CHESAPEAKE ENERGY CORP
Form 10-Q
May 11, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

[X] **Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the Quarterly Period Ended March 31, 2012

[ ] **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 May 7, 2012, there were 662,343,738 shares of our common stock, $0.01 par value, outstanding.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	xxxxxxxxx.xx March 31, 2012	xxxxxxxxx.xx December 31, 2011
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($47 and $1 attributable to our VIEs)	$ 438	$ 351
Restricted cash	81	44
Accounts receivable ($11 and $0 attributable to our VIEs)	2,596	2,505
Short-term derivative assets	47	13
Deferred income tax asset	632	139
Other current assets	130	125
Total Current Assets	3,924	3,177
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full cost accounting:		
Evaluated natural gas and oil properties ($488 and $498 attributable to our VIEs)	43,589	41,723
Unevaluated properties	17,644	16,685
Natural gas gathering systems and treating plants ($48 and $0 attributable to our VIEs)	2,034	1,763
Oilfield services equipment	1,646	1,498
Other property and equipment	3,591	3,360
Total Property and Equipment, at Cost	68,504	65,029
Less: accumulated depreciation, depletion and amortization (($18) and ($6) attributable to our VIEs)	(28,888)	(28,290)
Total Property and Equipment, Net	39,616	36,739
LONG-TERM ASSETS:		
Investments	1,618	1,531
Other long-term assets	431	388
TOTAL ASSETS	$ 45,589	$ 41,835
CURRENT LIABILITIES:		
Accounts payable	$ 2,854	$ 3,311
Short-term derivative liabilities ($13 and $9 attributable to our VIEs)	253	191
Accrued interest	137	183
Other current liabilities ($37 and $23 attributable to our VIEs)	3,420	3,397
Total Current Liabilities	6,664	7,082
LONG-TERM LIABILITIES:		
Long-term debt, net	13,082	10,626
Deferred income tax liabilities	3,984	3,484

Long-term derivative liabilities ($19 and $10 attributable to our VIEs)		1,605		1,541
Asset retirement obligations		335		323
Other long-term liabilities		1,025		818
Total Long-Term Liabilities		20,031		16,792
CONTINGENCIES AND COMMITMENTS (Note 4)				
EQUITY:				
Chesapeake Stockholders Equity:				
Preferred stock, $0.01 par value, 20,000,000 shares authorized: 7,251,515 shares outstanding		3,062		3,062
Common stock, $0.01 par value, 1,000,000,000 shares authorized: 664,181,137 and 660,888,159 shares issued		7		7
Paid-in capital		12,176		12,146
Retained earnings		1,481		1,608
Accumulated other comprehensive income (loss)		(159)		(166)
Less: treasury stock, at cost; 1,682,354 and 1,552,533 common shares		(36)		(33)
Total Chesapeake Stockholders Equity		16,531		16,624
Noncontrolling interests		2,363		1,337
Total Equity		18,894		17,961
TOTAL LIABILITIES AND EQUITY	$	45,589	$	41,835

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	$XXX,XX	$XXX,XX
	Three Months Ended March 31,	
	2012	**2011**
	($ in millions, except per share data)	
REVENUES:		
Natural gas and oil	$ 1,068	$ 494
Marketing, gathering and compression	1,216	1,017
Oilfield services	135	101
Total Revenues	2,419	1,612
OPERATING EXPENSES:		
Natural gas and oil production	349	238
Production taxes	47	45
Marketing, gathering and compression	1,197	985
Oilfield services	96	77
General and administrative	136	130
Natural gas and oil depreciation, depletion and amortization	506	358
Depreciation and amortization of other assets	84	68
Gains on sales of fixed assets	(2)	(5)
Total Operating Expenses	2,413	1,896
INCOME (LOSS) FROM OPERATIONS	6	(284)
OTHER INCOME (EXPENSE):		
Interest expense	(12)	(7)
Earnings (losses) on investments	(5)	25
Losses on purchases or exchanges of debt		(2)
Other income	6	2
Total Other Income (Expense)	(11)	18
INCOME (LOSS) BEFORE INCOME TAXES	(5)	(266)
INCOME TAX EXPENSE (BENEFIT):		
Current income taxes		6
Deferred income taxes	(2)	(110)
Total Income Tax Expense (Benefit)	(2)	(104)

NET INCOME (LOSS)		(3)		(162)
Net income attributable to noncontrolling interests		(25)		
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE		(28)		(162)
Preferred stock dividends		(43)		(43)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$	(71)	$	(205)
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$	(0.11)	$	(0.32)
Diluted	$	(0.11)	$	(0.32)
CASH DIVIDEND DECLARED PER COMMON SHARE	$	0.0875	$	0.075
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic		642		634
Diluted		642		634

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Unaudited)

	$XXX,XX	$XXX,XX
	Three Months Ended March 31,	
	2012	**2011**
	($ in millions)	
Net income (loss)	$ (3)	$ (162)
Other comprehensive income (loss), net of income tax:		
Gain (loss) on derivative instruments, net of income taxes of $2 million and $3 million	4	5
Reclassification of gain on settled derivative instruments, net of income taxes of ($1) million and ($28) million	(2)	(46)
Ineffective portion of derivatives designated as cash flow hedges, net of income taxes of $0 and ($4) million		(6)
Unrealized gain (loss) on available-for-sale securities, net of income taxes of $3 million and $2 million	5	3
Other comprehensive income (loss)	7	(44)
Comprehensive income (loss)	4	(206)
Net income attributable to noncontrolling interests	(25)	
Comprehensive income (loss) attributable to Chesapeake	$ (21)	$ (206)

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	$XXXX,,X	$XXXX,,X
	Three Months Ended March 31,	
	2012	**2011**
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME (LOSS)	$ (3)	$ (162)
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	590	426
Deferred income tax benefit	(2)	(110)
Unrealized losses on derivatives	276	1,188
Stock-based compensation	32	40
Gains on sales of fixed assets	(2)	(5)
(Gains) losses on investments	33	(5)
Losses on purchases or exchanges of debt		2
Other	(14)	7
Changes in assets and liabilities	(636)	(663)
Cash provided by operating activities	274	718
CASH FLOWS FROM INVESTING ACTIVITIES:		
Drilling and completion costs on proved and unproved properties	(2,574)	(1,692)
Acquisitions of proved and unproved properties	(1,135)	(1,258)
Proceeds from divestitures of proved and unproved properties	821	5,182
Additions to other property and equipment	(690)	(431)
Proceeds from sales of other assets	48	428
Proceeds from (additions to) investments	(73)	4
Increase in restricted cash	(37)	
Other	(10)	(7)
Cash provided by (used in) investing activities	(3,650)	2,226
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from credit facilities borrowings	5,688	3,617
Payments on credit facilities borrowings	(4,546)	(7,323)
Proceeds from issuance of senior notes, net of offering costs	1,263	977
Cash paid to purchase debt		(128)
Cash paid for common stock dividends	(56)	(48)
Cash paid for preferred stock dividends	(43)	(43)
Cash (paid) received on financing derivatives	(9)	660
Proceeds from sales of noncontrolling interests	1,044	
Proceeds from other financings	225	
Distributions to noncontrolling interest owners	(39)	
Net increase (decrease) in outstanding payments in excess of cash balance	(31)	119
Other	(33)	(28)

Cash provided by (used in) financing activities		3,463		(2,197)
Net increase in cash and cash equivalents		87		747
Cash and cash equivalents, beginning of period		351		102
Cash and cash equivalents, end of period	$	438	$	849

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

(Unaudited)

	$XXX,XX		$XXX,XX	
	Three Months Ended March 31,			
	2012		2011	
	($ in millions)			
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF NET CASH PAYMENTS (REFUNDS) FOR:				
Interest, net of capitalized interest	$	36	$	41
Income taxes, net of refunds received	$		$	

SUPPLEMENTAL SCHEDULE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:

As of March 31, 2012 and 2011, dividends payable on our common and preferred stock were $99 million and $90 million, respectively.

For the three months ended March 31, 2012 and 2011, natural gas and oil properties was adjusted by $26 million and $22 million, respectively, as a result of an increase in accrued acquisition, drilling and completion costs.

For the three months ended March 31, 2012 and 2011, other property and equipment was adjusted by $24 million and $5 million, respectively, as a result of an increase in accrued costs.

As of March 31, 2012 and 2011, we had recorded $79 million and $202 million, respectively, of various liabilities related to the purchase of proved and unproved properties and other assets.

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(Unaudited)

	$XXX,XX	$XXX,XX
	Three Months Ended March 31,	
	2012	**2011**
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning and end of period	$ 3,062	$ 3,065
COMMON STOCK:		
Balance, beginning and end of period	7	7
PAID-IN CAPITAL:		
Balance, beginning of period	12,146	12,194
Stock-based compensation	33	50
Purchase of contingent convertible notes		(21)
Reduction in tax benefit from stock-based compensation	(4)	
Dividends on common stock		(48)
Dividends on preferred stock		(15)
Exercise of stock options	1	1
Balance, end of period	12,176	12,161
RETAINED EARNINGS:		
Balance, beginning of period	1,608	190
Net loss attributable to Chesapeake	(28)	(162)
Dividends on common stock	(56)	
Dividends on preferred stock	(43)	(28)
Balance, end of period	1,481	
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(166)	(168)
Hedging activity	2	(47)
Investment activity	5	3
Balance, end of period	(159)	(212)
TREASURY STOCK COMMON:		
Balance, beginning of period	(33)	(24)
Purchase of 142,655 and 93,318 shares for company benefit plans	(3)	(2)
Release of 12,834 and 2,310 shares from company benefit plans		
Balance, end of period	(36)	(26)

TOTAL CHESAPEAKE STOCKHOLDERS EQUITY	16,531	14,995
NONCONTROLLING INTERESTS:		
Balance, beginning of period	1,337	
Sales of noncontrolling interests	1,040	
Net income attributable to noncontrolling interests	25	
Distributions to noncontrolling interest owners	(39)	
Balance, end of period	2,363	
TOTAL EQUITY	$ 18,894	$ 14,995

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Basis of Presentation and Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying unaudited condensed consolidated financial statements of Chesapeake Energy Corporation (Chesapeake or the Company) 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, 2011 (2011 Form 10-K) includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this Form 10-Q. All material adjustments (consisting solely of normal recurring adjustments) which, in the opinion of management, are necessary for a fair statement of the results for the interim periods have been reflected. The accompanying condensed consolidated financial statements of Chesapeake include the accounts of our direct and indirect wholly owned subsidiaries. All significant intercompany accounts and transactions have been eliminated. The results for the three months ended March 31, 2012 are not necessarily indicative of the results to be expected for the full year. This Form 10-Q relates to the three months ended March 31, 2012 (the Current Quarter) and the three months ended March 31, 2011 (the Prior Quarter).

Critical Accounting Policies

We consider accounting policies related to derivatives, variable interest entities, natural gas and oil properties and income taxes to be critical policies. These policies are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our 2011 Form 10-K.

Risks and Uncertainties

Approximately 83% of our estimated proved reserves volumes as of December 31, 2011 were natural gas and for the full year 2011 and Current Quarter, 84% and 81% of our natural gas and oil sales volumes were natural gas, respectively. Although we are shifting our strategy to a more liquids-heavy portfolio, having 61% of our natural gas and oil revenue before the effects of hedging derived from liquids production in the Current Quarter and curtailing drilling operations and production in our dry gas plays due to low natural gas prices, we have a material exposure to those low prices. While our derivative arrangements serve to mitigate a portion of the effect of price volatility on our cash flows, our forecasted natural gas production is currently not protected against downward price adjustments by derivative instruments and our use of crude oil derivatives to partially mitigate the price risk of our liquids production is subject to basis risk to the extent oil and natural gas liquids prices do not remain highly correlated. Sustained low natural gas prices, and volatile commodity prices in general, could have a material adverse effect on our financial position, results of operations and cash flows, which could adversely impact our ability to comply with financial covenants under our credit facilities and further limit our ability to fund our planned capital expenditures. In addition, sustained low commodity prices could result in a reduction in the estimated quantity of proved reserves we report and in the estimated future net cash flows expected to be generated from reserves that may require us to write down the carrying value of our natural gas and oil properties, and such amounts could be material.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

2. Net Income Per Share

Accounting guidance for earnings per share (EPS) requires presentation of basic and diluted earnings per share on the face of the statements of operations for all entities with complex capital structures as well as a reconciliation of the numerator and denominator of the basic and diluted EPS computations.

For the Current Quarter and the Prior Quarter, the following securities and associated adjustments to net income, consisting of dividends, were not included in the calculation of diluted EPS, as the effect was antidilutive:

	Net Income Adjustments ($ in millions)	Shares (in millions)
Three Months Ended March 31, 2012:		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$ 22	55
5.75% cumulative convertible preferred stock (series A)	$ 16	39
5.00% cumulative convertible preferred stock (series 2005B)	$ 3	5
4.50% cumulative convertible preferred stock	$ 3	6
Unvested restricted stock	$	4
Outstanding stock options	$	1
Three Months Ended March 31, 2011:		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$ 22	56
5.75% cumulative convertible preferred stock (series A)	$ 16	39
5.00% cumulative convertible preferred stock (series 2005B)	$ 3	5
4.50% cumulative convertible preferred stock	$ 3	6
Unvested restricted stock	$	8
Outstanding stock options	$	1

As a result of the net loss to common stockholders, both basic weighted average shares outstanding, which is used in computing basic EPS, and diluted weighted average shares outstanding, which is used in computing diluted EPS, were 642 million shares in the Current Quarter and 634 million shares in the Prior Quarter, respectively. The basic and diluted loss per common share was $0.11 and $0.32 in the Current Quarter and the Prior Quarter, respectively.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

3. Debt

Our long-term debt consisted of the following at March 31, 2012 and December 31, 2011:

	March 31, 2012	December 31, 2011
	($ in millions)	
7.625% senior notes due 2013	$ 464	$ 464
9.5% senior notes due 2015	1,265	1,265
6.25% euro-denominated senior notes due 2017[(a)]	459	446
6.5% senior notes due 2017	660	660
6.875% senior notes due 2018	474	474
7.25% senior notes due 2018	669	669
6.625% senior notes due 2019[(b)]	650	650
6.775% senior notes due 2019	1,300	
6.625% senior notes due 2020	1,300	1,300
6.875% senior notes due 2020	500	500
6.125% senior notes due 2021	1,000	1,000
2.75% contingent convertible senior notes due 2035[(c)]	396	396
2.5% contingent convertible senior notes due 2037[(c)]	1,168	1,168
2.25% contingent convertible senior notes due 2038[(c)]	347	347
Corporate revolving bank credit facility	2,462	1,719
Midstream revolving bank credit facility	258	1
Oilfield services revolving bank credit facility	172	29
Discount on senior notes[(d)]	(487)	(490)
Interest rate derivatives[(e)]	25	28
Total long-term debt, net	$ 13,082	$ 10,626

(a) The principal amount shown is based on the exchange rate of $1.3334 to 1.00 and $1.2973 to 1.00 as of March 31, 2012 and December 31, 2011, respectively. See Note 7 for information on our related foreign currency derivatives.

(b) Issuers are Chesapeake Oilfield Operating, L.L.C. (COO) and Chesapeake Oilfield Finance, Inc. (COF), a wholly owned subsidiary of COO formed solely to facilitate the offering of the 6.625% Senior Notes due 2019. COF is nominally capitalized and has no operations or revenues. Chesapeake Energy Corporation is the issuer of all other senior notes and the contingent convertible senior notes.

(c) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder s option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the first quarter of 2012, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes during the specified period and, as a result, the holders do not have the option to convert their notes into cash and common stock in the second quarter of 2012 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 in which contingent interest may be payable for the contingent convertible senior notes are as follows:

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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	$	48.51	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$	64.16	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$	107.27	June 14, 2019

(d) Discount at March 31, 2012 and December 31, 2011 included $427 million and $444 million, respectively, associated with the equity component of our contingent convertible senior notes. This discount is based on an effective yield method.

(e) See Note 7 for further discussion related to these instruments.

Chesapeake Senior Notes and Contingent Convertible Senior Notes

The Chesapeake senior notes and the contingent convertible senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior unsecured indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Chesapeake s obligations under the senior notes and the contingent convertible senior notes are jointly and severally, fully and unconditionally guaranteed by certain of our wholly owned subsidiaries. Chesapeake Midstream Development, L.P. (CMD) and its subsidiaries, Chesapeake Oilfield Services, L.L.C. (COS) and its subsidiaries, CHK Utica, L.L.C., CHK Cleveland Tonkawa, L.L.C., Chesapeake Granite Wash Trust and certain de minimis subsidiaries are not guarantors. 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. Our senior notes are governed by indentures containing covenants that may limit our ability and our subsidiaries ability to incur certain secured indebtedness, enter into sale/leaseback transactions, and consolidate, merge or transfer assets. The indentures governing the contingent convertible senior notes do not have any financial or restricted payment covenants.

We are required 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. These rates for 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 are 6.86%, 8.0% and 8.0%, respectively.

During the Current Quarter, we issued $1.3 billion of 6.775% Senior Notes due 2019 in a registered public offering. We used the net proceeds of $1.263 billion from the offering to repay indebtedness outstanding under our corporate revolving bank credit facility. At any time from and including November 15, 2012 to and including March 15, 2013, we may redeem some or all of the notes at a redemption price equal to 100% of the principal amount of the notes plus accrued and unpaid interest, if any, to the redemption date; provided that upon any redemption of the notes in part (and not in whole) pursuant to this redemption provision, at least $250 million aggregate principal amount of the notes remains outstanding.

During the Prior Quarter, we issued $1.0 billion of 6.125% Senior Notes due 2021 in a registered public offering. We used the net proceeds of $977 million from the offering to repay indebtedness outstanding under our corporate revolving bank credit facility.

During the Prior Quarter, we purchased $140 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for approximately $128 million. Associated with these purchases, we recognized a loss of $2 million.

No scheduled principal payments are required under our senior notes until July 2013 when $464 million is due.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

COO Senior Notes

In October 2011, our wholly owned subsidiaries, Chesapeake Oilfield Operating, L.L.C. (COO) and Chesapeake Oilfield Finance, Inc. issued $650 million principal amount of 6.625% Senior Notes due 2019 in a private placement. COO used the net proceeds of approximately $637 million from the placement to make a cash distribution to its direct parent, COS, to enable it to reduce indebtedness under an intercompany note with Chesapeake. Chesapeake then used the cash distribution to reduce indebtedness under its corporate revolving bank credit facility.

The COO senior notes are the unsecured senior obligations of COO and rank equally in right of payment with all of COO s other existing and future senior unsecured indebtedness and rank senior in right of payment to all of its future subordinated indebtedness. The COO senior notes are jointly and severally, fully and unconditionally guaranteed by all of COO s wholly owned subsidiaries, other than de minimis subsidiaries. The notes may be redeemed at any time at specified make-whole or redemption prices and, prior to November 15, 2014, up to 35% of the aggregate principal amount may be redeemed in connection with certain equity offerings. Holders of the COO notes have the right to require COO to repurchase their notes upon a change of control on the terms set forth in the indenture, and COO must offer to repurchase the notes upon certain asset sales. The COO senior notes are subject to covenants that may, among other things, limit the ability of COO and its subsidiaries to make restricted payments, incur indebtedness, issue preferred stock, create liens, and consolidate, merge or transfer assets.

Bank Credit Facilities

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

	Corporate Credit Facility[(a)]	Midstream Credit Facility[(b)] ($ in millions)	Oilfield Services Credit Facility[(c)]
Facility structure	Senior secured revolving	Senior secured revolving	Senior secured revolving
Maturity date	December 2015	June 2016	November 2016
Borrowing capacity	$ 4,000	$ 600[(d)]	$ 500[(e)]
Amount outstanding as of March 31, 2012	$ 2,462	$ 258	$ 172
Letters of credit outstanding as of March 31, 2012	$ 25	$	$

(a) Borrower is Chesapeake Exploration, L.L.C.

(b) Borrower is Chesapeake Midstream Operating, L.L.C.

(c) Borrower is Chesapeake Oilfield Operating, L.L.C.

(d) We estimate the capacity was limited to approximately $370 million as of March 31, 2012 by certain restrictive provisions.

(e) We estimate the capacity was limited to approximately $450 million as of March 31, 2012 by certain restrictive provisions.

Our corporate and oilfield services credit facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates under our corporate credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, our credit facilities do not contain provisions which would trigger an acceleration of amounts due under the respective facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Corporate Credit Facility

Our $4.0 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by natural gas and oil proved reserves 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 0.50% to 1.25% per annum according to our senior unsecured long-term debt ratings, or (ii) the Eurodollar rate, which is based on 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% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens and require us to maintain an indebtedness to total capitalization ratio and an indebtedness to EBITDA ratio, in each case as defined in the agreement. We were in compliance with all covenants under the agreement at March 31, 2012. 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 $50 million or more, 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 $125 million.

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

Midstream Credit Facility

Our $600 million midstream syndicated revolving bank credit facility is used to fund capital expenditures to build natural gas gathering and other systems in support of our drilling program and for general corporate purposes associated with our midstream operations. Borrowings under the midstream credit facility are secured by all of the assets, other than certain joint venture equity interests, of the wholly owned subsidiaries (the restricted subsidiaries) of CMD, itself a wholly owned subsidiary of Chesapeake. Amounts outstanding 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 are subject to a margin that varies from 1.00% to 1.75% or (ii) the Eurodollar rate, which is based on the LIBOR plus a margin that varies from 2.00% to 2.75% per annum. The unused portion of the facility is subject to a commitment fee that varies from 0.375% to 0.50% per annum. Both margins and commitment fees are determined according to the most recent leverage ratio described below. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The midstream 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 agreement requires maintenance of a leverage ratio based on the ratio of indebtedness to EBITDA and an interest coverage ratio based on the ratio of EBITDA to interest expense, in each case as defined in the agreement. The leverage ratio increases during any three-quarter period, beginning in the quarter in which CMD makes a material disposition of assets to our midstream master limited partnership affiliate, Chesapeake Midstream Partners, L.P. (CHKM). In December 2011, the leverage ratio increased for a three-fiscal-quarter period beginning October 1, 2011 due to the sale of CMD s wholly owned subsidiary, Appalachia Midstream Services, L.L.C. (AMS), as it was classified as a material disposition of assets. As a result, the capacity of the midstream credit facility was limited to approximately $370 million as of March 31, 2012. We were in compliance with all covenants under the agreement at March 31, 2012. 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 facility could be declared immediately due and payable. The midstream credit facility agreement also has cross default provisions that apply to other indebtedness CMD and its restricted subsidiaries may have from time to time with an outstanding principal amount in excess of $15 million.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Oilfield Services Credit Facility

Our $500 million oilfield services syndicated revolving bank credit facility is used to fund capital expenditures and for general corporate purposes associated with our oilfield services operations. Borrowings under the oilfield services credit facility are secured by all of the assets of the wholly owned subsidiaries of COO, itself a wholly owned subsidiary of Chesapeake. The facility has initial commitments of $500 million and may be expanded to $900 million at COO s option, subject to additional bank participation. Borrowings under the credit facility are secured by all of the equity interests and assets of COO and its wholly owned subsidiaries (the restricted subsidiaries), and bear interest at our option at either (i) the greater of the reference rate of Bank of America, N.A., the federal funds effective rate plus 0.50%, and one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 1.00% to 1.75% per annum, or (ii) the Eurodollar rate, which is based on LIBOR plus a margin that varies from 2.00% to 2.75% per annum. The unused portion of the credit facility is subject to a commitment fee that varies from 0.375% to 0.50% per annum. Both margins and commitment fees are determined according to the most recent leverage ratio described below. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The oilfield services credit facility agreement contains various covenants and restrictive provisions which limit the ability of COO and its restricted subsidiaries to incur additional indebtedness, make investments or loans and create liens. The agreement requires maintenance of a leverage ratio based on the ratio of lease adjusted indebtedness to EBITDAR, a senior secured leverage ratio based on the ratio of secured indebtedness to EBITDA and a fixed charge coverage ratio based on the ratio of lease adjusted interest expense to EBITDAR, in each case as defined in the agreement. As a result of those covenants, the capacity of the oilfield services credit facility was limited to approximately $450 million as of March 31, 2012. We were in compliance with all covenants under the agreement at March 31, 2012. If COO 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 facility could be declared immediately due and payable. The oilfield services credit facility agreement also has cross default provisions that apply to other indebtedness COO and its restricted subsidiaries may have from time to time with an outstanding principal amount in excess of $15 million.

4. Contingencies and Commitments
Contingencies

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. On September 2, 2010, the court denied the defendants motion to dismiss, and the court certified the class on March 30, 2012. Defendants moved for summary judgment on grounds of loss causation and materiality on December 16, 2011. Discovery in the case is proceeding. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with the case. A derivative action was also filed in the District Court of Oklahoma County, Oklahoma on March 10, 2009 against certain current and former directors and officers of the Company asserting breaches of fiduciary duties relating to alleged material omissions in the registration statement for the July 2008 offering. The derivative action was stayed pursuant to stipulation, and on April 20, 2012, plaintiffs filed a motion to lift the stay and permit plaintiffs to file an amended complaint. A second derivative action relating to the July 2008 offering was filed against certain current and former directors and officers of the Company in the U.S. District Court for the Western District of Oklahoma on September 6, 2011. This action also asserts breaches of fiduciary duties with respect to alleged material omissions in the offering registration statement. The Company filed a motion to dismiss the action on November 30, 2011, and plaintiffs filed an Opposition on January 9, 2012. Chesapeake is named as a nominal defendant in both derivative actions.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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, among other things, breaches of fiduciary duties relating to the 2008 compensation of the Company s CEO, Aubrey K. McClendon, and seeking unspecified damages, equitable relief and disgorgement. These three derivative actions were consolidated and a Consolidated Derivative Shareholder Petition naming Chesapeake as a nominal defendant was filed on June 23, 2009. Chesapeake s motion to dismiss was granted on February 26, 2010, and the Oklahoma Court of Civil Appeals affirmed the dismissal on August 26, 2011. The plaintiffs filed a petition for writ of certiorari with the Oklahoma Supreme Court on September 13, 2011.

On January 30, 2012, the District Court of Oklahoma County, Oklahoma approved a settlement between the parties in the consolidated derivative action, as well as a case on appeal at the Oklahoma Court of Civil Appeals requesting inspection of Company books and records relating to the December 2008 employment agreement with its CEO. The principal terms of the settlement include the rescission of the sale of an antique map collection that occurred in December 2008 between Mr. McClendon and the Company, whereby Mr. McClendon will pay the Company approximately $12 million plus interest and the Company will reconvey the map collection to Mr. McClendon, and the adoption and/or implementation of a variety of corporate governance measures. The court awarded attorney fees and expenses to plaintiffs counsel in the amount of $3,750,000, that was paid by Chesapeake. Pursuant to the settlement, the consolidated derivative action and books and records action were dismissed with prejudice against all defendants. On February 29, 2012, certain shareholders filed a petition in error with the Oklahoma Supreme Court opposing the terms of the settlement and on March 20, 2012 Chesapeake responded.

On September 6 and 8, 2011, in separate derivative actions filed in the U.S. District Court for the Western District of Oklahoma against certain of the Company s current and former directors, two shareholders alleged that the Chesapeake board wrongfully refused their demands to investigate purported breaches of fiduciary duties relating to Mr. McClendon s 2008 compensation and, as a result, each of these shareholders asserts he is entitled to seek relief on behalf of the Company. These federal derivative actions were consolidated on December 23, 2011 and on March 14, 2012 were stayed until 30 days after the Supreme Court of Oklahoma resolves the appeal of the settlement of the consolidated derivative action and books and records action. On May 3, 2012, plaintiffs filed a motion to lift the stay and sought leave to file an amended complaint.

From April 19 to May 3, 2012, nine nearly identical shareholder actions were filed in the U.S. District Court for the Western District of Oklahoma against the Company and its directors alleging, among other things, violations of Section 14 of the Securities Exchange Act of 1934 and Rule 14a-9 promulgated thereunder for purported material misstatements in the Company s 2009 and subsequent proxy statements related to Mr. McClendon s participation in the Founder Well Participation Program (FWPP) and breaches of fiduciary duties against the Board for failing to make proper disclosures in the proxy statements. On April 27, 2012, a shareholder derivative action was filed in the District Court of Oklahoma County, Oklahoma setting forth substantially similar claims to those alleged in the federal shareholder actions.

On April 26, 2012, a putative class action was filed in the U.S. District Court for the Western District of Oklahoma against the Company and Mr. McClendon alleging violations of Sections 10(b) (and Rule 10b-5 promulgated thereunder) and 20(a) of the Securities Exchange Act of 1934 for purported misstatements concerning Mr. McClendon s participation in the FWPP. The plaintiffs seek class certification, damages of an unspecified amount and attorneys fees and other costs.

On May 1, 2012, the Company announced that its Board of Directors had renegotiated the terms of the Company s FWPP with Mr. McClendon to provide for the early termination of the FWPP on June 30, 2014, 18 months before the end of its current term on December 31, 2015. The FWPP was approved by shareholders for a 10-year term in 2005. In conjunction with Mr. McClendon s employment agreement with the Company, the FWPP provides Mr. McClendon a contractual right to participate and invest as a working interest owner (with up to a 2.5% working interest) in new wells drilled on the Company s leasehold. Mr. McClendon will receive no compensation of any kind in connection with the early termination of the FWPP. The Board of Directors is conducting an internal review of the financing arrangements between Mr. McClendon (and the entities through which he participates in the FWPP) and any third party that has had or may have a relationship with the Company in any capacity.

On May 2, 2012, Chesapeake and Mr. McClendon received notice from the Securities and Exchange Commission that its Fort Worth Regional Office has commenced an informal inquiry and requested that the Company and Mr. McClendon retain documents related to the FWPP and certain transactions. The SEC noted in its request that its inquiry should not be construed as an indication that any violation of the federal securities laws has occurred. The Company and Mr. McClendon intend to cooperate with the SEC in responding to its inquiry.

On May 8, 2012, a derivative action was filed in the District Court of Oklahoma County, Oklahoma against the Company s directors alleging, among other things, breaches of fiduciary duties and corporate waste related to the Company s officers and directors use of the Company s fractionally owned corporate jets.

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, various mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their natural gas and oil

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 successfully defended a number of these cases in various courts, has settled others and believes that it has substantial defenses to the claims made in those pending at the trial court and on appeal. Based on management s current assessment, we are of the opinion that no pending or threatened lawsuit or dispute incidental to the Company s business operations is likely to have a material adverse effect on its 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.

The Company records an associated liability when a loss is probable and the amount is reasonably estimable. The Company accounts for legal defense costs in the period the costs are incurred.

Environmental Risk

Due to the nature of the natural gas and oil business, Chesapeake and its subsidiaries are exposed to environmental risks. Chesapeake has implemented various policies and procedures to reduce and mitigate such environmental risks. 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. 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.

There are presently pending against us orders for compliance issued by the U.S. Environmental Protection Agency (EPA) related to our compliance with Clean Water Act (CWA) permitting requirements in West Virginia, and for four of the sites subject to EPA orders for compliance, we have also received and have responded to a federal grand jury subpoena requesting documents. We understand that the U.S. Department of Justice is investigating possible criminal violations of and liabilities under the CWA with respect to three of the four sites. The CWA provides authority for significant civil and criminal penalties for the placement of fill in a jurisdictional stream or wetland without a permit from the Army Corps of Engineers. CWA civil penalties can be as high as $37,500 per day, per violation, and possible criminal penalties range from $2,500 to $25,000 per day, per violation, for misdemeanor liability (i.e., criminally negligent conduct) and from $5,000 to $50,000 per day, per violation, for felony liability (i.e., knowing conduct). While we expect that resolution of the EPA s compliance orders and the DOJ s investigation under the CWA will each include monetary sanctions exceeding $100,000, following discussions with the DOJ and EPA, we believe the liability with respect to these matters will not have a material effect on the consolidated financial position, results of operations or cash flow of the Company.

In addition, the West Virginia Department of Environmental Protection (WVDEP) has issued orders for compliance related to alleged violations of the West Virginia Dam Control and Safety Act at four structures constructed for Chesapeake in West Virginia. These orders for compliance have been resolved by a mutual settlement agreement dated April 20, 2012 between Chesapeake and the WVDEP. Pursuant to the settlement agreement, Chesapeake agreed to pay a fine of $325,000 and make a contribution in the amount of $125,000 to the West Virginia Department of Natural Resources Wildlife Recreation fund for supplemental projects centered on dam safety construction, maintenance, enhancement, or engineering in northwestern West Virginia.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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(Unaudited)

Commitments

Rig Leases

In a series of transactions since 2006, our drilling subsidiaries have sold 93 drilling rigs (net of one repurchased rig) and related equipment for $802 million and entered into master lease agreements under which we agreed to lease the rigs from the buyer for initial terms of five to ten years. The lease obligations are guaranteed by Chesapeake and certain of its subsidiaries. These transactions were recorded as sales and operating leasebacks and any related net gains are amortized to oilfield services expenses over the lease term. Under the leases, we can exercise an early purchase option or we can purchase the rigs at the expiration of the lease for the fair market value at the time. In addition, in most cases we have the option to renew the lease for negotiated new terms at the expiration of the lease. Commitments related to rig lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of March 31, 2012, the minimum aggregate undiscounted future rig lease payments were approximately $423 million.

Compressor Leases

Through various transactions since 2007, our compression subsidiary has sold 2,542 compressors (net of six repurchased units), a significant portion of its compressor fleet, for $635 million and entered into a master lease agreement. The term of the agreement varies by buyer ranging from four to ten years. The lease obligations are guaranteed by Chesapeake and certain of its subsidiaries. These transactions were recorded as sales and operating leasebacks and any related net gains are amortized to marketing, gathering and compression expenses over the lease term. Under the leases, we can exercise an early purchase option or we can purchase the compressors at the expiration of the lease for the fair market value at the time. In addition, in most cases 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 March 31, 2012, the minimum aggregate undiscounted future compressor lease payments were approximately $466 million.

Gathering, Processing and Transportation Agreements

We have contractual commitments with midstream service companies and pipeline carriers, including our equity affiliate CHKM, for future gathering, processing and transportation of natural gas and liquids to move certain of our production to market. Working interest owners will be responsible for their proportionate share of these costs under joint operating agreements. Commitments related to gathering, processing and transportation agreements are not recorded in the accompanying condensed consolidated balance sheets.

The aggregate undiscounted commitments under our gathering, processing and transportation agreements, excluding any reimbursement from working interest owners, are presented below.

	March 31, 2012 ($ in millions)
2012	$ 754
2013	1,162
2014	1,203
2015	1,284
2016	1,355
2017 - 2099	7,848

Total	$	13,606

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Drilling Contracts

Chesapeake has contracts with various drilling contractors to lease approximately 51 rigs with terms ranging from two months to three years. These commitments are not recorded in the accompanying condensed consolidated balance sheets. As of March 31, 2012, the aggregate undiscounted minimum future drilling rig commitment was approximately $351 million.

Drilling Obligations

In December 2011, as part of our Utica joint venture development agreement with Total, we committed to spud no less than 90 cumulative Utica wells by December 31, 2012, 270 cumulative wells by December 31, 2013 and 540 cumulative wells by December 31, 2014. If we fail to meet the drilling commitment at any such year end for any reason other than a force majeure event, the drilling carry percentage used to determine our promoted well reimbursement will be reduced from 60% to 45% for a number of wells drilled in the following calendar year equal to the number of wells we were short the drilling commitment. This reduction will not affect the total carry to be received.

We have also committed to drill wells in conjunction with our Utica and Cleveland Tonkawa financial transactions and in conjunction with the formation of the Chesapeake Granite Wash Trust. See Note 6 for discussion of these transactions and commitments.

Natural Gas and Oil Purchase Obligations

Our marketing segment regularly commits to purchase natural gas from other owners in our properties and such commitments typically are short term in nature. We have also committed to purchase any natural gas and oil associated with our volumetric production payment transactions. The purchase commitments are based on market prices at the time of production, and the purchased natural gas and oil is resold.

Net Acreage Maintenance Commitments

Under the terms of our joint venture agreements with Statoil and Total (see Note 8), we are required to extend, renew or replace certain expiring joint leasehold, at our cost, to ensure that the net acreage is maintained in certain designated areas.

Other Commitments

In April 2011, we entered into a master frac service agreement with our equity affiliate, FTS International, Inc. (FTS), which expires on December 31, 2014. Pursuant to this agreement, we are committed to enter into a predetermined number of backstop contracts if utilization of FTS fleets falls below a certain level. We have guaranteed a gross profit margin of 10% to FTS on such backstop contracts. To date, we have not entered into any backstop contracts, and since we use fracing services continuously, we do not anticipate any material payments under this commitment.

In July 2011, we agreed to invest $150 million in newly issued convertible promissory notes of Clean Energy Fuels Corp. (Nasdaq:CLNE), based in Seal Beach, California. The investment is being made in three equal $50 million promissory notes, the first of which was issued on July 11, 2011, with the remaining notes scheduled to be issued in June 2012 and June 2013. The notes bear interest at the annual rate of 7.5%, payable quarterly, and are convertible at our option into shares of Clean Energy s common stock at a 22.5% conversion premium, resulting in a conversion price of $15.80 per share. See Note 9 for further discussion of this investment.

In July 2011, we agreed to invest $155 million in preferred equity securities of Sundrop Fuels, Inc., a privately held cellulosic biofuels company based in Louisville, Colorado. The first $35 million tranche of our investment was funded in July 2011 and the remaining tranches of preferred equity investment will be scheduled around certain funding and operational milestones that are expected to be reached by July 2013. See Note 9 for further discussion of this investment.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

In December 2011, we sold Appalachia Midstream Services, L.L.C., a wholly owned subsidiary of CMD, to our equity affiliate, CHKM, for total consideration of $879 million, subject to a customary post-closing working capital adjustment. In addition, CMD has committed to pay CHKM for any quarterly shortfall between the actual adjusted EBITDA from the assets sold and specified quarterly targets, which total $100 million in 2012 and $150 million in 2013. We recorded this guarantee at an estimated fair value of $27 million at the time of the sale. It is included in other current and non-current liabilities on our consolidated balance sheet as of March 31, 2012. We will release this liability over the two-year term of the guarantee if the assets are meeting the specific quarterly targets. To the extent we are required to make payments under the guarantee, we will record the differences between the liability and the associated payments in earnings. No payment was required for the Current Quarter.

In conjunction with CMD s investments in the newly formed entities Utica East Ohio Midstream LLC, Cardinal Gas Services LLC, and Ranch Westex JV, LLC, as of March 31, 2012, CMD has committed to make capital contributions to these entities for a total of approximately $575 million over the next two years. See Notes 9 and 10 for further discussion of these investments.

In conjunction with an acceleration of the remaining drilling carry owed us by Total in our Barnett Shale joint venture, we agreed to maintain our operated rig count at no less than six rigs in the Barnett Shale through December 31, 2012. In May 2012, Chesapeake and Total agreed to reduce the minimum rig count from six to two rigs.

As part of our normal course of business, we enter into various agreements providing, or otherwise arranging, financial or performance assurances to third parties on behalf of our consolidated subsidiaries. These agreements may include future payment obligations or commitments regarding operational performance that effectively guarantees our subsidiaries future performance.

In connection with our purchase and sale agreements, we have frequently provided for indemnification to the counterparty for liabilities incurred as a result of a breach of a representation or warranty by the indemnifying party or in regards to perfecting title to property. These indemnifications generally have a discrete term and are intended to protect the parties against the risks that are difficult to predict or cannot be quantified at the time of the consummation of a particular transaction.

Certain of our natural gas and oil properties are burdened by non-operating interests such as royalties, overriding royalties and volumetric production payments. As the holder of the working interest from which such interests have been carved, we have the responsibility to bear the cost of developing and producing the reserves attributable to such interests.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

5. Other Long-Term Liabilities

Other long-term liabilities as of March 31, 2012 and December 31, 2011 are detailed below.

	xxxxxxxxxxxxx March 31, 2012	xxxxxxxxxxxxx December 31, 2011
	($ in millions)	
CHK Utica ORRI conveyance obligation[(a)]	$ 290	$ 290
CHK C-T ORRI conveyance obligation[(b)]	185	
Financing lease obligations[(c)]	143	143
Revenues and royalties due others	115	109
Mortgages payable[(d)]	56	56
Other	236	220
Total other long-term liabilities	$ 1,025	$ 818

(a) $9 million and $10 million of the total $299 million and $300 million obligation are recorded in other current liabilities as of March 31, 2012 and December 31, 2011, respectively. See Note 6 for further discussion of the CHK Utica financial transaction.

(b) $12 million of the total $197 million obligation is recorded in other current liabilities. See Note 6 for further discussion of the CHK C-T financial transaction.

(c) In 2009, we financed 113 real estate surface assets in the Barnett Shale area 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. This lease transaction was recorded as a financing lease and the cash received was recorded with an offsetting long-term liability on the consolidated balance sheet. Chesapeake exercised its option to repurchase two of the assets in 2010 and one of the assets in 2011. As of March 31, 2012, we had 110 assets remaining.

(d) In 2009, we financed our regional Barnett Shale headquarters building in Fort Worth, Texas for net proceeds of 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.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

6. Stockholders Equity, Restricted Stock, Stock Options and Noncontrolling Interests

Common Stock

The following is a summary of the changes in our common shares issued for the three months ended March 31, 2012 and 2011:

	xxxxxxxxx	xxxxxxxxx
	2012	**2011**
	(in thousands)	
Shares issued at January 1	660,888	655,251
Restricted stock issuances (net of forfeitures)	3,184	3,587
Stock option exercises	109	182
Shares issued at March 31	664,181	659,020

Preferred Stock

The following reflects our preferred shares outstanding for the three months ended March 31, 2012 and 2011:

	xxxxxxxxxx	xxxxxxxxxx	xxxxxxxxxx	xxxxxxxxxx
	5.75%	**5.75% (A)**	**4.50%**	**5.00% (2005B)**
		(in thousands)		
Shares outstanding at January 1, 2012 and March 31, 2012	1,497	1,100	2,559	2,096
Shares outstanding at January 1, 2011 and March 31, 2011	1,500	1,100	2,559	2,096

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.

Dividends on our outstanding preferred stock are payable quarterly. We may pay dividends on our 5.00% Cumulative Convertible Preferred Stock (Series 2005B) and our 4.50% Cumulative Convertible Preferred Stock in cash, common stock or a combination thereof, at our option. Dividends on both series of our 5.75% Cumulative Convertible Non-Voting Preferred Stock are payable only in cash.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Stock-Based Compensation

Chesapeake s stock-based compensation program consists of restricted stock and, prior to 2006, stock options issued to employees and non-employee directors. We recognize in our financial statements the cost of employee services received in exchange for awards of equity instruments based on the fair value of the equity instruments at the date of the grant. This value is amortized over the vesting period, which is generally four years from the date of grant for employees and three years for non-employee directors. To the extent compensation cost relates to employees directly involved in natural gas and oil acquisition, exploration and development activities, such amounts are capitalized to natural gas and oil properties. Amounts not capitalized to natural gas and oil properties are recognized as general and administrative expenses, natural gas and oil production expenses, marketing, gathering and compression expenses or oilfield services expenses. We recorded the following stock-based compensation during the Current Quarter and the Prior Quarter:

	xxxxxxxxxx	xxxxxxxxxx
	Three Months Ended March 31,	
	2012	2011
	($ in millions)	
Natural gas and oil properties	$ 20	$ 31
General and administrative expenses	19	23
Natural gas and oil production expenses	6	9
Marketing, gathering and compression expenses	4	5
Oilfield services expenses	3	3
Total	$ 52	$ 71

Restricted Stock. Chesapeake began issuing shares of restricted common stock to employees in January 2004 and to non-employee directors in July 2005. A summary of the changes in unvested shares of restricted stock for the three months ended March 31, 2012 is presented below.

	xxxxxxxxxx	xxxxxxxxxx
	Number of Unvested Restricted Shares (in thousands)	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2012	19,544	$ 26.97
Granted	4,708	$ 23.60
Vested	(3,450)	$ 27.21
Forfeited	(307)	$ 26.12
Unvested shares as of March 31, 2012	20,495	$ 26.17

The aggregate intrinsic value of restricted stock vested during the Current Quarter was approximately $80 million based on the stock price at the time of vesting.

As of March 31, 2012, there was $388 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of approximately three years.

The vesting of certain restricted stock grants could result in state and federal income tax benefits related to the difference between the market price of the common stock at the date of vesting and the date of grant. During the Current Quarter and the Prior Quarter, we recognized reductions in tax benefits related to restricted stock of $4 million and $1 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes.

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Stock Options. We granted stock options prior to 2006 under several stock compensation plans. Outstanding options expire ten years from the date of grant and vested over a four-year period. All of our outstanding stock options are fully vested and exercisable and there are no shares authorized for future grants.

The following table provides information related to stock option activity for the three months ended March 31, 2012:

	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, 2012	1,051	$ 9.84	1.41	$ 13
Exercised	(109)	$ 7.08		
Outstanding and exercisable at March 31, 2012	942	$ 10.17	1.24	$ 12

(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.

There is no remaining unrecognized compensation cost related to unvested stock options.

During the Current Quarter and the Prior Quarter, we recognized excess tax benefits related to stock options of a nominal amount and $1 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes.

Noncontrolling Interests

Cleveland Tonkawa Financial Transaction. We formed CHK Cleveland Tonkawa, L.L.C. (CHK C-T) in March 2012 to continue development of a portion of our Cleveland and Tonkawa plays. CHK C-T is an unrestricted subsidiary under our corporate credit facility agreement and is not a guarantor of, or otherwise liable for, any of our indebtedness or other liabilities, including under our indentures. In exchange for all of the common shares of CHK C-T, we contributed to CHK C-T approximately 245,000 net acres of leasehold and 360 existing wells within an area of mutual interest in the Cleveland and Tonkawa plays covering Ellis and Roger Mills counties in western Oklahoma. In March 2012, in a private placement, third-party investors contributed $1.25 billion in cash to CHK C-T in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3.75% overriding royalty interest (ORRI) in the existing wells and up to 1,000 net wells to be drilled on certain of our Cleveland and Tonkawa play leasehold. Subject to customary minority interest protections afforded the investors by the terms of the CHK C-T limited liability company agreement (the CHK C-T LLC Agreement), as the holder of all the common shares and the sole managing member of CHK C-T, we maintain voting and managerial control of CHK C-T and therefore include it in our condensed consolidated financial statements. Of the $1.25 billion of investment proceeds, we allocated $225 million to the ORRI obligation and $1.025 billion to the preferred shares based on estimates of fair values. The ORRI obligation is included in other current and long-term liabilities and the preferred shares are included in noncontrolling interests on our condensed consolidated balance sheet. Pursuant to the CHK C-T LLC Agreement, CHK C-T is required to retain $300 million of the $1.25 billion of investment proceeds to fund its development activities and make the next two quarters of preferred dividend payments. The amount reserved for paying such dividends, approximately $37 million, is reflected as restricted cash on our condensed consolidated balance sheet.

Dividends on the preferred shares are payable on a quarterly basis at a rate of 6% per annum based on $1,000 per share. This dividend rate is subject to increase in limited circumstances in the event that, and only for so long as, cash flow from the assets owned by CHK C-T is insufficient to fund the dividend in full in any quarter, whether as a result of capital expenditures, drilling results or otherwise. As the managing member of CHK C-T, we may, at our sole discretion and election at any time after March 31, 2014, distribute certain excess cash of CHK C-T, as determined in accordance with the CHK C-T LLC Agreement. Any such optional distribution of excess cash is allocated 75% to the preferred shares (which is applied toward redemption of the preferred shares) and 25% to the common shares unless we have not met our drilling commitment at such time, in which case such optional distributions would be allocated 100% to the preferred shares (and applied toward redemption thereof). We may also, at our sole election and discretion, in accordance with the CHK C-T LLC Agreement, cause CHK C-T to redeem all or a portion of the CHK C-T preferred shares for cash. The preferred shares will be redeemed at a valuation equal to the greater of a 9% internal rate of return or a return on investment of 1.35x, in each case inclusive of dividends paid at the rate of 6% per annum and optional distributions made through the applicable redemption date. In the event that redemption does not occur on or prior to March 31, 2019, the optional redemption valuation will increase to provide a 15% internal rate of return to the investors. The preferred shares are redeemed on a pro-rata basis in accordance with the then-applicable redemption valuation formula. As of March 31, 2012, the redemption price, and the liquidation preference, was $1,350 per preferred share. We have committed to drill, for the benefit of CHK C-T, a minimum of 37.5 net wells per six-month period through 2013 and 25 net wells per six-month period in 2014 through 2016 in the CHK C-T area of mutual interest, up to a minimum cumulative total of 300 net wells. If we fail to meet the then-current drilling commitment in any year, any optional cash distributions would be distributed 100% to the investors. If we fail to meet the then-current drilling commitment in two consecutive six-month periods, the then-applicable internal rate of return to investors at redemption would increase by 3% per annum. In addition, if we fail to meet the then-current drilling commitment in four consecutive six-month periods, the then-applicable internal rate of return to investors at redemption would be increased by an additional 3% per annum. Any such increase in the internal rate of return would be effective only until the end of the first succeeding six-month period in which we have met our then-current drilling commitment. CHK C-T is responsible for all capital and operating costs of the wells drilled for the benefit of the entity.

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The CHK C-T investors right to receive, proportionately, a 3.75% ORRI in the existing wells and up to 1,000 net wells drilled on our Cleveland and Tonkawa leasehold is subject to an increase to 5% in any year following a year in which we do not meet our commitment to drill the wells subject to the ORRI obligation, which runs from 2012 through the first quarter of 2025. However, in no event would we deliver to investors more than a total ORRI of 3.75% in 1,000 net wells. If at any time we hold fewer net acres than would enable us to drill all then-remaining net wells on 160-acre spacing, the investors have the right to require us to repurchase their right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining net wells. We retain the right to repurchase the investors right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining net wells once we have drilled a minimum of 867 net wells. The obligation to deliver future ORRIs has been recorded as a liability which will be settled through the future conveyance of the underlying ORRIs to the investors on a net-well basis, at which time the associated liability will be reversed and the sale of the ORRIs reflected as an adjustment to the capitalized cost of our natural gas and oil properties. As of March 31, 2012, $1.015 billion was recorded as noncontrolling interest on our condensed consolidated balance sheet representing the third-party investment in CHK C-T. For the Current Quarter, no income was attributable to the noncontrolling interests of CHK C-T.

Utica Financial Transaction. We formed CHK Utica, L.L.C. (CHK Utica) in October 2011 to develop a portion of our Utica Shale natural gas and oil assets. CHK Utica is an unrestricted subsidiary under our corporate credit facility agreement and is not a guarantor of, or otherwise liable for, any of our indebtedness or other liabilities, including under our indentures. In exchange for all of the common shares of CHK Utica, we contributed to CHK Utica approximately 700,000 net acres of leasehold and 19 existing wells within an area of mutual interest in the Utica Shale play covering 13 counties located primarily in eastern Ohio. During November and December 2011, in private placements, third-party investors contributed $1.25 billion in cash to CHK Utica in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3% ORRI in up to 1,500 net wells to be drilled on certain of our Utica Shale leasehold. Subject to customary minority interest protections afforded the investors by the terms of the CHK Utica limited liability company agreement (the CHK Utica LLC Agreement), as the holder of all the common shares and the sole managing member of CHK Utica, we maintain voting and managerial control of CHK Utica and therefore include it in our condensed consolidated financial statements. Of the $1.25 billion of investment proceeds, we allocated $300 million to the ORRI obligation and $950 million to the preferred shares based on estimates of fair values. The ORRI obligation is included in other current and long-term liabilities and the preferred shares are included in noncontrolling interests on our condensed consolidated balance sheet. Pursuant to the CHK Utica LLC Agreement, CHK Utica is required to retain $400 million of the $1.25 billion of investment proceeds to fund its development activities and make the next two quarters of preferred dividend payments. The amount reserved for paying such dividends, approximately $44 million, is reflected as restricted cash on our condensed consolidated balance sheet.

Dividends on the preferred shares are payable on a quarterly basis at a rate of 7% per annum based on $1,000 per share. This dividend rate is subject to increase in limited circumstances in the event that, and only for so long as, cash flow from the assets owned by CHK Utica is insufficient to fund the dividend

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in full in any quarter, whether as a result of capital expenditures, drilling results or otherwise. We have committed to drill, for the benefit of CHK Utica, a minimum of 50 net wells per year through 2016 in the CHK Utica area of mutual interest, up to a minimum cumulative total of 250 net wells. If we fail to meet the then-current drilling commitment in any year, we must pay to CHK Utica $5 million for each well we are short of such drilling commitment. As the managing member of CHK Utica, we may, at our sole discretion and election at any time after December 31, 2013, distribute certain excess cash of CHK Utica, as determined in accordance with the CHK Utica LLC Agreement. Any such optional distribution of excess cash is allocated 70% to the preferred shares (which is applied toward redemption of the preferred shares) and 30% to the common shares unless we have not met our drilling commitment at such time, in which case such optional distributions would be allocated 100% to the preferred shares (and applied toward redemption thereof). We may also, at our sole election and discretion, in accordance with the CHK Utica LLC Agreement, cause CHK Utica to redeem the CHK Utica preferred shares for cash, in whole or in part. The preferred shares will be redeemed at a valuation equal to the greater of a 10% internal rate of return or a return on investment of 1.4x, in each case inclusive of dividends paid at the rate of 7% per annum and optional distributions made through the applicable redemption date. In the event that redemption does not occur on or prior to October 31, 2018, the optional redemption valuation will increase to the greater of a 17.5% internal rate of return or a return on investment of 2.0x. The preferred shares are redeemed on a pro-rata basis in accordance with the then-applicable redemption valuation formula. As of March 31, 2012, the redemption price, and the liquidation preference, was approximately $1,375 per preferred share. CHK Utica is responsible for all capital and operating costs of the wells drilled for the benefit of the entity. CHK Utica also receives its proportionate share of the benefit of the drilling carry associated with our joint venture with Total in the Utica Shale. See Note 8 for further discussion of the joint venture.

The CHK Utica investors right to receive, proportionately, a 3% ORRI in the first 1,500 net wells drilled on our Utica Shale leasehold is subject to an increase to 4% in any year following a year in which we do not meet our commitment to drill the wells subject to the ORRI obligation, which runs from 2012 through 2023. However, in no event would we deliver to investors more than a total ORRI of 3% in 1,500 net wells. If at any time we hold fewer net acres than would enable us to drill all then-remaining net wells on 150-acre spacing, the investors have the right to require us to repurchase their right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining net wells. We retain the right to repurchase the investors right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining net wells once we have drilled a minimum of 1,300 net wells. The obligation to deliver future ORRIs has been recorded as a liability which will be settled through the future conveyance of the underlying ORRIs to the investors on a net-well basis, at which time the associated liability will be reversed and the sale of the ORRIs reflected as an adjustment to the capitalized cost of our natural gas and oil properties. As of March 31, 2012 and December 31, 2011, $950 million was recorded as noncontrolling interest on our condensed consolidated balance sheets representing the third-party investment in CHK Utica. For the Current Quarter, approximately $22 million of income was attributable to the noncontrolling interests of CHK Utica.

Chesapeake Granite Wash Trust. In November 2011, Chesapeake Granite Wash Trust (the Trust) sold 23,000,000 common units representing beneficial interests in the Trust at a price of $19.00 per common unit in its initial public offering. The common units are listed on the New York Stock Exchange and trade under the symbol CHKR . We own 12,062,500 common units and 11,687,500 subordinated units, which in the aggregate represent an approximate 51% beneficial interest in the Trust. The Trust has a total of 46,750,000 units outstanding.

In connection with the initial public offering of the Trust, we conveyed royalty interests to the Trust that entitle the Trust to receive (i) 90% of the proceeds (after deducting post-production expenses and any applicable taxes) that we receive from the production of hydrocarbons from 69 producing wells, and, (ii) 50% of the proceeds (after deducting post-production expenses and any applicable taxes) in 118 development wells that have been or will be drilled on approximately 45,400 gross acres (29,300 net acres) in the Colony Granite Wash play in Washita County in the Anadarko Basin of western Oklahoma. Pursuant to the terms of a development agreement with the Trust, we are obligated to drill, or cause to be drilled, the development wells at our own expense prior to June 30, 2016, and the Trust will not be responsible for any costs related to the drilling of the development wells or any other operating or capital costs of the Trust properties. In addition, we granted to the Trust a lien on our remaining royalty interests in the development wells in order to secure our drilling obligation to the Trust, although the maximum amount that may be recovered by the Trust under such lien could not exceed $263 million initially and is proportionately

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reduced as we fulfill our drilling obligation over time. As of March 31, 2012, we had drilled or caused to be drilled 21 development wells and the maximum amount recoverable under the drilling support lien was approximately $212 million.

The subordinated units we hold in the Trust are entitled to receive pro rata distributions from the Trust each quarter if and to the extent there is sufficient cash to provide a cash distribution on the common units that is not less than the applicable subordination threshold for such quarter. If there is not sufficient cash to fund such a distribution on all of the Trust units, the distribution to be made with respect to the subordinated units will be reduced or eliminated for such quarter in order to make a distribution, to the extent possible, of up to the subordination threshold amount on the common units. In exchange for agreeing to subordinate a portion of our Trust units, and in order to provide additional financial incentive to us to satisfy our drilling obligation and perform operations on the underlying properties in an efficient and cost-effective manner, Chesapeake is entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on the Trust units in any quarter exceeds the applicable incentive threshold for such quarter. The remaining 50% of cash available for distribution in excess of the applicable incentive threshold will be paid to Trust unitholders, including Chesapeake, on a pro rata basis. At the end of the fourth full calendar quarter following our satisfaction of our drilling obligation with respect to the development wells, the subordinated units will automatically convert into common units on a one-for-one basis and our right to receive incentive distributions will terminate. After such time, the common units will no longer have the protection of the subordination threshold, and all Trust unitholders will share in the Trust s distributions on a pro rata basis.

On February 8, 2012, the Trust declared a cash distribution of approximately $34 million, or $0.73 per unit, for the three-month period ended December 31, 2011 and covering production for the period from September 1, 2011 to November 30, 2011. The distribution was paid on March 1, 2012 to record unitholders as of February 20, 2012. Of the total distribution, approximately $17 million was paid to Chesapeake.

We have determined that the Trust constitutes a VIE and that Chesapeake is the primary beneficiary. As a result, the Trust is included in our condensed consolidated financial statements. As of March 31, 2012 and December 31, 2011, $367 million and $380 million was recorded as a noncontrolling interest, respectively, on our condensed consolidated balance sheets representing the public unitholders investment in common units of the Trust. For the Current Quarter, approximately $3 million of income was attributable to the Trust s noncontrolling interests in our condensed consolidated statement of operations. See Note 10 for further discussion of VIEs.

Cardinal Gas Services. Cardinal Gas Services, L.L.C. (Cardinal), an unrestricted, non-guarantor consolidated subsidiary, was formed in December 2011 to acquire, develop, operate and own midstream assets in the Utica Shale. In exchange for the contribution of approximately $14 million in midstream assets to Cardinal, we received 66% of the outstanding membership units of Cardinal. In exchange for approximately $5 million, Total E&P USA, Inc. (Total) received 25% of the outstanding membership units and in exchange for approximately $2 million, CGAS Properties, L.P. (CGAS), an affiliate of Enervest, Ltd., received 9% of the membership units. We have determined that Cardinal constitutes a VIE and that Chesapeake is the primary beneficiary. As a result, Cardinal is included in our condensed consolidated financial statements. The contributions from Total and CGAS were recorded as noncontrolling interests. Each member is responsible for its proportionate share of capital costs. As of March 31, 2012 and December 31, 2011, the noncontrolling interest balances on the condensed consolidated balance sheet associated with the contributions from Total and CGAS was approximately $31 million and $7 million, respectively. For the Current Quarter, a nominal loss was attributable to Cardinal s noncontrolling interests in our condensed consolidated statement of operations.

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7. Derivative and Hedging Activities

Natural Gas and Oil Derivatives

Our results of operations and 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 prices to be received for our hedged production. We believe our derivative instruments continue to be highly effective in achieving our risk management objectives. As of March 31, 2012 and December 31, 2011, our natural gas and oil derivative instruments consisted 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.

Call Options: Chesapeake sells, and occasionally buys, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess on sold call options, and Chesapeake receives such excess on bought call options. If the market price settles below the fixed price of the call option, no payment is due from either party.

Swaptions: Chesapeake sells swaptions to counterparties that allow them, on a specific date, to extend an existing fixed-price swap for a certain period of time.

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 a certain pre-determined knockout price.

Basis Protection Swaps: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas from a specified delivery point. Our basis protection swaps 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.

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.

The estimated fair values of our natural gas and oil derivative instruments as of March 31, 2012 and December 31, 2011 are provided below.

	XXXX,XXXX	XXXX,XXXX	XXXX,XXXX	XXXX,XXXX
	March 31, 2012		**December 31, 2011**	
	Volume	**Fair Value ($ in millions)**	**Volume**	**Fair Value ($ in millions)**
Natural gas (tbtu):				
Call options	1,318	$ (255)	1,357	$ (284)

Basis protection swaps	160		(40)	106		(42)
Total natural gas	1,478		(295)	1,463		(326)
Oil (mmbbl):						
Fixed-price swaps	24.9		(38)	14.9		15
Call options	90.3		(1,305)	94.7		(1,282)
Swaptions	15.0		(108)	7.8		(53)
Fixed-price knockout swaps	0.6		3	0.8		7
Total oil	130.8		(1,448)	118.2		(1,313)
Total estimated fair value		$	(1,743)		$	(1,639)

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Pursuant to accounting guidance for derivatives and hedging, certain derivatives qualify for designation as cash flow hedges. Following this guidance, 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. 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 within natural gas and oil sales. As of March 31, 2012, we did not have any natural gas and oil derivatives that were designated as cash flow hedges.

The components of natural gas and oil sales for the Current Quarter and the Prior Quarter are presented below.

	XXXX,XXX	XXXX,XXX
	Three Months Ended March 31,	
	2012	**2011**
	($ in millions)	
Natural gas and oil sales	$ 1,221	$ 1,188
Gains (losses) on natural gas and oil derivatives	(153)	(704)
Gains (losses) on ineffectiveness of cash flow hedges		10
Total natural gas and oil sales	$ 1,068	$ 494

Based upon the market prices at March 31, 2012, we expect to transfer approximately $4 million of net gain included in accumulated other comprehensive income to net income (loss) during the next 12 months in the related month of production. All derivative instruments as of March 31, 2012 are expected to mature by December 31, 2022.

Hedging Facility

We have a multi-counterparty secured hedging facility with 18 counterparties that have committed to provide approximately 6.5 tcfe of hedging capacity for commodity price derivatives and 6.5 tcfe for basis derivatives with an aggregate mark-to-market capacity of $17.5 billion under the terms of the facility. As of March 31, 2012, we had hedged under the facility 2.1 tcfe of our future production with price derivatives and 0.2 tcfe with basis derivatives. The multi-counterparty facility allows us to enter into cash-settled natural gas, oil and natural gas liquids price and basis derivatives with the counterparties. Our obligations under the multi-counterparty facility are secured by proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by at least 1.65 times at semi-annual collateral dates and 1.30 times in between those dates, and guarantees by certain subsidiaries that also guarantee our corporate revolving bank credit facility, indentures and sale/leaseback arrangements. 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 hedging capacity under the facility is governed by the expected production of the pledged reserve collateral, and volume-based hedging limits are applied separately to price and basis derivatives. In addition, there are volume-based sub-limits for natural gas, oil and natural gas liquids derivative instruments. 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 entering into derivative instruments with the Company on a prospective basis as long as obligations associated with any existing transactions in the facility continue to be satisfied in accordance with the terms of the agreement.

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Interest Rate Derivatives

To mitigate a portion of our exposure to volatility in interest rates related to our senior notes and bank credit facilities, we enter into interest rate derivatives. As of March 31, 2012 and December 31, 2011, our interest rate derivative instruments consisted 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.

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

The notional amount and the estimated fair value of our interest rate derivatives outstanding as of March 31, 2012 and December 31, 2011 are provided below.

	XXXX,XXXX	XXXX,XXXX	XXXX,XXXX	XXXX,XXXX
	March 31, 2012		**December 31, 2011**	
	Notional Amount	**Fair Value**	**Notional Amount**	**Fair Value**
		($ in millions)		
Interest rate:				
Swaps	$ 1,500	$ (43)	$ 1,050	$ (42)
Swaptions	400	(3)	300	
Totals	$ 1,900	$ (46)	$ 1,350	$ (42)

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 and the Prior Quarter are presented below.

	XXXX,XXXX	XXXX,XXXX
	Three Months Ended March 31,	
	2012	**2011**
	($ in millions)	
Interest expense on senior notes	$ 174	$ 177
Interest expense on credit facilities	21	21
(Gains) losses on interest rate derivatives	4	(1)
Amortization of loan discount and other	1	15

Capitalized interest		(188)		(205)
Total interest expense	$	12	$	7

We have terminated certain fair value hedges related to senior notes. Gains and losses related to these terminated hedges will be amortized as an adjustment to interest expense over the remaining term of the related senior notes. Over the next nine years, we will recognize $25 million in gains related to such transactions.

Foreign Currency Derivatives

In December 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 cross currency swaps to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. In May 2011, we purchased and subsequently retired 256 million in aggregate principal amount of these senior notes following a tender offer, and we simultaneously unwound the cross currency swaps for the same principal amount. As a result, we reclassified a loss of $38 million from accumulated other comprehensive income to the condensed consolidated statement of operations, $20 million of which related to the unwound notional amount and was included in losses on purchases or exchanges of debt, and $18 million

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of which related to future interest associated with the unwound principal and was included in interest expense. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay Chesapeake 11 million and Chesapeake pays the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake 344 million and Chesapeake will pay the counterparties $459 million. The terms of the cross currency swaps were based on the dollar/euro exchange rate on the issuance date of $1.3325 to 1.00. Through the cross currency swaps, we have eliminated any potential variability in Chesapeake s expected cash flows related to changes in foreign exchange rates and therefore the swaps qualify as cash flow hedges. The fair values of the cross currency swaps are recorded on the condensed consolidated balance sheet as a liability of $20 million at March 31, 2012. The euro-denominated debt in long-term debt has been adjusted to $459 million at March 31, 2012 using an exchange rate of $1.3334 to 1.00.

Additional Disclosures Regarding Derivative Instruments and Hedging Activities

In accordance with accounting guidance for derivatives and hedging, 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 sheets represent the estimated fair value of derivatives scheduled to settle over the next twelve months based on market prices/rates as of the respective balance sheet dates. The derivative settlement amounts are not due until the month in which the related underlying hedged transaction occurs. Cash settlements of our derivative instruments are generally classified as operating cash flows unless the derivative is deemed to contain, for accounting purposes, a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying condensed consolidated statements of cash flows.

The following table presents the fair value and location of each classification of derivative instrument disclosed in the condensed consolidated balance sheets as of March 31, 2012 and December 31, 2011 on a gross basis without regard to same-counterparty netting:

	$XXX,XX	$XXX,XX	$XXX,XX
		Fair Value	
	Balance Sheet Location	March 31, 2012	December 31, 2011
		($ in millions)	
Asset Derivatives:			
Derivatives not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	$ 76	$ 54
Commodity contracts	Long-term derivative instruments	11	1
Total		87	55
Liability Derivatives:			
Derivatives designated as hedging instruments:			
Foreign currency contracts	Long-term derivative instruments	(20)	(38)
Total		(20)	(38)
Derivatives not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	(277)	(232)
Commodity contracts	Long-term derivative instruments	(1,553)	(1,462)

Interest rate contracts	Short-term derivative instruments	(3)	
Interest rate contracts	Long-term derivative instruments	(43)	(42)
Equity contracts	Short-term derivative instruments	(2)	
Total		(1,878)	(1,736)
Total derivative instruments		$ (1,811)	$ (1,719)

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

A consolidated summary of the effect of derivative instruments on the condensed consolidated statements of operations for the Current Quarter and the Prior Quarter is provided below, separating fair value, cash flow and non-qualifying derivatives.

Fair Value Hedges

For interest rate derivative instruments designated as fair value hedges, the fair values of the hedges are recorded on the condensed consolidated balance sheets as assets or liabilities, with corresponding offsetting adjustments to the debt s carrying value. Our qualifying interest rate swaps are considered 100% effective and therefore no ineffectiveness was recorded for the periods presented below. Changes in the fair value of non-qualifying interest rate derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported in the condensed consolidated statements of operations within interest expense.

The following table presents the gain (loss) recognized in the condensed consolidated statements of operations for instruments designated as fair value derivatives:

	$XX,XXX	$XX,XXX	$XX,XXX
		Three Months Ended March 31,	
Fair Value Derivatives	**Location of Gain (Loss)**	**2012**	**2011**
		($ in millions)	
Interest rate contracts	Interest expense	$ 2	$ 6

We include the expense on the hedged item (i.e., fixed-rate borrowings) in the same line item interest expense as the offsetting gain or loss on the related interest rate swap listed above. For the Current Quarter and the Prior Quarter, this expense was $0 and $13 million respectively.

Cash Flow Hedges

A reconciliation of the changes of accumulated other comprehensive income (loss) in the condensed consolidated statements of stockholders equity related to our cash flow hedges is presented below.

	$XXXX,XX	$XXXX,XX	$XXXX,XX	$XXXX,XX
	Three Months Ended March 31,			
	2012		**2011**	
	Before Tax	**After Tax**	**Before Tax**	**After Tax**
Balance, beginning of period	$ (287)	$ (178)	$ (291)	$ (181)
Net change in fair value	6	4	(2)	(1)
Gains reclassified to income	(3)	(2)	(75)	(46)
Balance, end of period	$ (284)	$ (176)	$ (368)	$ (228)

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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) related to instruments designated as cash flow derivatives:

	$XX,XXX	$XX,XXX		$XX,XXX	
		Three Months Ended March 31,			
Cash Flow Derivatives	**Location of Gain (Loss)**	**2012**		**2011**	
		($ in millions)			
Gain (Loss) Recognized in AOCI (Effective Portion)					
Commodity contracts	AOCI	$	1	$	16
Foreign currency contracts	AOCI		5		(18)
		$	6	$	(2)
Gain (Loss) Reclassified from AOCI into Income (Effective Portion)					
Commodity contracts	Natural gas and oil sales	$	3	$	74
Gain (Loss) Recognized in Income Commodity contracts					
Ineffective Portion	Natural gas and oil sales	$		$	10
Amount initially excluded from effectiveness testing	Natural gas and oil sales				22
		$		$	32

Non-Qualifying Derivatives

The following table presents the gain (loss) recognized in the condensed consolidated statements of operations for instruments not qualifying as cash flow or fair value derivatives:

	$XX,XXX	$XX,XXX	$XX,XXX
		Three Months Ended March 31,	
Non-Qualifying Derivatives	**Location of Gain (Loss)**	**2012**	**2011**

		($ in millions)	
Commodity contracts	Natural gas and oil sales	$ (156)	$ (800)
Interest rate contracts	Interest expense	(6)	(5)
Equity contracts	Other income	(2)	
Total		$ (164)	$ (805)

Credit Risk

Derivative instruments that enable us to manage our exposure to commodity prices and interest rate volatility expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with counterparties that are rated investment-grade and deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. On March 31, 2012, our commodity and interest rate derivative instruments were spread among 18 counterparties. Additionally, counterparties to our multi-counterparty secured hedging facility described previously are required to secure their natural gas and oil derivative obligations in excess of defined thresholds. We use this facility for the majority of our natural gas, oil and natural gas liquids derivatives.

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(Unaudited)

8. Acquisitions and Divestitures

Fayetteville Shale Asset Sale

In March 2011, we sold all of our Fayetteville Shale assets in central Arkansas to BHP Billiton Petroleum, a wholly owned subsidiary of BHP Billiton Limited (NYSE:BHP; ASX:BHP), for net proceeds of approximately $4.65 billion in cash. The properties sold consisted of approximately 487,000 net acres of leasehold, net production at closing of approximately 415 million cubic feet of natural gas equivalent per day and midstream assets consisting of approximately 420 miles of pipeline. Of the total proceeds received, $350 million was allocated to our Fayetteville Shale midstream assets and a $7 million gain was recorded for the divestiture of those assets. The remainder of the proceeds was allocated to our Fayetteville Shale natural gas and oil properties. Under full cost accounting rules, we accounted for the sale of our Fayetteville Shale natural gas and oil properties as an adjustment to capitalized costs, with no recognition of gain or loss.

Joint Ventures

As of March 31, 2012, we had entered into seven significant joint ventures with other leading energy companies pursuant to which we sold a portion of our leasehold, producing properties and other assets located in seven different resource plays and received cash of $7.1 billion and commitments for future drilling and completion cost sharing totaling $9.0 billion. In each of these joint ventures, Chesapeake serves as the operator and conducts all leasing, drilling, completion, operations and marketing activities for the project. These transactions have allowed us to recover much or all of our initial leasehold investments and reduce our ongoing capital costs in these plays. For accounting purposes, initial cash proceeds from these joint venture transactions were reflected as a reduction of natural gas and oil properties with no gain or loss recognized. The transactions are detailed below.

Primary Play	Joint Venture Partner[a]	Joint Venture Date	Interest Sold	Cash Proceeds Received at Closing	Total Drilling Carries	Total Cash and Drilling Carry Proceeds	Drilling Carries Remaining[b]
				($ in millions)			
Utica	TOT	December 2011	25.0%	$ 610	$ 1,422	$ 2,032	$ 1,372
Niobrara	CNOOC	February 2011	33.3%	570	697	1,267	544
Eagle Ford & Pearsall	CNOOC	November 2010	33.3%	1,120	1,080	2,200	
Barnett	TOT	January 2010	25.0%	800	1,404[c]	2,204	
Marcellus	STO	November 2008	32.5%	1,250	2,125	3,375	
Fayetteville	BP	September 2008	25.0%	1,100	800	1,900	
Haynesville & Bossier	PXP	July 2008	20.0%	1,650	1,508[d]	3,158	
				$ 7,100	$ 9,036	$ 16,136	$ 1,916

(a) Joint venture partners include Total S.A. (TOT), CNOOC Limited (CNOOC), Statoil (STO), BP America (BP) and Plains Exploration & Production Company (PXP).

(b) As of March 31, 2012. The Utica carry must be used by January 2018 and the Niobrara carry must be used by December 2014. We expect to fully utilize these drilling carry commitments prior to expiration. See Note 4 for further discussion.

(c) In conjunction with an agreement requiring us to maintain our operated rig count at no less than 12 rigs in the Barnett Shale through December 31, 2012, TOT accelerated the payment of its remaining joint venture drilling carry in exchange for an approximate 9% reduction in the total amount of drilling carry obligation owed to us at that time. As a result, in October 2011, we received $471 million in cash from TOT, which included $46 million of carry obligation billed and $425 million for the remaining carry obligation. In January 2012, Chesapeake and TOT agreed to reduce the minimum rig count from 12 to six rigs. In May 2012, Chesapeake and TOT agreed to reduce the minimum rig count from six to two rigs.

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(Unaudited)

(d) In September 2009, PXP accelerated the payment of its remaining carry in exchange for an approximate 12% reduction to the remaining drilling carry obligation owed to us at that time.

During the Current Quarter and the Prior Quarter, our drilling and completion costs included the benefit of approximately $448 million and $527 million, respectively, in drilling and completion carries paid by our joint venture partners, CNOOC, TOT and STO.

During the Current Quarter, as part of our joint venture agreement with TOT, we sold interests in additional leasehold in the Barnett and Utica shale plays to TOT for approximately $18 million. In the Prior Quarter, as part of our joint venture agreements with CNOOC, TOT, STO and PXP, we sold interests in additional leasehold in the Eagle Ford and Pearsall, Barnett, Marcellus and Haynesville and Bossier shale plays to our joint venture partners for approximately $224 million.

Volumetric Production Payments

From time to time, we have monetized certain of our producing assets which are located in more mature producing regions through the sale of volumetric production payments (VPPs). A VPP is a limited-term overriding royalty interest in natural gas and oil reserves that (i) entitles the purchaser to receive scheduled production volumes over a period of time from specific lease interests; (ii) is free and clear of all associated future production costs and capital expenditures; (iii) is nonrecourse to the seller (i.e., the purchaser s only recourse is to the reserves acquired); (iv) transfers title of the reserves to the purchaser; and (v) allows the seller to retain the remaining reserves, if any, after the scheduled production volumes have been delivered. We retain drilling rights on the properties below currently producing intervals and outside of producing well bores. We also retain all production beyond the specified volumes sold in the transaction.

We have completed the following VPP transactions since 2007:

Date of VPP	Division	Proceeds ($ in millions)	Proved Reserves (at time of sale) (bcfe)	$ / mcfe	Original Term (years)
March 2012	Anadarko Basin Granite Wash	$ 744	160	$ 4.68	10
May 2011	Mid-Continent	853	177	$ 4.82	10
September 2010	Barnett Shale	1,150	390	$ 2.93	5
June 2010	Permian Basin	335	38	$ 8.73	10
February 2010	East Texas and Texas Gulf Coast	180	46	$ 3.95	10
August 2009	South Texas	370	68	$ 5.46	7.5
December 2008	Anadarko and Arkoma Basins	412	98	$ 4.19	8
August 2008	Anadarko Basin	600	93	$ 6.38	11
May 2008	Texas, Oklahoma	622	94	$ 6.53	11

	and Kansas						
December 2007	Kentucky and West Virginia		1,100	208	$	5.29	15
		$	6,366	1,372	$	4.64	

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

For accounting purposes, cash proceeds from these transactions were reflected as a reduction of natural gas and oil properties with no gain or loss recognized, and our proved reserves were reduced accordingly.

9. Investments

At March 31, 2012 and December 31, 2011, we had the following investments:

	Approximate % Owned	Accounting Method	Carrying Value March 31, 2012	Carrying Value December 31, 2011
			($ in millions)	
Chesapeake Midstream Partners, L.P.	46%	Equity	$ 986	$ 987
FTS International, Inc.	30%	Equity	263	235
Chaparral Energy, Inc.	20%	Equity	138	143
Clean Energy Fuels Corp.		Cost	50	50
Utica East Ohio Midstream, LLC	59%	Equity	38	
Sundrop Fuels, Inc.	25%	Equity	34	34
Twin Eagle Resource Management, LLC	30%	Equity	26	20
Clean Energy Fuels Corp.	1%	Fair Value	21	12
Gastar Exploration Ltd.	10%	Fair Value	20	22
Ranch Westex JV, LLC	33%	Equity	13	1
Other			29	27
			$ 1,618	$ 1,531

Chesapeake Midstream Partners, L.P. Chesapeake Midstream Partners, L.P. (NYSE:CHKM) is a master limited partnership which we and Global Infrastructure Partners-A, L.P. and affiliated funds managed by Global Infrastructure Management, LLC and certain of their respective subsidiaries and affiliates (collectively, GIP) formed in 2010 to own, operate, develop and acquire gathering systems and other midstream energy assets. CHKM completed its initial public offering on August 3, 2010. As of March 31, 2012, public security holders, GIP and Chesapeake owned 30.5%, 23.4% and 46.1%, respectively, of all outstanding CHKM limited partner interests. CHKM limited partners, collectively, have a 98.0% interest in CHKM, and the general partner, which is owned and controlled 50/50 by Chesapeake and GIP, has a 2.0% interest in CHKM. CHKM is principally focused on natural gas gathering, the first segment of midstream energy infrastructure that connects natural gas produced at the wellhead to third-party takeaway pipelines. CHKM currently operates in Texas, Louisiana, Oklahoma, Kansas, Arkansas, Pennsylvania and West Virginia and provides gathering, treating and compression services to Chesapeake and other producers under long-term, fixed-fee contracts.

During the Current Quarter, we recorded positive equity method adjustments of $24 million for our share of CHKM s income, received cash distributions of $27 million from CHKM and recorded accretion adjustments of $2 million related to our share of equity in excess of cost. The carrying value of our investment in CHKM is less than our underlying equity in net assets by approximately $154 million as of March 31, 2012. This difference is being accreted over the 20-year estimated useful lives of the underlying assets. See Note 10 for further discussion of CHKM.

FTS International, Inc. FTS International, Inc. (FTS), based in Fort Worth, Texas, is the privately held parent company which, through its subsidiaries, provides pressure pumping and well stimulation to oil and gas companies. In the Current Quarter, we recorded positive equity method adjustments, prior to intercompany profit eliminations, of $17 million for our share of FTS s income and recorded accretion adjustments of $11 million related to our share of equity in excess of cost. The carrying value of our investments in FTS is less than our underlying equity in net assets by approximately $857 million as of March 31, 2012. The value not allocated to goodwill is being accreted over the nine-year estimated useful lives of the underlying assets.

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(Unaudited)

Chaparral Energy, Inc. Chaparral Energy, Inc., based in Oklahoma City, Oklahoma, is a private independent oil and natural gas company engaged in the production, acquisition and exploitation of oil and natural gas properties.

In the Current Quarter, we recorded a $4 million charge related to our share of Chaparral s net loss and depreciation adjustments of $1 million related to the excess of our cost over our proportionate share of Chaparral s book equity. The carrying value of our investment in Chaparral is in excess of our underlying equity in net assets by approximately $54 million as of March 31, 2012. 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.

Clean Energy Fuels Corp. In July 2011, we agreed to invest $150 million in newly issued convertible promissory notes of Clean Energy Fuels Corp. (Nasdaq:CLNE), based in Seal Beach, California. The investment is being made in three equal $50 million promissory notes, the first of which was issued on July 11, 2011, with the remaining notes scheduled to be issued in June 2012 and June 2013. The notes bear interest at the annual rate of 7.5%, payable quarterly, and are convertible at our option into shares of Clean Energy s common stock at a 22.5% conversion premium, resulting in a conversion price of $15.80 per share. Under certain circumstances following the second anniversary of the issuance of a note, Clean Energy can force conversion of the debt. The entire principal balance of each note is due and payable seven years following issuance. Clean Energy will use our $150 million investment to accelerate its build-out of LNG fueling infrastructure for heavy-duty trucks at truck stops across interstate highways in the U.S.

In December 2011, we also purchased one million shares of Clean Energy common stock for $10 million. During the Current Quarter, the common stock price of Clean Energy increased from $12.46 per share to $21.28 per share.

Utica East Ohio Midstream L.L.C. On March 9, 2012, CMD entered into an agreement to form Utica East Ohio Midstream LLC (UEOM) with M3 Midstream, L.L.C. and EV Energy Partners, L.P. to develop necessary infrastructure for the gathering and processing of natural gas and natural gas liquids in the Utica Shale play in eastern Ohio. The infrastructure complex will consist of natural gas gathering and compression facilities constructed and operated by CMD, as well as processing, NGL fractionation, loading and terminal facilities constructed and operated by M3 Midstream, L.L.C. CMD made an initial cash contribution of $38 million in exchange for an ownership of approximately 59% in UEOM. See Note 10 for further discussion of UEOM. UEOM is not consolidated since we do not have a controlling interest.

Sundrop Fuels, Inc. In July 2011, we agreed to invest $155 million in preferred equity securities of Sundrop Fuels, Inc., a privately held cellulosic biofuels company based in Louisville, Colorado. The investment will fund construction of a nonfood biomass-based green gasoline plant, capable of annually producing more than 40 million gallons of gasoline from natural gas and waste cellulosic material. The investment is intended to accelerate the development of an affordable, stable, room-temperature, natural gas-based fuel for immediate use in automobiles, diesel engine vehicles and aircraft. The first $35 million tranche of our investment was funded in July 2011 and the remaining tranches of preferred equity investment will be scheduled around certain funding and operational milestones that are expected to be reached by July 2013. The full investment will represent 50% of Sundrop Fuels equity on a fully diluted basis.

The carrying value of our investment in Sundrop is in excess of our underlying equity in net assets by approximately $25 million as of March 31, 2012. This excess will be amortized over the life of the plant, once it is placed into service.

Twin Eagle Resource Management LLC. In 2010, we invested $20 million in Twin Eagle Resource Management LLC, a natural gas trading and management firm. In February 2012, we invested an additional $9 million. During the Current Quarter, we recorded a $3 million charge related to our share of Twin Eagle s net loss. The carrying value of our investment in Twin Eagle is in excess of our equity in net assets by approximately $6 million as of March 31, 2012. This excess is being amortized over the 15-year estimated useful lives of the underlying assets.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Gastar Exploration Ltd. Gastar Exploration Ltd. (NYSE Amex:GST), based in Houston, Texas, is an independent energy company engaged in the exploration, development and production of natural gas and oil in the U.S. During the Current Quarter, the common stock price of Gastar decreased from $3.18 per share to $2.99 per share.

Ranch Westex, JV LLC. In December 2011, CMD entered into an agreement to form Ranch Westex JV, LLC with two other parties to develop, construct and operate necessary infrastructure for the processing and gathering of natural gas in Ward County, Texas. CMD s total commitment is $36 million. As of March 31, 2012, we had funded $13 million of the total commitment.

10. Variable Interest Entities

In accordance with accounting guidance for consolidation, we consolidate the activities of VIEs of which we are the primary beneficiary. The primary beneficiary of a VIE is that variable interest holder possessing a controlling financial interest through (i) its power to direct the activities of the VIE that most significantly impact the VIE s economic performance and (ii) its obligation to absorb losses or its right to receive benefits from the VIE that could potentially be significant to the VIE. In order to determine whether we own a variable interest in a VIE, we perform qualitative analysis of the entity s design, organizational structure, primary decision makers and relevant agreements.

Consolidated VIEs

Chesapeake Granite Wash Trust. For discussion of the formation, operations and presentation of the Trust, please see *Noncontrolling Interests* in Note 6. The Trust is considered a VIE due to the lack of voting or similar decision-making rights by its equity holders regarding activities that have a significant effect on the economic success of the Trust. Our ownership in the Trust and our obligations under the development agreement and related drilling support lien constitute variable interests. We have determined that we are the primary beneficiary of the Trust as (i) we have the power to direct the activities that most significantly impact the economic performance of the Trust via our obligations to perform under the development agreement, and (ii) as a result of the subordination and incentive thresholds applicable to the subordinated units we hold in the Trust, we have the obligation to absorb losses and the right to receive residual returns that could potentially be significant to the Trust. As a result, we consolidate the Trust in our financial statements and the common units of the Trust owned by third parties are reflected as a noncontrolling interest.

The Trust is a consolidated entity whose legal existence is separate from Chesapeake and our other consolidated subsidiaries and the Trust is not a guarantor of any of Chesapeake s debt. The creditors or beneficial holders of the Trust have no recourse to the general credit of Chesapeake; however, we have certain obligations to the Trust through the development agreement that are secured by a drilling support lien on our retained interest in the development wells up to a specified maximum amount recoverable by the Trust, which could result in the Trust acquiring all or a portion of our retained interest in the development wells, if we do not meet our drilling commitment. In consolidation, as of March 31, 2012, approximately $471 million of net natural gas and oil properties, $38 million of current liabilities and $19 million in long-term liabilities were attributable to the Trust. We have presented parenthetically on the face of the condensed consolidated balance sheets the assets of the Trust that can be used only to settle obligations of the Trust and the liabilities of the Trust for which creditors do not have recourse to the general credit of Chesapeake.

Cardinal Gas Services, L.L.C. We own an approximate 66% interest in Cardinal, a consolidated midstream subsidiary (see Note 6 under *Noncontrolling Interests* for further discussion). Cardinal is considered a VIE because its total equity at risk, as of March 31, 2012, is not sufficient to permit it to finance its activities without additional subordinated financial support. It is expected that we, along with the other equity partners, will make regular capital contributions to Cardinal for our proportionate share of its capital costs. This VIE is consolidated since we have a controlling interest in the VIE through voting rights. In consolidation, as of March 31, 2012, approximately $46 million of cash and cash equivalents, $48 million of net natural gas gathering systems and treating plants and $12 million of current liabilities were attributable to Cardinal, which we have presented parenthetically on the face of the condensed consolidated balance sheets.

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(Unaudited)

Unconsolidated VIEs

Chesapeake Midstream Partners, L.P. We have an approximate 46% interest in CHKM through our ownership of common, general partner and subordinated units. CHKM focuses on unregulated business activities in service to both Chesapeake and third-party natural gas producers and its revenues are generated from gathering, compression, dehydration and treating services. Certain Chesapeake employees provide services to CHKM through an employee secondment agreement and CHKM utilizes various support functions within Chesapeake, including accounting, human resources and information technology in return for certain cost reimbursements. As of March 31, 2012, common units owned by public security holders represented 30.5% of all outstanding limited partner interests, and Chesapeake and GIP held 46.1% and 23.4%, respectively, of all outstanding limited partner interests. Of the limited partner units, approximately 51% and 100% of the units were subordinated for Chesapeake and GIP, respectively. The limited partners, collectively, have a 98% limited partner interest in CHKM, and Chesapeake and GIP each own 50% of the remaining 2% general partner interest.

The partnership agreement provides that, during the subordination period, the common units are entitled to distributions of available cash each quarter in an amount equal to the minimum quarterly distribution, which is $0.3375 per common unit, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash are permitted on the subordinated units. The subordination period will lapse at such time when the partnership has earned and paid at least $0.3375 per quarter on each common unit, subordinated unit and general partner unit for any three consecutive, non-overlapping four-quarter periods ending on or after June 30, 2013. Also, if the partnership has earned and paid at least 150% of the minimum quarterly distribution on each outstanding common unit, subordinated unit and general partner unit for each calendar quarter in a four-quarter period, the subordination period will terminate automatically. The subordination period will also terminate automatically if the general partner is removed without cause and the units held by the general partner and its affiliates are not voted in favor of removal. When the subordination period lapses or otherwise terminates, all remaining subordinated units will convert into common units on a one-for-one basis and the common units will no longer be entitled to arrearages. All subordinated units are held indirectly by Chesapeake and GIP.

CHKM is considered a VIE because of the significance of its operations to us and the contractual arrangements between Chesapeake and CHKM that pass certain economic risks to us which are disproportionate to our economic interest. These primarily include certain gas gathering agreements with CHKM pursuant to which we have committed to deliver annually specified minimum volumes of natural gas under firm transportation agreements, an EBITDA guarantee CMD issued to CHKM in conjunction with our December 2011 sale of Appalachia Midstream Services, L.L.C. (AMS), and the subordination of our units to those of other unitholders. Our ownership in CHKM, and our rights and commitments under our contractual arrangements with CHKM constitute variable interests. See *Other Commitments* in Note 4.

Because the general partner controls CHKM, we have determined that the power to direct the activities which are most significant to its economic performance are shared between us and GIP. See Note 9 for a discussion of the accounting for, and the carrying value of, our investment in CHKM.

Our risk of loss related to CHKM includes our investment balance and certain commitments to CHKM through the EBITDA guarantee and under our firm transportation agreements that could require us to make shortfall payments in the event we do not meet our minimum volume commitments. The creditors or other beneficial holders of CHKM common units have no other recourse to the general credit of Chesapeake.

Utica East Ohio Midstream L.L.C. We have an approximate 59% interest in Utica East Ohio Midstream L.L.C. (UEOM), an unconsolidated entity which we formed with M3 Midstream L.L.C. and EV Energy Partners, L.P. to develop necessary infrastructures for gathering and processing of natural gas and natural gas liquids in the Utica shale play in eastern Ohio (see Note 9 for further details). UEOM is considered a VIE because its total equity at risk, as of March 31, 2012, is not sufficient to permit it to finance its activities without additional subordinated financial support. It is expected that we, along with the other equity partners, will make regular capital contributions to UEOM for our proportionate share of its capital costs. This VIE remains unconsolidated since the power to direct the activities, which are most significant to UEOM s economic performance are shared between us and the other equity holders. We are using the equity method to account for this investment.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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(Unaudited)

11. Fair Value Measurements

Certain financial instruments are reported at fair value on the condensed consolidated balance sheets. Under fair value measurement accounting guidance, fair value is defined 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 a market valuation approach based on available inputs and the following methods and assumptions to measure the fair values of its assets and liabilities, which may or may not be observable in the market.

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. (NYSE Amex: GST) and Clean Energy Fuels Corporation (NASDAQ:CLNE) 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.

Derivatives. The fair values of our commodity derivatives, interest rate swaps and cross currency swaps are based on third-party pricing models which utilize inputs that are either readily available in the public market, such as natural gas and oil forward curves and discount rates, or can be corroborated from active markets or broker quotes. These values are then compared to the values given by our counterparties for reasonableness. Since commodity, interest rate and cross currency swaps do not include optionality and therefore generally have no unobservable inputs, they are classified as Level 2. All other derivatives have some level of unobservable input, such as volatility curves, and are therefore classified as Level 3. For interest rate options and swaptions, we use the fair value estimates provided by our respective counterparties. These values are reviewed internally for reasonableness using future interest rate curves and time to maturity. Derivatives are also subject to the risk that counterparties will be unable to meet their obligations. We factor non-performance risk into the valuation of our derivatives using current published credit default swap rates. To date, this 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 related qualifying interest rate swaps.

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(Unaudited)

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of March 31, 2012:

	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	$ 519	$	$	$ 519
Investments	41			41
Other long-term assets	69			69
Other long-term liabilities	(71)			(71)
Derivatives:				
Commodity assets		37	50	87
Commodity liabilities		(75)	(1,755)	(1,830)
Interest rate liabilities		(43)	(3)	(46)
Foreign currency liabilities		(20)		(20)
Equity liabilities		(2)		(2)
Total derivatives		(103)	(1,708)	(1,811)
Total	$ 558	$ (103)	$ (1,708)	$ (1,253)

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2011:

	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	$ 395	$	$	$ 395
Investments	34			34
Other long-term assets	61			61
Other long-term liabilities	(62)			(62)
Derivatives:				
Commodity assets		46	9	55
Commodity liabilities		(31)	(1,663)	(1,694)

Interest rate liabilities		(42)		(42)
Foreign currency liabilities		(38)		(38)
Total derivatives		(65)	(1,654)	(1,719)
Total	$ 428	$ (65)	$ (1,654)	$ (1,291)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

A summary of the changes in Chesapeake s assets (liabilities) classified as Level 3 measurements during the Current Quarter and the Prior Quarter is presented below.

	$xxxxxxxxxxxxxx	$xxxxxxxxxxxxxx	$xxxxxxxxxxxxxx	$xxxxxxxxxxxxxx
		Derivatives		
	Commodity	Interest Rate	Foreign Currency	Debt
		($ in millions)		
Beginning Balance as of January 1, 2012	$ (1,654)	$	$	$
Total gains (losses) (realized/unrealized):				
Included in earnings or change in net assets[(a)]	(59)	(1)		
Total purchases, issuances, sales and settlements:				
Sales		(2)		
Settlements	8			
Ending Balance as of March 31, 2012	$ (1,705)	$ (3)	$	$
Beginning Balance as of January 1, 2011	$ (1,954)	$ (69)	$ (43)	$ (1,371)
Total gains (losses) (realized/unrealized):				
Included in earnings or change in net assets[(a)]	(873)	16		
Total purchases, issuances, sales and settlements:				
Settlements	44	(1)		
Transfers in and out of Level 3[(b)]		54	43	1,371
Ending Balance as of March 31, 2011	$ (2,783)	$	$	$

(a)

	Natural Gas and Oil Sales		Interest Expense	
	2012	2011	2012	2011
	($ in millions)			
Total gains (losses) included in earnings (or change in net assets) for the period	$ (59)	$ (873)	$ (1)	$ 16
Change in unrealized gains (losses) relating to assets still held at reporting date	$ (132)	$ (868)	$ (3)	$ 2

(b) The values related to interest rate and cross currency swaps were transferred from Level 3 to Level 2 as a result of our ability to use data readily available in the public market to corroborate our estimated fair values.

Qualitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

The significant unobservable inputs for Level 3 derivative contracts include forward prices of commodities, forward interest rate curves, market volatility and credit risk of counterparties. Changes in these inputs will impact the fair value measurement of our derivative contracts, e.g. an increase (decrease) in the forward prices and volatility of commodities will decrease (increase) the fair value of commodity derivatives; an increase (decrease) in forward price and volatility of interest rates will decrease (increase) the fair value of interest rate derivatives; and adverse changes to our counterparties credit worthiness will decrease the fair value of our derivatives.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Quantitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value March 31, 2012 ($ in millions)
Oil Trades[a]	NYMEX oil price forward curve	$ 91.47 - $105.33	$ 97.95	$ (1,410)
	Oil price volatility curve	16.39% - 31.03%	23.16%	
Natural Gas Trades[a]	NYMEX natural gas price forward curve	$2.13 - $5.81	$ 3.91	$ (255)
	Natural gas price volatility curve	21.40% - 53.67%	28.27%	
Gas Basis Swaps[b]	NYMEX natural gas forward curve	$1.95 -$5.06	$ 3.22	$ (40)
	Physical pricing point forward curves	($1.29) -$0.20	$ (0.22)	
Interest Rate Swaptions[a]	Forward interest rate curve	0.41% -3.66%	1.80%	$ (3)
	Interest rate volatility	40.04% - 52.07%	47.40%	

(a) Fair value is based on an estimate derived from option models.

(b) Fair value is based on an estimate of discounted cash flows.

Fair Value of Other Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. 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 primarily using quoted market prices (Level 1). Fair value is compared to the carrying value, excluding the impact of interest rate derivatives, in the table below.

	00000000000	00000000000	00000000000	00000000000
	March 31, 2012		December 31, 2011	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Long-term debt	$ 13,056	$ 13,671	$ 10,598	$ 11,399

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

12. Segment Information

In accordance with accounting guidance for disclosures about segments of an enterprise and related information, we have three reportable operating segments. Our exploration and production operating segment, natural gas and oil marketing, gathering and compression operating segment and oilfield services operating segment are managed separately because of the nature of their products and services. The exploration and production operating segment is responsible for finding and producing natural gas and oil. The marketing, gathering and compression operating segment is responsible for marketing, gathering and compression of natural gas and oil primarily from Chesapeake-operated wells. The oilfield services operating segment is responsible for contract drilling, oilfield trucking, oilfield rentals, hydraulic fracturing and other oilfield services operations for both Chesapeake-operated wells and wells operated by third parties.

COO, a wholly owned subsidiary of COS, is a diversified oilfield services company that we formed in October 2011 to own and operate our oilfield service assets. COO provides a wide range of well site services, primarily to Chesapeake and its working interest partners, including contract drilling, hydraulic fracturing, oilfield rentals, transportation and manufacturing of natural gas compressor packages and related production equipment. In connection with the reorganization of our oilfield services subsidiaries and operations, those subsidiaries were released from the guarantees and other credit support obligations that existed for the benefit of Chesapeake and its other subsidiaries, including Chesapeake s senior notes and contingent convertible senior notes, its corporate revolving bank credit facility and its multi-counterparty hedging facility. In addition, COO and its subsidiaries entered into agreements with Chesapeake pursuant to which they sublease rigs, provide certain oilfield services and obtain certain administrative services.

As a result of the formal reorganization of our oilfield services business in October 2011, we are recognizing our oilfield services business as a new reportable segment. Historically, our oilfield services business was presented as part of other operations. All prior year information has been restated to reflect the addition of our oilfield services business as a new reportable segment.

Management evaluates the performance of our segments based upon income (loss) before income taxes. Revenues from the sale of natural gas and oil related to Chesapeake s ownership interests by the marketing, gathering and compression operating segment are reflected as exploration and production revenues. Such amounts totaled $1.176 billion and $1.204 billion for the Current Quarter and the Prior Quarter, respectively. The following table presents selected financial information for Chesapeake s operating segments.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Exploration and Production	Marketing, Gathering and Compression	Oilfield Services	Other Operations	Intercompany Eliminations	Consolidated Total
			($ in millions)			
For the Three Months Ended March 31, 2012:						
Revenues	$ 1,068	$ 2,392	$ 447	$	$ (1,488)	$ 2,419
Intersegment revenues		(1,176)	(312)		1,488	
Total revenues	$ 1,068	$ 1,216	$ 135	$	$	$ 2,419
Income (loss) before income taxes	$ 86	$ 66	$ 40	$ (100)	$ (97)	$ (5)
For the Three Months Ended March 31, 2011:						
Revenues	$ 494	$ 2,221	$ 248	$	$ (1,351)	$ 1,612
Intersegment revenues		(1,204)	(147)		1,351	
Total revenues	$ 494	$ 1,017	$ 101	$	$	$ 1,612
Income (loss) before income taxes	$ (307)	$ 87	$ 21	$ 9	$ (76)	$ (266)
As of March 31, 2012:						
Total Assets	$ 39,060	$ 4,264	$ 1,869	$ 2,431	$ (2,035)	$ 45,589
As of December 31, 2011:						
Total Assets	$ 35,403	$ 4,047	$ 1,571	$ 2,718	$ (1,904)	$ 41,835

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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. Our obligations under our outstanding senior notes and contingent convertible senior notes listed in Note 3 are fully and unconditionally guaranteed, jointly and severally, by certain of our wholly owned subsidiaries on a senior unsecured basis. Our midstream and oilfield services subsidiaries, CMD and COS, respectively, and their subsidiaries, are not guarantors of our senior notes and corporate credit facility but are subject to the covenants and guarantees in their respective revolving bank credit facility agreements referred to in Note 6 that restrict them from paying dividends or distributions or making loans to Chesapeake. COS and its subsidiaries were released as guarantors of our senior notes and corporate credit facility in October 2011 when they were formally reorganized and capitalized. All prior year information has been restated to reflect COS and its subsidiaries as non-guarantor subsidiaries. In addition, CHK Utica, CHK C-T, Chesapeake Granite Wash Trust and certain de minimis subsidiaries are also non-guarantors.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Set forth below are condensed consolidating financial statements for Chesapeake Energy Corporation (parent) on a stand-alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries as of March 31, 2012 and December 31, 2011 and for the three months ended March 31, 2012 and 2011. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the subsidiaries operated as independent entities.

CONDENSED CONSOLIDATING BALANCE SHEET

AS OF MARCH 31, 2012

($ in millions)

	XXXXX.X	XXXXX.X	XXXXX.X	XXXXX.X	XXXXX.X
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 1	$ 437	$	$ 438
Other	2	3,272	640	(428)	3,486
Total Current Assets	2	3,273	1,077	(428)	3,924
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full cost accounting, net		31,065	2,982	(522)	33,525
Other property and equipment at cost, net		3,012	3,082	(3)	6,091
Total Property and Equipment, Net		34,077	6,064	(525)	39,616
LONG-TERM ASSETS:					
Other assets	188	1,058	1,180	(377)	2,049
Investments in subsidiaries and intercompany advances	3,286	622		(3,908)	
TOTAL ASSETS	$ 3,476	$ 39,030	$ 8,321	$ (5,238)	$ 45,589
CURRENT LIABILITIES:					
Current liabilities	$ 225	$ 6,209	$ 652	$ (422)	$ 6,664
Intercompany payable to (receivable from) parent	(23,256)	21,298	2,180	(222)	
Total Current Liabilities	(23,031)	27,507	2,832	(644)	6,664
LONG-TERM LIABILITIES:					

Long-term debt, net	9,540	2,462	1,080		13,082
Deferred income tax liabilities	413	3,383	497	(309)	3,984
Other liabilities	23	2,392	927	(377)	2,965
Total Long-Term Liabilities	9,976	8,237	2,504	(686)	20,031
EQUITY:					
Chesapeake stockholders equity	16,531	3,286	622	(3,908)	16,531
Noncontrolling interests			2,363		2,363
Total Equity	16,531	3,286	2,985	(3,908)	18,894
TOTAL LIABILITIES AND EQUITY	$ 3,476	$ 39,030	$ 8,321	$ (5,238)	$ 45,589

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING BALANCE SHEET

AS OF DECEMBER 31, 2011

($ in millions)

	XXXXX.X	XXXXX.X	XXXXX.X	XXXXX.X	XXXXX.X
	Parent(a)	Guarantor Subsidiaries(a)	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 1	$ 350	$	$ 351
Other	1	2,664	418	(257)	2,826
Total Current Assets	1	2,665	768	(257)	3,177
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost, based on full cost accounting, net		29,659	2,017	(476)	31,200
Other property and equipment at cost, net		2,831	2,708		5,539
Total Property and Equipment, Net		32,490	4,725	(476)	36,739
LONG-TERM ASSETS:					
Other assets	161	1,004	1,131	(377)	1,919
Investments in subsidiaries and intercompany advances	3,284	819		(4,103)	
TOTAL ASSETS	$ 3,446	$ 36,978	$ 6,624	$ (5,213)	$ 41,835
CURRENT LIABILITIES:					
Current liabilities	$ 288	$ 6,509	$ 543	$ (258)	$ 7,082
Intercompany payable to (receivable from) parent	(22,139)	20,283	2,045	(189)	
Total Current Liabilities	(21,851)	26,792	2,588	(447)	7,082
LONG-TERM LIABILITIES:					
Long-term debt, net	8,226	1,719	681		10,626
Deferred income tax liabilities	409	2,897	464	(286)	3,484
Other liabilities	38	2,286	735	(377)	2,682

Total Long-Term Liabilities		8,673		6,902		1,880		(663)		16,792
EQUITY:										
Chesapeake stockholders equity		16,624		3,284		819		(4,103)		16,624
Noncontrolling interests						1,337				1,337
Total Equity		16,624		3,284		2,156		(4,103)		17,961
TOTAL LIABILITIES AND EQUITY	$	3,446	$	36,978	$	6,624	$	(5,213)	$	41,835

(a) We have revised the amounts presented as long-term debt in the Guarantor Subsidiaries and Parent columns to properly reflect the long-term debt issued by the Parent of $8.2 billion, which was incorrectly presented as long-term debt attributable to the Guarantors subsidiaries as of December 31, 2011. The impact of this error was not material to the prior period December 31, 2011 financial statements.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

THREE MONTHS ENDED MARCH 31, 2012

($ in millions)

	XXXXX.X Parent	XXXXX.X Guarantor Subsidiaries	XXXXX.X Non-Guarantor Subsidiaries	XXXXX.X Eliminations	XXXXX.X Consolidated
REVENUES:					
Natural gas and oil	$	$ 1,044	$ 24	$	$ 1,068
Marketing, gathering and compression		1,201	43	(28)	1,216
Oilfield services			447	(312)	135
Total Revenues		2,245	514	(340)	2,419
OPERATING EXPENSES:					
Natural gas and oil production		348	1		349
Production taxes		46	1		47
Marketing, gathering and compression		1,188	27	(18)	1,197
Oilfield services		1	353	(258)	96
General and administrative		109	26	1	136
Natural gas and oil depreciation, depletion and amortization		492	14		506
Depreciation and amortization of other assets		46	72	(34)	84
Gains on sales of fixed assets		(1)	(1)		(2)
Total Operating Expenses		2,229	493	(309)	2,413
INCOME (LOSS) FROM OPERATIONS		16	21	(31)	6
OTHER INCOME (EXPENSE):					
Interest expense	(161)	(2)	(18)	169	(12)
Earnings (losses) on investments		(30)	25		(5)
Losses on purchases or exchanges of debt					
Other income	163	8	34	(199)	6
Equity in net earnings of subsidiary	(29)	1		28	
Total Other Income (Expense)	(27)	(23)	41	(2)	(11)
INCOME (LOSS) BEFORE INCOME TAXES	(27)	(7)	62	(33)	(5)

INCOME TAX EXPENSE (BENEFIT)		1		(3)		24		(24)	(2)
NET INCOME (LOSS)		(28)		(4)		38		(9)	(3)
Other comprehensive income (loss), net of income tax		3		4					7
COMPREHENSIVE INCOME (LOSS)		(25)				38		(9)	4
Net income attributable to noncontrolling interests						(25)			(25)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$	(25)	$		$	13	$	(9)	$ (21)

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

THREE MONTHS ENDED MARCH 31, 2011

($ in millions)

	XXXXX.X Parent	XXXXX.X Guarantor Subsidiaries	XXXXX.X Non-Guarantor Subsidiaries	XXXXX.X Eliminations	XXXXX.X Consolidated
REVENUES:					
Natural gas and oil	$	$ 494	$	$	$ 494
Marketing, gathering and compression		991	55	(29)	1,017
Oilfield services			248	(147)	101
Total Revenues		1,485	303	(176)	1,612
OPERATING EXPENSES:					
Natural gas and oil production		238			238
Production taxes		45			45
Marketing, gathering and compression		968	39	(22)	985
Oilfield services			182	(105)	77
General and administrative		114	16		130
Natural gas and oil depreciation, depletion and amortization		358			358
Depreciation and amortization of other assets		43	43	(18)	68
(Gains) losses on sales of fixed assets		2	(7)		(5)
Total Operating Expenses		1,768	273	(145)	1,896
INCOME (LOSS) FROM OPERATIONS		(283)	30	(31)	(284)
OTHER INCOME (EXPENSE):					
Interest expense	(183)	7	(8)	177	(7)
Earnings on investments		6	19		25
Losses on purchases or exchanges of debt	(2)				(2)
Other income	177	1	3	(179)	2
Equity in net earnings of subsidiary	(157)	7		150	

Total Other Income (Expense)		(165)	21	14	148	18
INCOME (LOSS) BEFORE INCOME TAXES		(165)	(262)	44	117	(266)
INCOME TAX EXPENSE (BENEFIT)		(3)	(105)	17	(13)	(104)
NET INCOME (LOSS)		(162)	(157)	27	130	(162)
Other comprehensive income (loss), net of income tax		(11)	(33)			(44)
COMPREHENSIVE INCOME (LOSS)		(173)	(190)	27	130	(206)
Net income attributable to noncontrolling interests						
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$	(173)	(190)	27	130	(206)

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

THREE MONTHS ENDED MARCH 31, 2012

($ in millions)

	XXXXX.X Parent	XXXXX.X Guarantor Subsidiaries	XXXXX.X Non-Guarantor Subsidiaries	XXXXX.X Eliminations	XXXXX.X Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 1,313	$ 48	$ (1,087)	$ 274
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to proved and unproved properties		(3,520)	(189)		(3,709)
Proceeds from divestitures of proved and unproved properties		821			821
Additions to other property and equipment		(228)	(461)	(1)	(690)
Other investing activities		(231)	(36)	195	(72)
Cash used in investing activities		(3,158)	(686)	194	(3,650)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		4,945	743		5,688
Payments on credit facilities borrowings		(4,203)	(343)		(4,546)
Proceeds from issuance of senior notes, net of offering costs	1,263				1,263
Cash paid to purchase debt					
Proceeds from sales of noncontrolling interests			1,044		1,044
Other financing activities	(131)	(24)	(724)	893	14
Intercompany advances, net	(1,132)	1,127	5		
Cash provided by financing activities		1,845	725	893	3,463
Net increase (decrease) in cash and cash equivalents			87		87
Cash and cash equivalents, beginning of period		1	350		351

Cash and cash equivalents, end of period	$		$	1	$	437	$		$	438

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

THREE MONTHS ENDED MARCH 31, 2011

($ in millions)

	XXXXX.X	XXXXX.X	XXXXX.X	XXXXX.X	XXXXX.X
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 842	$ 101	$ (225)	$ 718
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to proved and unproved properties		(2,950)			(2,950)
Proceeds from divestitures of proved and unproved properties		5,182			5,182
Additions to other property and equipment		(95)	(328)	(8)	(431)
Other investing activities		(9)	374	60	425
Cash provided by investing activities		2,128	46	52	2,226
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		3,202	415		3,617
Payments on credit facilities borrowings		(6,814)	(509)		(7,323)
Proceeds from issuance of senior notes, net of offering costs	977				977
Cash paid to purchase debt	(128)				(128)
Other financing activities	(120)	758	(89)	111	660
Intercompany advances, net	(729)	667		62	
Cash provided by (used in) financing activities		(2,187)	(183)	173	(2,197)
Net increase (decrease) in cash and cash equivalents		783	(36)		747
Cash and cash equivalents, beginning of period		2	100		102

Cash and cash equivalents, end of period	$	$ 785	$ 64	$	$ 849

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

14. Recently Issued and Proposed Accounting Standards

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

In December 2011, the FASB issued guidance on disclosure of information about offsetting and related arrangements to enable users of a company s financial statements to understand the effect of those arrangements on its financial position. The standard is effective for annual reporting periods beginning on or after January 1, 2013. This guidance will not have an impact on our financial position or results of operations.

In June 2011, the FASB issued guidance on comprehensive income, which provides two options for presenting items of net income, comprehensive income and total comprehensive income, by either creating one continuous statement of comprehensive income or two separate consecutive statements. We adopted this guidance in 2011. Adoption had no impact on our financial position or results of operations. In December 2011, the FASB deferred the effective date of certain presentation requirements for items reclassified out of accumulated other comprehensive income. This guidance will not have an impact on our financial position or results of operations.

In May 2011, the FASB issued guidance on fair value measurement and disclosure requirements which expands existing fair value disclosure requirements, particularly for Level 3 inputs. The new requirements include quantitative disclosure of the unobservable inputs and assumptions used in the measurement; description of the valuation processes in place and sensitivity of the fair value to changes in unobservable inputs; and the level of items (in the fair value hierarchy) that are not measured at fair value in the balance sheet but whose fair value must be disclosed. The guidance was effective for interim and annual periods beginning on or after December 15, 2011. Adoption had no impact on our financial position or results of operations.

15. Subsequent Events

On April 30, 2012, we sold 58,400 net acres of leasehold in the Texoma Woodford play in Bryan, Carter, Johnston and Marshall counties in Oklahoma to XTO Energy Inc., a subsidiary of Exxon Mobil Corporation (NYSE:XOM), for approximately $572 million in cash after certain deductions and closing costs. The properties included approximately 25 mmcfe per day of current net production.

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ITEM 2. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

Overview

The following table sets forth certain information regarding the production volumes, natural gas and oil sales, average sales prices received, other operating income and expenses for the three months ended March 31, 2012 (the Current Quarter) and the three months ended March 31, 2011 (the Prior Quarter):

	Three Months Ended March 31,	
	2012	**2011**
Net Production:		
Natural gas (bcf)	270.8	243.3
Oil (mmbbl)[a]	10.3	6.0
Natural gas equivalent (bcfe)[b]	332.8	279.6
Natural Gas and Oil Sales ($ in millions):		
Natural gas sales	$ 478	$ 788
Natural gas derivatives realized gains (losses)	158	505
Natural gas derivatives unrealized gains (losses)	(147)	(549)
Total natural gas sales	489	744
Oil sales[a]	743	400
Oil derivatives realized gains (losses)	(41)	(17)
Oil derivatives unrealized gains (losses)	(123)	(633)
Total oil sales	579	(250)
Total natural gas and oil sales	$ 1,068	$ 494
Average Sales Price (excluding gains (losses) on derivatives):		
Natural gas ($ per mcf)	$ 1.77	$ 3.24
Oil ($ per bbl)[a]	$ 71.91	$ 66.08
Natural gas equivalent ($ per mcfe)	$ 3.67	$ 4.25
Average Sales Price (excluding unrealized gains (losses) on derivatives):		
Natural gas ($ per mcf)	$ 2.35	$ 5.31
Oil ($ per bbl)[a]	$ 67.92	$ 63.20
Natural gas equivalent ($ per mcfe)	$ 4.02	$ 5.99
Other Operating Income[c] ($ in millions):		
Marketing, gathering and compression net margin	$ 19	$ 32
Oilfield services net margin	$ 39	$ 24
Other Operating Income[c] ($ per mcfe):		
Marketing, gathering and compression net margin	$ 0.06	$ 0.11
Oilfield services net margin	$ 0.12	$ 0.09
Expenses ($ per mcfe):		
Production expenses	$ 1.05	$ 0.85
Production taxes	$ 0.14	$ 0.16
General and administrative expenses	$ 0.41	$ 0.46

Natural gas and oil depreciation, depletion and amortization	$ 1.52	$ 1.28
Depreciation and amortization of other assets	$ 0.25	$ 0.24
Interest expense[(d)]	$ 0.02	$ 0.00
Interest Expense ($ in millions):		
Interest expense[(d)]	$ 8	$ 8
Interest rate derivatives realized (gains) losses		(7)
Interest rate derivatives unrealized (gains) losses	4	6
Total interest expense	$ 12	$ 7

(a) Includes natural gas liquids (NGLs).

(b) Natural gas equivalent is based on six mcf of natural gas to one barrel of oil. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given recent commodity prices, the price for an mcfe of natural gas is significantly less than the price for an mcfe of oil or NGLs.

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

(d) Includes the effects of realized (gains) losses from interest rate derivatives, but excludes the effects of unrealized (gains) losses and is net of amounts capitalized.

We are the second-largest producer of natural gas, a top 15 producer of oil and natural gas liquids (collectively liquids) and the most active driller of new wells in the U.S. We own interests in approximately 46,400 producing natural gas and oil wells that are currently producing approximately 3.6 bcfe per day, net to our interest. The Company has built a large resource base of onshore U.S. natural gas assets in the Haynesville and Bossier Shales in northwestern Louisiana and East Texas; the Marcellus Shale in the northern Appalachian Basin of West Virginia and Pennsylvania and the Barnett Shale in the Fort Worth Basin of north-central Texas. In addition, we have built leading positions in the liquids-rich resource plays of the Eagle Ford Shale in South Texas; the Utica Shale in Ohio, West Virginia and Pennsylvania; the Granite Wash, Cleveland, Tonkawa and Mississippi Lime plays in the Anadarko Basin in western Oklahoma and the Texas Panhandle; the Bone Spring, Avalon, Wolfcamp and Wolfberry plays in the Permian and Delaware Basins in West Texas and southern New Mexico; and the Niobrara Shale in the Powder River Basin in Wyoming. We have also vertically integrated many of our operations and own substantial midstream, compression and oilfield services assets as discussed below under *Business Strategy*.

Proved Reserves. Chesapeake began 2012 with estimated proved reserves of 18.789 tcfe and ended the Current Quarter with 19.821 tcfe, an increase of 1.032 tcfe, or 5%. The Current Quarter s proved reserve movement included 333 bcfe of production, 1.474 tcfe of extensions, 342 bcfe of positive performance revisions and 300 bcfe of downward revisions resulting from lower natural gas prices using the average first-day-of-the-month price for the twelve months ended March 31, 2012, compared to the twelve months ended December 31, 2011. During the Current Quarter, we acquired 8 bcfe of estimated proved reserves and divested 159 bcfe of estimated proved reserves.

Drilling and Completion Expenditures. During the Current Quarter, we invested $2.133 billion in operated wells (using an average of 163 operated rigs) and $347 million in non-operated wells (using an average of 71 non-operated rigs) for total drilling and completing costs on proved and unproved properties of $2.480 billion, net of drilling and completion carries of $448 million.

Production. Our total Current Quarter production of 333 bcfe consisted of 271 bcf of natural gas (81% on a natural gas equivalent basis) and 10.3 mmbbls of oil and natural gas liquids (19% on a natural gas equivalent basis). Daily production for the Current Quarter averaged 3.658 bcfe, an increase of 551 mmcfe, or 18%, over the 3.107 bcfe produced per day in the Prior Quarter.

During February and March in the Current Quarter, Chesapeake voluntarily curtailed 54 bcf of gross natural gas production, or an average of approximately 900 million cubic feet (mmcf) per day, resulting in net curtailments to Chesapeake of 30 bcf, or approximately 330 mmcf per day of natural gas spread across the entire quarter. We have undertaken these curtailments in response to continued low natural gas prices and as an effort to help bring U.S. natural gas supply and demand into better balance. The curtailed volumes are located primarily in the Haynesville and Barnett shale plays. In addition, wherever possible, the company is deferring completions of dry gas wells that have been drilled, but not yet completed, and is also deferring pipeline connections of dry gas wells that have already been completed.

Leasehold and Seismic Inventories. Since 2000, Chesapeake has built the largest combined inventories of onshore leasehold (15.6 million net acres) and 3-D seismic (31.8 million acres) in the U.S. We have also accumulated the largest inventory of U.S. natural gas shale play leasehold (2.2 million net acres) and now own a leading position in 11 of what we believe are the top 15 unconventional liquids-rich plays in the U.S. We are currently using 154 operated drilling rigs to further develop our inventory of approximately 39,400 net drillsites. We are targeting to invest approximately $1.6 billion in net undeveloped leasehold expenditures in 2012, of which approximately 90% will be in liquids-rich plays and 100% will be in plays where the company is already active. This compares to net undeveloped leasehold expenditures of approximately $3.5 billion and $5.8 billion in 2011 and 2010, respectively.

Emphasis on Increasing Liquids Production. In recognition of the value gap between liquids and natural gas prices, Chesapeake has directed a significant portion of its technological and leasehold acquisition expertise during the past three years to identify, secure and commercialize new unconventional liquids-rich plays. This planned transition will result in a more balanced and likely more profitable portfolio between natural gas and liquids. To date, we have built leasehold positions and established production in multiple liquids-rich plays on approximately 6.8 million net leasehold acres with 1.0 billion bbls of oil equivalent of proved reserves. In the Current Quarter, our production of liquids averaged approximately 113,600 bbls per day, a 69% increase over the average during the Prior Quarter, as a result of the increased development of our unconventional liquids-rich plays. We are projecting that the portion of our operated drilling and completion expenditures allocated to liquids development will reach 90% in 2012, and we expect to increase our liquids production through our drilling activities to an average of approximately 115,000 bbls per day in 2012 and to more than 150,000 bbls per day in 2013 and 250,000 bbls per day by 2015.

Business Strategy

Our business strategy is to create value for investors by building and developing one of the largest onshore natural gas and liquids resource bases in the U.S. The key elements of our business strategy, as described in *Business Strategy* in Item 1 of our 2011 Form 10-K, are the following: growing production and proved reserves through the drillbit; controlling substantial land and drilling location inventories and building operating focus and scale; developing proprietary technological advantages; focusing on achieving low costs through our focused activities, vertical integration and increasing scale; mitigating commodity price risk through our hedging program; entering into value-creating joint ventures; improving our balance sheet through reduction of debt; transforming the U.S. transportation fuels market and increasing demand for U.S. natural gas; and maintaining an entrepreneurial culture.

Capital Expenditures

In the Current Quarter, our capital expenditures for exploration, development and acquisition activities, net of drilling and completion carries, were $3.471 billion, including $2.503 billion for drilling and completion costs and $968 million for acquisitions of unproved properties. A disproportionately high percentage of our total budgeted 2012 capital expenditures was made early in the year, and this was the result of several factors which are discussed further below. Our current budget for 2012 includes drilling and completion capital expenditures, net of drilling and completion carries, of $7.5 $8.0 billion and net undeveloped leasehold expenditures of $1.6 billion.

Drilling and completion costs during the Current Quarter reflected the effects of our transition to liquids-focused drilling and reduced natural gas drilling. During the 2011 fourth quarter, our rig count was as high as 172 rigs as we were rapidly ramping up our liquids-focused drilling while, at the same time, we were deliberately but more slowly ramping down drilling of natural gas wells. As of May 1, 2012, our rig count had been reduced to 154 rigs, and we expect further reductions to approximately 125 rigs in the 2012 third quarter. Our budget reflects sharp reductions in our natural gas drilling activities, from 50 rigs at the beginning of 2012 to an average of 12 rigs in the second half of 2012. The Current Quarter drilling and completion expenditures also reflected significant well completion costs for natural gas wells that had been drilled in prior periods. These completions, which we expect will represent more than 50% of all natural gas wells we complete during 2012, enabled us to hold the related leasehold according to the terms of our leases. For 2013, we are budgeting $6.5 $7.0 billion for drilling and completion capital expenditures, net of drilling and completion carries.

Approximately 60% of our leasehold acquisition costs during the Current Quarter were focused on adding acreage in the Utica and Mississippi Lime plays to complete our leasehold acquisition strategies in connection with completed or planned joint ventures in these areas. We anticipate significantly lower leasehold spending in the remainder of 2012, and we are projecting that our 2013 net undeveloped leasehold expenditures will decline to approximately $500 million. Having captured what we believe are the most promising areas of our core plays, we have now shifted our focus to exploiting these assets.

During the Current Quarter, our capital expenditures related to our midstream, oilfield services and other assets were approximately $770 million. Our projected 2012 and 2013 capital expenditures are $2.5 $3.5 billion and $2.0 $2.5 billion, respectively.

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Recent Asset Monetizations

An essential part of our business strategy is using the proceeds from asset monetizations to fund our capital expenditures in excess of operating cash flow and to reduce our indebtedness. Below we describe transactions completed in 2012 and the continuing benefits of our joint ventures which were completed in 2008, 2010 and 2011.

Volumetric Production Payment (VPP). In March 2012, we monetized certain of our producing assets in the Anadarko Basin Granite Wash through a ten-year VPP for proceeds of approximately $745 million. The transaction included approximately 160 bcfe of proved reserves and approximately 125 mmcfe per day of net production. Chesapeake has retained drilling rights on the properties below currently producing intervals and outside of existing producing wellbores and we also retain all production beyond the specified volumes sold in the transaction. This transaction was our tenth VPP. The cash proceeds for this transaction were reflected as a reduction of natural gas and oil properties with no gain or loss recognized. Other VPPs we completed in 2007 2011 are detailed in Note 8 of the condensed consolidated financial statements included in Item 1 of this report.

Cleveland Tonkawa Financial Transaction. We formed CHK Cleveland Tonkawa, L.L.C. (CHK C-T) in March 2012 to continue development of a portion of our Cleveland and Tonkawa plays. CHK C-T is an unrestricted subsidiary under our corporate credit facility agreement and is not a guarantor of, or otherwise liable for, any of our indebtedness or other liabilities, including under our indentures. In exchange for all of the common shares of CHK C-T, we contributed to CHK C-T approximately 245,000 net acres of leasehold and 360 existing wells within an area of mutual interest in the Cleveland and Tonkawa plays covering Ellis and Roger Mills counties in western Oklahoma. In March 2012, in a private placement, third-party investors contributed $1.25 billion in cash to CHK C-T in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3.75% overriding royalty interest (ORRI) in the existing wells and up to 1,000 net wells to be drilled on certain of our Cleveland and Tonkawa play leasehold.

Dividends on the preferred shares are payable on a quarterly basis at a rate of 6% per annum based on $1,000 per share. This dividend rate is subject to increase in limited circumstances in the event that, and only for so long as, cash flow from the assets owned by CHK C-T is insufficient to fund the dividend in full in any quarter. As the managing member of CHK C-T, we may, at our sole discretion and election at any time after March 31, 2014, distribute certain excess cash of CHK C-T. If we are current in our drilling commitment at the time, any such optional distribution of excess cash is allocated 75% to the preferred shares (which is applied toward redemption of the preferred shares) and 25% to the common shares. We may also cause CHK C-T to redeem all or a portion of the CHK C-T preferred shares for cash. The preferred shares will be redeemed at a valuation equal to the greater of a 9% internal rate of return or a return on investment of 1.35x, in each case inclusive of dividends paid at the rate of 6% per annum and optional distributions made through the applicable redemption date. In the event that redemption does not occur on or prior to March 31, 2019, the optional redemption valuation will increase to provide a 15% internal rate of return. As of March 31, 2012, the redemption price, and the liquidation preference, was $1,350 per preferred share. We have committed to drill, for the benefit of CHK C-T, a minimum of 37.5 net wells per six-month period through 2013 and 25 net wells per six-month period in 2014 through 2016 in the CHK C-T area of mutual interest, up to a minimum cumulative total of 300 net wells. CHK C-T is responsible for all capital and operating costs of the wells drilled for the benefit of the entity. For further discussion, see *Noncontrolling Interests* in Note 6 of the notes to our condensed consolidated financial statements in Item 1 of this report.

Utica East Ohio Midstream L.L.C. In March 2012, Chesapeake Midstream Development, L.P. (CMD) entered into an agreement to form Utica East Ohio Midstream L.L.C. (UEOM) with M3 Midstream L.L.C. and EV Energy Partners, L.P. to develop necessary infrastructure for the gathering and processing of natural gas and natural gas liquids in the Utica Shale play in eastern Ohio. The infrastructure complex will consist of natural gas gathering and compression facilities constructed and operated by CMD, as well as processing, NGL fractionation, loading and terminal facilities constructed and operated by M3 Midstream L.L.C. CMD made an initial cash contribution of $38 million in exchange for an ownership of approximately 59% in UEOM.

Texoma Woodford Asset Sale. In April 2012, we sold 58,400 net acres of leasehold in the Texoma Woodford play in Bryan, Carter, Johnston and Marshall counties in Oklahoma to XTO Energy Inc., a subsidiary of Exxon Mobil Corporation (NYSE:XOM), for approximately $572 million in cash after certain deductions and closing costs. The properties included approximately 25 mmcfe per day of current net production.

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Joint Ventures. As of March 31, 2012, we had entered into seven significant joint ventures with other leading energy companies pursuant to which we sold a portion of our leasehold, producing properties and other assets located in seven different resource plays and received cash of $7.1 billion and commitments for future drilling and completion cost sharing of $9.0 billion. In each of these joint ventures, Chesapeake serves as the operator and conducts all leasing, drilling, completion, operations and marketing activities for the project. These transactions have allowed us to recover much or all of our initial leasehold investments and reduce our ongoing capital costs in these plays. The transactions are detailed below.

Primary Play	Joint Venture Partner[a]	Joint Venture Date	Interest Sold	Cash Proceeds Received at Closing	Total Drilling Carries	Total Cash and Drilling Carry Proceeds	Drilling Carries Remaining[b]
				($ in millions)			
Utica	TOT	December 2011	25.0%	$ 610	$ 1,422	$ 2,032	$ 1,372
Niobrara	CNOOC	February 2011	33.3%	570	697	1,267	544
Eagle Ford & Pearsall	CNOOC	November 2010	33.3%	1,120	1,080	2,200	
Barnett	TOT	January 2010	25.0%	800	1,404[c]	2,204	
Marcellus	STO	November 2008	32.5%	1,250	2,125	3,375	
Fayetteville	BP	September 2008	25.0%	1,100	800	1,900	
Haynesville & Bossier	PXP	July 2008	20.0%	1,650	1,508[d]	3,158	
				$ 7,100	$ 9,036	$ 16,136	$ 1,916

(a) Joint venture partners include Total S.A. (TOT), CNOOC Limited (CNOOC), Statoil (STO), BP America (BP) and Plains Exploration & Production Company (PXP).

(b) As of March 31, 2012.

(c) In conjunction with an agreement requiring us to maintain our operated rig count at no less than 12 rigs in the Barnett Shale through December 31, 2012, TOT accelerated the payment of its remaining joint venture drilling carry in exchange for an approximate 9% reduction in the total amount of drilling carry obligation owed to us at that time. As a result, in October 2011, we received $471 million in cash from TOT, which included $46 million of carry obligation billed and $425 million for the remaining carry obligation. In January 2012, Chesapeake and TOT agreed to reduce the minimum rig count from 12 to six rigs. In May 2012, Chesapeake and TOT agreed to reduce the minimum rig count from six to two rigs.

(d) In September 2009, PXP accelerated the payment of its remaining carry in exchange for an approximate 12% reduction to the remaining drilling carry obligation owed to us at that time.

The drilling and completion carries in our joint venture agreements create a significant cost advantage that allows us to reduce our future finding costs. During the Current Quarter and the Prior Quarter, our drilling and completion costs included the benefit of approximately $448 million and $527 million, respectively, of drilling and completion carries paid by our joint venture partners. Our drilling and completion costs for 2012, 2013 and 2014 will continue to be partially offset by the use of our remaining drilling and completion carries associated with our joint venture agreements.

During the Current Quarter, as part of our joint venture agreements with TOT, we sold interests in additional leasehold in the Barnett and Utica shale plays for proceeds of approximately $18 million that had an estimated cost to us of approximately $9 million. The cash proceeds from these transactions are reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

Planned Asset Monetizations

We are pursuing a joint venture transaction in our Mississippi Lime play in northern Oklahoma and southern Kansas, where we own approximately 2.0 million net acres, and we are pursuing a 100% sale of our position in the Permian Basin in West Texas and southern New Mexico, where we own approximately 1.5 million net acres. Our Permian Basin assets represent approximately 5% of the Company s total proved reserves and current net production. We are targeting completion of the Mississippi Lime and Permian Basin transactions during the 2012 third quarter.

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In April 2012, our wholly owned service industry affiliate Chesapeake Oilfield Services, Inc. filed a registration statement with the Securities Exchange Commission (SEC) relating to the proposed initial public offering of shares of its Class A common stock. Application will be made to list the Class A common stock on the New York Stock Exchange under the symbol COS . There can be no assurance that we will complete this transaction, as it is subject to market conditions and other uncertainties, as well as completion of the SEC review process.

Finally, we plan to continue to seek monetizations of various non-core oil and gas assets, a portion of our midstream assets, our oilfield services assets and other miscellaneous investments.

While we expect that the proceeds from our planned asset monetizations will be sufficient to fund our planned capital expenditures, we do not have binding agreements for any of these transactions and our ability to consummate each of these transactions is subject to changes in market conditions and other factors. As a result, there can be no assurance that we will complete any of these transactions on a timely basis or at all. To the extent that proceeds from these potential transactions are inadequate to fund our planned spending, we would be required to modify our drilling program or monetize different or additional assets.

Recent Developments

On May 1, 2012, the Company announced that its Board of Directors had renegotiated the terms of the Company s Founder Well Participation Program (FWPP) with Chairman and Chief Executive Officer Aubrey K. McClendon to provide for the early termination of the FWPP on June 30, 2014, 18 months before the end of its current term on December 31, 2015. The FWPP was approved by shareholders for a 10-year term in 2005. In conjunction with Mr. McClendon s employment agreement with the Company, the FWPP provides Mr. McClendon a contractual right to participate and invest as a working interest owner (with up to a 2.5% working interest) in new wells drilled on the Company s leasehold. Mr. McClendon will receive no compensation of any kind in connection with the early termination of the FWPP.

Following consultation with the Company s Board of Directors, on April 26, 2012, Mr. McClendon separately disclosed personal financial and operational information regarding his oil and gas investments through the FWPP.

The Board of Directors is conducting an internal review of the financing arrangements between Mr. McClendon (and the entities through which he participates in the FWPP) and any third party that has had or may have a relationship with the Company in any capacity. In addition, the Board of Directors will name an independent, Non-Executive Chairman in the near future. The Board s Nominating and Corporate Governance Committee is considering potential candidates and is soliciting input from major shareholders. Upon the appointment of a Non-Executive Chairman, Mr. McClendon will relinquish the position of Chairman and continue as Chief Executive Officer and a member of the Board. Mr. McClendon has indicated his support of the Board s decision to name a Non-Executive Chairman and waived any rights he might have under his employment agreement as a result of no longer serving as Chairman.

From April 19 to May 3, 2012, at least ten nearly identical shareholder actions have been filed against the Company and its directors alleging, among other things, that Company proxy statements have contained material misstatements related to Mr. McClendon s participation in the FWPP and breaches of fiduciary duties against the Board for failing to make proper disclosures in the proxy statements. Also, on April 26, 2012, a putative class action was filed against the Company and Mr. McClendon alleging violations of Sections 10(b) (and Rule 10b-5 promulgated thereunder) and 20(a) of the Securities Exchange Act of 1934 for purported misstatements concerning Mr. McClendon s participation in the FWPP. On May 8, 2012, a derivative action was filed against the Company s directors alleging, among other things, breaches of fiduciary duties and corporate waste related to the Company s officers and directors use of the Company s fractionally owned corporate jets. See Legal Proceedings in Part II, Item 1 for a description of these actions.

On May 2, 2012, Chesapeake and Mr. McClendon received notice from the Securities and Exchange Commission that its Fort Worth Regional Office has commenced an informal inquiry and requested that the Company and Mr. McClendon retain documents related to the FWPP and certain transactions. The SEC noted in its request that its inquiry should not be construed as an indication that any violation of the federal securities laws has occurred. The Company and Mr. McClendon intend to cooperate with the SEC in responding to its inquiry.

Liquidity and Capital Resources

Liquidity Overview

Our business strategy is to continue our reserves and production growth and transition to increased liquids production. As part of this strategy, we plan to make capital expenditures in 2012 that will significantly exceed our projected cash flow from operations. During the Current Quarter, the combination of high front-end capital expenditures and reduced cash flow as a result of low natural gas prices required that we increase our long-term debt, net of unrestricted cash, by approximately $2.4 billion to $12.6 billion to fund our capital expenditure needs. As of March 31, 2012, we had approximately $2.4 billion in cash availability compared to $3.1 billion as of December 31, 2011; however, our working capital deficit improved during the Current Quarter, and we expect this deficit to continue to decrease based on our projected capital expenditures and cash flow. For the remainder of 2012, we plan to fund capital expenditures with operating cash flow and various asset monetization transactions, potentially including joint ventures, volumetric production payments and other property and investment dispositions, including sales of a portion of our midstream and oilfield services assets. In addition, since early 2011, it has been our plan, which we call the 25/25 Plan, to reduce our net long-term debt to no more than $9.5 billion by December 31, 2012, a 25% reduction from year-end 2010, and increase our production by 25% during the two years ended December 31, 2012.

We expect that the proceeds from our 2012 closed or planned monetization transactions, which we estimate could be $11.5 $14 billion, will be sufficient to fund our budgeted capital expenditures, meet our long-term debt reduction plans by year-end 2012 and provide additional liquidity for 2013. We do not have binding agreements for any of these monetization transactions, however, and our ability to consummate each of them is subject to changes in market conditions and other factors. As a result, there can be no assurance that we will complete any of the planned transactions on a timely basis or at all. If we are unable to consummate these transactions or if they do not generate the proceeds we are anticipating, we would be required to reduce capital spending and/or seek funds from other sources, including interim financing that would address near-term liquidity needs. Our ability to obtain capital from asset monetizations is dependent upon many factors, and they may be beyond our control. If our access to alternative asset monetizations were limited, our ability to develop and replace our reserves could be reduced.

As part of our asset monetization planning and capital expenditure budgeting process, we closely monitor the resulting effects on the amounts and timing of our sources and uses of funds, particularly as they affect our ability to maintain compliance with the financial covenants of our corporate revolving bank credit facility. While asset monetizations enhance our liquidity, sales of producing natural gas and oil properties adversely affect the amount of cash flow we generate and reduce the amount and value of collateral available to secure our obligations, both of which are exacerbated by low natural gas prices. Thus the assets we select and schedule for monetization, our budgeted capital expenditures and our commodity price forecasts are carefully considered as we project our future ability to comply with the requirements of our corporate credit facility. As a result, we may delay one or more of our currently planned asset monetizations, or select other assets for monetization, in order to maintain our compliance. Continued compliance, however, is subject to all the risks that may impact our business strategy.

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Through the vertical integration of our business and as operator of a substantial number of our properties under development, we retain significant control and flexibility over the development plan and the associated timing, which we believe is instrumental to our business plan and strategy. While our capital raising activities enabled us to fund our capital program in 2011 and pursue our goal of long-term debt reduction, certain recent transactions require us to meet performance obligations and we have significant other contractual cash obligations to third parties pursuant to various lease arrangements, gathering, processing, and transportation agreements, drilling commitments, leasehold maintenance arrangements, fleet utilization agreements, and investments in new ventures (see Note 4 of the notes to our condensed consolidated financial statements included in Item 1 of this report). While our business plan assumes that we will meet these commitments in the ordinary course of business, we are required to meet our performance and payment obligations regardless of whether our business plan changes for circumstances beyond our control.

Sources of Funds

Cash flow from operations is a significant source of liquidity we use to fund capital expenditures, pay dividends and repay debt. Cash provided by operating activities was $274 million in the Current Quarter compared to $718 million in the Prior Quarter. The decline in the cash flow from operations is primarily the result of a decrease in the realized natural gas price (excluding the effect of unrealized gains or losses on derivatives) from $5.31 per mcf in the Prior Quarter to $2.35 per mcf in the Current Quarter. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding various non-cash items such as depreciation, depletion and amortization, deferred income taxes, mark-to-market changes in our derivative instruments and gains or losses on the sales and impairments of fixed assets. See the discussion below under *Results of Operations*.

The volatility in the energy markets make it extremely difficult to predict future natural gas and oil price movements with any certainty leaving us exposed to potential reduction in our operating cash flow and therefore affecting our ability to fund our capital expenditures. While our derivative arrangements serve to mitigate a portion of the effect of price volatility on our cash flows, our forecasted natural gas production is currently not protected against downward price adjustments by derivative instruments and our use of crude oil derivatives to partially mitigate the price risk of our liquids production is subject to basis risk to the extent oil and natural gas liquids prices do not remain highly correlated. Sustained low natural gas prices, and volatile commodity prices in general, could have a material adverse effect on our financial position, results of operations and cash flows, which could adversely impact our ability to maintain compliance with financial covenants under our credit facilities and further limit our ability to fund our planned capital expenditures. In addition, sustained low commodity prices could result in a reduction in the estimated quantity of proved reserves we report and in the estimated future net cash flows expected to be generated from reserves that may require us to write down the carrying value of our natural gas and oil properties, and such amounts could be material. Our natural gas and oil derivatives as of March 31, 2012 are detailed in Item 3 of Part I of this report. Depending on changes in commodity futures markets and management s view of underlying commodity supply and demand trends, we may increase or decrease our current derivative positions. As commodity prices dip and reach supportable low prices, however, we may take the opportunity to close out open swap positions in order to lock in substantial mark-to-market gains.

During the Current Quarter, third-party investors contributed $1.25 billion in cash to CHK C-T, in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3.75% overriding royalty interest in 360 existing wells and up to 1,000 net wells to be drilled on certain of our Cleveland and Tonkawa play leasehold. CHK C-T is an unrestricted, non-guarantor consolidated subsidiary we formed in March 2012 to continue development of a portion of our Cleveland and Tonkawa plays covering Ellis and Roger Mills counties in western Oklahoma.

Current Quarter property divestiture proceeds of $821 million included approximately $745 million from our tenth VPP transaction. Prior Quarter property divestiture proceeds of $5.182 billion included $4.310 billion from the sale of our Fayetteville assets, $570 million at the closing of our Niobrara Shale joint venture and $302 million from other property sales.

Our $4.0 billion corporate revolving bank credit facility, our $600 million midstream revolving bank credit facility (which we estimate was limited to approximately $370 million as of March 31, 2012), our $500 million oilfield services revolving bank credit facility (which we estimate was limited to approximately $450 million as of March 31, 2012) and cash and cash equivalents are other sources of liquidity. We use the credit facilities and cash on hand to fund daily operating activities and capital expenditures as needed. We borrowed $5.688 billion and repaid $4.546 billion in the Current Quarter, and we borrowed $3.617 billion and repaid $7.323 billion in the Prior Quarter under our revolving bank credit facilities. Our corporate facility is secured by natural gas and oil proved reserves. A significant portion of our natural gas and oil reserves are currently unencumbered and therefore available to be pledged as additional collateral if needed to respond to borrowing base and collateral redeterminations our lenders might make in the future. Accordingly, we believe our borrowing capacity under this facility will not be reduced as a result of any such future redeterminations. Our midstream and oilfield services facilities are secured by substantially all of their respective wholly owned assets and are not subject to periodic borrowing base redeterminations. Our revolving bank credit facilities are described below under *Bank Credit Facilities*.

During the Current Quarter, we issued $1.3 billion of 6.775% Senior Notes due 2019 in a registered public offering. We used the net proceeds of $1.263 billion from the offering to repay indebtedness outstanding under our corporate revolving bank credit facility. At any time from and including November 15, 2012 to and including March 15, 2013, we may redeem some or all of the notes at a redemption price equal to 100% of the principal amount of the notes plus accrued and unpaid interest, if any, to the redemption date; provided that any redemption of the notes in part (and not in whole) pursuant to this redemption provision, at least $250 million aggregate principal amount of the notes remains outstanding.

During the Prior Quarter, we issued $1.0 billion of 6.125% Senior Notes due 2021 in a registered public offering. We used the net proceeds of $977 million from the offering to repay indebtedness outstanding under our corporate revolving bank credit facility.

Cash settlements of our derivative instruments are generally classified as operating cash flows unless the derivative is deemed to contain, for accounting purposes, a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows. In the Current Quarter, we paid $9 million and in the Prior Quarter, we received $660 million for settlements of derivatives which were classified as cash flows from financing activities.

Uses of Funds

Our primary use of funds is for capital expenditures related to exploration, development and acquisition of natural gas and oil properties. We refer you to the table under *Investing Activities* below, which sets forth the components of our natural gas and oil investing activities and our other investing activities for the Current Quarter and the Prior Quarter. We retain a significant degree of control over the timing of our capital expenditures, which permits us to defer or accelerate certain capital expenditures if necessary to address any potential liquidity issues. In addition, changes in drilling and field operating costs, drilling results that alter planned development schedules, acquisitions or other factors could cause us to revise our drilling program, which is largely discretionary.

During the Prior Quarter, we purchased $140 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for approximately $128 million. Associated with these purchases, we recognized a loss of $2 million.

We paid dividends on our common stock of $56 million and $48 million in the Current Quarter and the Prior Quarter, respectively. We paid dividends of $43 million on our preferred stock in both the Current Quarter and the Prior Quarter.

During the Current Quarter, we distributed $39 million in cash to certain of our noncontrolling interest owners.

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Credit Risk

Derivative instruments that enable us to manage our exposure to commodity prices and interest rate volatility expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with counterparties that are rated investment-grade and 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. On March 31, 2012, our commodity and interest rate derivative instruments were spread among 18 counterparties. Additionally, the counterparties under our multi-counterparty secured hedging facility are required to secure their natural gas and oil hedging obligations in excess of defined thresholds. We use this facility for the majority of our natural gas, oil and natural gas liquids derivatives.

Our accounts receivable are primarily from purchasers of natural gas and oil ($927 million at March 31, 2012) and exploration and production companies which own interests in properties we operate ($1.399 billion at March 31, 2012). 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 Prior Quarter, we recognized nominal amounts of bad debt expense related to potentially uncollectible receivables.

Investing Activities

Cash used in investing activities increased to $3.650 billion during the Current Quarter, compared to cash provided by investing activities of $2.226 billion during the Prior Quarter. The majority of the $5.876 billion increase in cash used in investing activities was the result of the sale of our Fayetteville Shale assets in the Prior Quarter. We made significant additions to our liquids-rich leasehold acreage in both the Current Quarter and the Prior Quarter, with acquisitions of unproved properties totaling $968 million and $1.065 billion, respectively. Drilling and completion costs on proved and unproved properties increased $882 million to $2.503 billion in the Current Quarter compared to $1.621 billion in the Prior Quarter. This increase is due to increased drilling activity. See *Capital Expenditures* for a description of our Current Quarter and budgeted capital expenditures. The following table shows our cash used in investing activities during these periods:

	Three Months Ended March 31	
	2012	2011
	($ in millions)	
Natural Gas and Oil Investing Activities:		
Drilling and completion costs on proved and unproved properties	$ (2,503)	$ (1,621)
Acquisitions of proved properties	(5)	(18)
Acquisitions of unproved properties	(968)	(1,065)
Proceeds from divestitures of proved and unproved properties	821	5,182
Geological and geophysical costs[a]	(71)	(71)
Interest capitalized on unproved properties	(162)	(175)
Total natural gas and oil investing activities	(2,888)	2,232
Other Investing Activities:		
Additions to other property and equipment	(690)	(431)
Proceeds from sales of other assets	48	428
Proceeds from (additions to) investments	(73)	4
Other	(47)	(7)
Total other investing activities	(762)	(6)
Total cash provided by (used in) investing activities	$ (3,650)	$ 2,226

(a) Including related capitalized interest.

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Bank Credit Facilities

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

	Corporate Credit Facility[(a)]	Midstream Credit Facility[(b)] ($ in millions)	Oilfield Services Credit Facility[(c)]
Facility structure	Senior secured revolving	Senior secured revolving	Senior secured revolving
Maturity date	December 2015	June 2016	November 2016
Borrowing capacity	$ 4,000	$ 600[(d)]	$ 500[(e)]
Amount outstanding as of March 31, 2012	$ 2,462	$ 258	$ 172
Letters of credit outstanding as of March 31, 2012	$ 25	$	$

(a) Borrower is Chesapeake Exploration, L.L.C.

(b) Borrower is Chesapeake Midstream Operating, L.L.C.

(c) Borrower is Chesapeake Oilfield Operating, L.L.C.

(d) We estimate the capacity was limited to approximately $370 million as of March 31, 2012 by certain restrictive provisions.

(e) We estimate the capacity was limited to approximately $450 million as of March 31, 2012 by certain restrictive provisions.

Our corporate and oilfield services credit facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates under our corporate credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, our credit facilities do not contain provisions which would trigger an acceleration of amounts due under the respective facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

Corporate Credit Facility

Our $4.0 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by natural gas and oil proved reserves 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 0.50% to 1.25% per annum according to our senior unsecured long-term debt ratings, or (ii) the Eurodollar rate, which is based on 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% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens and require us to maintain an indebtedness to total capitalization ratio and an indebtedness to EBITDA ratio, in each case as defined in the agreement. We were in compliance with all covenants under the agreement at March 31, 2012. 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 $50 million or more, 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 $125 million.

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

Midstream Credit Facility

Our $600 million midstream syndicated revolving bank credit facility is used to fund capital expenditures to build natural gas gathering and other systems in support of our drilling program and for general corporate purposes associated with our midstream operations. Borrowings under the midstream credit facility are secured by all of the assets other than certain joint venture equity interests, of the wholly owned subsidiaries (the restricted subsidiaries) of CMD, itself a wholly owned subsidiary of Chesapeake. Amounts outstanding 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 are subject to a margin that varies from 1.00% to 1.75% or (ii) the Eurodollar rate, which is based on LIBOR plus a margin that varies from 2.00% to 2.75% per annum. The unused portion of the facility is subject to a commitment fee that varies from 0.375% to 0.50% per annum. Both margins and commitment fees are determined according to the most recent leverage ratio described below. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The midstream 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 agreement requires maintenance of a leverage ratio based on the ratio of indebtedness to EBITDA and an interest coverage ratio based on the ratio of EBITDA to interest expense, in each case as defined in the agreement. The leverage ratio increases during any three-quarter period, beginning in the quarter in which CMD makes a material disposition of assets to our midstream master limited partnership midstream affiliate, CHKM. In December 2011, the leverage ratio increased for a three-fiscal-quarter period beginning October 1, 2011 due to the sale of CMD s wholly owned subsidiary, AMS, as it was classified as a material disposition of assets. As a result, the capacity of the midstream credit facility was limited to approximately $370 million as of March 31, 2012. We were in compliance with all covenants under the agreement at March 31, 2012. 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 facility could be declared immediately due and payable. The midstream credit facility agreement also has cross default provisions that apply to other indebtedness CMD and its restricted subsidiaries may have from time to time with an outstanding principal amount in excess of $15 million.

Oilfield Services Credit Facility

Our $500 million oilfield services syndicated revolving bank credit facility is used to fund capital expenditures and for general corporate purposes associated with our oilfield services operations. Borrowings under the oilfield services credit facility are secured by all of the assets of the wholly owned subsidiaries of Chesapeake Oilfield Operating, L.L.C. (COO), itself a wholly owned subsidiary of Chesapeake. The facility has initial availability of $500 million and may be expanded to $900 million at COO s option, subject to additional bank participation. Borrowings under the credit facility are secured by all of the equity interests and assets of COO and its wholly owned subsidiaries (the restricted subsidiaries), and bear interest at our option at either (i) the greater of the reference rate of Bank of America, N.A., the federal funds effective rate plus 0.50%, and one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 1.00% to 1.75% per annum or (ii) the Eurodollar rate, which is based on LIBOR plus a margin that varies from 2.00% to 2.75% per annum. The unused portion of the credit facility is subject to a commitment fee that varies from 0.375% to 0.50% per annum. Both margins and commitment fees are determined according to the most recent leverage ratio described below. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The oilfield services credit facility agreement contains various covenants and restrictive provisions which limit the ability of COO and its restricted subsidiaries to incur additional indebtedness, make investments or loans and create liens. The agreement requires maintenance of a leverage ratio based on the ratio of lease adjusted indebtedness to EBITDAR, a senior secured leverage ratio based on a ratio of secured indebtedness to EBITDA and a fixed charge coverage ratio based on the ratio of lease adjusted interest expense to EBITDAR, in each case as defined in the agreement. As a result of those covenants, the capacity of the oilfield services credit facility was limited to approximately $450 million as of March 31, 2012. We were in compliance with all covenants under the agreement at March 31, 2012. If COO 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 facility could be declared immediately due and payable. The oilfield services credit facility agreement also has cross default provisions that apply to other indebtedness COO and its restricted subsidiaries may have from time to time with an outstanding principal amount in excess of $15 million.

Hedging Facility

We have a multi-counterparty secured hedging facility with 18 counterparties that have committed to provide approximately 6.5 tcfe of hedging capacity for commodity price derivatives and 6.5 tcfe for basis derivatives with an aggregate mark-to-market capacity of $17.5 billion under the terms of the facility. As of March 31, 2012, we had hedged under the facility 2.1 tcfe of our future production with price derivatives and 0.2 tcfe with basis derivatives. The multi-counterparty facility allows us to enter into cash-settled natural gas, oil and natural gas liquids price and basis derivatives with the counterparties. Our obligations under the multi-counterparty facility are secured by proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by at least 1.65 times at semi-annual collateral dates and 1.30 times in between these dates, and guarantees by certain subsidiaries that also guarantee our corporate revolving bank credit facility, indentures and sale/leaseback arrangements. 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 derivative instruments. In addition, there are volume-based sub-limits for natural gas, oil and natural gas liquids derivative instruments. 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 entering into derivative instruments with the Company on a prospective basis as long as obligations associated with any existing transactions in the facility continue to be satisfied in accordance with the terms of the agreement.

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Senior Note Obligations

In addition to outstanding borrowings under our revolving bank credit facilities discussed above, as of March 31, 2012, our long-term debt consisted of the following ($ in millions):

7.625% senior notes due 2013	$	464
9.5% senior notes due 2015		1,265
6.25% euro-denominated senior notes due 2017(a)		459
6.5% senior notes due 2017		660
6.875% senior notes due 2018		474
7.25% senior notes due 2018		669
6.625% senior notes due 2019(b)		650
6.775% senior notes due 2019		1,300
6.625% senior notes due 2020		1,300
6.875% senior notes due 2020		500
6.125% senior notes due 2021		1,000
2.75% contingent convertible senior notes due 2035(c)		396
2.5% contingent convertible senior notes due 2037(c)		1,168
2.25% contingent convertible senior notes due 2038(c)		347
Discount on senior notes(d)		(487)
Interest rate derivatives(e)		25
	$	10,190

(a) The principal amount shown is based on the exchange rate of $1.3334 to 1.00 as of March 31, 2012. See Note 7 of our condensed consolidated financial statements included in this report for information on our related foreign currency derivatives.

(b) Issuers are COO and Chesapeake Oilfield Finance, Inc. (COF), a wholly owned subsidiary of COO formed solely to facilitate the offering of the 6.625% Senior Notes due 2019. COF is nominally capitalized and has no operations or revenues. Chesapeake Energy Corporation is the issuer of all other senior notes and the contingent convertible senior notes.

(c) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder s option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the first quarter of 2012, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes during the specified period and, as a result, the holders do not have the option to convert their notes into cash and common stock in the second quarter of 2012 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 in which 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	$ 48.51	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 64.16	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 107.27	June 14, 2019

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(d) Included in this discount is $427 million at March 31, 2012 associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method.

(e) See Note 7 of our condensed consolidated financial statements included in this report for discussion related to these instruments.

Chesapeake Senior Notes and Contingent Convertible Notes

The Chesapeake senior notes and the contingent convertible senior notes, as defined in note (b) to the table above, are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior unsecured indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Chesapeake s obligations under the senior notes and the contingent convertible senior notes are jointly and severally, fully and unconditionally guaranteed by certain of our wholly owned subsidiaries. CMD and its subsidiaries, Chesapeake Oilfield Services, L.L.C. (COS) and its subsidiaries, CHK Utica, CHK C-T, Chesapeake Granite Wash Trust and certain de minimis subsidiaries are not guarantors. See Note 13 of the notes to our condensed consolidated financial statements in Item 1 of 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. Our senior notes are governed by indentures containing covenants that may limit our ability and our subsidiaries ability to incur certain secured indebtedness, enter into sale/leaseback transactions, and consolidate, merge or transfer assets. The indentures governing the contingent convertible senior notes do not have any financial or restricted payment covenants.

We are required 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. These rates for 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 are 6.86%, 8.0% and 8.0%, respectively.

COO Senior Notes

In October 2011, our wholly owned subsidiary, COO, issued $650 million principal amount of 6.625% Senior Notes due 2019 in a private placement. COO used the net proceeds of approximately $637 million from the placement to make a cash distribution to its direct parent, COS, to enable it to reduce indebtedness under an intercompany note with Chesapeake. Chesapeake then used the cash distribution to reduce indebtedness under its corporate revolving bank credit facility.

The COO senior notes are the unsecured senior obligations of COO and rank equally in right of payment with all of COO s other existing and future senior unsecured indebtedness and rank senior in right of payment to all of its future subordinated indebtedness. The COO senior notes are jointly and severally, fully and unconditionally guaranteed by all of COO s wholly owned subsidiaries, other than de minimis subsidiaries. The notes may be redeemed at any time at specified make-whole or redemption prices and, prior to November 15, 2014, up to 35% of the aggregate principal amount may be redeemed in connection with certain equity offerings. Holders of the COO notes have the right to require COO to repurchase their notes upon a change of control on the terms set forth in the indenture, and COO must offer to repurchase the notes upon certain asset sales. The COO senior notes are subject to covenants that may, among other things, limit the ability of COO and its subsidiaries to make restricted payments, incur indebtedness, issue preferred stock, create liens, and consolidate, merge or transfer assets.

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Contractual Obligations and Off-balance Sheet Arrangements

From time to time, we enter into arrangements and transactions that can give rise to off-balance sheet obligations. As of March 31, 2012, these arrangements and transactions included (i) operating lease agreements, (ii) VPP obligations (to physically deliver volumes and pay related lease operating expenses in the future), (iii) open purchase commitments, (iv) open delivery commitments, (v) open drilling commitments, (vi) undrawn letters of credit and (vii) variable interests held in VIEs. Other than described above, we have no off-balance sheet arrangements or transactions that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources; however, we enter into various commitments through the normal course of business that could potentially result in a future cash obligation that we are unable to quantify. See Notes 4 and 10 of the notes to our consolidated financial statements in Item 1 of this report for further discussion of commitments and VIEs, respectively.

Results of Operations   Three Months Ended March 31, 2012 vs. March 31, 2011

General. For the Current Quarter, Chesapeake had a net loss of $28 million, or $0.11 per diluted common share, on total revenues of $2.419 billion. This compares to a net loss of $162 million, or $0.32 per diluted common share, on total revenues of $1.612 billion during the Prior Quarter.

Natural Gas and Oil Sales. During the Current Quarter, natural gas and oil sales were $1.068 billion compared to $494 million in the Prior Quarter. In the Current Quarter, Chesapeake produced and sold 332.8 bcfe at a weighted average price of $4.02 per mcfe, compared to 279.6 bcfe produced and sold in the Prior Quarter at a weighted average price of $5.99 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on derivatives of ($270) million and ($1.182) 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 $656 million and increased production resulted in a $319 million increase, for a total decrease in revenues of $337 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 through the drillbit.

For the Current Quarter, we realized an average price per mcf of natural gas of $2.35, compared to $5.31 in the Prior Quarter (weighted average prices exclude the effect of unrealized gains or losses on derivatives). In the Prior Quarter, realized prices of natural gas include gains related to swaps that had an above-market fixed price on the origination date. We obtained these above-market swaps by selling out-year call options on a portion of our projected natural gas and oil production. See Item 3 of Part I of this report for a complete listing of all of our derivative instruments as of March 31, 2012. Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $67.92 and $63.20 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 $117 million, or $0.35 per mcfe, in the Current Quarter and a net increase of $488 million, or $1.74 per mcfe, in the Prior Quarter.

A change in natural gas and oil prices has a significant impact on our natural gas and oil revenues and cash flows. Assuming the Current Quarter production levels, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in Current Quarter revenues and cash flows of approximately $27 million and $26 million, respectively, and an increase or decrease of $1.00 per barrel of oil sold would result in an increase or decrease in Current Quarter revenues and cash flows of approximately $10 million without considering the effect of hedging activities.

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The following tables show our production and prices received by operating division for the Current Quarter and the Prior Quarter:

	Three Months Ended March 31, 2012						
	Natural Gas		Oil[a]		Total		
	(bcf)	($/mcf)[b]	(mmbbl)	($/bbl)[b]	(bcfe)	%	($/mcfe)[b]
Southern[c]	149.8	1.59	0.7	64.46	153.8	47%	1.83
Northern	53.3	2.18	6.1	66.05	89.7	28	5.75
Eastern	53.8	1.89	0.4	53.46	56.2	16	2.25
Western	13.9	1.61	3.1	87.04	33.1	9	9.05
Total	270.8	1.77	10.3	71.91	332.8	100%	3.67

	Three Months Ended March 31, 2011						
	Natural Gas		Oil[a]		Total		
	(bcf)	($/mcf)[b]	(mmbbl)	($/bbl)[b]	(bcfe)	%	($/mcfe)[b]
Southern[c]	111.1	2.84	0.3	41.40	112.7	40%	2.90
Northern	91.5	3.49	4.4	63.27	118.2	41	5.08
Eastern	27.7	3.52	0.2	57.59	29.0	11	3.84
Western	13.0	4.25	1.1	82.59	19.7	8	7.53
Total[d]	243.3	3.24	6.0	66.08	279.6	100%	4.25

(a) Includes NGLs.

(b) The average sales price excludes gains (losses) on derivatives.

(c) Our Southern division primarily includes the Haynesville/Bossier Shale and the Barnett Shale which held approximately 22% and 18%, respectively, of our estimated proved reserves by volume as of March 31, 2012. Production for the Haynesville/Bossier Shale for the Current Quarter and the Prior Quarter was 102.4 bcfe and 85.4 bcfe, respectively. Production for the Barnett Shale for the Current Quarter and the Prior Quarter was 46.5 bcfe and 25.4 bcfe, respectively.

Our Barnett Shale production is concentrated in urban areas where the cost to develop the necessary infrastructure to gather and deliver the natural gas to intrastate pipelines significantly exceeds the cost of similar infrastructure in non-urban areas. Additionally, the rapid development of the Barnett Shale required the construction of new pipelines to provide an adequate market for these new gas reserves. In order to support the timely construction of these new pipelines, we entered into firm transportation contracts that obligate the Company to pay demand fees even if we do not deliver specified volumes of natural gas into certain gathering systems and intrastate pipelines. The demand fees associated with unused capacity and the other gathering and transportation fees described above have resulted in lower natural gas price realizations in the Barnett Shale.

(d) The Current Quarter production reflects the sale of all of our Fayetteville Shale assets, which closed in March 2011 and various other asset sales. See Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of this report for information on divestitures.

Our average daily production of 3.658 bcfe for the Current Quarter consisted of 2.976 bcf of natural gas (81% on a natural gas equivalent basis) and approximately 113,600 bbls of liquids (19% on a natural gas equivalent basis). Our year-over-year growth rate of natural gas production was 10% and our year-over-year growth rate of liquids production was 69%. Our percentage of revenue from liquids in the Current Quarter was 61% of unhedged natural gas and oil revenue compared to 34% in the Prior Quarter.

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Marketing, Gathering and Compression Sales and Expenses. Marketing, gathering and compression sales and expenses consist of third-party revenue and expenses related to our marketing, gathering and compression operations. Marketing, gathering and compression activities are performed by Chesapeake primarily for owners in Chesapeake-operated wells. Chesapeake realized $1.216 billion in marketing, gathering and compression sales in the Current Quarter with corresponding expenses of $1.197 billion, for a net margin before depreciation of $19 million. This compares to sales of $1.017 billion, expenses of $985 million and a net margin before depreciation of $32 million in the Prior Quarter. In the Current Quarter, Chesapeake realized an increase in marketing, gathering and compression sales and expenses primarily due to an increase in third-party marketing, gathering and compression volumes. This increase was offset by a decrease in revenues, expenses and margins related to certain of our Appalachian midstream assets sold to CHKM in December 2011.

Oilfield Services Revenues and Expenses. Oilfield services consist of third-party revenue and expenses related to our oilfield services operations. Chesapeake recognized $135 million in oilfield services revenue in the Current Quarter with corresponding expenses of $96 million, for a net margin before depreciation of $39 million. This compares to revenue of $101 million, expenses of $77 million and a net margin before depreciation of $24 million in the Prior Quarter. Oilfield services revenues, expenses and margins have increased as our oilfield service business has grown.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $349 million in the Current Quarter and $238 million in the Prior Quarter. On a unit-of-production basis, production expenses were $1.05 per mcfe in the Current Quarter compared to $0.85 per mcfe in the Prior Quarter. The per unit expense increase in the Current Quarter was primarily the result of a new fee retroactively imposed in Pennsylvania on spud wells, an overall increase in field rates and the effect of VPP transactions in which we are still burdened by production expenses.

Production Taxes. Production taxes were $47 million in the Current Quarter compared to $45 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.14 per mcfe in the Current Quarter compared to $0.16 per mcfe in the Prior Quarter. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas and oil prices are higher. The $2 million increase in production taxes in the Current Quarter was primarily due to an increase in production of 53 bcfe.

General and Administrative Expenses. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our natural gas and oil properties and other property, plant and equipment, were $136 million in the Current Quarter and $130 million in the Prior Quarter. General and administrative expenses were $0.41 and $0.46 per mcfe for the Current Quarter and Prior Quarter, respectively. Included in general and administrative expenses is stock-based compensation of $19 million for the Current Quarter and $23 million for the Prior Quarter. Restricted stock expense is based on the price of our common stock on the grant date of the award.

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock and helps offset the fact that we do not have a pension plan. Employee restricted stock awards generally vest over a period of four years. Our non-employee director awards vest over a period of three years. The discussion of stock-based compensation in Note 6 of our condensed consolidated financial statements included in Item 1 of Part I of this report provides additional detail on the accounting for and reporting of our stock-based compensation.

Chesapeake follows the full cost method of accounting under which all costs associated with natural gas and oil property acquisition, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, drilling and completion activities and do not include any costs related to production, general corporate overhead or similar activities. In addition, we capitalize internal costs that can be identified with the construction of certain of our property, plant and equipment. We capitalized $115 million and $109 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our natural gas and oil property acquisition, drilling and completion efforts and the construction of our property, plant and equipment.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of natural gas and oil properties was $506 million and $358 million during the Current Quarter and the Prior Quarter, respectively. The $148 million increase is primarily the result of a 19% increase in production from the Prior Quarter compared to the Current Quarter and an increase in estimated future development costs and capitalized costs compared to the increase in estimated proved reserves. 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 $1.52 and $1.28 in the Current Quarter and the Prior Quarter, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $84 million in the Current Quarter and $68 million in the Prior Quarter. Depreciation and amortization of other assets was $0.25 and $0.24 per mcfe for the Current Quarter and the Prior Quarter, respectively. The increase in the Current Quarter is primarily due to additional depreciation expense associated with assets acquired over the past year, offset by assets sold over the past year. 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 twenty 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 drilling and completion costs.

Gains on Sales of Fixed Assets. In the Current Quarter, we recorded a $2 million net gain on the sales of fixed assets. The gains in the Current Quarter were related to various sales of other fixed assets, including the sale of pipe, gas gathering systems and other miscellaneous assets. In the Prior Quarter, we recorded a $5 million net gain associated with the sales of other fixed assets, primarily in our Fayetteville Shale asset sale to BHP Billiton.

Interest Expense. Interest expense was $12 million in the Current Quarter compared to $7 million in the Prior Quarter as follows:

	Three Months Ended March 31,	
	2012	2011
	($ in millions)	
Interest expense on senior notes	$ 174	$ 177
Interest expense on credit facilities	21	21
Realized (gains) losses on interest rate derivatives		(7)
Unrealized (gains) losses on interest rate derivatives	4	6
Amortization of loan discount and other	1	15
Capitalized interest	(188)	(205)
Total interest expense	$ 12	$ 7
Average long-term borrowings	$ 10,152	$ 10,196

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.02 per mcfe in the Current Quarter compared to a nominal amount per mcfe in the Prior Quarter.

Earnings (Losses) on Investments. Earnings (losses) on investments were ($5) million and $25 million in the Current Quarter and the Prior Quarter, respectively, primarily as result of our equity in the net income of certain investments.

Losses on Purchases or Exchanges of Debt. In the Prior Quarter, we purchased $140 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for approximately $128 million, including accrued interest. Associated with these purchases, we recognized a loss of $2 million in the Prior Quarter.

Other Income. Other income was $6 million in the Current Quarter and $2 million in the Prior Quarter. The Current Quarter consisted of $1 million of interest income and $5 million of miscellaneous income. The Prior Quarter included $1 million of interest income and $1 million of miscellaneous income.

Income Taxes. Chesapeake recorded an income tax benefit of $2 million in the Current Quarter and $104 million in the Prior Quarter as a result of the increase in net income before taxes. Our effective income tax rate was 39% in both the Current Quarter and the Prior Quarter. Our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences.

In the first quarter of 2012, the Internal Revenue Service (IRS) completed the field work related to its examination of our federal income tax returns for 2007 through 2009 and issued revenue agent reports for these years. As a result of these events, we reduced the balance of our unrecognized tax benefits related to NOL carryforwards and alternative minimum tax by approximately $269 million in the Current Quarter. This had no impact on our income tax expense or the effective income tax rate for the quarter. In connection with the audit of our 2008 and 2009 returns, the IRS is reviewing certain issues with respect to the Founder Well Participation Program. We have been in discussion with representatives of the IRS and believe that resolution of these issues will not have a material impact on the Company.

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded net income attributable to noncontrolling interests of $25 million in the Current Quarter related to third-party ownership in CHK Utica, the Chesapeake Granite Wash Trust and Cardinal Gas Services, L.L.C., all of which were formed in the fourth quarter of 2011. There was no net income attributable to noncontrolling interests in the Prior Quarter.

Application of Critical Accounting Policies

We consider accounting policies related to derivatives, variable interest entities, natural gas and oil properties and income taxes to be critical policies. These policies are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our 2011 Form 10-K.

Recently Issued and Proposed Accounting Standards

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

In December 2011, the FASB issued guidance on disclosure of information about offsetting and related arrangements to enable users of a company s financial statements to understand the effect of those arrangements on its financial position. The standard is effective for annual reporting periods beginning on or after January 1, 2013. This guidance will not have an impact on our financial position or results of operations.

In June 2011, the FASB issued guidance on comprehensive income, which provides two options for presenting items of net income, comprehensive income and total comprehensive income, by either creating one continuous statement of comprehensive income or two separate consecutive statements. We adopted this guidance in 2011. Adoption had no impact on our financial position or results of operations. In December 2011, the FASB deferred the effective date of certain presentation requirements for items reclassified out of accumulated other comprehensive income. This guidance will not have an impact on our financial position or results of operations.

In May 2011, the FASB issued guidance on fair value measurement and disclosure requirements which expands existing fair value disclosure requirements, particularly for Level 3 inputs. The new requirements include quantitative disclosure of the unobservable inputs and assumptions used in the measurement; description of the valuation processes in place and sensitivity of the fair value to changes in unobservable inputs; and the level of items (in the fair value hierarchy) that are not measured at fair value in the balance sheet but whose fair value must be disclosed. The guidance was effective for interim and annual periods beginning on or after December 15, 2011. Adoption had no impact on our financial position or results of operations.

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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, as amended (the Exchange Act). 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 drilling activity and drilling and completion capital expenditures, and anticipated asset monetizations, 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 2011 Form 10-K. They include:

- the volatility of natural gas and oil prices;
- the limitations our level of indebtedness may have on our financial flexibility;
- 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;
- inability to generate profits or achieve targeted results in our development and exploratory drilling and well operations;
- 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;
- drilling and operating risks, including potential environmental liabilities;
- changes in legislation and regulation adversely affecting our industry and our business;
- general economic conditions negatively impacting us and our business counterparties;

- oilfield services shortages, pipeline and gathering system capacity constraints and transportation interruptions that could adversely affect our cash flow; and

- losses possible from pending or future litigation.

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

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

Natural Gas and Oil Derivatives

Our results of operations and 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 prices to be received for our hedged production. 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 commodity 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 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 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 and options (calls and swaptions). All of these are described in more detail below. We typically use swaps for a large portion of the natural gas and oil volume we hedge. Swaps are used when the price level is acceptable. We also sell calls, taking advantage of market volatility for a portion of our projected production volumes. We do this when we would be satisfied to sell our production at the price being capped by the call strike price or believe it would 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. In the second half of 2011, we bought natural gas calls to, in effect, lock in sold call positions. Due to the low natural gas prices, we were able to achieve this at a low cost to us. We deferred the payment of the premium on these trades to the related month of production being hedged. At times, we have taken advantage of attractive strip prices in out-years and sold natural gas and oil call options to our counterparties in exchange for near-term natural gas swaps with fixed prices above the then current market price. This effectively allowed us to sell out-year volatility through call options at terms acceptable to us in exchange for natural gas swaps with fixed prices in excess of the market price for natural gas at that time. In the fourth quarter of 2011, we entered into oil swaps that can be extended at the option of the counterparty. This allows us to receive a higher fixed price on these swaps than what the market would have offered without such an option. Some of our derivatives are deemed to contain, for accounting purposes, a significant financing element at contract inception and the cash settlements associated with these instruments are classified as financing cash flows in the accompanying consolidated statement of cash flows.

We determine the volume we may potentially hedge by reviewing our 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 derivative instruments are already executed for some volume above the new production forecasts, the positions are reversed. The actual fixed price on our derivative instruments is derived from bidding and the reference NYMEX price, as reflected in current NYMEX trading. The pricing dates of our derivative contracts follow NYMEX futures. All of our derivative instruments are net settled based on the difference between the fixed price as stated in the contract and the floating-price payment, resulting in a net amount due to or from the counterparty.

We adjust our derivative positions in response to changes in prices and market conditions as part of an ongoing dynamic process. We review our derivative positions continuously and if future market conditions change and prices are at 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 trade that effectively reverses the current position. 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 derivative position. Gains or losses related to closed positions will be realized in the month of related production based on the terms specified in the original contract.

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

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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 partially mitigated under our 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. See Note 11 of the notes to our consolidated financial statements in Item 1 of this report for further discussion of the fair value measurements associated with our derivatives.

As of March 31, 2012, our natural gas and oil derivative instruments consisted of the following:

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

Call Options: Chesapeake sells, and occasionally buys, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess on sold call options, and Chesapeake receives such excess on bought call options. If the market price settles below the fixed price of the call options, no payment is due from either party.

Swaptions: Chesapeake sells swaptions to counterparties that allow them, on a specific date, to extend an existing fixed-price swap for a certain period of time.

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 a certain pre-determined knockout price.

Basis protection Swaps: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas from a specified delivery point. Our basis protection swaps 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.

As of March 31, 2012, we had the following open natural gas and oil derivative instruments.

	XXXXXX	XXXXXX	XXXXXX	XXXXXX	XXXXXX	XXXXXX	XXXXXX
			Weighted Average Price			Cash Flow	Fair
	Volume	Fixed	Put	Call	Differential	Hedge	Value
	(tbtu)		(per mmbtu)				($ in millions)
Natural Gas:							
Call Options (sold):							
2012	271	$	$	$ 7.36	$	No	$
2013	415			6.44		No	(16)
2014	330			6.43		No	(36)
2015	226			6.31		No	(47)
2016	279			6.72		No	(89)
2017 2020	114			10.92		No	(21)
Call Options (bought)[(a)]:							
2012	(163)			7.90		No	
2015	(110)			6.16		No	(35)
2016	(44)			6.00		No	(11)
Basis Protection Swaps							

Q2 2012	20	(0.80)	No		(12)
Q3 2012	21	(0.80)	No		(13)
Q4 2012	8	(0.74)	No		(5)
2013	44	(0.21)	No		
2014	28	(0.32)	No		(2)
2015	31	(0.34)	No		(2)
2016 2022	8	(1.02)	No		(6)
Total Natural Gas				$	(295)

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	Volume (mmbbl)	Weighted Average Price Fixed	Put	Call (per bbl)	Differential	Cash Flow Hedge	Fair Value ($ in millions)
Oil:							
Non-Qualified Swaps:							
Q2 2012	7.1	$ 102.40	$	$	$	No	$ (6)
Q3 2012	6.0	103.27				No	(6)
Q4 2012	5.5	102.92				No	(11)
2013	4.9	102.85				No	(4)
2014	0.9	90.72				No	(8)
2015	0.5	88.75				No	(3)
Call Options (sold)[(b)]:							
Q2 2012	2.0			77.97		No	(15)
Q3 2012	2.1			77.97		No	(22)
Q4 2012	2.1			77.97		No	(27)
2013	19.4			94.74		No	(331)
2014	20.7			97.48		No	(298)
2015	24.6			100.45		No	(326)
2016	18.9			104.71		No	(223)
2017	5.3			83.50		No	(107)
Call Options (bought):							
Q2 2012	(1.6)			100.00		No	9
Q3 2012	(1.6)			100.00		No	16
Q4 2012	(1.6)			100.00		No	19
Swaptions:							
Q3 2012	1.8	106.38				No	(9)
Q4 2012	2.3	106.45				No	(13)
2013	5.6	104.39				No	(51)
2014	2.9	106.69				No	(23)
2015	2.4	106.61				No	(12)
Knock-Out Swaps:							
Q2 2012	0.2	109.50	60.00			No	1
Q3 2012	0.2	109.50	60.00			No	1
Q4 2012	0.2	109.50	60.00			No	1
Total Oil							$ (1,448)
Total Natural Gas and Oil							$ (1,743)

(a) Included in the fair value are deferred premiums of $60 million and $28 million which we will pay in 2015 and 2016, respectively.

(b) Included in oil call options are NGL call options in the amount of 5,000 bbls per day at $38.01 per bbl for 2012.

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In addition to the open derivative positions disclosed above, at March 31, 2012, we had $183 million of net hedging gains related to settled trades for future production periods that will be recorded within natural gas and oil sales as realized gains (losses) as they are transferred from either accumulated other comprehensive income or unrealized gains (losses) in the month of related production based on the terms specified in the original contract as noted below.

	March 31, 2012 ($ in millions)
Q2 2012	$ 143
Q3 2012	(35)
Q4 2012	(60)
2013	43
2014	(139)
2015	216
2016 2022	15
Total	$ 183

The table below reconciles the changes in fair value of our natural gas and oil derivatives during the Current Quarter. Of the $1.743 billion fair value liability as of March 31, 2012, $201 million related to contracts maturing in the next 12 months and $1.542 billion related to contracts maturing after 12 months. All open derivative instruments as of March 31, 2012 are expected to mature by December 31, 2022.

	2012 ($ in millions)
Fair value of contracts outstanding, as of January 1	$ (1,639)
Change in fair value of contracts	(155)
Fair value of new contracts when entered into	(66)
Contracts realized or otherwise settled	13
Fair value of contracts when closed	104
Fair value of contracts outstanding, as of March 31	$ (1,743)

The change in natural gas and oil prices during the Current Quarter increased the liability of our derivative instruments by $155 million. This loss is recorded in natural gas and oil sales. We entered into new contracts which were in a liability position of $66 million. We settled contracts that were in a liability position for $13 million and we closed out contracts that were in a liability position for $104 million. The realized loss is recorded in natural gas and oil sales in the month of related production.

Pursuant to accounting guidance for derivatives and hedging, 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). Realized gains (losses) consist of settled contracts related to the production periods being reported. Unrealized gains (losses) consist of both temporary fluctuations in the mark-to-market values of non-qualifying contracts and settled values of non-qualifying derivatives related to future production periods. As of March 31, 2012, we did not have any natural gas and oil derivatives that were designated as cash flow hedges.

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The components of natural gas and oil sales for the Current Quarter and the Prior Quarter are presented below.

	xxxxxxxx	xxxxxxxx
	Three Months Ended March 31,	
	2012	2011
	($ in millions)	
Natural gas and oil sales	$ 1,221	$ 1,188
Realized gains (losses) on natural gas and oil derivatives	117	488
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(270)	(1,192)
Unrealized gains (losses) on ineffectiveness of cash flow hedges		10
Total natural gas and oil sales	$ 1,068	$ 494

Interest Rate Risk

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

	Years of Maturity						
	2012	2013	2014	2015	2016	Thereafter	Total
	($ in millions)						
Liabilities:							
Long-term debt fixed rate[(a)]	$	$ 464	$	$ 1,265	$ 8,923	$	$ 10,652
Average interest rate		7.63%		9.50%	5.75%		6.28%
Long-term debt variable rate	$	$	$	$ 2,462	$ 430	$	$ 2,892
Average interest rate				2.00%	2.72%		2.10%

(a) This amount does not include the discount included in long-term debt of ($487) million and interest rate derivatives of $25 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.

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Interest Rate Derivatives

To mitigate a portion of our exposure to volatility in interest rates related to our senior notes and credit facilities, we enter into interest rate derivatives. As of March 31, 2012, our interest rate derivative instruments consisted 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 a pay fixed interest rate) to manage our interest rate exposure related to our bank credit facility borrowings.

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 March 31, 2012, the following interest rate derivatives were outstanding:

	Notional Amount ($ in millions)	Weighted Average Rate Fixed	Weighted Average Rate Floating[a]	Fair Value Hedge	Net Premiums ($ in millions)	Fair Value ($ in millions)
Fixed to Floating:						
Swaps Mature 2017 2021	$ 450	6.42%	1 3 mL plus 456 bp	No	$	$ (3)
Swaption Q2 2012	$ 400	6.36%	3 mL plus 437 bp	No	2	(3)
Floating to Fixed:						
Swaps Mature 2014 2015	$ 1,050	2.13%	1 6 mL	No		(40)
					$ 2	$ (46)

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

In addition to the open derivative positions disclosed above, at March 31, 2012 we had $79 million of net gains related to settled derivative contracts that will be recorded within interest expense as realized gains (losses) as they are transferred from either our senior note liability or unrealized interest expense gains (losses) over the next nine-year term of the related senior notes.

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 and the Prior Quarter are presented below.

	Three Months Ended March 31, 2012 ($ in millions)	Three Months Ended March 31, 2011 ($ in millions)
Interest expense on senior notes	$ 174	$ 177
Interest expense on credit facilities	21	21
Realized (gains) losses on interest rate derivatives		(7)

Unrealized (gains) losses on interest rate derivatives	4	6
Amortization of loan discount and other	1	15
Capitalized interest	(188)	(205)
Total interest expense	$ 12	$ 7

Foreign Currency Derivatives

In December 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 cross currency swaps to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. In May 2011, we purchased and subsequently retired 256 million in aggregate principal amount of these senior notes following a tender offer, and we simultaneously unwound the cross currency swaps for the same principal amount. As a result, we reclassified a loss of $38 million from accumulated other comprehensive income to the condensed consolidated statement of operations, $20 million of which related to the unwound notional amount and was included in losses on purchases or exchanges of debt, and $18 million of which related to future interest associated with the unwound principal and was included in interest expense. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay Chesapeake 11 million and Chesapeake pays the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake 344 million and Chesapeake will pay the counterparties $459 million. The terms of the cross currency swaps were based on the dollar/euro exchange rate on the issuance date of $1.3325 to 1.00. Through the cross currency swaps, we have eliminated any potential variability in Chesapeake s expected cash flows related to changes in foreign exchange rates and therefore the swaps qualify as cash flow hedges. The fair values of the cross currency swaps are recorded on the condensed consolidated balance sheet as a liability of $20 million at March 31, 2012. The euro-denominated debt in long-term debt has been adjusted to $459 million at March 31, 2012 using an exchange rate of $1.3334 to 1.00.

ITEM 4. *Controls and Procedures*

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed in reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC 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 management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of Chesapeake s disclosure controls and procedures pursuant to 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 were effective as of March 31, 2012.

No changes in our internal control over financial reporting occurred during the Current Quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. *Legal Proceedings*

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. On September 2, 2010, the court denied the defendants motion to dismiss, and the court certified the class on March 30, 2012. Defendants moved for summary judgment on grounds of loss causation and materiality on December 16, 2011. Discovery in the case is proceeding. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with the case. A derivative action was also filed in the District Court of Oklahoma County, Oklahoma on March 10, 2009 against certain current and former directors and officers of the Company asserting breaches of fiduciary duties relating to alleged material omissions in the registration statement for the July 2008 offering. The derivative action was stayed pursuant to stipulation, and on April 20, 2012, plaintiffs filed a motion to lift the stay and permit plaintiffs to file an amended complaint. A second derivative action relating to the July 2008 offering was filed against certain current and former directors and officers of the Company in the U.S. District Court for the Western District of Oklahoma on September 6, 2011. This action also asserts breaches of fiduciary duties with respect to alleged material omissions in the offering registration statement. The Company filed a motion to dismiss the action on November 30, 2011, and plaintiffs filed an Opposition on January 9, 2012. Chesapeake is named as a nominal defendant in both derivative actions.

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, among other things, breaches of fiduciary duties relating to the 2008 compensation of the Company s CEO, Aubrey K. McClendon, and seeking unspecified damages, equitable relief and disgorgement. These three derivative actions were consolidated and a Consolidated Derivative Shareholder Petition naming Chesapeake as a nominal defendant was filed on June 23, 2009. Chesapeake s motion to dismiss was granted on February 26, 2010, and the Oklahoma Court of Civil Appeals affirmed the dismissal on August 26, 2011. The plaintiffs filed a petition for writ of certiorari with the Oklahoma Supreme Court on September 13, 2011.

On January 30, 2012, the District Court of Oklahoma County, Oklahoma approved a settlement between the parties in the consolidated derivative action, as well as a case on appeal at the Oklahoma Court of Civil Appeals requesting inspection of Company books and records relating to the December 2008 employment agreement with its CEO. The principal terms of the settlement include the rescission of the sale of an antique map collection that occurred in December 2008 between Mr. McClendon and the Company, whereby Mr. McClendon will pay the Company approximately $12 million plus interest and the Company will reconvey the map collection to Mr. McClendon, and the adoption and/or implementation of a variety of corporate governance measures. The court awarded attorney fees and expenses to plaintiffs counsel in the amount of $3,750,000, that was paid by Chesapeake. Pursuant to the settlement, the consolidated derivative action and books and records action were dismissed with prejudice against all defendants. On February 29, 2012, certain shareholders filed a petition in error with the Oklahoma Supreme Court opposing the terms of the settlement and on March 20, 2012 Chesapeake responded.

On September 6 and 8, 2011, in separate derivative actions filed in the U.S. District Court for the Western District of Oklahoma against certain of the Company s current and former directors, two shareholders alleged that the Chesapeake board wrongfully refused their demands to investigate purported breaches of fiduciary duties relating to Mr. McClendon s 2008 compensation and, as a result, each of these shareholders asserts he is entitled to seek relief on behalf of the Company. These federal derivative actions were consolidated on December 23, 2011 and on March 14, 2012 were stayed until 30 days after the Supreme Court of Oklahoma resolves the appeal of the settlement of the consolidated derivative action and books and records action. On May 3, 2012, plaintiffs filed a motion to lift the stay and sought leave to file an amended complaint.

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From April 19 to May 3, 2012, nine nearly identical shareholder actions were filed in the U.S. District Court for the Western District of Oklahoma against the Company and its directors alleging, among other things, violations of Section 14 of the Securities Exchange Act of 1934 and Rule 14a-9 promulgated thereunder for purported material misstatements in the Company s 2009 and subsequent proxy statements related to Mr. McClendon s participation in the Founder Well Participation Program and breaches of fiduciary duties against the Board for failing to make proper disclosures in the proxy statements. On April 27, 2012, a shareholder derivative action was filed in the District Court of Oklahoma County, Oklahoma setting forth substantially similar claims to those alleged in the federal shareholder actions.

On April 26, 2012, a putative class action was filed in the U.S. District Court for the Western District of Oklahoma against the Company and Mr. McClendon alleging violations of Sections 10(b) (and Rule 10b-5 promulgated thereunder) and 20(a) of the Securities Exchange Act of 1934 for purported misstatements concerning Mr. McClendon s participation in the Founder Well Participation Program. The plaintiffs seek class certification, damages of an unspecified amount and attorneys fees and other costs.

On May 2, 2012, Chesapeake and Mr. McClendon received notice from the Securities and Exchange Commission that its Fort Worth Regional Office has commenced an informal inquiry and requested that the Company and Mr. McClendon retain documents related to the Founder Well Participation Program and certain transactions. The SEC noted in its request that its inquiry should not be construed as an indication that any violation of the federal securities laws has occurred. The Company and Mr. McClendon intend to cooperate with the SEC in responding to its inquiry.

On May 8, 2012, a derivative action was filed in the District Court of Oklahoma County, Oklahoma against the Company s directors alleging, among other things, breaches of fiduciary duties and corporate waste related to the Company s officers and directors use of the Company s fractionally owned corporate jets.

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, various mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their natural gas and oil 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 successfully defended a number of these cases in various courts, has settled others and believes that it has substantial defenses to the claims made in those pending at the trial court and on appeal. Based on management s current assessment, we are of the opinion that no pending or threatened lawsuit or dispute incidental to the Company s business operations is likely to have a material adverse effect on its 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.

The Company records an associated liability when a loss is probable and the amount is reasonably estimable. The Company accounts for legal defense costs in the period the costs are incurred.

Environmental Proceedings

We refer you to information in Item 3. *Legal Proceedings* of our 2011 Form 10-K about settlements the Company entered into in February 2012 with the Pennsylvania Department of Environmental Protection (DEP) that terminated DEP proceedings regarding three separate matters (a well control incident; soil erosion and encroachment of a forested wetland associated with the construction of a well pad; and soil erosion and sediment control associated with another pad site).

The West Virginia Department of Environmental Protection (WVDEP) has issued orders for compliance related to alleged violations of the West Virginia Dam Control and Safety Act at four structures constructed for Chesapeake in West Virginia. These orders for compliance have been resolved by a mutual settlement agreement dated April 20, 2012 between Chesapeake and the WVDEP. Pursuant to the settlement agreement, Chesapeake agreed to pay a fine of $325,000 and make a contribution in the amount of $125,000 to the West Virginia Department of Natural Resources Wildlife Recreation fund for supplemental projects centered on dam safety construction, maintenance, enhancement, or engineering in northwestern West Virginia.

There are also outstanding orders for compliance initiated in the 2010 fourth quarter by the U.S. Environmental Protection Agency (EPA) related to our compliance with Clean Water Act (CWA) permitting requirements in West Virginia. We have responded to all pending orders and are actively working with the EPA to resolve these matters. For four of the sites subject to EPA orders for compliance, we have received and have responded to a subpoena requesting documents issued by the grand jury of the U.S. District Court for the Northern District of West Virginia. We understand that the U.S. Department of Justice (DOJ) is investigating possible criminal violations of and liabilities under the CWA with respect to three of the four sites. We are cooperating with the DOJ s investigation. The CWA provides authority for significant civil and criminal penalties for the placement of fill in a jurisdictional stream or wetland without a permit from the Army Corps of Engineers. CWA civil penalties can be as high as $37,500 per day, per violation, and possible criminal penalties range from $2,500 to $25,000 per day, per violation, for misdemeanor liability (i.e., criminally negligent conduct) and from $5,000 to $50,000 per day, per violation, for felony liability (i.e., knowing conduct). The CWA sets forth subjective criteria, including degree of fault and history of prior violations, that influence CWA penalty assessments, and the EPA may also seek to recover the economic benefit derived from non-compliance.

The duration and outcome of the DOJ s investigation are uncertain and the status of the investigation and our assessment of its potential impact may change as the investigation unfolds on a timetable that we cannot confidently predict and that may be affected by developments over the next few quarters. While we expect that resolution of the EPA s compliance orders and the DOJ s investigation under the CWA will include monetary sanctions exceeding $100,000, following discussions with the DOJ and EPA, we believe the liability with respect to these matters will not have a material effect on the consolidated financial position, results of operations or cash flow of the Company.

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 2011 Form 10-K. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

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

The following table presents information about repurchases of our common stock during the Current Quarter:

Period	Total Number of Shares Purchased[(a)]	Average Price Paid Per Share [(a)]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs[(b)]
January 1, 2012 through January 31, 2012	1,175,926	$ 23.18		
February 1, 2012 through February 29, 2012	15,007	$ 24.96		
March 1, 2012 through March 31, 2012	26,077	$ 24.13		
Total	1,217,010	$ 23.22		

(a) Reflects 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. ***Mine Safety Disclosures***

Not applicable.

ITEM 5. ***Other Information***

Not applicable.

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ITEM 6. ***Exhibits***

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

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
3.1.1	Chesapeake s Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	08/10/2009		
3.1.2	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008		
3.1.3	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	08/11/2008		
3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	05/20/2010		
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	08/09/2010		
3.2	Chesapeake s Amended and Restated Bylaws.	8-K	001-13726	3.1	11/17/2008		
4.1*	Ninth Supplemental Indenture dated February 16, 2012 to Indenture dated as of August 2, 2010, with respect to 6.775% Senior Notes due 2019.	8-A	001-13726	4.2	2/24/2012		
10.1	Letter Agreement, dated as of April 30, 2012, between the Board of Directors and Aubrey K. McClendon.	8-K	001-13726	1.1	05/02/2012		
10.2	Restated Chesapeake Energy Corporation Founder Well Participation Program.	8-K	001-13726	1.2	05/02/2012		
12	Ratios of Earnings to Fixed Charges and Combined 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	Domenic J. Dell Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
32.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.						X

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32.2	Domenic J. Dell Osso, Jr., 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

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SIGNATURES

Pursuant to the requirement of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CHESAPEAKE ENERGY CORPORATION

Date: May 11, 2012	By: /s/ AUBREY K. MCCLENDON Aubrey K. McClendon *Chairman of the Board and* *Chief Executive Officer*
Date: May 11, 2012	By: /s/ DOMENIC J. DELL OSSO, JR. Domenic J. Dell Osso, Jr. *Executive Vice President and* *Chief Financial Officer*

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101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.						X