49 to 1 at September 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 CMP facility could be declared immediately due and payable. The CMP 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.

Table of Contents

Hedging Facilities

We began 2009 with six secured hedging facilities, each of which permitted 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 of the facilities were collateralized by certain of our natural gas and oil properties that did not secure any of our other obligations. On June 11, 2009, we entered into a multi-counterparty hedge facility with 13 counterparties that have committed to provide approximately 3.9 tcfe of trading capacity and an aggregate mark-to-market capacity of $10.4 billion under the terms of the facility. The new multi-counterparty facility was intended to consolidate and replace the six secured hedge facilities. As of September 30, 2009, there were trades outstanding on three of the six secured hedge facilities with a fair value of $86 million, and trades covering 122.9 bcfe had been novated into the multi-counterparty facility. As of November 6, 2009, all remaining trades had been novated and pledged collateral transferred to the multi-counterparty facility, resulting in 905.7 bcfe hedged and collateral value of approximately $4.1 billion. These trades 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 multi-counterparty facility allows us to enter into cash-settled natural gas and oil price and basis hedges with the counterparties. Our obligations under the multi-counterparty facility are 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 corporate revolving bank credit facility and indentures. The counterparties obligations under the facility must 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.

Table of Contents

Senior Note Obligations

In addition to outstanding borrowings under our revolving bank credit facilities discussed above, as of September 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]	878
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]	888
Discount on senior notes[c]	(991)
Interest rate derivatives[d]	80
	$ 10,443

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.4630 to 1.00 as of September 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 third 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 fourth 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

Convertible Senior Notes		Thresholds		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) Included in this discount is $859 million associated with the equity component of our contingent convertible senior notes. See Note 6 of our condensed consolidated financial statements for a description of the accounting treatment applied to these notes.

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

As of September 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).

Table of Contents

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. Our senior note obligations are guaranteed by certain of our wholly-owned subsidiaries. See Note 13 of the financial statements included in this report for condensed consolidating financial information regarding our guarantor and non-guarantor subsidiaries. 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 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 September 30, 2009, we estimate that secured commercial bank indebtedness of approximately $5.691 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 September 30, 2009. These include commitments related to drilling rig, compressor and real estate surface asset 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 September 30, 2009 vs. September 30, 2008

General. For the Current Quarter, Chesapeake had net income of $192 million, or $0.30 per diluted common share, on total revenues of $1.811 billion. This compares to net income of $3.322 billion, or $5.62 per diluted common share, on total revenues of $7.491 billion during the Prior Quarter. The Prior Quarter included an unrealized non-cash after-tax mark-to-market gain of $2.840 billion related to future period natural gas and oil hedges resulting primarily from lower natural gas and oil prices as of September 30, 2008 compared to June 30, 2008.

Natural Gas and Oil Sales. During the Current Quarter, natural gas and oil sales were $1.187 billion compared to $6.408 billion in the Prior Quarter. In the Current Quarter, Chesapeake produced 228.5 bcfe at a weighted average price of $6.44 per mcfe, compared to 213.5 bcfe produced in the Prior Quarter at a weighted average price of $8.38 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on natural gas and oil derivatives of ($285) million and $4.618 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 $443 million and increased production resulted in a $125 million increase, for a net decrease in revenues of $318 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 by organic growth.

For the Current Quarter, we realized an average price per mcf of natural gas of $6.04, compared to $8.02 in the Prior Quarter (weighted average prices exclude the effect of unrealized gains or (losses) on derivatives). Oil prices realized per barrel (excluding unrealized gains or (losses) on derivatives) were $66.42 and $75.74 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 $687 million, or $3.00 per mcfe, in the Current Quarter and a decrease of $246 million, or $1.15 per mcfe, in the Prior Quarter.

Changes in natural gas and oil prices have a significant impact on our natural gas and oil revenues and cash flows. Assuming the Current Quarter production levels, a change of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $23 million and $22 million, respectively, and a change of $1.00 per barrel of oil sold would have resulted in an increase or decrease in revenues and cash flow of approximately $3 million without considering the effect of derivative activities.

Table of Contents

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

	For the Three Months Ended September 30,			
	2009		2008	
	Bcfe	Percent	Bcfe	Percent
Mid-Continent[(a)(b)]	79.5	35%	88.5	42%
Barnett Shale	58.6	26	47.7	22
Haynesville Shale	24.0	10	7.4	4
Fayetteville Shale[(a)]	23.1	10	15.3	7
Permian and Delaware Basins	18.8	8	20.4	9
South Texas/Gulf Coast/Ark-La-Tex	12.8	6	24.7	11
Appalachian Basin	6.6	3	8.7	4
Marcellus Shale	5.1	2	0.8	1
Total production	228.5	100%	213.5	100%

(a) The Current Quarter and the Prior Quarter production was reduced by an estimated 9.7 bcfe and 4.1 bcfe, respectively, of production related to divestitures.

(b) The Current Quarter and the Prior Quarter production was reduced by 11.7 bcfe and 2.9 bcfe, respectively, of production related to VPP transactions that closed in 2008 and 2009.

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.

Marketing, Gathering and Compression Sales and Operating Expenses. Marketing, gathering and compression activities are substantially for third parties who are owners in Chesapeake-operated wells. Chesapeake realized $575 million in marketing, gathering and compression sales in the Current Quarter, with corresponding marketing, gathering and compression expenses of $546 million, for a net margin before depreciation of $29 million. This compares to sales of $1.038 billion, expenses of $1.014 billion and a net margin before depreciation of $24 million in the Prior Quarter. In the Current Quarter, Chesapeake realized an increase in marketing, gathering and compression 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 $49 million in service operations revenue in the Current Quarter with corresponding service operations expense of $49 million, for a net margin before depreciation of a nominal amount. This compares to revenue of $45 million, expenses of $37 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 ongoing 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 $218 million in the Current Quarter compared to $239 million in the Prior Quarter. On a unit-of-production basis, production expenses were $0.96 per mcfe in the Current Quarter compared to $1.12 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.

Production Taxes. Production taxes were $25 million in the Current Quarter compared to $87 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 $62 million decrease in production taxes in the Current Quarter is primarily due to a decrease in the average realized sales price of natural gas and oil of $6.10 per mcfe (excluding gains or losses on derivatives) which was partially offset by an increase in production of 15 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.

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 $95 million in the Current Quarter and $108 million in the Prior Quarter. General and administrative expenses were $0.42 and $0.51 per mcfe for the Current Quarter and Prior Quarter, respectively. The decrease in the Current Quarter is primarily due to a reduction in advertising costs partially offset by an increase in payroll costs. Included in general and administrative expenses is stock-based compensation of $22 million for the Current Quarter and $26 million the Prior Quarter.

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 $91 million and $101 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 $480 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 $1.29 and $2.25 in the Current Quarter and in the Prior Quarter, respectively. The $0.96 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 and 2009, the utilization of joint venture drilling carries in the Current Quarter and the impairment of natural gas and oil properties in 2008 and 2009.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $62 million in the Current Quarter and $48 million in the Prior Quarter. Depreciation and amortization of other assets was $0.27 and $0.22 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.

Impairment of Natural Gas and Oil Properties and Other Assets. In the Current Quarter, we recorded an $82 million impairment of certain of the gathering systems contributed to the joint venture with GIP, as well as a $4 million impairment of debt issuance costs associated with the portion of our $460 million CMD credit facility that was reduced to $250 million.

Loss on Sale of Other Property and Equipment. In the Current Quarter, we recorded a $38 million loss on the sale of two gathering systems.

Other Income (Expense). Other income (expense) was ($30) million and ($12) million in the Current Quarter and in the Prior Quarter, respectively. The Current Quarter consisted of $1 million of interest income, a ($24) million loss related to our equity in certain investments and ($7) million of miscellaneous expense. The Prior Quarter consisted of $5 million of interest income, a ($17) million loss related to our equity in certain investments, ($10) million of consent solicitation fees and $10 million of miscellaneous income.

Table of Contents

Interest Expense. Interest expense increased to $43 million in the Current Quarter compared to $34 million in the Prior Quarter as follows:

	Three Months Ended September 30,	
	2009	2008
	($ in millions)	
Interest expense on senior notes	$ 195	$ 171
Interest expense on credit facilities	18	23
Capitalized interest	(153)	(166)
Realized (gain) loss on interest rate derivatives	(7)	5
Unrealized (gain) loss on interest rate derivatives	(20)	(8)
Amortization of loan discount and other	10	9
Total interest expense	$ 43	$ 34
Average long-term borrowings on senior notes	$ 11,372	$ 10,929

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.28 per mcfe in the Current Quarter compared to $0.20 in the Prior Quarter. The increase in interest expense per mcfe is primarily due to the February 2009 issuance of $1.425 billion of our 9.5% Senior Notes due 2015. Capitalized interest decreased by $13 million as a result of a decrease in both unevaluated properties, the base on which interest is capitalized, and our average borrowing rates in the Current Quarter compared to the Prior Quarter.

Loss on Exchanges of Chesapeake Debt. In the Current Quarter, we privately exchanged approximately $153 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 4,176,671 shares of our common stock valued at approximately $110 million. Through these transactions, we were able to redeem this debt for common stock valued at less than 80% of the face value of the notes. Associated with these exchanges, we recorded a loss of $17 million. In connection with ASC 470-20, we are required to account for the liability and equity components of our convertible debt instruments separately. Of the $153 million principal amount of convertible notes exchanged in the Current Quarter, $96 million was allocated to the debt component and the remaining $57 million was allocated to the equity conversion feature and was recorded as an adjustment to paid-in-capital. The difference between the debt component and value of the common stock exchanged in these transactions resulted in a $14 million loss. In addition, we expensed $3 million in deferred charges associated with the exchanges. In the Prior Quarter, we repurchased $300 million of our 7.75% Senior Notes due 2015 in order to re-finance a portion of our long-term debt at a lower rate of interest. In connection with the transaction we recorded a $31 million loss, which consisted of a $12 million premium and $19 million of discounts, interest rate derivatives and deferred charges associated with the notes.

Income Tax Expense (Benefit). Chesapeake recorded income tax expense of $115 million in the Current Quarter, compared to income tax expense of $2.079 billion in the Prior Quarter. Of the $1.964 billion decrease in income tax expense recorded in the Current Quarter, $1.961 billion was the result of the decrease in net income before income taxes and $3 million was 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 Nine Months Ended September 30, 2009 vs. September 30, 2008

General. For the Current Period, Chesapeake had a net loss of $5.306 billion, or $8.78 per diluted common share, on total revenues of $5.480 billion. This compares to net income of $1.600 billion, or $2.76 per diluted common share, on total revenues of $8.648 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.

Natural Gas and Oil Sales. During the Current Period, natural gas and oil sales were $3.681 billion compared to $5.587 billion in the Prior Period. In the Current Period, Chesapeake produced 664.6 bcfe at a weighted average price of $6.14 per mcfe, compared to 629.7 bcfe produced in the Prior Period at a weighted average price of $8.75 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on natural gas and oil derivatives of ($401) million and $80 million in the Current Period and Prior Period, respectively). In the Current Period, the decrease in prices resulted in a decrease in revenue of $1.730 billion and increased production resulted in a $306 million increase, for a net decrease in revenues of $1.424 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 by organic growth.

Table of Contents

For the Current Period, we realized an average price per mcf of natural gas of $5.88, compared to $8.41 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 $54.37 and $75.82 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 $1.802 billion, or $2.71 per mcfe, in the Current Period and a decrease of $454 million, or $0.72 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 $66 million and $64 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 $9 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 Nine Months Ended September 30,			
	2009		2008	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent[(a)(b)]	231.4	35%	277.4	44%
Barnett Shale	175.4	26	129.0	20
Haynesville Shale	49.5	7	18.6	3
Fayetteville Shale[(a)]	61.8	9	39.4	6
Permian and Delaware Basins	57.5	9	59.9	10
South Texas/Gulf Coast/Ark-La-Tex	56.6	9	79.0	12
Appalachian Basin	23.4	4	24.7	4
Marcellus Shale	9.0	1	1.7	1
Total production	664.6	100%	629.7	100%

(a) The Current Period and the Prior Period production was reduced by an estimated 25.1 bcfe and 4.1 bcfe, respectively, of production related to divestitures.

(b) The Current Period and the Prior Period production was reduced by 29.7 bcfe and 2.9 bcfe, respectively, of production related to VPP transactions that closed in 2008 and 2009.

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.

Marketing, Gathering and Compression Sales and Operating Expenses. Marketing, gathering and compression activities are substantially for third parties who are owners in Chesapeake-operated wells. Chesapeake realized $1.660 billion in marketing, gathering and compression sales in the Current Period, with corresponding marketing, gathering and compression expenses of $1.569 billion, for a net margin before depreciation of $91 million. This compares to sales of $2.934 billion, expenses of $2.864 billion and a net margin before depreciation of $70 million in the Prior Period. In the Current Period, Chesapeake realized an increase in marketing, gathering and compression 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 $139 million in service operations revenue in the Current Period with corresponding service operations expense of $136 million, for a net margin before depreciation of $3 million. This compares to revenue of $127 million, expenses of $104 million and a net margin before depreciation of $23 million in the Prior Period. The decrease in margin during the Current Period was the result of both a reduction in drilling rates and ongoing 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 $670 million in the Current Period compared to $658 million in the Prior Period. On a unit-of-production basis, production expenses were $1.01 per mcfe in the Current Period compared to $1.04 per mcfe in the Prior Period. The decrease in the Current Period per unit of production was primarily due to lower service costs in the field as a result of the economic downturn.

Table of Contents

Production Taxes. Production taxes were $71 million in the Current Period compared to $250 million in the Prior Period. On a unit-of-production basis, production taxes were $0.11 per mcfe in the Current Period compared to $0.40 per mcfe in the Prior Period. The $179 million decrease in production taxes in the Current Period is primarily due to a decrease in the average realized sales price of natural gas and oil of $6.04 per mcfe (excluding gains or losses on derivatives) which was partially offset by an increase in production of 35 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.

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 $259 million in the Current Period and $288 million in the Prior Period. General and administrative expenses were $0.39 and $0.46 per mcfe for the Current Period and Prior Period, respectively. The decrease in the Current Period is primarily due to a reduction in advertising costs partially offset by an increase in payroll costs. Included in general and administrative expenses is stock-based compensation of $60 million and $66 million for the Current Period and the Prior Period, respectively.

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 $282 million and $268 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 $1.037 billion and $1.518 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 $1.56 and $2.41 in the Current Period and in the Prior Period, respectively. The $0.85 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 and 2009, the utilization of joint venture drilling carries in the Current Period and the impairment of natural gas and oil properties in 2008 and 2009.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $177 million in the Current Period and $124 million in the Prior Period. Depreciation and amortization of other assets was $0.27 and $0.20 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.

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.

Table of Contents

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 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.

Also in the Current Period, we recorded an $82 million impairment of certain of the gathering systems contributed to the joint venture with GIP, as well as a $4 million impairment of debt issuance costs associated with the portion of our $460 million CMD credit facility that was reduced to $250 million.

Finally, we recognized a $22 million charge in the Current Period for a deposit on canceled contracts that were not refunded.

Loss on Sale of Other Property and Equipment. In the Current Period, we recorded a $38 million loss on the sale of two gathering systems.

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 restructured 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 10 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 ($25) million in the Current Period compared to ($23) million in the Prior Period. The Current Period consisted of $6 million of interest income, an ($32) million loss related to our equity in certain investments and $1 million of miscellaneous income. The Prior Period income consisted of $9 million of interest income, a ($34) million loss related to our equity in certain investments, ($10) million of consent solicitation fees and $12 million of miscellaneous income.

Interest Expense. Interest expense decreased to $52 million in the Current Period compared to $186 million in the Prior Period as follows:

	Nine Months Ended September 30,	
	2009	**2008**
	($ in millions)	
Interest expense on senior notes	$ 572	$ 472
Interest expense on credit facilities	47	83
Capitalized interest	(467)	(390)
Realized (gain) loss on interest rate derivatives	(19)	1
Unrealized (gain) loss on interest rate derivatives	(106)	(9)
Amortization of loan discount and other	25	29
Total interest expense	$ 52	$ 186
Average long-term borrowings on senior notes	$ 11,172	$ 9,974

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.24 per mcfe in the Current Period compared to $0.31 in the Prior Period. The decrease in interest expense per mcfe is primarily due to an increase in capitalized interest and increased production volumes offset by an increase in interest expense associated with the February 2009 issuance of $1.425 billion of our 9.5% Senior Notes due 2015. Capitalized interest increased by $77 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.

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 $238 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 6,707,321 shares of our common stock valued at approximately $164 million. Through these transactions, we were able to redeem this debt for common stock valued at less than 80% of the face value of the notes. Associated with these exchanges, we recorded a loss of $19 million. In connection with ASC 470-20, we are required to account for the liability and equity components of our convertible debt instruments separately. Of the $238 million principal amount of convertible notes exchanged in the Current Period, $148 million was allocated to the debt component and the remaining $90 million was allocated to the equity conversion feature and was recorded as an adjustment to paid-in capital. The difference between the debt component and value of the common stock exchanged in these transactions resulted in a $16 million loss. In addition, we expensed $3 million in deferred charges associated with the exchanges. In the Prior Period, we repurchased $300 million of our 7.75% Senior Notes due 2015 in order to re-finance a portion of our long-term debt at a lower rate of interest. In connection with the transaction we recorded a $31 million loss, which consisted of a $12 million premium and $19 million of discounts, interest rate derivatives and deferred charges associated with the notes.

Income Tax Expense (Benefit). Chesapeake recorded an income tax benefit of $3.184 billion in the Current Period, compared to an income tax expense of $1.002 billion in the Prior Period. Of the $4.186 billion decrease in income tax expense recorded in the Current Period, $4.271 billion was the result of the decrease in net income before income taxes which was offset by $85 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 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.

Table of Contents

In June 2009, the FASB issued Accounting Standards Update (ASU) 2009-01, *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 has become the single source of authoritative nongovernmental U.S. GAAP, except for rules and interpretive releases of the SEC, which are sources of authoritative U.S. GAAP for SEC registrants. This standard is effective for financial statements for interim or annual reporting periods ended after September 15, 2009. We began to use the new guidelines and numbering system prescribed by the Codification when referring to GAAP in the Current Quarter. As the Codification was not intended to change or alter existing GAAP, it did not have any impact on our consolidated financial statements.

In August 2009, the FASB issued ASU 2009-05, *Fair Value Measurements and Disclosures (Topic 820) Measuring Liabilities at Fair Value*. This update provides clarification for the fair value measurement of liabilities. ASU 2009-05 is effective for the first reporting period beginning after issuance and we have adopted its provisions in the Current Quarter. ASU 2009-05 did not have a significant impact on our financial position, results of operations, cash flows or disclosures.

Forward-Looking Statements

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

Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under Risk Factors in Item 1A of our 2008 Form 10-K and in Item 1A in Part II of our 2009 second quarter Form 10-Q. 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 proposed legislative and regulatory changes affecting our business,

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 our risk management objectives.

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 derivative 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 natural gas and oil volume 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 the knockout threshold on the pricing date. We use knockouts when we think the put level is less likely to be reached and we are able to obtain a premium for the put thereby increasing our effective swap price. Historically, swaps which have become ineffective as a result of knockouts have had an immaterial effect on our results of operations and cash flows. For example, after a precipitous drop in natural gas and oil prices in the second half of 2008, swaps that were knocked out covered 2.7% of the company s total natural gas and oil production (2.3% of natural gas production and 7.1% of oil production) during the six months ended December 31, 2008 and 1.5% of the company s total natural gas and oil production (less than 1% of natural gas production and 8.2% of oil production) during the nine months ended September 30, 2009. We also sell calls, taking advantage of the volatility inherent in the market, for a 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 stay below the call strike price plus the premium we will receive.

We determine the volume we may potentially hedge 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 monthly 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.

Hedging positions, including swaps, knockouts and collars, are adjusted in response to changes in prices and market conditions as part of an ongoing dynamic process. We review our hedging positions continuously and if future market conditions change, and prices have fallen to levels we believe could jeopardize the effectiveness of a position, we will mitigate such risk by either doing a cash settlement with our counterparty, restructuring the position, or by entering into a new swap that effectively reverses the current position (a counter-swap). In September 2008, for example, in response to declining natural gas and oil prices, we began restructuring knockout swap positions which we considered at risk. This restructuring allowed us to recover approximately $700 million of value for the nine months ended September 30, 2009 that would have been lost under the original positions. The factors we consider in closing or restructuring a position before the settlement date are identical to those we reviewed when deciding to enter into the original hedge position.

Table of Contents

As of September 30, 2009, our natural gas and oil derivative instruments were comprised of the following:

Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.

Collars: These instruments 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 put and the call strike price, no payments are due from either party. On occasion, we make a three-way collar by selling an additional put option with the collar in exchange for a more favorable strike price on the collar. This eliminates the counterparty s downside exposure below the second put option.

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.

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 either party.

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 either party.

Basis protection swaps: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas 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.

In accordance with ASC 815 and ASC 210, 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.

Table of Contents

As of September 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 September 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	ASC 815 Hedge	Net Premiums ($ in millions)	Fair Value at September 30, 2009 ($ in millions)
Natural Gas:								
Swaps:								
Q4 2009	103,183	$ 6.90	$	$	$	Yes	$	$ 197
Q1 2010	17,048	9.24				Yes		56
Q2 2010	15,641	8.21				Yes		35
Q3 2010	8,732	9.04				Yes		25
Q4 2010	9,972	9.27				Yes		25
CNR Swaps[a]:								
Q4 2009	4,600	5.18				Yes		2
Other Swaps[b]:								
Q4 2009	3,680	11.15				No		23
Q1 2010	3,600	11.35				No		
Q2 2010	8,190	9.89				No		(1)
Q3 2010	8,280	9.89				No		
Q4 2010	8,280	9.89				No		(1)
2011	4,500	8.73				No		
Counter Swaps								
Q4 2009	(3,680)	9.26				No		(17)
Collars:								
Q4 2009	17,220		7.36	8.24		Yes		47
Q1 2010	22,500		6.00	8.00		Yes		12
CNR Collars[a]:								
Q4 2009	920		4.50	6.00		Yes		
Other Collars[c]:								
Q4 2009	34,910		5.40/7.01	9.51		No	6	83
Q1 2010	20,700		4.86/7.03	9.06		No		23
Q2 2010	16,380		5.12/7.04	9.17		No	5	18
Q3 2010	3,680		7.60	11.75		No	4	7
Q4 2010	3,680		7.60	11.75		No	4	5
2011	7,300		7.70	11.50		No	7	10
Knockout Swaps:								
Q4 2009	1,830	9.43	6.00			No		1
Q1 2010	11,700	10.71	6.33			No		12
Q2 2010	11,830	9.66	6.00			No		9
Q3 2010	23,000	9.81	6.21			No		12
Q4 2010	23,000	9.99	6.20			No		11
2011	23,650	9.86	6.29			No		8
Call Options:								
Q4 2009	6,405			9.90		No	20	
Q1 2010	65,700			10.19		No	42	(3)
Q2 2010	66,430			10.10		No	42	(4)
Q3 2010	67,160			10.20		No	42	(7)

Q4 2010	67,160	10.31	No	43	(13)
2011	68,438	10.35	No	42	(13)
2012 2020	180,872	11.70	No	100	(85)

Table of Contents

	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	ASC 815 Hedge	Net Premiums ($ in millions)	Fair Value at September 30, 2009 ($ in millions)
Put Options:								
Q4 2009	(9,200)		3.00			No	1	
Q1 2010	(9,000)		5.75			No	1	(5)
Q2 2010	(9,100)		5.75			No	1	(6)
Q3 2010	(9,200)		5.75			No	1	(6)
Q4 2010	(9,200)		5.75			No	1	(6)
2011	(36,500)		5.75			No	26	(20)
Basis Protection Swaps:								
Non-Appalachian Basin:								
Q4 2009	10,420				(1.64)	No		(15)
2011	45,090				(0.82)	No	(3)	(12)
2012 2018	57,961				(0.90)	No	(3)	(19)
Basis Protection Swaps:								
Appalachian Basin:								
Q4 2009	4,438				0.27	No		1
Q1 2010	2,294				0.27	No		
Q2 2010	2,513				0.27	No		
Q3 2010	2,660				0.26	No		
Q4 2010	2,732				0.26	No		
2011	12,086				0.25	No		
2012 2022	134				0.11	No		
Total Natural Gas							382	389

	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	ASC 815 Hedge	Net Premiums ($ in millions)	Fair Value at September 30, 2009 ($ in millions)
Oil:								
Counter Swaps:								
Q4 2009	(230)	69.10				No		
Knockout Swaps:								
Q4 2009	1,288	85.71	52.79			No	(17)	18
Q1 2010	1,170	90.25	60.00			No		10
Q2 2010	1,183	90.25	60.00			No		6
Q3 2010	1,196	90.25	60.00			No		3
Q4 2010	1,196	90.25	60.00			No		1
2011	1,095	104.75	60.00			No		7
2012	732	109.50	60.00			No		5
Call Options:								
Q4 2009	920			112.50		No	(1)	(1)
Q1 2010	810			115.00		No	(1)	(1)
Q2 2010	819			115.00		No	(1)	(1)
Q3 2010	828			115.00		No	(1)	(2)
Q4 2010	828			115.00		No	(1)	(3)

2011	3,650	105.00	No	16	(20)
2012	3,660	105.00	No	16	(27)
Total Oil				10	(5)
Total Natural Gas and Oil				$ 392	$ 384

(a) 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 ASC 805, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million ($11 million liability remaining as of September 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, 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 ASC 815, 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.

(b) 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 for 50,000 mmbtu/day at $8.73/mmbtu, callable by the counterparty in December 2009 and March 2010, respectively.

(c) Included in Other Collars for 2009 and 2010 are 11,420 bbtu and 26,220 bbtu of three-way collars which have written put options with weighted average prices of $5.40 and $4.97, respectively, which limit the counterparty s exposure.

We have determined 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 $384 million fair value asset, $531 million relates to contracts maturing in the next 12 months, of which we expect to transfer approximately $340 million (net of income taxes) from accumulated other comprehensive income to net income (loss), and ($147) million relates to contracts maturing after 12 months. All transactions hedged as of September 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	1,202
Fair value of contracts when entered into	(46)
Contracts realized or otherwise settled	(1,674)
Fair value of contracts when closed	(403)
Fair value of contracts outstanding, as of September 30	$ 384

The change in natural gas and oil prices during the Current Period increased the value of our derivative assets by $1.202 billion. This gain is recorded in natural gas and oil sales or in accumulated other comprehensive income. We entered into new contracts which had premiums of $46 million, and a liability was recorded. We settled and closed out contracts, reducing our assets by $1.674 billion and $403 million, respectively, and the realized gain is recorded in natural gas and oil sales in the month of related production.

Table of Contents

Pursuant to ASC 815, certain derivatives qualify for designation as cash flow hedges. Following these provisions, 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 as the physical transactions being hedged occur. Any change in fair value resulting from ineffectiveness is currently recognized in natural gas and oil sales as unrealized gains (losses). 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 natural gas and oil sales. Realized gains (losses) are included in natural gas and oil sales in the month of related production.

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. 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 ASC 815. 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.

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 September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	($ in millions)			
Natural gas and oil sales	$ 785	$ 2,036	$ 2,280	$ 5,961
Realized gains (losses) on natural gas and oil derivatives	687	(246)	1,802	(454)
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(278)	4,543	(484)	134
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(7)	75	83	(54)
Total natural gas and oil sales	$ 1,187	$ 6,408	$ 3,681	$ 5,587

To mitigate our exposure to the fluctuation in price of diesel fuel which is used in our exploration and development activities, we have entered into diesel swaps from October 2009 to March 2010 for a total of 19,800,000 gallons with an average fixed price of $1.58 per gallon. Chesapeake pays the fixed price and receives the floating price. The fair value of these swaps as of September 30, 2009 was an asset of $6 million.

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	$ 10,490	$ 11,354
Average interest rate					7.6%	6.1%	6.2%
Long-term debt variable rate	$	$	$	$ 1,630	$	$	$ 1,630
Average interest rate				2.91%			2.91%

(a) This amount does not include the discount included in long-term debt of ($991) million and interest rate derivatives of $80 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.

Table of Contents

Interest Rate Derivatives

To mitigate our exposure to volatility in interest rates related to our senior notes and credit facilities, we enter into interest rate derivatives. As of September 30, 2009 our interest rate derivative instruments were comprised of the following types of instruments:

Swaps: Chesapeake enters into fixed-to-floating interest rate swaps (we receive a fixed interest rate and pay a floating market rate) to mitigate our exposure to changes in the fair value of our senior notes. We enter into floating-to-fixed interest rate swaps (we receive a floating market rate and pay a fixed interest rate) to manage our interest rate exposure related to our bank credit facility borrowings.

Collars: These instruments contain a fixed floor rate (floor) and a ceiling rate (cap). If the floating rate is above the cap, we have a net receivable from the counterparty and if the floating rate is below the floor, we have a net payable to the counterparty. If the floating rate is between the floor and the cap, there is no payment due from either party. Collars are used to manage our interest rate exposure related to our bank credit facilities borrowings.

Call options: Occasionally we sell call options for a premium when we think it is more likely that the option will expire unexercised. The option allows the counterparty to terminate an open swap at a specific date.

Swaptions: Occasionally we sell an option to a counterparty for a premium which allows the counterparty to enter into a swap with us on a specific date.

As of September 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	$ 1,200	8.02%	1 6 mL plus 537 bp	Yes	$	$ (29)
May 2008 November 2020	$ 750	8.63%	1 mL plus 562 bp	No	$ (3)	$ 1
Call Options						
November 2009	$ 250	6.88%	1 mL plus 287 bp	No	$	$ (9)
Floating-to-Fixed Interest Rate:						
Swaps						
November 2007 July 2012	$ 1,375	3.30%	1 6 mL	No	$	$ (46)
Collars[a]						
August 2007 August 2010	$ 250	4.52%	6 mL	No	$	$ (8)
					$ (3)	$ (91)

(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 $50 million, of which $25 million was recognized in interest expense. The remaining $25 million was from interest rate derivatives designated as fair value hedges which are accounted for as a reduction to our senior notes. The settlement amounts received will be amortized as a reduction to realized interest expense over the remaining term of the related senior notes ranging from four to eleven years.

For interest rate derivative instruments designated as fair value hedges (in accordance with ASC 815), 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.

Table of Contents

Gains or losses from interest rate derivative transactions are reflected as adjustments to interest expense on the condensed consolidated statements of operations. The components of interest expense for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period are presented below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	($ in millions)			
Interest expense on senior notes	$ 195	$ 171	$ 572	$ 472
Interest expense on credit facilities	18	23	47	83
Capitalized interest	(153)	(166)	(467)	(390)
Realized (gains) losses on interest rate derivatives	(7)	5	(19)	1
Unrealized (gains) losses on interest rate derivatives	(20)	(8)	(106)	(9)
Amortization of loan discount and other	10	9	25	29
Total interest expense	$ 43	$ 34	$ 52	$ 186

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 ASC 815. The fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as an asset of $44 million at September 30, 2009. The euro-denominated debt in notes payable has been adjusted to $878 million at September 30, 2009 using an exchange rate of $1.4630 to 1.00.

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.

Table of Contents

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 and our Form 10-Q for the 2009 second quarter. This information should be considered carefully, together with other information in this report and other reports and materials we file with the Securities and Exchange Commission.

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

The following table presents information about repurchases of our common stock during the three months ended September 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)]
July 1, 2009 through July 31, 2009	727,462	$ 19.173		
August 1, 2009 through August 31, 2009	1,363,414	23.349		
September 1, 2009 through September 30, 2009	31,275	28.495		
Total	2,122,151	$ 21.993		

(a) Represents 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.

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

Not applicable.

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

Not applicable.

ITEM 5. ***Other Information***

Not applicable.

Table of Contents

ITEM 6. ***Exhibits***

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

		Incorporated by Reference					
			SEC File				Furnished
Exhibit Number	Exhibit Description	Form	Number	Exhibit	Filing Date	Filed Herewith	Herewith
3.1.1	Chesapeake s Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	08/10/2009		
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		
10.1.1	Chesapeake s 2003 Stock Incentive Plan, as amended					X	
10.1.14	Chesapeake s Amended and Restated Long Term Incentive Plan.					X	
10.2.2	Employment Agreement dated as of September 30, 2009 between Marcus C. Rowland and Chesapeake Energy Corporation.	8-K	001-13726	10.2.2	10/01/2009		
10.2.3	Employment Agreement dated as of September 30, 2009 between Steven C. Dixon and Chesapeake Energy Corporation.	8-K	001-13726	10.2.3	10/01/2009		
10.2.4	Employment Agreement dated as of September 30, 2009 between J. Mark Lester and Chesapeake Energy Corporation.	8-K	001-13726	10.2.4	10/01/2009		
10.2.5	Employment Agreement dated as of September 30, 2009 between Douglas J. Jacobson and Chesapeake Energy Corporation.	8-K	001-13726	10.2.5	10/01/2009		
10.2.7	Form of Employment Agreement between Senior Vice President and Chesapeake Energy Corporation.					X	
12	Ratios of Earnings to Fixed Charges and Preferred Dividends.					X	
31.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
31.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	

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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
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.						X

Table of Contents

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
Date: November 9, 2009	By: /s/ AUBREY K. MCCLENDON Aubrey K. McClendon *Chairman of the Board and* *Chief Executive Officer*
Date: November 9, 2009	By: /s/ MARCUS C. ROWLAND Marcus C. Rowland *Executive Vice President and* *Chief Financial Officer*

Table of Contents

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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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