CHESAPEAKE ENERGY CORP
Form 10-Q
May 07, 2014

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, 2014
[ ] 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 April 30, 2014, there were 666,211,707 shares of our $0.01 par value common stock outstanding.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
INDEX TO FORM 10-Q FOR THE QUARTER ENDED MARCH 31, 2014

PART I. FINANCIAL INFORMATION

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	March 31, 2014	December 31, 2013
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($1 and $1 attributable to our VIE)	$1,004	$837
Restricted cash	75	75
Accounts receivable, net	2,593	2,222
Short-term derivative assets	2	—
Deferred income tax asset	243	223
Other current assets	358	299
Total Current Assets	4,275	3,656
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full cost accounting:		
Proved natural gas and oil properties ($488 and $488 attributable to our VIE)	57,399	56,157
Unproved properties	11,672	12,013
Oilfield services equipment	2,239	2,192
Other property and equipment	3,429	3,203
Total Property and Equipment, at Cost	74,739	73,565
Less: accumulated depreciation, depletion and amortization (($190) and ($168) attributable to our VIE)	(37,844)	(37,161)
Property and equipment held for sale, net	627	730
Total Property and Equipment, Net	37,522	37,134
LONG-TERM ASSETS:		
Investments	288	477
Long-term derivative assets	11	4
Other long-term assets	509	511
TOTAL ASSETS	$42,605	$41,782

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS – (Continued)
(Unaudited)

	March 31, 2014	December 31, 2013
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$1,786	$1,596
Short-term derivative liabilities ($6 and $5 attributable to our VIE)	417	208
Current maturities of long-term debt, net	316	—
Accrued interest	145	200
Other current liabilities ($19 and $22 attributable to our VIE)	3,294	3,511
Total Current Liabilities	5,958	5,515
LONG-TERM LIABILITIES:		
Long-term debt, net	12,653	12,886
Deferred income tax liabilities	3,828	3,407
Long-term derivative liabilities	395	445
Asset retirement obligations	443	405
Other long-term liabilities	851	984
Total Long-Term Liabilities	18,170	18,127
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: 665,214,625 and 666,192,371 shares issued	7	7
Paid-in capital	12,459	12,446
Retained earnings	1,012	688
Accumulated other comprehensive loss	(153)	(162)
Less: treasury stock, at cost; 1,986,178 and 2,002,029 common shares	(46)	(46)
Total Chesapeake Stockholders' Equity	16,341	15,995
Noncontrolling interests	2,136	2,145
Total Equity	18,477	18,140
TOTAL LIABILITIES AND EQUITY	$42,605	$41,782

The accompanying notes are an integral part of these condensed consolidated financial statements.
2

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended March 31,	
	2014	2013
	($ in millions except per share data)	
REVENUES:		
Natural gas, oil and NGL	$1,766	$1,453
Marketing, gathering and compression	3,015	1,781
Oilfield services	265	190
Total Revenues	5,046	3,424
OPERATING EXPENSES:		
Natural gas, oil and NGL production	288	307
Production taxes	50	53
Marketing, gathering and compression	2,980	1,745
Oilfield services	220	155
General and administrative	79	110
Restructuring and other termination costs	(7)	133
Natural gas, oil and NGL depreciation, depletion and amortization	628	648
Depreciation and amortization of other assets	78	78
Impairments of fixed assets and other	20	27
Net gains on sales of fixed assets	(23)	(49)
Total Operating Expenses	4,313	3,207
INCOME FROM OPERATIONS	733	217
OTHER INCOME (EXPENSE):		
Interest expense	(39)	(21)
Losses on investments	(21)	(37)
Net gain on sales of investments	67	—
Other income	6	6
Total Other Income (Expense)	13	(52)
INCOME BEFORE INCOME TAXES	746	165
INCOME TAX EXPENSE		
Current income taxes	3	1
Deferred income taxes	277	62
Total Income Tax Expense	280	63
NET INCOME	466	102
Net income attributable to noncontrolling interests	(41)	(44)
NET INCOME ATTRIBUTABLE TO CHESAPEAKE	425	58
Preferred stock dividends	(43)	(43)
Earnings allocated to participating securities	(8)	—
NET INCOME AVAILABLE TO COMMON STOCKHOLDERS	$374	$15
EARNINGS PER COMMON SHARE:		
Basic	$0.57	$0.02
Diluted	$0.54	$0.02
CASH DIVIDEND DECLARED PER COMMON SHARE	$0.0875	$—
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):		

Basic	658	651
Diluted	765	651

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Three Months Ended March 31,	
	2014	2013
	($ in millions)	
NET INCOME	$466	$102
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX:		
Unrealized gain (loss) on derivative instruments, net of income tax expense (benefit) of $1 million and ($1) million	3	(1)
Reclassification of loss on settled derivative instruments, net of income tax expense of $7 million and $7 million	11	12
Unrealized loss on investments, net of income tax benefit of $0 and ($3) million	—	(5)
Reclassification of (gain) loss on investment, net of income tax expense (benefit) of ($3) million and $4 million	(5)	6
Other Comprehensive Income	9	12
COMPREHENSIVE INCOME	475	114
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(41)	(44)
COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE	$434	$70

The accompanying notes are an integral part of these condensed consolidated financial statements.
4

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended March 31,	
	2014	2013
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME	$466	$102
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	706	726
Deferred income tax expense	277	62
Derivative losses, net	363	143
Cash (payments) receipts on derivative settlements, net	(157)	12
Stock-based compensation	20	32
Net gains on sales of fixed assets	(23)	(49)
Impairments of fixed assets and other	12	27
Losses on investments	21	29
Net gain on sales of investments	(67)	—
Restructuring and other termination costs	(9)	105
Other	5	(10)
Changes in assets and liabilities	(323)	(255)
Net Cash Provided By Operating Activities	1,291	924
CASH FLOWS FROM INVESTING ACTIVITIES:		
Drilling and completion costs	(897)	(1,579)
Acquisitions of proved and unproved properties	(187)	(280)
Proceeds from divestitures of proved and unproved properties	49	190
Additions to other property and equipment	(437)	(330)
Proceeds from sales of other assets	239	201
Additions to investments	(3)	(3)
Proceeds from sales of investments	239	—
Decrease in restricted cash	—	55
Other	(2)	1
Net Cash Used In Investing Activities	(999)	(1,745)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from credit facilities borrowings	421	3,632
Payments on credit facilities borrowings	(362)	(2,811)
Cash paid for common stock dividends	(58)	(58)
Cash paid for preferred stock dividends	(43)	(43)
Cash paid on financing derivatives	(15)	(11)
Cash paid for prepayment of mortgage	—	(55)
Distributions to noncontrolling interest owners	(53)	(57)
Other	(15)	(30)
Net Cash Provided By (Used In) Financing Activities	(125)	567
Net increase (decrease) in cash and cash equivalents	167	(254)
Cash and cash equivalents, beginning of period	837	287
Cash and cash equivalents, end of period	$1,004	$33

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS – (Continued)
(Unaudited)

Supplemental disclosures to the condensed consolidated statements of cash flows are presented below:

	Three Months Ended March 31,	
	2014	2013
	($ in millions)	
SUPPLEMENTAL CASH FLOW INFORMATION:		
Interest paid, net of capitalized interest	$75	$60
Income taxes paid, net of refunds received	$—	$—
SUPPLEMENTAL DISCLOSURE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Change in accrued drilling and completion costs	$(168)	$(79)
Change in accrued acquisitions of proved and unproved properties	$7	$(3)
Change in accrued additions to other property and equipment	$(2)	$11

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(Unaudited)

	Three Months Ended March 31, 2014	2013
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning and end of period	$3,062	$3,062
COMMON STOCK:		
Balance, beginning and end of period	7	7
PAID-IN CAPITAL:		
Balance, beginning of period	12,446	12,293
Stock-based compensation	5	70
Tax benefit (reduction in tax benefit) from stock-based compensation	3	(10)
Exercise of stock options	5	2
Balance, end of period	12,459	12,355
RETAINED EARNINGS:		
Balance, beginning of period	688	437
Net income attributable to Chesapeake	425	58
Dividends on common stock	(58)	—
Dividends on preferred stock	(43)	—
Balance, end of period	1,012	495
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(162)	(182)
Hedging activity	14	11
Investment activity	(5)	1
Balance, end of period	(153)	(170)
TREASURY STOCK – COMMON:		
Balance, beginning of period	(46)	(48)
Purchase of 10,156 and 160,145 shares for company benefit plans	—	(3)
Release of 26,007 and 77,892 shares from company benefit plans	—	2
Balance, end of period	(46)	(49)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY	16,341	15,700
NONCONTROLLING INTERESTS:		
Balance, beginning of period	2,145	2,327
Net income attributable to noncontrolling interests	41	44
Distributions to noncontrolling interest owners	(50)	(57)
Balance, end of period	2,136	2,314
TOTAL EQUITY	$18,477	$18,014

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation and Summary of Significant Accounting Policies

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements of Chesapeake Energy Corporation ("Chesapeake" or the "Company") and its subsidiaries are prepared in accordance with accounting principles generally accepted in the United States (U.S. GAAP) and include the accounts of our direct and indirect wholly owned subsidiaries and entities in which Chesapeake has a controlling financial interest. Intercompany accounts and balances have been eliminated.

This Form 10-Q relates to the three months ended March 31, 2014 (the “Current Quarter”) and the three months ended March 31, 2013 (the “Prior Quarter”). Chesapeake’s annual report on Form 10-K for the year ended December 31, 2013 (“2013 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 presentation of the results for the interim periods have been reflected. The results for the Current Quarter are not necessarily indicative of the results to be expected for the full year.

Risks and Uncertainties

We recently conducted a company-wide review of our operations, assets and organizational structure to best position the Company to maximize shareholder value as we focus on our strategic priorities of financial discipline and profitable and efficient growth from captured resources. We intend to apply financial discipline through all aspects of our business, and we believe that the successful execution of this strategy will allow us to better balance capital expenditures with cash flow from operations as well as reduce financial leverage and complexity. While furthering our strategic priorities, certain actions that would reduce financial leverage and complexity could negatively impact our future results of operations and/or liquidity. We expect to incur various cash and noncash charges, including but not limited to impairments of fixed assets, lease termination charges, financing extinguishment costs and charges for unused natural gas transportation and gathering capacity.

2. Earnings Per Share

Basic earnings per share (EPS) is calculated using the weighted average number of common shares outstanding during the period and includes the effect of any participating securities as appropriate. Participating securities consist of unvested restricted stock issued to our employees and non-employee directors that provide dividend rights.

Diluted EPS is calculated assuming issuance of common shares for all potentially dilutive securities, provided the effect is not antidilutive. For the Current Quarter and the Prior Quarter, our contingent convertible senior notes did not have a dilutive effect and therefore were excluded from the calculation of diluted EPS. See Note 3 for further discussion of our contingent convertible senior notes.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

For the Prior Quarter, our cumulative convertible preferred stock and participating securities and associated adjustments to net income, consisting of dividends on such shares, were excluded from the calculation of diluted EPS, as the effect was antidilutive. The impact of our stock options was immaterial in the calculation of diluted EPS for both the Current Quarter and the Prior Quarter. The following table sets forth the net income adjustments and shares of common stock related to our outstanding cumulative convertible preferred stock and participating securities in the Prior Quarter:

	Net Income Adjustments ($ in millions)	Shares (in millions)
Three Months Ended March 31, 2013:		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$21	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
Participating securities	$—	—

For the Current Quarter, all outstanding equity securities that were convertible into common stock were included in the calculation of diluted EPS. A reconciliation of basic EPS and diluted EPS for the Current Quarter is as follows:

	Net Income Available to Common Stockholders (Numerator)	Weighted Average Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
Three Months Ended March 31, 2014:			
Basic EPS	$374	658	$0.57
Effect of Dilutive Securities:			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 5.75% cumulative convertible preferred stock	21	56	
Common shares assumed issued for 5.75% cumulative convertible preferred stock (series A)	16	39	
Common shares assumed issued for 5.00% cumulative convertible preferred stock (series 2005B)	3	5	
Common shares assumed issued for 4.50% cumulative convertible preferred stock	3	6	
Outstanding stock options	—	1	
Diluted EPS	$417	765	$0.54

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

3. Debt

Our long-term debt consisted of the following as of March 31, 2014 and December 31, 2013:

	March 31, 2014	December 31, 2013
	($ in millions)	
Term loan due 2017[a]	$2,000	$2,000
9.5% senior notes due 2015[b]	1,265	1,265
3.25% senior notes due 2016	500	500
6.25% euro-denominated senior notes due 2017[c]	473	473
6.5% senior notes due 2017	660	660
6.875% senior notes due 2018[d]	97	97
7.25% senior notes due 2018	669	669
6.625% senior notes due 2019[e]	650	650
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
5.375% senior notes due 2021	700	700
5.75% senior notes due 2023	1,100	1,100
2.75% contingent convertible senior notes due 2035[f]	396	396
2.5% contingent convertible senior notes due 2037[f]	1,168	1,168
2.25% contingent convertible senior notes due 2038[f]	347	347
Corporate revolving bank credit facility	—	—
Oilfield services revolving bank credit facility	464	405
Discount on senior notes and term loan[g]	(333)	(357)
Interest rate derivatives[h]	13	13
Total debt, net	12,969	12,886
Less current maturities of long-term debt, net[b]	(316)	—
Total long-term debt, net	$12,653	$12,886

(a) We repaid the borrowings outstanding under the term loan due 2017 on April 24, 2014 with a portion of the net proceeds from our offering of $3.0 billion in aggregate principal amount of senior notes issued on April 24, 2014. See Note 19 for further discussion of refinancing transactions subsequent to March 31, 2014.

(b) On April 10, 2014, we commenced a tender offer for the 9.5% Senior Notes due 2015 concurrently with an offering of senior notes. On April 24, 2014, we purchased approximately $946 million aggregate principal amount of notes that were tendered by the early tender date. The tender offer will expire on May 7, 2014, unless extended. See Note 19 for further discussion of refinancing transactions subsequent to March 31, 2014. The remaining $319 million in aggregate principal amount not tendered by the early tender date and the associated $3 million of discount are reflected as a current liability on our March 31, 2014 condensed consolidated balance sheet.

(c) The principal amount shown is based on the exchange rate of $1.3769 to €1.00 and $1.3743 to €1.00 as of March 31, 2014 and December 31, 2013, respectively. See Note 8 for information on our related foreign currency derivatives.

(d) On April 10, 2014, we called the 6.875% Senior Notes due 2018 for redemption on May 12, 2014. See Note 19 for discussion of refinancing transactions subsequent to March 31, 2014.

(e) Issuers are Chesapeake Oilfield Operating, L.L.C. (COO), an indirect wholly owned subsidiary of the Company, and Chesapeake Oilfield Finance, Inc. (COF), a wholly owned subsidiary of COO formed solely to facilitate the

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

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.

(f) 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 quarterly. In the first quarter of 2014, 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 2014 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. The notes were not convertible under this provision in the Current Quarter or the Prior Quarter. 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. Under certain conditions, we will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years. 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	$48.09	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$63.62	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$106.75	June 14, 2019

(g) Discount as of March 31, 2014 and December 31, 2013 included $284 million and $303 million, respectively, associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method. Discount also included $30 million and $33 million as of March 31, 2014 and December 31, 2013, respectively, associated with our term loan discussed further below.

(h) See Note 8 for further discussion related to these instruments.

Term Loan

In November 2012, we established an unsecured five-year term loan credit facility in an aggregate principal amount of $2.0 billion for net proceeds of $1.935 billion. The term loan provided that it could be voluntarily repaid before November 9, 2015 at par plus a specified premium and at any time thereafter at par. The maturity date of the term loan was December 2, 2017. On April 24, 2014, the Company used a portion of the net proceeds from its offering of $3.0 billion in aggregate principal amount of senior notes to repay the borrowings under, and terminate, the term loan. See Note 19 for further discussion related to the refinancing transactions subsequent to March 31, 2014.

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 direct and indirect 100% owned subsidiaries. See Note 17 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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

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 senior notes and the contingent convertible senior notes do not have any financial or restricted payment covenants. The senior notes and contingent convertible senior notes indentures have cross default provisions that apply to other indebtedness the Company or any guarantor subsidiary may have from time to time with an outstanding principal amount of at least $50 million, depending on the indenture.

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. The applicable 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.

In March 2013, the Company brought suit in the U.S. District Court for the Southern District of New York (the "Court") against The Bank of New York Mellon Trust Company, N.A. ("BNY Mellon"), the indenture trustee for the 2019 Notes. The Company sought a declaration that the notice it issued on March 15, 2013 to redeem all of the 2019 Notes at par (plus accrued interest through the redemption date) was timely and effective pursuant to the special early redemption provision of the supplemental indenture governing the 2019 Notes. BNY Mellon asserted that the March 15, 2013 notice was not effective to redeem the 2019 Notes at par because it was not timely for that purpose and because of the specific phrasing in the notice that provided it would not be effective unless the Court concluded it was timely. The Court conducted a trial on the matter in late April and on May 8, 2013 ruled in the Company's favor. On May 11, 2013, BNY Mellon filed notice of an appeal of the decision with the United States Court of Appeals for the Second Circuit and the appeal is currently pending.

No scheduled principal payments are required on our senior notes until February 2015. See Note 19 for discussion of senior notes refinancing transactions subsequent to March 31, 2014.

COO Senior Notes

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 by COO 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. The COO senior notes have cross default provisions that apply to other indebtedness COO or any of its guarantor subsidiaries may have from time to time with an outstanding principal amount of $50 million or more.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

Bank Credit Facilities

During the Current Quarter, we had the following two revolving bank credit facilities as sources of liquidity:

	Corporate Credit Facility[(a)]	Oilfield Services Credit Facility[(b)]
	($ in millions)	
Facility structure	Senior secured revolving	Senior secured revolving
Maturity date	December 2015	November 2016
Borrowing capacity	$4,000	$500
Amount outstanding as of March 31, 2014	$—	$464
Letters of credit outstanding as of March 31, 2014	$23	$—

(a) Co-borrowers are Chesapeake Exploration, L.L.C., Chesapeake Appalachia, L.L.C. and Chesapeake Louisiana, L.P.

(b) Borrower is COO.

Although the applicable interest rates under our corporate credit facility fluctuate 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 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 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.

Our corporate 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 our corporate credit facility agreement as of March 31, 2014.

Our corporate credit facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and certain of our wholly owned subsidiaries. If we should fail to perform our obligations under the credit facility agreement, 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 and contingent convertible senior note indentures, which could in turn result in the acceleration of a significant portion of such indebtedness. The credit facility agreement also has cross default provisions that apply to our secured hedging facility, equipment master lease agreements, term loan and other indebtedness of Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $125 million. In addition, the facility contains a restriction on our ability to declare and pay cash dividends on our common or preferred stock if an event of default has occurred.

Oilfield Services Credit Facility. Our $500 million syndicated oilfield services 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 an indirect 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 for this facility, which are unrestricted subsidiaries under Chesapeake's senior notes, contingent convertible senior notes, term loan and corporate revolving bank credit facility), and bear interest at our option at either

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

(i) the greater of the reference rate of Bank of America, N.A., the federal funds effective rate plus 0.50%, or 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 enter into asset sales, 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 earnings before interest, taxes, depreciation, amortization and rent (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 EBITDAR to lease-adjusted interest expense, in each case as defined in the agreement. COO was in compliance with all covenants under the agreement as of March 31, 2014. If COO or its restricted subsidiaries should fail to perform their obligations under the agreement, 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 COO senior note indenture, which could in turn result in the acceleration of the COO senior note indebtedness. 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.

Fair Value of Other Financial Instruments

We estimate the fair value of our exchange-traded debt using quoted market prices (Level 1). The fair value of all other debt, which consists of our credit facilities and our term loan, is estimated using our credit default swap rate (Level 2). Fair value is compared to the carrying value, excluding the impact of interest rate derivatives, in the table below.

	March 31, 2014		December 31, 2013	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
		($ in millions)		
Long-term debt (Level 1)	$10,522	$11,639	$10,501	$11,557
Long-term debt (Level 2)	$2,434	$2,432	$2,372	$2,369

4. Contingencies and Commitments

Contingencies

Litigation and Regulatory Proceedings

The Company is involved in a number of litigation and regulatory proceedings (including those described below). Many of these proceedings are in early stages, and many of them seek or may seek damages and penalties, the amount of which is indeterminate. We estimate and provide for potential losses that may arise out of litigation and regulatory proceedings to the extent that such losses are probable and can be reasonably estimated. Significant judgment is required in making these estimates and our final liabilities may ultimately be materially different. Our total estimated liability in respect of litigation and regulatory proceedings is determined on a case-by-case basis and represents an estimate of probable losses after considering, among other factors, the progress of each case or proceeding, our experience and the experience of others in similar cases or proceedings, and the opinions and views of legal counsel. We account for legal defense costs in the period the costs are incurred.

July 2008 Common Stock Offering. On February 25, 2009, a putative class action was filed in the U.S. District Court for the Southern District of New York against the Company and certain of its officers and directors along with certain underwriters of the Company’s July 2008 common stock offering. The 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. Chesapeake and the officer and director defendants moved for summary judgment on grounds of loss causation and materiality on December 28, 2011, and the motion was granted as to all claims as a matter of law on March 29, 2013. Final judgment in favor of Chesapeake and the officer and director defendants was entered on June 21, 2013, and the plaintiff filed a notice of appeal on July 19, 2013 in the U.S. Court of Appeals for the Tenth Circuit. The appeal has been fully briefed and oral argument is scheduled for May 14, 2014. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with this matter.
A derivative action relating to the July 2008 offering filed in the U.S. District Court for the Western District of Oklahoma on September 6, 2011 is pending. Following the denial on September 28, 2012 of its motion to dismiss and pursuant to court order, nominal defendant Chesapeake filed an answer in the case on October 12, 2012. By stipulation between the parties, the case is stayed pending resolution of the Tenth Circuit appeal.
2012 Securities and Shareholder Litigation. A putative class action was filed in the U.S. District Court for the Western District of Oklahoma on April 26, 2012 against the Company and its former Chief Executive Officer (CEO), Aubrey K. McClendon. On July 20, 2012, the court appointed a lead plaintiff, which filed an amended complaint on October 19, 2012 against the Company, Mr. McClendon and certain other officers. The amended complaint asserted claims under Sections 10(b) (and Rule 10b-5 promulgated thereunder) and 20(a) of the Securities Exchange Act of 1934 based on alleged misrepresentations regarding the Company’s asset monetization strategy, including liabilities associated with its volumetric production payment (VPP) transactions, as well as Mr. McClendon’s personal loans and the Company’s internal controls. On December 6, 2012, the Company and other defendants filed a motion to dismiss the action. On April 10, 2013, the Court granted the motion, and on April 16, 2013, entered judgment against the plaintiff and dismissed the complaint with prejudice. The plaintiff filed a notice of appeal on June 14, 2013 in the U.S. Court of Appeals for the Tenth Circuit. Briefing on the appeal was complete on August 2, 2013, and on November 18, 2013 argument was heard. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with this matter.
A related federal consolidated derivative action and an Oklahoma state court derivative action are stayed pursuant to the parties' stipulation pending resolution of the appeal in the federal securities class action.
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. On August 21, 2012, the District Court granted the Company's motion to dismiss for lack of derivative standing, and the plaintiff appealed the ruling on December 6, 2012.
2014 Shareholder Litigation. On April 10, 2014, a derivative action was filed in the District Court of Oklahoma County, Oklahoma against current and former directors and officers of the Company alleging, among other things, breach of fiduciary duties, waste of corporate assets, gross mismanagement and unjust enrichment related to the Company’s payment of shareholder dividends since October 2012.
Regulatory Proceedings. On May 2, 2012, Chesapeake and Mr. McClendon received notice from the U.S. Securities and Exchange Commission that its Fort Worth Regional Office had commenced an informal inquiry into, among other things, certain of the matters alleged in the foregoing 2012 securities and shareholder lawsuits. On December 21, 2012, the SEC’s Fort Worth Regional Office advised Chesapeake that its inquiry was continuing as an investigation. The Company provided information and testimony to the SEC pursuant to subpoenas and otherwise in connection with this matter and is also responding to related inquiries from other governmental and regulatory agencies and self-regulatory organizations. On April 8, 2014, the SEC’s Fort Worth Regional Office advised Chesapeake that it had concluded its investigation and, based on the information it had as of that date, did not intend to recommend an enforcement action by the SEC.
The Company has received, from the Antitrust Division of the U.S. Department of Justice (DOJ) and certain state governmental agencies, subpoenas and demands for documents, information and testimony in connection with investigations into possible violations of federal and state laws relating to our purchase and lease of oil and gas rights in various states. Chesapeake has engaged in discussions with the DOJ and state agencies and continues to respond to such subpoenas and demands. On March 5, 2014, the Attorney General of the state of Michigan filed a criminal complaint against Chesapeake in Michigan state court alleging misdemeanor antitrust violations and attempted

antitrust violations under state law arising out of the Company's leasing activities in Michigan during 2010.
Business Operations. Chesapeake is involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions. With regard to contract actions, 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. Regarding royalty claims, Chesapeake and other natural gas producers have been named in various lawsuits alleging royalty underpayment. The suits allege that we used below-market prices, made improper deductions, used improper measurement techniques and/or entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sale of natural gas and NGL. The Company is defending against certain pending claims, has resolved a number of claims through negotiated settlements of past and future royalties and has prevailed in various other lawsuits.
Based on management's current assessment, we are of the opinion that no pending or threatened lawsuit or dispute relating 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.
Environmental Proceedings
The nature of the natural gas and oil business carries with it certain environmental risks for Chesapeake and its subsidiaries. Chesapeake has implemented various policies, procedures, training and auditing to reduce and mitigate such environmental risks. Chesapeake conducts periodic reviews, on a company-wide basis, to assess changes in our environmental risk profile. Environmental reserves are established for environmental liabilities for which economic losses are probable and reasonably estimable. We manage our exposure to environmental liabilities in acquisitions by using an evaluation process that seeks to identify pre-existing contamination or compliance concerns and addressing the potential liability. Depending on the extent of an identified environmental concern, Chesapeake may, among other things, exclude a property from the transaction, require the seller to remediate the property to our satisfaction in an acquisition or agree to assume liability for the remediation of the property.
On December 19, 2013, our subsidiary Chesapeake Appalachia, LLC (CALLC) entered into a consent decree with the U.S. Environmental Protection Agency (EPA), the U.S. Department of Justice (DOJ) and the West Virginia Department of Environmental Protection (WVDEP) to resolve alleged violations of the Clean Water Act (CWA) and the West Virginia Water Pollution Control Act at 27 sites in West Virginia. In a complaint filed against CALLC the same day in the U.S. District Court for the Northern District of West Virginia, the EPA and WVDEP alleged that CALLC impounded streams and discharged sand, dirt, rocks and other fill material into streams and wetlands without a federal permit in order to construct well pads, impoundments, road crossings and other facilities related to natural gas extraction. The consent decree was approved and entered by the court on March 11, 2014.
In accordance with the consent decree, CALLC paid a civil penalty of $3.2 million, which was divided evenly between the U.S. and the state of West Virginia. The consent decree settlement also requires that CALLC restore the affected wetlands and streams in accordance with an agreed plan, monitor the restored sites for up to 10 years to assure the success of the restoration, and implement a comprehensive compliance program to ensure future compliance with the CWA and applicable West Virginia law. To offset the impacts to sites, CALLC is required by the consent decree to perform compensatory mitigation, which will likely involve purchasing credits from a wetland mitigation bank located in a local watershed. We believe that compliance with the consent decree will not have a material adverse impact on our business.
In a related case, in December 2012, CALLC pled guilty to three misdemeanor violations of the CWA for unauthorized discharge at one of the sites subject to the consent decree of crushed stone and gravel into a local stream to create a roadway to improve access to a drilling site. CALLC paid a $600,000 penalty and is subject to a two-year probation ending in December 2014. CALLC has fully restored the site, and we believe that CALLC is in compliance with the terms of probation. By operation of law, a CWA conviction triggers "disqualification", by which the disqualified entity is prohibited from receiving federal contracts or benefits until the EPA certifies that the conditions giving rise to the conviction have been corrected. Disqualification of CALLC has not had, and we do not expect it to

have, a material adverse impact on our business.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

Commitments

Rig Leases

As of March 31, 2014, we leased 25 rigs under master lease agreements with an aggregate undiscounted future lease commitment of $20 million. The lease commitments are guaranteed by Chesapeake and certain of its subsidiaries. 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 a 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. During the Current Quarter, we purchased 20 leased rigs from various lessors for an aggregate purchase price of approximately $77 million and paid approximately $8 million in lease termination costs. Through these transactions, we lowered our minimum aggregate undiscounted future rig lease payments by approximately $43 million.

Compressor Leases

As of March 31, 2014, we leased 346 compressors under master lease agreements with an aggregate undiscounted future lease commitment of $63 million. The lease commitments are guaranteed by Chesapeake and certain of its subsidiaries. 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 a 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. During the Current Quarter, we purchased 1,435 leased compressor units from various lessors for an aggregate purchase price of approximately $271 million, lowering our minimum aggregate undiscounted future compressor lease payments by approximately $196 million.

Gathering, Processing and Transportation Agreements

We have contractual commitments with midstream service companies and pipeline carriers for future gathering, processing and transportation of natural gas and liquids to move certain of our production to market. Working interest owners and royalty interest owners, where appropriate, will be responsible for their proportionate share of these costs. Commitments related to gathering, processing and transportation agreements are not recorded in the accompanying condensed consolidated balance sheets; however, they are reflected as adjustments to natural gas, oil and NGL sales prices used in our proved reserves estimates.

The aggregate undiscounted commitments under our gathering, processing and transportation agreements, excluding any reimbursement from working interest and royalty interest owners or credits for third-party volumes, are presented below.

	March 31, 2014 ($ in millions)
2014	$1,546
2015	1,830
2016	1,915
2017	1,948
2018	1,749
2019 - 2099	7,746
Total	$16,734

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

Drilling Contracts

Chesapeake has contracts with various drilling contractors to utilize 13 rigs with terms ranging from six months to three years. These commitments are not recorded in the accompanying condensed consolidated balance sheets. As of March 31, 2014, the aggregate undiscounted minimum future payments under these drilling rig commitments were approximately $109 million.

Drilling Commitments

In December 2011, as part of our Utica joint venture development agreement with Total S.A. (Total) (see Note 9), 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 July 31, 2015. Through March 31, 2014, we had spud 488 cumulative Utica wells and had met our 2012 and 2013 commitments. If we fail to meet the drilling commitment at July 31, 2015 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 the number of wells drilled in the subsequent 12-month period represented by the shortfall versus our drilling commitment. As such, any reduction would only affect the timing of the receipt of the drilling carry but not the total drilling carry to be received.

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

Property and Equipment Purchase Commitments

Much of the oilfield services and other equipment we purchase requires long production lead times. As a result, we have outstanding orders and commitments for such equipment. As of March 31, 2014, we had $117 million of purchase commitments related to future inventory and capital expenditures for oilfield services and other equipment.

Natural Gas and Liquids Purchase Commitments

We regularly commit to purchase natural gas and liquids from other owners in the properties we operate, including owners associated with our VPP transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices. See Note 9 for further discussion of our VPP transactions.

Net Acreage Maintenance Commitments

Under the terms of our joint venture agreements with Statoil, Total and Sinopec (see Note 9), 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. To date, we have satisfied our replacement commitments under the Statoil and Sinopec agreements. We estimate a shortfall of approximately 14,000 net acres pursuant to our net acreage maintenance commitment with Total under the terms of our Barnett Shale joint venture agreement and have accrued $28 million as of March 31, 2014. Total has disputed our estimate of the shortfall, however, and the cash payment we ultimately make to Total could exceed amounts we have accrued.

Affiliate Commitments

Under the terms of our corporate revolving bank credit facility, certain of our subsidiaries, including our oilfield services companies, are not guarantors of the credit facility debt. Transactions between us and our non-guarantor subsidiaries may affect our EBITDA or indebtedness for purposes of our credit facility covenant calculations, but they would have no effect on our consolidated financial statements because the transactions would be eliminated through consolidation. See Note 3 for discussion of our covenant calculations.

In October 2011, we entered into a services agreement with our wholly owned subsidiary, COO, under which we guarantee the utilization of a portion of COO’s drilling rig and hydraulic fracturing fleets during the term of the agreement. Through October 2016, we are subject to non-utilization fees if we do not operate a specific number of COO’s drilling rigs or utilize a specific number of its hydraulic fracturing fleets. We were not subject to any non-utilization fees in the Current Quarter or the Prior Quarter.

16

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

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, providing at least a 10% gross margin to FTS, if utilization of FTS fleets falls below a certain level. To date, we have not been required to enter into any backstop contracts.

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 Longmont, Colorado, $35 million of which was invested in July 2011 and the remainder of which was payable in separate tranches linked to specified funding and operational milestones. We also provided Sundrop with a one-time option to require us to purchase up to $25 million in additional preferred equity securities following the full payment of the initial investment, subject the occurrence of specified milestones. As of March 31, 2014, we had funded our initial $155 million commitment in full and the milestones related to the option had not been met. See Note 10 for further discussion of this investment.

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 wholly owned guarantor subsidiaries. These agreements may include future payment obligations or commitments regarding operational performance that effectively guarantee our subsidiaries' future performance.

In connection with divestitures, our purchase and sale agreements generally provide 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 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 royalty and overriding royalty interests, including overriding royalty interests sold through our VPP transactions. As the holder of the working interest from which such interests have been created, we have the responsibility to bear the cost of developing and producing the reserves attributable to such interests. See Note 9 for further discussion of our VPP transactions.

5. Other Liabilities

Other current liabilities as of March 31, 2014 and December 31, 2013 are detailed below.

	March 31, 2014	December 31, 2013
	($ in millions)	
Revenues and royalties due others	$1,499	$1,409
Accrued natural gas, oil and NGL drilling and production costs	285	457
Joint interest prepayments received	530	464
Accrued compensation and benefits	228	320
Other accrued taxes	113	161
Accrued dividends	101	101
Other	538	599
Total other current liabilities	$3,294	$3,511

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

Other long-term liabilities as of March 31, 2014 and December 31, 2013 are detailed below.

	March 31, 2014	December 31, 2013
	($ in millions)	
CHK Utica ORRI conveyance obligation[a]	$242	$250
CHK C-T ORRI conveyance obligation[b]	146	149
Financing obligations	30	31
Other	433	554
Total other long-term liabilities	$851	$984

(a) $15 million and $13 million of the total $257 million and $263 million obligations are recorded in other current liabilities as of March 31, 2014 and December 31, 2013, respectively. See Note 6 for further discussion of the transaction.

(b) $15 million and $12 million of the total $161 million and $161 million obligations are recorded in other current liabilities as of March 31, 2014 and December 31, 2013, respectively. See Note 6 for further discussion of the transaction.

6. Equity

Common Stock

The following is a summary of the changes in our common shares issued for the three months ended March 31, 2014 and 2013:

	Three Months Ended March 31, 2014	2013
	(in thousands)	
Shares issued as of January 1	666,192	666,468
Restricted stock issuances (net of forfeitures)[a]	(1,236)	2,631
Stock option exercises	259	176
Shares issued as of March 31	665,215	669,275

(a) In the second quarter of 2013, we began granting restricted stock units (RSUs) in lieu of restricted stock awards (RSAs) to non-employee directors and employees. Shares of common stock underlying RSUs are issued when the units vest, whereas restricted shares of common stock are issued on the grant date of RSAs. We refer to RSAs and RSUs collectively as restricted stock.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

Preferred Stock
The following reflects the shares outstanding and liquidation preferences of our cumulative convertible preferred stock for the three months ended March 31, 2014 and 2013:

	5.75%	5.75% (A)	4.50%	5.00% (2005B)
Shares outstanding as of January 1, 2014 and 2013 and March 31, 2014 and 2013 (in thousands)	1,497	1,100	2,559	2,096
Liquidation preference per share	$1,000	$1,000	$100	$100

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.
Accumulated Other Comprehensive Income (Loss)
For the Current Quarter and the Prior Quarter, changes in accumulated other comprehensive income (loss) by component, net of tax, are detailed below.

	Net Gains (Losses) on Cash Flow Hedges	Net Gains (Losses) on Investments	Total
	($ in millions)		
Balance, December 31, 2013	$(167)	$5	$(162)
Other comprehensive income before reclassifications	3	—	3
Amounts reclassified from accumulated other comprehensive income	11	(5)	6
Net other comprehensive income	14	(5)	9
Balance, March 31, 2014	$(153)	$—	$(153)

	Net Gains (Losses) on Cash Flow Hedges	Net Gains (Losses) on Investments	Total
	($ in millions)		
Balance, December 31, 2012	$(189)	$7	$(182)
Other comprehensive income before reclassifications	(1)	(5)	(6)
Amounts reclassified from accumulated other comprehensive income	12	6	18
Net other comprehensive income	11	1	12
Balance, March 31, 2013	$(178)	$8	$(170)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

For the Current Quarter and the Prior Quarter, amounts reclassified from accumulated other comprehensive income (loss), net of tax, into the condensed consolidated statements of operations are detailed below.

Details About Accumulated Other Comprehensive Income (Loss) Components	Affected Line Item in the Statement Where Net Income is Presented	Three Months Ended March 31, 2014	2013
		($ in millions)	
Net losses on cash flow hedges:			
Commodity contracts	Natural gas, oil and NGL revenues	$11	$12
Investments:			
Impairment of investment	Losses on investments	—	6
Sale of investment	Net gain on sale of investment	(5)	—
Total reclassifications for the period, net of tax		$6	$18

Noncontrolling Interests

Cleveland Tonkawa Financial Transaction. We formed CHK C-T in March 2012 to continue development of a portion of our natural gas and oil assets in 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 indebtedness 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 the existing wells within an area of mutual interest in the plays between the top of the Tonkawa and the top of the Big Lime formations 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 future net wells to be drilled on the contributed 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 remaining 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 sheets. Pursuant to the CHK C-T LLC Agreement, CHK C-T is required to retain an amount of cash equal to the next two quarters of preferred dividend payments and, until December 31, 2013, it was also required to retain an amount of cash equal to its projected operating funding shortfall for the next six months. The amounts retained, approximately $38 million as of March 31, 2014 and December 31, 2013, were reflected as restricted cash on our condensed consolidated balance sheets.
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, any dividend amount is not paid in full for 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, 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 an optional distribution would be allocated 100% to the preferred shares (and applied toward redemption thereof). We may also, at our sole discretion and election, 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 may 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 through redemption 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 can be redeemed on a pro-rata basis in accordance with the then-applicable redemption valuation formula. As of March 31, 2014 and December 31, 2013, the redemption price and the liquidation preference were each approximately $1,230 and $1,245, respectively, per preferred share.
We initially committed to drill and complete, for the benefit of CHK C-T in the area of mutual interest, a minimum of 37.5 net wells per six-month period through 2013, inclusive of wells drilled in 2012, and 25 net wells per six-month

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

period in 2014 through 2016, up to a minimum cumulative total of 300 net wells. In April 2014, the drilling commitment was amended to require us only to drill and complete 12.5 net wells in each of the six-month periods ending June 30, 2014 and December 31, 2014. If we fail to meet the then-current cumulative drilling commitment in any six-month period, any optional cash distributions would be distributed 100% to the investors. If we fail to meet the then-current cumulative 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 cumulative 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 cumulative drilling commitment. CHK C-T is responsible for all capital and operating costs of the wells drilled for the benefit of the entity. Under the development agreement, approximately 3 and 21 qualified net wells were added in the Current Quarter and the Prior Quarter, respectively. Through March 31, 2014, we had met all current drilling commitments associated with the CHK C-T transaction.

The CHK C-T investors’ right to receive, proportionately, a 3.75% ORRI in the contributed wells and up to 1,000 future net wells on our contributed leasehold is subject to an increase to 5% on net wells earned in any year following a year in which we do not meet our net well commitment under the ORRI obligation, which runs from 2012 through the first quarter of 2025. However, in no event would we be required to deliver to investors more than a total ORRI of 3.75% in existing wells and 1,000 future net wells. If at any time CHK C-T holds 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 ORRIs. CHK C-T retains 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 ORRIs 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 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. Under the ORRI obligation, we delivered an ORRI in approximately 3 net wells in the Current Quarter and 22 net wells in the Prior Quarter. Although operations began on April 1, 2012, all wells completed since January 1, 2012 are credited to the ORRI obligation of 1,000 future net wells.

As of March 31, 2014 and December 31, 2013, $1.015 billion of noncontrolling interests on our condensed consolidated balance sheets was attributable to CHK C-T. In both the Current Quarter and the Prior Quarter, income of $19 million was attributable to the noncontrolling interests of CHK C-T.

Utica Financial Transaction. We formed 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 indebtedness 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 the 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 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 remaining 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 sheets. Pursuant to the CHK Utica LLC Agreement, CHK Utica is required to retain a cash balance equal to the next two quarters of preferred dividend payments. The amount reserved for paying such dividends, approximately $37 million as of March 31, 2014 and December 31, 2013, was reflected as restricted cash on our condensed consolidated balance sheets. In addition, pursuant to the CHK Utica LLC Agreement, with respect to any divestiture proceeds as defined by the agreement, CHK Utica is required to separately account for, and dedicate all of such divestiture proceeds to either (i) capital expenditures made by CHK Utica in connection with its assets or (ii) the redemption of CHK Utica preferred shares.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

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, any dividend amount is not paid in full for any quarter. 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. We may also, at our sole discretion and election, 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 may 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 provide the investors the greater of a 17.5% internal rate of return or a return on investment of 2.0x. The preferred shares can be redeemed on a pro-rata basis in accordance with the then-applicable redemption valuation formula. As of March 31, 2014 and December 31, 2013, the redemption price and the liquidation preference were each approximately $1,235 and $1,252, respectively, per preferred share.

We have committed to drill and complete, for the benefit of CHK Utica in the area of mutual interest, a minimum of 50 net wells per year from 2012 through 2016, up to a minimum cumulative total of 250 net wells. CHK Utica is responsible for all capital and operating costs of the wells drilled for the benefit of the entity. If we fail to meet the then-current drilling commitment in any year, we must pay CHK Utica $5 million for each well we are short of such drilling commitment. 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 9 for further discussion of the joint venture. Under the development agreement, approximately 22 and 28 qualified net wells were added in the Current Quarter and the Prior Quarter, respectively. Through March 31, 2014, we had met all current drilling commitments associated with the CHK Utica transaction.

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% on net wells earned in any year following a year in which we do not meet our net well commitment under the ORRI obligation, which runs from 2012 through 2023. However, in no event would we be required to 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 ORRIs. 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 ORRIs 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. Under the ORRI obligation, we delivered an ORRI in approximately 32 new net wells in the Current Quarter and 14 net wells in the Prior Quarter. Because we did not meet our ORRI commitment in 2012, the ORRI increased to 4% for wells earned in 2013, and the ultimate number of wells in which we must assign an interest will be reduced accordingly. Through March 31, 2014, we were on target to meet the ORRI conveyance commitments associated with the CHK Utica transaction.

As of March 31, 2014 and December 31, 2013, $807 million of noncontrolling interests on our condensed consolidated balance sheets was attributable to CHK Utica. In the Current Quarter and the Prior Quarter, income of approximately $19 million and $22 million, respectively, 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 certain 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 certain post-production expenses and any applicable taxes) in 118 development wells that have been or will be drilled on approximately 45,400 gross acres (29,000 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 interests in the undeveloped properties that are subject to the development agreement 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 reduced as we fulfill our drilling obligation over time. As of March 31, 2014 and 2013, we had drilled or caused to be drilled approximately 89 and 64 development wells, respectively, as calculated under the development agreement, and the maximum amount recoverable under the drilling support lien was approximately $65 million and $120 million, respectively.

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. The distribution made with respect to the subordinated units to Chesapeake was either reduced or eliminated for each of the most recent seven quarters of distributions paid. 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.

For the Current Quarter and the Prior Quarter, the Trust declared and paid the following distributions:

Production Period	Distribution Date	Cash Distribution per Common Unit	Cash Distribution per Subordinated Unit
September 2013 - November 2013	March 3, 2014	$0.6624	$—
September 2012 - November 2012	March 1, 2013	$0.6700	$0.3772

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, 2014 and December 31, 2013, $306 million and $314 million, respectively, of noncontrolling interests on our condensed consolidated balance sheets were attributable to the Trust. In both the Current Quarter and the Prior Quarter, income of approximately $5 million was attributable to the Trust's noncontrolling interests in our condensed consolidated statements of operations. See Note 11 for further discussion of VIEs.

Wireless Seismic, Inc. We have a controlling 51% equity interest in Wireless Seismic, Inc. (Wireless), a privately owned company engaged in research, development and production of wireless seismic systems and any related technology that deliver seismic information obtained from standard geophones in real time to laptop and desktop computers. As of March 31, 2014 and December 31, 2013, $8 million and $9 million, respectively, of noncontrolling interests on our condensed consolidated balance sheets were attributable to Wireless. In both the Current Quarter and the Prior Quarter, losses of $1 million were attributable to noncontrolling interests of Wireless in our condensed consolidated statements of operations.

23

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

7. Share-Based Compensation

Chesapeake’s share-based compensation program consists of restricted stock, stock options and performance share units (PSUs) granted to employees and restricted stock granted to non-employee directors under our Long Term Incentive Plan. The restricted stock and stock options are equity-classified awards and the PSUs are liability-classified awards.

Equity-Classified Awards

Restricted Stock. We grant restricted stock to employees and non-employee directors. Restricted stock vests over a minimum of three years and the holder receives dividends or dividend equivalents on unvested shares. A summary of the changes in unvested shares of restricted stock during the Current Quarter is presented below.

	Number of Unvested Restricted Shares (in thousands)	Weighted Average Grant Date Fair Value
Unvested shares as of January 1, 2014	13,400	$23.38
Granted	3,943	$25.13
Vested	(2,350)	$26.41
Forfeited	(638)	$25.69
Unvested shares as of March 31, 2014	14,355	$23.26

The aggregate intrinsic value of restricted stock that vested during the Current Quarter was approximately $62 million based on the stock price at the time of vesting.

As of March 31, 2014, there was $255 million of total unrecognized compensation expense related to unvested restricted stock. The expense is expected to be recognized over a weighted average period of approximately 2.5 years.

The vesting of certain restricted stock grants may 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, we recognized excess tax benefits related to restricted stock of $3 million and during the Prior Quarter we recognized reductions in tax benefits related to restricted stock of $10 million, which were recorded as adjustments to additional paid-in capital and deferred income taxes.

Stock Options. In the Current Quarter and the Prior Quarter, we granted members of senior management stock options that will vest ratably over a three-year period. In the Prior Quarter, we also granted retention awards to certain officers of stock options that will vest one-third on each of the third, fourth and fifth anniversaries of the grant date. Each stock option award has an exercise price equal to the closing price of the Company’s common stock on the grant date. Outstanding options generally expire ten years from the date of grant.

We utilize the Black-Scholes option pricing model to measure the fair value of stock options. The expected life of an option is determined using the "simplified method", as there is no adequate historical exercise behavior available. Volatility assumptions are estimated based on an average of historical volatility of Chesapeake stock over the expected life of an option. The risk-free interest rate is based on the U.S. Treasury rate in effect at the time of the grant over the expected life of the option. The dividend yield is based on an annual dividend yield, taking into account the Company's current dividend policy over the expected life of the option. The Company used the following assumptions to estimate the grant date fair value of the stock options granted in the Current Quarter:

Expected option life - years	6.0	
Volatility	48.33	%
Risk-free interest rate	1.97	%
Dividend yield	1.36	%

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

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

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[(a)]
	(in thousands)			($ in millions)
Outstanding at January 1, 2014	5,268	$19.28	6.66	$41
Granted	786	$25.71		
Exercised	(270)	$18.23		$2
Expired	—	$—		
Outstanding at March 31, 2014	5,784	$20.20	7.15	$31
Exercisable at March 31, 2014	1,766	$18.95	3.72	$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.

As of March 31, 2014, there was $21 million of total unrecognized compensation expense related to stock options. The expense is expected to be recognized over a weighted average period of approximately 2.4 years.

The vesting of certain stock option grants may 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 excess tax benefits related to stock options of a nominal amount and $0, respectively. All amounts were recorded as adjustments to additional paid-in capital and deferred income taxes.

Compensation Expenses. We recorded the following compensation expenses related to restricted stock and stock options during the Current Quarter and the Prior Quarter:

	Three Months Ended March 31,	
	2014	2013
	($ in millions)	
General and administrative expenses	$12	$20
Natural gas and oil properties	7	21
Natural gas, oil and NGL production expenses	4	6
Marketing, gathering and compression expenses	2	3
Oilfield services expenses	2	3
Total	$27	$53

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

Liability-Classified Awards

Performance Share Units. In 2012, 2013 and 2014, we granted PSUs to senior management under our Long Term Incentive Plan that settle in cash at the end of their respective performance periods and vest ratably over their respective terms. The 2012 awards were granted in one-, two- and three-year tranches and are settled in cash on the first, second and third anniversary dates of the awards, and the 2013 and 2014 awards are settled in cash on the third anniversary of the awards. The ultimate amount earned is based on the performance metrics established by the Compensation Committee of the Board of Directors, which include relative and absolute total shareholder return (TSR) and, for certain of the awards, the achievement of operational performance goals such as production and proved reserve growth. The TSR metric is considered a market condition and generally requires a Monte Carlo simulation to determine the fair value.

For PSUs granted in 2012, each of the TSR and operational payout components can range from 0% to 125% resulting in a maximum total payout of 250%. For PSUs granted in 2013, the TSR component can range from 0% to 125% and each of the two operational components can range from 0% to 62.5%; however, the maximum total payout is capped at 200%. For PSUs granted in 2014, the TSR component can range from 0% to 200%, with no operational components. For the 2013 and 2014 PSUs, the payout percentage is capped at 100% if the Company’s absolute TSR is less than zero. The following table presents a summary of our PSU awards as of March 31, 2014:

	Units	Fair Value as of Grant Date	Fair Value	Liability for Vested Amount
		($ in millions)		
2012 Awards [(a)]				
Payable 2015	834,248	$23	$21	$21
2013 Awards				
Payable 2016	1,600,438	$35	$52	$45
2014 Awards				
Payable 2017	620,669	$17	$16	$4

(a) In the Current Quarter and the Prior Quarter, we paid $11 million and $2 million, respectively, related to 2012 PSU awards.

Compensation Expenses. We recorded the following compensation expenses related to PSUs during the Current Quarter and the Prior Quarter:

	Three Months Ended March 31, 2014	2013
	($ in millions)	
Natural gas and oil properties	$1	$4
General and administrative expenses	(1)	5
Marketing, gathering and compression expenses	—	2
Total	$—	$11

26

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

8. Derivative and Hedging Activities

Chesapeake uses commodity derivative instruments to secure attractive pricing and margins on production, to reduce its exposure to fluctuations in future commodity prices and to protect its expected operating cash flow against significant market movements or volatility. Chesapeake also uses derivative instruments to mitigate a portion of our exposure to interest rate and foreign currency exchange rate fluctuations. 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.

Natural Gas and Oil Derivatives

As of March 31, 2014 and December 31, 2013, 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.
- Collars: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike prices, no payments are due from either party. Three-way collars include an additional put option in exchange for a more favorable strike price on the call option. This eliminates the counterparty’s downside exposure below the second put option strike price.
- 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 call swaptions in exchange for a premium that allows a counterparty, on a specific date, to enter into a fixed-price swap for a certain period of time.
- Basis Protection Swaps: These instruments are arrangements that guarantee a price differential to NYMEX from a specified delivery point. Our current natural gas basis protection swaps 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. Our current oil basis protection swaps have positive differentials to NYMEX. Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

The estimated fair values of our natural gas and oil derivative instrument assets (liabilities) as of March 31, 2014 and December 31, 2013 are provided below.

	March 31, 2014		December 31, 2013	
	Volume	Fair Value ($ in millions)	Volume	Fair Value ($ in millions)
Natural gas (tbtu):				
Fixed-price swaps	394	$(125)	448	$(23)
Three-way collars	387	(48)	288	(7)
Call options	193	(202)	193	(210)
Call swaptions	—	—	12	—
Basis protection swaps	151	(14)	68	3
Total natural gas	1,125	(389)	1,009	(237)
Oil (mmbbl):				
Fixed-price swaps	22.8	(81)	25.3	(50)
Call options	41.9	(257)	42.5	(265)
Basis protection swaps	0.3	1	0.4	1
Total oil	65.0	(337)	68.2	(314)
Total estimated fair value		$(726)		$(551)

We have terminated certain commodity derivative contracts that were previously designated as cash flow hedges for which the hedged production is still expected to occur. See further discussion below under Effect of Derivative Instruments - Accumulated Other Comprehensive Income (Loss).

Interest Rate Derivatives

As of March 31, 2014 and December 31, 2013, our interest rate derivative instruments consisted of 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.

The notional amount of our interest rate derivative liabilities as of March 31, 2014 and December 31, 2013 was $2.250 billion. The estimated fair value of our interest rate derivative liabilities as of March 31, 2014 and December 31, 2013 was $80 million and $98 million, respectively.

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 seven years, we will recognize $13 million in net gains related to such transactions.

Foreign Currency Derivatives

We are party to cross currency swaps to mitigate our exposure to foreign currency exchange rate fluctuations that may result from the €344 million principal amount of our euro-denominated senior notes. 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. Under the terms of the cross currency swaps we currently hold, on each semi-annual interest payment date, the counterparties pay us €11 million and we pay the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay us €344 million and we will pay the counterparties $459 million. The swaps are designated as cash flow hedges and, because they are entirely effective in having eliminated any potential variability in our expected cash flows related to changes in foreign exchange rates, changes in their fair value do not impact earnings. The fair values of the cross currency swaps are recorded on the condensed consolidated balance sheet as an asset of $7 million as of March 31, 2014. The euro-denominated debt in long-term debt has been adjusted to $473 million as of March 31, 2014 using an exchange rate of $1.3769 to €1.00.

28

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

Effect of Derivative Instruments – Condensed Consolidated Balance Sheets

The following table presents the fair value and location of each classification of derivative instrument included in the condensed consolidated balance sheets as of March 31, 2014 and December 31, 2013 on a gross basis and after same-counterparty netting:

	March 31, 2014		
Balance Sheet Classification	Gross Fair Value	Amounts Netted in Condensed Consolidated Balance Sheet	Net Fair Value Presented in Condensed Consolidated Balance Sheet
	($ in millions)		
Commodity Contracts			
Short-term derivative asset	$13	$(11)	$2
Long-term derivative asset	3	1	4
Short-term derivative liability	(425)	11	(414)
Long-term derivative liability	(317)	(1)	(318)
Total commodity contracts	(726)	—	(726)
Interest Rate Contracts			
Short-term derivative liability	(3)	—	(3)
Long-term derivative liability	(77)	—	(77)
Total interest rate contracts	(80)	—	(80)
Foreign Currency Contracts[(a)]			
Long-term derivative asset	7	—	7
Total foreign currency contracts	7	—	7
Total Derivatives	$(799)	$—	$(799)

	December 31, 2013		
Balance Sheet Classification	Gross Fair Value	Amounts Netted in Condensed Consolidated Balance Sheet	Net Fair Value Presented in Condensed Consolidated Balance Sheet
	($ in millions)		
Commodity Contracts			
Short-term derivative asset	$29	$(29)	$—
Long-term derivative asset	11	(9)	2
Short-term derivative liability	(231)	29	(202)
Long-term derivative liability	(362)	9	(353)
Total commodity contracts	(553)	—	(553)
Interest Rate Contracts			
Short-term derivative liability	(6)	—	(6)
Long-term derivative liability	(92)	—	(92)
Total interest rate contracts	(98)	—	(98)

Foreign Currency Contracts[a]			
Long-term derivative asset	2	—	2
Total foreign currency contracts	2	—	2
Total Derivatives	$(649)	$—	$(649)

29

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

(a) Designated as cash flow hedging instruments.

As of March 31, 2014 and December 31, 2013, we did not have any cash collateral balances for these derivatives.

Effect of Derivative Instruments – Condensed Consolidated Statements of Operations

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

	Three Months Ended March 31,	
	2014	2013
	($ in millions)	
Natural gas, oil and NGL sales	$2,148	$1,595
Losses on undesignated natural gas, oil and NGL derivatives	(365)	(123)
Losses on terminated cash flow hedges	(17)	(19)
Total natural gas, oil and NGL sales	$1,766	$1,453

The components of interest expense for the Current Quarter and the Prior Quarter are presented below.

	Three Months Ended March 31,	
	2014	2013
	($ in millions)	
Interest expense on senior notes	$180	$186
Interest expense on term loans	29	29
Amortization of loan discount, issuance costs and other	19	19
Interest expense on credit facilities	8	12
Gains on terminated fair value hedges	(1)	—
(Gains) losses on undesignated interest rate derivatives	(18)	4
Capitalized interest	(178)	(229)
Total interest expense	$39	$21

Effect of Derivative Instruments – Accumulated Other Comprehensive Income (Loss)

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

	Three Months Ended March 31,			
	2014		2013	
	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)			
Balance, beginning of period	$(269)	$(167)	$(304)	$(189)
Net change in fair value	4	3	(2)	(1)
Losses reclassified to income	18	11	19	12
Balance, end of period	$(247)	$(153)	$(287)	$(178)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

Approximately $148 million of the $153 million of accumulated other comprehensive loss as of March 31, 2014 represents the net deferred loss associated with commodity derivative contracts that were previously designated as cash flow hedges for which the hedged production is still expected to occur. These amounts will be recognized in earnings in the month in which the originally forecasted hedged production occurs. As of March 31, 2014, we expect to transfer approximately $23 million of net loss included in accumulated other comprehensive income to net income (loss) during the next 12 months. The remaining amounts will be transferred by December 31, 2022.

Credit Risk Considerations

Over-the-counter traded derivative instruments expose us to our counterparties' credit risk. 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. As of March 31, 2014, our natural gas, oil and interest rate derivative instruments were spread among 16 counterparties.

Hedging Facility

Our secured commodity hedging facility with 17 counterparties provides approximately 1.063 bboe of hedging capacity for natural gas, oil and NGL price derivatives and 1.063 bboe for basis derivatives with an aggregate mark-to-market capacity of $17.0 billion. It is 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 redetermination dates and 1.30 times in between those dates, and guarantees by certain subsidiaries that also guarantee our corporate revolving bank credit facility, indentures, term loan and equipment master lease agreements. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that certain requirements are met including maintaining specified collateral coverage ratios as well as maintaining credit ratings with either of the designated rating agencies at or above current levels. 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. As of March 31, 2014, we had hedged under the facility 224 mmboe of our future production with price derivatives and 26 mmboe with basis derivatives.

Fair Value

The fair value of most of our derivatives is 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 compared to the values given by our counterparties for reasonableness. Since natural gas, oil, 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. Derivatives are also subject to the risk that either party to a contract will be unable to meet its 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

The following table provides information for financial assets (liabilities) measured at fair value on a recurring basis as of March 31, 2014 and December 31, 2013:

As of March 31, 2014	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
Derivative Assets (Liabilities):				
Commodity assets	$—	$10	$6	$16
Commodity liabilities	—	(229)	(513)	(742)
Interest rate liabilities	—	(80)	—	(80)
Foreign currency assets	—	7	—	7
Total derivatives	$—	$(292)	$(507)	$(799)

As of December 31, 2013	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
Derivative Assets (Liabilities):				
Commodity assets	$—	$25	$15	$40
Commodity liabilities	—	(100)	(493)	(593)
Interest rate liabilities	—	(98)	—	(98)
Foreign currency assets	—	2	—	2
Total derivatives	$—	$(171)	$(478)	$(649)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

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

	Derivatives Commodity	Interest Rate
	($ in millions)	
Beginning Balance as of January 1, 2014	$(478)	$—
Total gains (losses) (realized/unrealized):		
Included in earnings[a]	(80)	—
Total purchases, issuances, sales and settlements:		
Settlements	55	—
Transfers[b]	(4)	—
Ending Balance as of March 31, 2014	$(507)	$—
Beginning Balance as of January 1, 2013	$(1,016)	$—
Total gains (losses) (realized/unrealized):		
Included in earnings[a]	194	(1)
Total purchases, issuances, sales and settlements:		
Sales	—	(1)
Settlements	37	—
Ending Balance as of March 31, 2013	$(785)	$(2)

(a)

	Natural Gas, Oil and NGL Sales		Interest Expense	
	2014	2013	2014	2013
	($ in millions)			
Total gains (losses) included in earnings for the period	$(80)	$194	$—	$(1)
Change in unrealized gains (losses) related to assets still held at reporting date	$(57)	$191	$—	$(2)

(b) The values related to basis swaps were transferred from Level 3 to Level 2 as a result of our ability to begin using data readily available in the public market to corroborate our estimated fair values.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

Qualitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements
The significant unobservable inputs for Level 3 derivative contracts include unpublished forward prices of natural gas and oil, market volatility and credit risk of counterparties. Changes in these inputs impact the fair value measurement of our derivative contracts. For example, an increase (decrease) in the forward prices and volatility of natural gas and oil prices decreases (increases) the fair value of natural gas and oil derivatives and adverse changes to our counterparties' creditworthiness decreases the fair value of our derivatives.
Quantitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

Instrument Type	Unobservable Input	Range	Weighted Average		Fair Value March 31, 2014[a] ($ in millions)	
Oil trades	Oil price volatility curves	10.56% - 21.78%	15.43	%	$(256	)
Natural gas trades	Natural gas price volatility curves	18.03% - 38.37%	24.32	%	$(251	)

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

9. Natural Gas and Oil Property Divestitures

During the Current Quarter and the Prior Quarter, excluding proceeds received from selling additional interests in our joint venture leasehold described under Joint Ventures below, we received proceeds of approximately $41 million and $165 million, respectively, related to divestitures of noncore natural gas and oil properties.
Under full cost accounting rules, we have accounted for the sale of natural gas and oil properties as an adjustment to capitalized costs, with no recognition of gain or loss as the sales have not involved a significant change in proved reserves or significantly altered the relationship between costs and proved reserves.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

Joint Ventures

As of March 31, 2014, we had entered into eight 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 eight different resource plays and received cash of $8.0 billion and commitments by our counterparties to pay our share of future drilling and completion costs of $9.0 billion. In each of these joint ventures, Chesapeake serves as the operator and conducts all drilling, completion and operations, the majority of leasing and, in certain transactions, marketing activities for the project. The carries paid by a joint venture partner are for a specified percentage of our drilling and completion costs. In addition, a joint venture partner is responsible for its proportionate share of drilling and completion costs as a working interest owner. We bill our joint venture partners for their drilling carries at the same time we bill them and other joint working interest owners for their share of drilling costs as they are incurred. 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	Initial Proceeds[b]		Total Drilling Carries		Total Initial Proceeds and Drilling Carries	Drilling Carries Remaining[c]
				($ in millions)					
Mississippi Lime	Sinopec	June 2013	50.0%	$949	(d)	$—		$949	$—
Utica	TOT	December 2011	25.0%	610		1,422	(e)	2,032	478
Niobrara	CNOOC	February 2011	33.3%	570		697	(f)	1,267	64
Eagle Ford	CNOOC	November 2010	33.3%	1,120		1,080		2,200	—
Barnett	TOT	January 2010	25.0%	800		1,403		2,203	—
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	FCX	July 2008	20.0%	1,650		1,508		3,158	—
				$8,049		$9,035		$17,084	$542

(a) Joint venture partners are Sinopec International Petroleum Exploration and Production (Sinopec), Total S.A. (TOT), CNOOC Limited (CNOOC), Statoil (STO), BP America (BP) and Freeport-McMoRan Copper & Gold (FCX), formerly known as Plains Exploration & Production Company.
(b) Excludes closing and post-closing adjustments.
(c) As of March 31, 2014.
(d) Excludes $71 million of net proceeds (or 7% of the total transaction) expected to be received pursuant to certain post-closing adjustments and approximately $90 million received at closing for closing adjustments.
(e) The Utica drilling carry covers 60% of our drilling and completion costs for Utica wells drilled and must be used by December 2018. We expect to fully utilize this drilling carry commitment prior to expiration. See Note 4 for further discussion of the Utica drilling carries.
(f) The Niobrara drilling carry covers 67% of our drilling and completion costs for Niobrara wells drilled and must be used by December 2014. We expect to fully utilize this drilling carry commitment prior to expiration.

During the Current Quarter and the Prior Quarter, our drilling and completion costs included the benefit of approximately $188 million and $180 million, respectively, in drilling and completion carries paid by our joint venture partners.

During the Current Quarter and the Prior Quarter, we sold interests in additional leasehold we acquired in the Marcellus, Barnett, Utica, Haynesville, Eagle Ford, Mid-Continent and Niobrara Shale plays to our joint venture partners for approximately $8 million and $25 million, respectively.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

Volumetric Production Payments

From time to time, we have sold certain of our producing assets located in more mature producing regions through the sale of 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 all production beyond the specified volumes, if any, after the scheduled production volumes have been delivered. For all of our VPP transactions, we have novated hedges to each of the respective VPP buyers and such hedges covered all VPP volumes sold. If contractually scheduled volumes exceed the actual volumes produced from the VPP wellbores that are attributable to the ORRI conveyed, either the shortfall will be made up from future production from these wellbores (or, at our option, from our retained interest in the wellbores) through an adjustment mechanism, or the initial term of the VPP will be extended until all scheduled volumes, to the extent produced, are delivered from the VPP wellbores to the VPP buyer. We retain drilling rights on the properties below currently producing intervals and outside of producing wellbores.

As the operator of the properties from which the VPP volumes have been sold, we bear the cost of producing the reserves attributable to such interests, which we include as a component of production expenses and production taxes in our condensed consolidated statements of operations in the periods such costs are incurred. As with all non-expense-bearing royalty interests, volumes conveyed in a VPP transaction are excluded from our estimated proved reserves; however, the estimated production expenses and taxes associated with VPP volumes expected to be delivered in future periods are included as a reduction of the future net cash flows attributable to our proved reserves for purposes of determining our full cost ceiling test for impairment purposes and in determining our standardized measure. Pursuant to SEC guidelines, the estimates used for purposes of determining the cost center ceiling and the standardized measure are based on current costs. Our commitment to bear the costs on any future production of VPP volumes is not reflected as a liability on our balance sheet. The costs that will apply in the future will depend on the actual production volumes as well as the production costs and taxes in effect during the periods in which such production actually occurs, which could differ materially from our current and historical costs, and production may not occur at the times or in the quantities projected, or at all.

For accounting purposes, cash proceeds from the sale of VPPs were reflected as a reduction of natural gas and oil properties with no gain or loss recognized, and our proved reserves were reduced accordingly. We have also committed to purchase natural gas and liquids associated with our VPP transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices.

Our outstanding VPPs consist of the following:

				Volume Sold			
VPP #	Date of VPP	Location	Proceeds	Natural Gas	Oil	NGL	Total
			($ in millions)	(bcf)	(mmbbl)	(mmbbl)	(bcfe)
10	March 2012	Anadarko Basin Granite Wash	$744	87	3.0	9.2	160
9	May 2011	Mid-Continent	853	138	1.7	4.8	177
8	September 2010	Barnett Shale	1,150	390	—	—	390
6	February 2010	East Texas and NW Louisiana	180	44	0.3	—	46
5	August 2009	South Texas	370	67	0.2	—	68
4	December 2008	Anadarko and Arkoma	412	95	0.5	—	98

		Basins					
3	August 2008	Anadarko Basin	600	93	—	—	93
2	May 2008	Texas, Oklahoma and Kansas	622	94	—	—	94
1	December 2007	Kentucky and West Virginia	1,100	208	—	—	208
			$6,031	1,216	5.7	14.0	1,334

36

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

The volumes produced on behalf of our VPP buyers for the Current Quarter and the Prior Quarter were as follows:

	Three Months Ended March 31, 2014				Three Months Ended March 31, 2013			
VPP #	Natural Gas	Oil	NGL	Total	Natural Gas	Oil	NGL	Total
	(bcf)	(mbbl)	(mbbl)	(bcfe)	(bcf)	(mbbl)	(mbbl)	(bcfe)
10	2.8	109.0	345.2	5.5	3.7	154.0	407.7	6.9
9	4.0	49.0	106.5	4.9	4.4	56.2	118.8	5.5
8	15.7	—	—	15.7	18.0	—	—	18.0
6	1.1	6.0	—	1.2	1.2	6.0	—	1.2
5	1.7	6.3	—	1.8	2.0	6.0	—	2.0
4	2.3	12.4	—	2.4	2.6	14.2	—	2.7
3	1.9	—	—	1.9	2.1	—	—	2.1
2	2.4	—	—	2.4	2.7	—	—	2.7
1	3.6	—	—	3.6	3.8	—	—	3.8
	35.5	182.7	451.7	39.4	40.5	236.4	526.5	44.9

The volumes remaining to be delivered on behalf of our VPP buyers as of March 31, 2014 were as follows:

		Volume Remaining as of March 31, 2014			
VPP #	Term Remaining	Natural Gas	Oil	NGL	Total
	(in months)	(bcf)	(mmbbl)	(mmbbl)	(bcfe)
10	95	45.8	1.6	5.6	89.2
9	83	84.7	1.0	2.2	104.0
8	17	80.9	—	—	80.9
6	70	20.3	0.1	—	21.1
5	34	15.2	0.1	—	15.5
4	33	22.0	0.1	—	22.7
3	64	29.2	—	—	29.2
2	61	17.6	—	—	17.6
1	105	101.8	—	—	101.8
		417.5	2.9	7.8	482.0

10. Investments

A summary of our investments, including our approximate ownership percentage as of March 31, 2014 and December 31, 2013, is presented below.

		Approximate Ownership %		Carrying Value	
	Accounting Method	March 31, 2014	December 31, 2013	March 31, 2014	December 31, 2013
				($ in millions)	
FTS International, Inc.	Equity	30%	30%	$129	$138
Chaparral Energy, Inc.	Equity	—%	20%	—	143
Sundrop Fuels, Inc.	Equity	56%	56%	134	135
Other	—	—%	—%	25	61
Total investments				$288	$477

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

FTS International, Inc. FTS International, Inc. (FTS), based in Fort Worth, Texas, is a privately held company which, through its subsidiaries, provides hydraulic fracturing and other services to oil and gas companies. During the Current Quarter, we recorded negative equity method and other adjustments, prior to intercompany profit eliminations, of $15 million for our share of FTS's net loss and recorded an accretion adjustment of $6 million related to the excess of our underlying equity in net assets of FTS over our carrying value.

As of March 31, 2014, the carrying value of our investment in FTS was less than our underlying equity in net assets by approximately $48 million, of which $14 million was attributed to non-depreciable assets. The value attributed to depreciable assets is being accreted over the estimated useful lives of the underlying assets.

Chaparral Energy, Inc. Chaparral Energy, Inc. (Chaparral), 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 sold all of our interest in Chaparral for net cash proceeds of $209 million. We recorded a $73 million gain related to the sale.

Sundrop Fuels, Inc. Sundrop Fuels, Inc. (Sundrop), based in Longmont, Colorado, is a privately held cellulosic biofuels company that is constructing a nonfood biomass-based "green gasoline" plant. In the Current Quarter, we recorded a $3 million charge related to our share of Sundrop's net loss and capitalized interest totaling $2 million associated with the construction of Sundrop's plant. The capitalized interest is added to the investment carrying value in excess of our underlying equity and will be amortized over the life of the plant, once it is placed into service. The carrying value of our investment in Sundrop was in excess of our underlying equity in net assets by approximately $65 million.

Other. In the Current Quarter, we sold an equity investment in a natural gas trading and management firm for cash proceeds of $30 million and recorded a loss of $6 million associated with the transaction.

11. Variable Interest Entities

We consolidate the activities of VIEs for which we are the primary beneficiary. 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 VIE

Chesapeake Granite Wash Trust. For a 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 because (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 undeveloped portion of an area of mutual interest, if we do not meet our drilling commitment. In consolidation, as of March 31, 2014, $1 million of cash and cash equivalents, approximately $298 million of net natural gas and oil properties, $6 million of short-term derivative liabilities and $19 million of other current 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

Unconsolidated VIE
Mineral Acquisition Company I, L.P. In 2012, MAC-LP, L.L.C., a wholly owned non-guarantor unrestricted subsidiary of Chesapeake, entered into a partnership agreement with KKR Royalty Aggregator LLC (KKR) to form Mineral Acquisition Company I, L.P. The purpose of the partnership is to acquire mineral interests, or royalty interests carved out of mineral interests, in oil and natural gas basins in the continental United States. We are committed to acquire for our own account (outside the partnership) 10% of any acquisition agreed upon by the partnership up to a maximum of $25 million, and the partnership will acquire the remaining 90% up to a maximum of $225 million, funded entirely by KKR, making KKR the sole equity investor. We have significant influence over the decisions made by the partnership, as we hold two of five seats on the board of directors. We will receive proportionate distributions from the partnership of any cash received from royalties in excess of expenses paid, ranging from 7% to 22.5%. The partnership is considered a VIE because KKR's control over the partnership is disproportionate to its economic interest. This VIE remains unconsolidated as the power to direct the activities of the partnership is shared between the Company and KKR. We are using the equity method to account for this investment.

12. Other Property and Equipment

Net Gains on Sales of Fixed Assets

A summary by asset class of (gains) or losses on sales of fixed assets for the Current Quarter and the Prior Quarter is as follows:

	Three Months Ended March 31,	
	2014	2013
	($ in millions)	
Natural gas compressors	$(26)	$—
Gathering systems and treating plants	3	(69)
Drilling rigs and equipment	2	1
Buildings and land	—	22
Other	(2)	(3)
Total net gains on sales of fixed assets	$(23)	$(49)

Natural Gas Compressors. In the Current Quarter, we sold 102 compressors and related equipment to Access Midstream Partners, L.P. (NYSE:ACMP) for proceeds of approximately $159 million. We recorded a $24 million gain associated with the transaction.

Gathering Systems and Treating Plants. In the Prior Quarter, we sold our interest in certain gathering system assets in Pennsylvania to Western Gas Partners, LP (NYSE:WES) for proceeds of approximately $134 million. We recorded a $55 million gain associated with this transaction.

Buildings and Land. In the Prior Quarter, we recorded net losses of $22 million on sales of buildings and land located primarily in our Barnett Shale operating area.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

Assets Held for Sale
In 2013, we determined we would sell certain of our buildings and land (other than our core campus) in the Oklahoma City area. In addition, as of March 31, 2014 we were continuing to pursue the sale of various land and buildings located in the Fort Worth, Texas area. The land and buildings in both the Oklahoma City and Fort Worth areas are reported under our other segment. We are also pursuing the sale of various other property and equipment, including certain drilling rigs, compressors and gathering systems. See Note 19 for more information on our compressors held for sale as of March 31, 2014 that were subsequently sold in April 2014. The drilling rigs are reported under our oilfield services operating segment, and the compressors and gathering systems are reported under our marketing, gathering and compression operating segment. These assets are being actively marketed, and we believe it is probable they will be sold over the next 12 months. As a result, these assets qualified as held for sale as of March 31, 2014. Natural gas and oil properties that we intend to sell are not presented as held for sale pursuant to the rules governing full cost accounting for oil and gas properties. A summary of the assets held for sale on our condensed consolidated balance sheets as of March 31, 2014 and December 31, 2013 is detailed below.

	March 31, 2014	December 31, 2013
	($ in millions)	
Natural gas gathering systems and treating plants, net of accumulated depreciation	$10	$11
Oilfield services equipment, net of accumulated depreciation	58	29
Compressors, net of accumulated depreciation	322	285
Buildings and land, net of accumulated depreciation	237	405
Property and equipment held for sale, net	$627	$730

In March 2014, management determined that certain properties in the Fort Worth area of the Barnett Shale, previously classified as held for sale as of December 31, 2013, would be reclassified as held for use. As of December 31, 2013, management's development plan for the Barnett Shale did not contemplate the need for the underlying properties (for pad drilling in certain urban locations around Fort Worth) and the properties were marketed for sale. Management modified its development plan during the Current Quarter and consequently these properties no longer met the criteria to be classified as held for sale as of March 31, 2014. The properties were measured at the lesser of their fair value at the date of the decision not to sell or their carrying amount before being classified as held for sale. Approximately $116 million, primarily consisting of land that had been classified as held for sale as of December 31, 2013, was reclassified as held for use as of March 31, 2014. There was no impact to the statements of operations related to this reclassification in the Current Quarter.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

13. Impairments of Fixed Assets and Other

We review our long-lived assets, other than our natural gas and oil properties which are subject to quarterly full cost ceiling tests, for recoverability whenever events or changes in circumstances indicate that carrying amounts may not be recoverable and recognize an impairment loss if the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. A summary of our impairments of fixed assets by asset class and other charges for the Current Quarter and the Prior Quarter is as follows:

	Three Months Ended March 31,	
	2014	2013
	($ in millions)	
Drilling rigs and equipment	$20	$—
Buildings and land	—	27
Total impairments of fixed assets and other	$20	$27

Drilling Rigs and Equipment. In the Current Quarter, we purchased 20 leased rigs and equipment from various lessors for an aggregate purchase price of $77 million and paid approximately $8 million in early lease termination costs, which is included in impairments of fixed assets and other in the condensed consolidated statement of operations. In addition, we impaired approximately $12 million of leasehold improvements and other costs associated with these transactions. See Note 4 for a description of the master lease agreements. We measured the fair value of these assets based on recent sales information for comparable rigs and equipment. The drilling rigs and equipment are included in our oilfield services operating segment.

Buildings and Land. In the Prior Quarter, we recognized $27 million of impairment losses on certain of our buildings and land in the Oklahoma City area (other than our core campus) classified as held for sale. We measured the fair value of these assets based on purchase offers we received from third parties. The buildings and land are included in our other operating segment.

Nonrecurring Fair Value Measurements

Fair value measurements for impairments on the drilling rigs and equipment discussed above were based on recent sales information for comparable rigs and assets. As the fair value was estimated using the market approach based on recent prices from orderly sales transactions for comparable assets between market participants, the values were classified as Level 2 in the fair value hierarchy. Fair value measurements for impairments on the buildings and land discussed above were based on a bid we received from a third party. Since the input used was not observable in the market, these values were classified as Level 3 in the fair value hierarchy.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

14. Restructuring and Other Termination Costs

On April 1, 2013, Aubrey K. McClendon, the co-founder of the Company, ceased serving as President and CEO and as a director of the Company pursuant to his agreement with the Board of Directors announced on January 29, 2013. Mr. McClendon’s departure from the Company was treated as a termination without cause under his employment agreement. On April 18, 2013, the Company and Mr. McClendon entered into a Founder Separation and Services Agreement, effective January 29, 2013, regarding his separation from employment and to facilitate the relationship between the Company and Mr. McClendon as joint working interest owners of oil and gas wells, leases and acreage. In the Prior Quarter, we incurred charges of approximately $64 million related to Mr. McClendon’s departure.

In December 2012, Chesapeake announced that it had offered a voluntary separation program (VSP) to certain employees as part of the Company's ongoing efforts to improve efficiencies and reduce costs. The VSP was offered to approximately 275 employees who met criteria based upon a combination of age and years of Chesapeake service, and 211 accepted prior to the expiration of the offer in February 2013. We recognized the expense related to their termination benefits over their remaining service period, which resulted in $56 million of expense for the Prior Quarter.

During the Prior Quarter, we also incurred charges of approximately $13 million related to other workforce reductions, including separations of executive officers other than the CEO. Substantially all of the restructuring and other termination costs in 2013 are in the exploration and production operating segment. Below is a summary of our restructuring and other termination costs for the Current Quarter and the Prior Quarter:

	Three Months Ended March 31,	
	2014	2013
	($ in millions)	
Termination benefits provided to Mr. McClendon:		
Salary and bonus expense	$—	$11
Acceleration of 2008 performance bonus clawback	—	11
Acceleration of stock-based compensation	—	22
Acceleration of performance share unit awards[a]	(4)	13
Estimated aircraft usage benefits	—	7
Total termination benefits provided to Mr. McClendon	(4)	64
Termination benefits provided to VSP participants:		
Salary and bonus expense	—	30
Acceleration of stock-based compensation	—	24
Other termination benefits	—	2
Total termination benefits provided to VSP participants	—	56
Other termination benefits[a]	(3)	13
Total restructuring and other termination costs	$(7)	$133

(a) The Current Quarter amount primarily related to negative fair value adjustments to PSUs granted to former executives of the Company. For further discussion of our PSUs, see Note 7.

42

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

15. Fair Value Measurements
Recurring Fair Value Measurement
Other Current Assets. Assets related to Company matches of employee contributions to Chesapeake's employee benefit plans are included in other current assets. The fair value of these assets is determined using quoted market prices as they consist of exchange-traded securities.
Other Current Liabilities. Liabilities related to Chesapeake's deferred compensation plan are included in other current liabilities. The fair values of these liabilities are determined using quoted market prices, as the plan consists of exchange-traded mutual funds.
The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of March 31, 2014 and December 31, 2013:

As of March 31, 2014	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):				
Other current assets	$78	$—	$—	$78
Other current liabilities	(80)	—	—	(80)
Total	$(2)	$—	$—	$(2)

As of December 31, 2013	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):				
Other current assets	$80	$—	$—	$80
Other current liabilities	(82)	—	—	(82)
Total	$(2)	$—	$—	$(2)

See Note 3 for information regarding fair value of other financial instruments. See Note 8 for information regarding fair value measurement of derivatives. See Note 13 regarding nonrecurring fair value measurements.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

16. Segment Information

We have three reportable operating segments, each of which is managed separately because of the nature of its products and services. The exploration and production operating segment is responsible for finding and producing natural gas, oil and NGL. The marketing, gathering and compression operating segment is responsible for marketing, gathering and compression of natural gas, oil and NGL. The oilfield services operating segment is responsible for drilling, oilfield trucking, oilfield rentals, hydraulic fracturing and other oilfield services operations for both Chesapeake-operated wells and wells operated by third parties.

Management evaluates the performance of our segments based upon income (loss) before income taxes. Revenues from the sale of natural gas, oil and NGL related to Chesapeake's ownership interests by the marketing, gathering and compression operating segment are reflected as revenues within our exploration and production operating segment. Such amounts totaled $2.408 billion and $1.748 billion for the Current Quarter and the Prior Quarter, respectively. Revenues generated by the oilfield services operating segment for work performed for Chesapeake's exploration and production operating segment are reclassified to the full cost pool based on Chesapeake's ownership interest. Revenues reclassified totaled $271 million and $352 million for the Current Quarter and the Prior Quarter, respectively. No income is recognized in our condensed consolidated statements of operations related to oilfield services performed for Chesapeake-operated wells. The following table presents selected financial information for Chesapeake's operating segments:

	Exploration and Production	Marketing, Gathering and Compression	Oilfield Services	Other	Intercompany Eliminations	Consolidated Total
	($ in millions)					
Three Months Ended March 31, 2014:						
Revenues	$1,766	$5,423	$510	$26	$(2,679)	$5,046
Intersegment revenues	—	(2,408)	(271)	—	2,679	—
Total revenues	$1,766	$3,015	$239	$26	$—	$5,046
Income (Loss) Before Income Taxes	$687	$105	$(42)	$60	$(64)	$746
Three Months Ended March 31, 2013:						
Revenues	$1,453	$3,529	$538	$10	$(2,106)	$3,424
Intersegment revenues	—	(1,748)	(352)	(6)	2,106	—
Total revenues	$1,453	$1,781	$186	$4	$—	$3,424
Income (Loss) Before Income Taxes	$170	$129	$22	$(58)	$(98)	$165
As of March 31, 2014:						
Total Assets	$36,102	$2,950	$2,058	$5,516	$(4,021)	$42,605
As of December 31, 2013:						
Total Assets	$35,341	$2,430	$2,018	$5,750	$(3,757)	$41,782

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

17. Condensed Consolidating Financial Information

Chesapeake Energy Corporation is a holding company, 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 100% owned subsidiaries on a senior unsecured basis. Our oilfield services subsidiaries are separately capitalized and are not guarantors of our senior notes or our other debt obligations, but are subject to the covenants and guarantees in the oilfield services revolving bank credit facility agreement described in Note 3 that limit their ability to pay dividends or distributions or make loans to Chesapeake. In addition, subsidiaries with noncontrolling interests, consolidated variable interest entities and certain de minimis subsidiaries are non-guarantors.

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, 2014 and December 31, 2013 and for the three months ended March 31, 2014 and 2013. Such financial information may not necessarily be indicative of our results of operations, cash flows or financial position had these subsidiaries operated as independent entities.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF MARCH 31, 2014
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$974	$—	$ 75	$(45)	$1,004
Restricted cash	—	—	82	(7)	75
Other	88	2,862	623	(377)	3,196
Intercompany receivable, net	25,431	—	—	(25,431)	—
Total Current Assets	26,493	2,862	780	(25,860)	4,275
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full cost accounting, net	—	29,891	3,075	(94)	32,872
Other property and equipment, net	—	2,523	1,501	(1)	4,023
Property and equipment held for sale, net	—	569	58	—	627
Total Property and Equipment, Net	—	32,983	4,634	(95)	37,522
LONG-TERM ASSETS:					
Other assets	109	962	109	(372)	808
Investments in subsidiaries and intercompany advances	2,387	(201)	—	(2,186)	—
TOTAL ASSETS	$28,989	$36,606	$ 5,523	$(28,513)	$42,605
CURRENT LIABILITIES:					
Current liabilities	$550	$5,445	$ 392	$(429)	$5,958
Intercompany payable, net	—	24,922	257	(25,179)	—
Total Current Liabilities	550	30,367	649	(25,608)	5,958
LONG-TERM LIABILITIES:					
Long-term debt, net	11,539	—	1,114	—	12,653
Deferred income tax liabilities	293	2,834	1,117	(416)	3,828
Other long-term liabilities	266	1,018	777	(372)	1,689
Total Long-Term Liabilities	12,098	3,852	3,008	(788)	18,170
EQUITY:					
Chesapeake stockholders’ equity	16,341	2,387	1,866	(4,253)	16,341
Noncontrolling interests	—	—	—	2,136	2,136
Total Equity	16,341	2,387	1,866	(2,117)	18,477
TOTAL LIABILITIES AND EQUITY	$28,989	$36,606	$ 5,523	$(28,513)	$42,605

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2013
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$799	$—	$ 39	$(1)	$837
Restricted cash	—	—	82	(7)	75
Other	103	2,392	616	(367)	2,744
Intercompany receivable, net	25,369	—	—	(25,369)	—
Total Current Assets	26,271	2,392	737	(25,744)	3,656
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full cost accounting, net	—	29,295	3,113	185	32,593
Other property and equipment, net	—	2,315	1,497	(1)	3,811
Property and equipment held for sale, net	—	701	29	—	730
Total Property and Equipment, Net	—	32,311	4,639	184	37,134
LONG-TERM ASSETS:					
Other assets	111	1,146	111	(376)	992
Investments in subsidiaries and intercompany advances	2,349	(251)	—	(2,098)	—
TOTAL ASSETS	$28,731	$35,598	$ 5,487	$(28,034)	$41,782
CURRENT LIABILITIES:					
Current liabilities	$300	$5,211	$ 379	$(375)	$5,515
Intercompany payable, net	—	24,752	593	(25,345)	—
Total Current Liabilities	300	29,963	972	(25,720)	5,515
LONG-TERM LIABILITIES:					
Long-term debt, net	11,831	—	1,055	—	12,886
Deferred income tax liabilities	209	2,264	847	87	3,407
Other liabilities	396	1,022	788	(372)	1,834
Total Long-Term Liabilities	12,436	3,286	2,690	(285)	18,127
EQUITY:					
Chesapeake stockholders' equity	15,995	2,349	1,825	(4,174)	15,995
Noncontrolling interests	—	—	—	2,145	2,145
Total Equity	15,995	2,349	1,825	(2,029)	18,140
TOTAL LIABILITIES AND EQUITY	$28,731	$35,598	$ 5,487	$(28,034)	$41,782

47

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
THREE MONTHS ENDED MARCH 31, 2014
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas, oil and NGL	$—	$1,545	$222	$(1)	$1,766
Marketing, gathering and compression	—	3,014	1	—	3,015
Oilfield services	—	—	536	(271)	265
Total Revenues	—	4,559	759	(272)	5,046
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	269	19	—	288
Production taxes	—	49	1	—	50
Marketing, gathering and compression	—	2,979	1	—	2,980
Oilfield services	—	17	437	(234)	220
General and administrative	—	53	26	—	79
Restructuring and other termination costs	—	(7)	—	—	(7)
Natural gas, oil and NGL depreciation, depletion and amortization	—	568	62	(2)	628
Depreciation and amortization of other assets	—	39	74	(35)	78
Impairment of natural gas and oil properties	—	—	59	(59)	—
Impairments of fixed assets and other	—	—	20	—	20
Net gains on sales of fixed assets	—	(24)	1	—	(23)
Total Operating Expenses	—	3,943	700	(330)	4,313
INCOME FROM OPERATIONS	—	616	59	58	733
OTHER INCOME (EXPENSE):					
Interest expense	(192)	—	(21)	174	(39)
Losses on investments	—	(15)	—	(6)	(21)
Gain on sale of investment	—	67	—	—	67
Other income (loss)	344	(141)	1	(198)	6
Equity in net earnings of subsidiary	330	(17)	—	(313)	—
Total Other Income (Expense)	482	(106)	(20)	(343)	13
INCOME BEFORE INCOME TAXES	482	510	39	(285)	746
INCOME TAX EXPENSE	57	198	15	10	280
NET INCOME	425	312	24	(295)	466
Net income attributable to noncontrolling interests	—	—	—	(41)	(41)
NET INCOME ATTRIBUTABLE TO CHESAPEAKE	425	312	24	(336)	425
Other comprehensive income	2	7	—	—	9
COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE	$427	$319	$24	$(336)	$434

48

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
THREE MONTHS ENDED MARCH 31, 2013
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas, oil and NGL	$—	$1,322	$128	$3	$1,453
Marketing, gathering and compression	—	1,778	3	—	1,781
Oilfield services	—	—	554	(364)	190
Total Revenues	—	3,100	685	(361)	3,424
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	296	11	—	307
Production taxes	—	51	2	—	53
Marketing, gathering and compression	—	1,742	3	—	1,745
Oilfield services	—	23	426	(294)	155
General and administrative	—	87	23	—	110
Restructuring and other termination costs	—	131	2	—	133
Natural gas, oil and NGL depreciation, depletion and amortization	—	591	57	—	648
Depreciation and amortization of other assets	—	48	71	(41)	78
Impairment of natural gas and oil properties	—	—	91	(91)	—
Impairments of fixed assets and other	—	27	—	—	27
Net gains on sales of fixed assets	—	(49)	—	—	(49)
Total Operating Expenses	—	2,947	686	(426)	3,207
INCOME FROM OPERATIONS	—	153	(1)	65	217
OTHER INCOME (EXPENSE):					
Interest expense	(219)	(8)	(16)	222	(21)
Losses on investments	—	(37)	—	—	(37)
Other income	216	42	(2)	(250)	6
Equity in net earnings (losses) of subsidiary	60	(87)	—	27	—
Total Other Income (Expense)	57	(90)	(18)	(1)	(52)
INCOME (LOSS) BEFORE INCOME TAXES	57	63	(19)	64	165
INCOME TAX EXPENSE (BENEFIT)	(1)	57	(7)	14	63
NET INCOME (LOSS)	58	6	(12)	50	102
Net income attributable to noncontrolling interests	—	—	—	(44)	(44)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	58	6	(12)	6	58
Other comprehensive income (loss)	(2)	14	—	—	12
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$56	$20	$(12)	$6	$70

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
THREE MONTHS ENDED MARCH 31, 2014
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$—	$1,027	$264	$—	$1,291
CASH FLOWS FROM INVESTING ACTIVITIES:					
Acquisitions of proved and unproved properties	—	(956)	(128)	—	(1,084)
Proceeds from divestitures of proved and unproved properties	—	48	1	—	49
Additions to other property and equipment	—	(319)	(118)	—	(437)
Other investing activities	—	442	5	26	473
Net Cash Used In Investing Activities	—	(785)	(240)	26	(999)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	140	281	—	421
Payments on credit facilities borrowings	—	(140)	(222)	—	(362)
Other financing activities	(116)	47	(45)	(70)	(184)
Intercompany advances, net	291	(289)	(2)	—	—
Net Cash Provided By (Used In) Financing Activities	175	(242)	12	(70)	(125)
Net increase (decrease) in cash and cash equivalents	175	—	36	(44)	167
Cash and cash equivalents, beginning of period	799	—	39	(1)	837
Cash and cash equivalents, end of period	$974	$—	$75	$(45)	$1,004

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
THREE MONTHS ENDED MARCH 31, 2013
($ in millions)

	Parent[(a)]	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$—	$790	$146	$(12)	$924
CASH FLOWS FROM INVESTING ACTIVITIES:					
Acquisitions of proved and unproved properties	—	(1,643)	(216)	—	(1,859)
Proceeds from divestitures of proved and unproved properties	—	138	52	—	190
Additions to other property and equipment	—	(186)	(144)	—	(330)
Other investing activities	—	135	74	45	254
Net Cash Used In Investing Activities	—	(1,556)	(234)	45	(1,745)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	3,395	237	—	3,632
Payments on credit facilities borrowings	—	(2,563)	(248)	—	(2,811)
Other financing activities	(133)	(94)	6	(33)	(254)
Intercompany advances, net	(95)	28	67	—	—
Net Cash Provided By (Used In) Financing Activities	(228)	766	62	(33)	567
Net increase in cash and cash equivalents	(228)	—	(26)	—	(254)
Cash and cash equivalents, beginning of period	228	—	59	—	287
Cash and cash equivalents, end of period	$—	$—	$33	$—	$33

(a) We have revised the amounts presented as cash and cash equivalents in the Guarantor Subsidiaries and Parent columns to properly reflect the cash of the Parent of $228 million, which was incorrectly presented in the Guarantor Subsidiaries column. The impact of this error was not material to any previously issued financial statements.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

18. Recently Issued Accounting Standards

In February 2013, the Financial Accounting Standards Board issued guidance on the recognition, measurement and disclosure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. We adopted this standard January 1, 2014, and it did not have a material impact on our financial statements.

19. Subsequent Events

On April 10, 2014, we sold 337 compressors and related equipment to Exterran Partners, L.P. for approximately $362 million.

On April 24, 2014, we issued $3.0 billion in aggregate principal amount of senior notes at par. The offering included two series of notes: $1.5 billion in aggregate principal amount of Floating Rate Senior Notes due 2019 and $1.5 billion in aggregate principal amount of 4.875% Senior Notes due 2022. We used a portion of the net proceeds of $2.966 billion to repay the borrowings under, and terminate, our term loan credit facility. We will use the remaining proceeds along with cash on hand to redeem approximately $97 million aggregate principal amount of 6.875% Senior Notes due 2018 and to purchase outstanding 9.5% Senior Notes due 2015 through a tender offer that we commenced concurrently with the senior notes offering. On April 24, 2014, we purchased approximately $946 million aggregate principal amount of the 9.5% Senior Notes due 2015 that were tendered by the early tender date. The tender offer will expire on May 7, 2014, unless extended, and the redemption of the 6.875% Senior Notes due 2018 is expected to occur on May 12, 2014.

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

Financial Data

The following table sets forth certain information regarding our production volumes, natural gas, oil and natural gas liquids (NGL) sales, average sales prices received, other operating income and expenses for the periods indicated:

	Three Months Ended March 31,	
	2014	2013
Net Production:		
Natural gas (bcf)	260.0	273.1
Oil (mmbbl)	9.9	9.3
NGL (mmbbl)	7.6	4.9
Oil equivalent (mmboe)[a]	60.8	59.7
Natural Gas, Oil and NGL Sales ($ in millions):		
Natural gas sales	$1,005	$573
Natural gas derivatives - realized gains (losses)[b]	(154)	8
Natural gas derivatives - unrealized gains (losses)[b]	(154)	(278)
Total natural gas sales	697	303
Oil sales	922	884
Oil derivatives - realized gains (losses)[b]	(84)	(4)
Oil derivatives - unrealized gains (losses)[b]	10	132
Total oil sales	848	1,012
NGL sales	221	138
NGL derivatives - realized gains (losses)[b]	—	—
NGL derivatives - unrealized gains (losses)[b]	—	—
Total NGL sales	221	138
Total natural gas, oil and NGL sales	$1,766	$1,453
Average Sales Price (excluding gains (losses) on derivatives):		
Natural gas ($ per mcf)	$3.86	$2.10
Oil ($ per bbl)	$93.60	$95.23
NGL ($ per bbl)	$29.23	$28.25
Oil equivalent ($ per boe)	$35.35	$26.71
Average Sales Price (including realized gains (losses) on derivatives):		
Natural gas ($ per mcf)	$3.27	$2.13
Oil ($ per bbl)	$85.08	$94.85
NGL ($ per bbl)	$29.23	$28.25
Oil equivalent ($ per boe)	$31.44	$26.79

	Three Months Ended March 31, 2014	2013
Other Operating Income[c] ($ in millions):		
Marketing, gathering and compression net margin	$35	$36
Oilfield services net margin	$45	$35
Expenses ($ per boe):		
Natural gas, oil and NGL production	$4.73	$5.14
Production taxes	$0.83	$0.89
General and administrative[d]	$1.30	$1.84
Natural gas, oil and NGL depreciation, depletion and amortization	$10.33	$10.86
Depreciation and amortization of other assets	$1.29	$1.31
Interest expense[e]	$0.90	$0.25
Interest Expense ($ in millions):		
Interest expense	$58	$17
Interest rate derivatives – realized (gains) losses[f]	(3)	(2)
Interest rate derivatives – unrealized (gains) losses[f]	(16)	6
Total interest expense	$39	$21

(a) Oil equivalent is based on six mcf of natural gas to one barrel of oil or one barrel of NGL. This ratio reflects an energy content equivalency and not a price or revenue equivalency. In recent years, the price for a bbl of oil and NGL has been significantly higher than the price for six mcf of natural gas.

(b) Realized gains and losses include the following items: (i) settlements of non-designated derivatives related to current period production revenues, (ii) prior period settlements for option premiums and for early-terminated derivatives originally scheduled to settle against current period production revenues, and (iii) gains and losses related to de-designated cash flow hedges originally designated to settle against current period production revenues. Unrealized gains and losses include the change in fair value of open derivatives scheduled to settle against future period production revenues offset by amounts reclassified as realized gains and losses during the period.

(c) Includes revenue and operating costs. See Depreciation and Amortization of Other Assets under Results of Operations for details of the depreciation and amortization associated with our marketing, gathering, and compression and oilfield services operating segments.

(d) Includes stock-based compensation but excludes restructuring and other termination costs.

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

(f) Realized (gains) losses include settlements related to the current period interest accrual and the effect of (gains) losses on early terminated trades. Settlements of early-terminated trades are reflected in realized (gains) losses over the original life of the hedged item. Unrealized (gains) losses include changes in the fair value of open interest rate derivatives offset by amounts reclassified to realized (gains) losses during the period.

Overview

Chesapeake is currently the second-largest producer of natural gas and the tenth-largest producer of liquids in the United States. We own interests in approximately 47,400 natural gas and oil wells that produced an average of approximately 675 mboe per day in the Current Quarter, net to our interest. We have a large and geographically diverse resource base of onshore U.S. unconventional natural gas and liquids assets. We have leading positions in the liquids-rich resource plays of the Eagle Ford Shale in South Texas; the Utica Shale in Ohio and Pennsylvania; the Granite Wash/Hogshooter, Cleveland, Tonkawa and Mississippi Lime plays in the Anadarko Basin in northwestern Oklahoma, the Texas Panhandle and southern Kansas; and the Niobrara Shale in the Powder River Basin in Wyoming. Our core natural gas resource plays are the Haynesville/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. We also own substantial marketing, compression and oilfield services businesses.

Our Strategy

With substantial leasehold positions in most of the premier U.S. onshore resource plays, Chesapeake is focused on finding and producing hydrocarbons in a responsible and efficient manner that seeks to maximize shareholder returns. We are committed to increasing our profitability and decreasing our financial complexity through the execution of our business strategy, which consists of two fundamental tenets: financial discipline and profitable and efficient growth from captured resources.

We are applying financial discipline to all aspects of our business, with the primary goals of balancing capital expenditures with cash flow from operations, divesting noncore assets and affiliates, achieving investment grade metrics, lowering our per unit costs, and reducing financial and operational risk and complexity while we continue responsible environmental stewardship. As a result of our focus on financial discipline, average per unit production expenses during the Current Quarter decreased 8% from the Prior Quarter, while general and administrative expenses (excluding stock-based compensation and restructuring and other termination costs) decreased 27%.

The Company’s substantial inventory of hydrocarbon resources provides a strong foundation for future growth. We believe that focusing on profitable and efficient growth from our captured resources will allow us to deliver attractive financial returns through all phases of the commodity price cycle. We have seen and continue to see increased efficiencies through our leveraging of first-well investments made in prior periods, including drilling on pre-existing pads. We also have a competitive capital allocation process designed to optimize our asset portfolio and identify the highest quality projects for future investment. To better understand our opportunities for continuous improvement, we benchmark our performance against that of our peers and evaluate the performance of completed projects. We also pay careful attention to safety, regulatory compliance and environmental stewardship measures while executing our business strategy.

Operating Results

Our Current Quarter production of 61 mmboe consisted of 260 bcf of natural gas (71% on an oil equivalent basis), 10 mmbbls of oil (16% on an oil equivalent basis) and 8 mmbbls of NGL (13% on an oil equivalent basis). Liquids represented 29% of total production for the Current Quarter, up from 24% in the Prior Quarter. Our daily production for the Current Quarter averaged approximately 675 mboe, an increase of 2% from the Prior Quarter and 11% when adjusted for 2013 asset sales. Compared to the Prior Quarter, our natural gas production in the Current Quarter decreased by 5%, or 145 mmcf per day; our oil production increased by 6%, or approximately 6 mbbls per day; and our NGL production increased by 55%, or approximately 30 mbbls per day. In addition, the price we received for our natural gas, oil and NGL production increased approximately 32%, from $26.71 per boe in the Prior Quarter to $35.35 per boe in the Current Quarter (excluding gains or losses on natural gas and oil derivatives). Coupled with our liquids production increases, our revenues (excluding gains or losses on natural gas and oil derivatives) increased approximately $553 million in the Current Quarter compared to the Prior Quarter. See Results of Operations below for additional details.

In the Current Quarter, our total capital expenditures were approximately $850 million, of which drilling and completion costs were approximately $729 million. We invested $882 million of cash during the Current Quarter in drilling and completion activities. This was partially offset by lower-than-expected drilling and completion costs and other adjustments, related to prior periods, of approximately $153 million, for net drilling and completion costs of approximately $729 million. This level of drilling and completion expenditures represents a decrease of approximately $735 million, or 50%, compared to the Prior Quarter. In the Current Quarter, we operated an average of 62 rigs, a decrease of 22 rigs compared to the Prior Quarter. In addition to a decreased rig count, drilling and completion costs were lower in the Current Quarter than in the Prior Quarter as a result of improving capital efficiencies and approximately 35% fewer well completions.

Net expenditures for the acquisition of unproved properties were approximately $24 million during the Current Quarter compared to approximately $44 million in the Prior Quarter. Other capital expenditures were approximately $97 million during the Current Quarter compared to approximately $330 million during the Prior Quarter. The reduction in other capital expenditures in the Current Quarter from the Prior Quarter is primarily the result of a reduction in capital expenditures for construction of our corporate headquarters and field offices and for our oilfield services business and the sale of substantially all of our midstream business and most of our gathering assets in 2012 and 2013. In addition, in the Current Quarter, we also purchased rigs and compressors previously sold under long-term lease arrangements for approximately $340 million to facilitate asset sales and a possible spin-off or sale of Chesapeake Oilfield Services as discussed below under Divestitures - Chesapeake Oilfield Services.

Based on planned activity levels for 2014 and 2015, we project that 2014 total capital expenditures will be $5.2 - $5.6 billion, an approximate 20% decrease from $6.8 billion of total capital expenditures in 2013.

Divestitures

We will continue to pursue opportunities to high-grade our portfolio so we can focus on existing assets that best fit our strategy of profitable growth from captured resources. We seek divestitures that are value-accretive and enable us to further reduce financial complexity and lower overall leverage. Our 2014 capital budget is expected to approximate our operating cash flow and is not dependent on divestitures.

Sale of Investments

In January 2014, we received $209 million of net proceeds from the sale of our common equity ownership in Chaparral Energy, Inc. We recorded a $73 million gain related to the sale.

In March 2014, we sold an equity investment in a natural gas trading and management firm for cash proceeds of $30 million and recorded a loss of $6 million associated with the transaction.

Sale of Buildings and Land

In the Current Quarter, we sold buildings and land noncore to our operations, primarily in the Oklahoma City area, for proceeds of approximately $55 million.

Midstream Compression Asset Sales

In March 2014, we sold 102 compressors and related equipment to Access Midstream Partners, L.P. for approximately $159 million. In April 2014, we sold 337 compressors and related equipment to Exterran Partners, L.P. for approximately $362 million.

Chesapeake Oilfield Services

In February 2014, we announced that we are pursuing strategic alternatives for our oilfield services business, Chesapeake Oilfield Services (COS), including a potential spin-off to Chesapeake shareholders or an outright sale (any such transaction, a “Separation Transaction”). COS services include drilling, hydraulic fracturing, oilfield rentals, rig relocation, and fluid handling and disposal. On March 17, 2014, our wholly owned subsidiary, Chesapeake Oilfield Operating, LLC (COO), filed a Registration Statement on Form 10 with the SEC. The Form 10 contains a preliminary information statement about the potential terms and conditions of a spin-off of COO to Chesapeake shareholders. It also provides initial information regarding COO as a stand-alone company, including financial, business, risk factor and management information. Immediately prior to completion of the possible spin-off, COO would convert into a corporation and change its name to Seventy Seven Energy Inc. Chesapeake intends for the potential spin-off to be tax-free to its shareholders for U.S. federal income tax purposes and, to that end, has obtained a private letter ruling from the Internal Revenue Service. Shareholders who want more complete information regarding the possible spin-off of COO, including the potential benefits and risks associated with the transaction, should consult the Form 10, which may be revised or updated in the future.

As of March 31, 2014, COS had approximately 5,200 employees and owned or leased 114 land drilling rigs, including 10 proprietary, fit-for-purpose PeakeRigs™ that utilize advanced electronic drilling technology. Also, as of March 31, 2014, COS owned nine hydraulic fracturing fleets with an aggregate of 360,000 horsepower; a diversified oilfield tool rental business; an oilfield trucking fleet consisting of 260 rig relocation trucks; 67 cranes and forklifts used to move drilling rigs and other heavy equipment; and 247 fluid hauling trucks. As described under Liquidity and Capital Resources below, COO had $1.114 billion in aggregate principal amount of long-term debt outstanding as of March 31, 2014, including $650 million of 6.825% Senior Notes due 2019 and $464 million outstanding under a revolving bank credit facility that matures in November 2016. See Note 16 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for financial information about COS, which is one of our reportable operating segments, and Results of Operations below for further discussion of the results of our oilfield services business for the Current Quarter and the Prior Quarter.

No agreement as to a Separation Transaction currently exists, no decision regarding a Separation Transaction has been made by our Board of Directors, and we can offer no assurance regarding the form, terms, timing or conditions of a Separation Transaction or that a Separation Transaction will ultimately occur or be consummated.

Liquidity and Capital Resources

Liquidity Overview

As of March 31, 2014, we had approximately $5.017 billion in cash availability (defined as unrestricted cash on hand plus borrowing capacity under our revolving bank credit facilities) compared to $4.909 billion as of December 31, 2013. As of March 31, 2014, we had full availability under our $4.0 billion corporate revolving bank credit facility. During the Current Quarter, we decreased our debt, net of unrestricted cash, by approximately $92 million, to $11.957 billion. As of March 31, 2014, we had negative working capital of approximately $1.683 billion compared to negative working capital of approximately $1.859 billion as of December 31, 2013. Historically, working capital deficits have existed primarily because our capital spending has exceeded our cash flow from operations. For 2014, we are projecting that our capital expenditures will approximate our operating cash flow.

Proceeds from any asset sales completed in 2014 and beyond may be used to reduce financial leverage and complexity and further enhance our liquidity. While furthering our strategic priorities, certain actions that would reduce financial leverage and complexity could negatively impact our future cash flows. We may incur various cash charges including but not limited to lease termination charges, financing extinguishment costs and charges for unused transportation and gathering capacity.

To add more certainty to our future estimated cash flows, we currently have downside price protection, in the form of over-the-counter derivative contracts, on approximately 64% of our remaining 2014 estimated natural gas production at an average price of $4.10 per mcf and 70% of our remaining 2014 estimated oil production at an average price of $94.32 per bbl. See Quantitative and Qualitative Disclosures about Market Risk in Item 3 of Part I in this report. Our use of derivative contracts allows us to reduce the effect of price volatility on our cash flows and EBITDA (defined as earnings before interest, taxes, depreciation, depletion and amortization), but the amount of estimated production

subject to derivative contracts for any period depends on our outlook on future prices and risk assessment.
Based upon our 2014 capital expenditure budget, our forecasted operating cash flow and projected levels of indebtedness, we are projecting that we will be in compliance with the financial maintenance covenants of our corporate revolving bank credit facility. Further, we expect to meet in the ordinary course of business other contractual cash commitments to third parties pursuant to various agreements described in Contractual Obligations and Off-Balance Sheet Arrangements below and in Note 4 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report, recognizing that we may be required to meet such commitments even if our business plan assumptions were to change. We believe the assumptions underlying our budget for this period are reasonable and that we have adequate flexibility, including the ability to adjust discretionary capital expenditures and other spending to adapt to potential negative developments if needed.

Recent Refinancing

In the 2014 second quarter, we have taken a series of steps to reduce our interest costs and to lengthen the maturity profile of our outstanding indebtedness. On April 24, 2014, we issued $3.0 billion in aggregate principal amount of senior notes at par. The offering included two series of notes: $1.5 billion in aggregate principal amount of Floating Rate Senior Notes due 2019 and $1.5 billion in aggregate principal amount of 4.875% Senior Notes due 2022. We used a portion of the net proceeds of $2.966 billion to repay the borrowings under, and terminate, our term loan credit facility. We will use the remaining proceeds along with cash on hand to redeem approximately $97 million aggregate principal amount of 6.875% Senior Notes due 2018 and to purchase outstanding 9.5% Senior Notes due 2015 through a tender offer that we commenced concurrently with the senior notes offering. On April 24, 2014, we purchased approximately $946 million aggregate principal amount of the 9.5% Senior Notes due 2015 that were tendered by the early tender date. The tender offer will expire on May 7, 2014, unless extended, and the redemption of the 6.875% Senior Notes due 2018 is expected to occur on May 12, 2014.

Sources of Funds

The following table presents the sources of our cash and cash equivalents for the Current Quarter and the Prior Quarter. See Notes 9, 10 and 12 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of sales of natural gas and oil assets, other assets and investments.

	Three Months Ended March 31,	
	2014	2013
	($ in millions)	
Cash provided by operating activities	$1,291	$924
Sales of natural gas and oil assets:		
Joint venture leasehold	7	25
Other natural gas and oil properties	42	165
Total sales of natural gas, oil and other assets	49	190
Sales of other assets:		
Sale of compressors to ACMP	159	—
Sales of other property and equipment	80	201
Total proceeds from sales of other property and equipment	239	201
Other sources of cash and cash equivalents:		
Proceeds from sales of other investments	239	—
Proceeds from credit facility borrowings, net	59	821
Other	—	56
Total other sources of cash and cash equivalents	298	877
Total sources of cash and cash equivalents	$1,877	$2,192

Cash provided by operating activities was $1.291 billion in the Current Quarter compared to $924 million in the Prior Quarter. The increase in cash provided by operating activities from the Prior Quarter to the Current Quarter is primarily the result of an increase in prices received for natural gas sold (excluding the effect of gains or losses on derivatives) from $2.10 per mcf in the Prior Quarter to $3.86 per mcf in the Current Quarter, an increase in oil and NGL sales volumes and decreases in certain of our operating expenses per unit. 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, impairments of other assets, deferred income taxes and mark-to-market changes in our derivative instruments. See the discussion below under Results of Operations.

Our $4.0 billion corporate revolving bank credit facility, our $500 million oilfield services revolving bank credit facility and cash and cash equivalents are other sources of liquidity. We use these revolving bank credit facilities and cash on hand to fund daily operating activities and capital expenditures as needed. We borrowed $421 million and repaid $362 million in the Current Quarter and borrowed $3.632 billion and repaid $2.811 billion in the Prior Quarter under our revolving bank credit facilities. As of March 31, 2014, we had no borrowings outstanding under our corporate revolving bank credit facility and had utilized approximately $23 million of the facility for various letters of credit. As of March 31, 2014, we had $464 million of outstanding borrowings under our oilfield services credit facility. Our corporate facility is secured by natural gas and oil proved reserves. A significant portion of our natural gas and oil reserves is currently unencumbered and therefore available to be pledged as additional collateral if needed to respond to borrowing base and collateral redeterminations that our lenders might make in the future. We believe our borrowing capacity under our corporate facility will not be reduced as a result of any such future redeterminations. Our oilfield services facility is secured by substantially all of our wholly owned oilfield services assets and is not subject to periodic borrowing base redeterminations.

Uses of Funds

The following table presents the uses of our cash and cash equivalents for the Current Quarter and the Prior Quarter:

	Three Months Ended March 31,	
	2014	2013
	($ in millions)	
Natural Gas and Oil Expenditures:		
Drilling and completion costs[(a)]	$(893)	$(1,566)
Acquisitions of proved and unproved properties	(29)	(73)
Geological and geophysical costs	(4)	(13)
Interest capitalized on unproved properties	(158)	(207)
Total natural gas and oil expenditures	(1,084)	(1,859)
Other Uses of Cash and Cash Equivalents:		
Cash paid to purchase leased rigs and compressors	(340)	—
Additions to other property and equipment	(97)	(330)
Cash paid for prepayment of mortgage	—	(55)
Dividends paid	(101)	(101)
Distributions to noncontrolling interest owners	(53)	(57)
Cash paid for financing derivatives[(b)]	(15)	(11)
Additions to investments	(3)	(3)
Other	(17)	(30)
Total other uses of cash and cash equivalents	(626)	(587)
Total uses of cash and cash equivalents	$(1,710)	$(2,446)

(a) Net of $188 million and $180 million in drilling and completion carries received from our joint venture partners during the Current Quarter and the Prior Quarter, respectively.

(b) Reflects derivatives deemed to contain, for accounting purposes, a significant financing element at contract inception.

Our primary use of funds is for capital expenditures related to exploration and development of natural gas and oil properties. Historically, a significant use was also for the acquisition of leasehold and construction and acquisition of other property and equipment. During the Current Quarter, our average operated rig count was 62 rigs compared to an average rig count of 84 operated rigs in the Prior Quarter. Our Prior Quarter drilling and completion expenditures also reflected significant well completion costs for natural gas wells that had been drilled, but not completed, in prior periods. These completions were delayed as we awaited the construction of infrastructure necessary to transport the natural gas produced to market.

Capital expenditures related to our midstream, oilfield services and other fixed assets were $97 million and $330 million during the Current Quarter and the Prior Quarter, respectively. The reduction of such expenditures in the Current Quarter from the Prior Quarter is primarily the result of a reduction in capital expenditures for construction of our corporate headquarters, field offices and our oilfield services business and the sale of substantially all of our midstream business and most of our gathering assets in 2012 and 2013.

In the Current Quarter, we also purchased rigs and compressors previously sold under long-term lease arrangements for approximately $340 million as part of a strategic initiative to reduce complexity and future commitments as well as to facilitate asset sales and a possible spin-off or sale of COS.

We paid dividends on our common stock of $58 million in both the Current Quarter and the Prior Quarter. We paid dividends on our preferred stock of $43 million in both the Current Quarter and the Prior Quarter.

Bank Credit Facilities

During the Current Quarter, we had the following two revolving bank credit facilities as sources of liquidity:

	Corporate Credit Facility[(a)]	Oilfield Services Credit Facility[(b)]
	($ in millions)	
Facility structure	Senior secured revolving	Senior secured revolving
Maturity date	December 2015	November 2016
Borrowing capacity	$4,000	$500
Amount outstanding as of March 31, 2014	$—	$464
Letters of credit outstanding as of March 31, 2014	$23	$—

(a) Co-borrowers are Chesapeake Exploration, L.L.C., Chesapeake Appalachia, L.L.C. and Chesapeake Louisiana, L.P.

(b) Borrower is Chesapeake Oilfield Operating, L.L.C. (COO).

Although the applicable interest rates under our corporate credit facility fluctuate 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 proved reserves and bear interest at a variable rate. We were in compliance with all covenants under the credit facility agreement as of March 31, 2014, including the financial covenant requiring us to maintain an indebtedness to EBITDA ratio of 4.0 to 1.0. As of March 31, 2014, our indebtedness to EBITDA ratio was approximately 2.44 to 1.00. The ratio compares consolidated indebtedness to consolidated EBITDA, both non-GAAP financial measures that are defined in the credit facility agreement, for the 12-month period ending on the measurement date. Consolidated indebtedness consists of outstanding indebtedness, less the cash and cash equivalents of Chesapeake and certain of our subsidiaries. Consolidated EBITDA consists of the net income of Chesapeake and certain of our subsidiaries, excluding income from investments and non-cash income plus interest expense, taxes, depreciation, amortization expense and other non-cash or non-recurring expenses, and is calculated on a pro forma basis to give effect to any acquisitions, divestitures or other adjustments. See Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of the terms of our corporate credit facility.

Oilfield Services Credit Facility. Our $500 million syndicated oilfield services revolving bank credit facility is used to fund capital expenditures and for general corporate purposes associated with our oilfield services operations. The facility may be expanded from $500 million to $900 million at COO's option, subject to additional bank participation. Borrowings under the credit facility bear interest at a variable interest rate and are secured by all of the equity interests and assets of COO and its wholly owned subsidiaries (the restricted subsidiaries for this facility, which are unrestricted subsidiaries under Chesapeake's senior notes, contingent convertible senior notes, corporate revolving bank credit facility, secured hedging facility and equipment master lease agreements). COO was in compliance with all covenants under the credit facility agreement as of March 31, 2014. For further discussion of the terms of our oilfield services credit facility, see Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report.

Hedging Facility

We have a multi-counterparty secured hedging facility with 17 counterparties that have committed to provide approximately 1.063 bboe of hedging capacity for natural gas, oil and NGL price derivatives and 1.063 bboe for basis derivatives with an aggregate mark-to-market capacity of $17.0 billion under the terms of the facility. For further discussion of the terms of our hedging facility, see Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report.

Term Loan

Prior to April 24, 2014, we had a $2.0 billion unsecured term loan credit facility. We used a portion of the proceeds from our offering of $3.0 billion in aggregate principal amount of senior notes that closed on April 24, 2014 to repay the borrowings under the term loan. See Recent Refinancing above for further discussion of the refinancing transactions. Our obligations under the facility ranked equally with our outstanding senior notes and contingent convertible senior notes and were unconditionally guaranteed on a joint and several basis by our direct and indirect wholly owned subsidiaries that are subsidiary guarantors under the indentures for such notes. Amounts borrowed under the facility bore interest at a variable rate. See Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of the term loan.

Senior Note Obligations

Our senior note obligations consisted of the following as of March 31, 2014:

	March 31, 2014
	($ in millions)
9.5% senior notes due 2015[(a)]	$1,265
3.25% senior notes due 2016	500
6.25% euro-denominated senior notes due 2017[(b)]	473
6.5% senior notes due 2017	660
6.875% senior notes due 2018[(c)]	97
7.25% senior notes due 2018	669
6.625% senior notes due 2019[(d)]	650
6.625% senior notes due 2020	1,300
6.875% senior notes due 2020	500
6.125% senior notes due 2021	1,000
5.375% senior notes due 2021	700
5.75% senior notes due 2023	1,100
2.75% contingent convertible senior notes due 2035[(e)]	396
2.5% contingent convertible senior notes due 2037[(e)]	1,168
2.25% contingent convertible senior notes due 2038[(e)]	347
Discount on senior notes[(f)]	(303)
Interest rate derivatives[(g)]	13
Total senior notes, net	10,535
Less current maturities of long-term debt[(a)]	(316)
Total long-term senior notes, net	$10,219

(a) On April 10, 2014, we commenced a tender offer for the 9.5% Senior Notes due 2015 concurrently with an offering of senior notes. On April 24, 2014, we purchased approximately $946 million aggregate principal amount of notes that were tendered by the early tender date. The tender offer will expire on May 7, 2014, unless extended. See Recent Refinancing above for further discussion of the refinancing transactions. The remaining $319 million in aggregate principal amount not tendered by the early tender date and the associated $3 million of discount are reflected as a current liability on our March 31, 2014 condensed consolidated balance sheet.

(b) The principal amount shown is based on the exchange rate of $1.3769 to €1.00 as of March 31, 2014. See Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for information on our related foreign currency derivatives.

(c) On April 10, 2014, we called the 6.875% Senior Notes due 2018 for redemption on May 12, 2014. See Recent Refinancing above for further discussion of the refinancing transactions.

(d) Issuers are COO, an indirect wholly owned subsidiary of the Company, 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.

61

(e) 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.

(f) Included in this discount was $284 million as of March 31, 2014 associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method.

(g) See Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for discussion related to these instruments.

For further discussion and details regarding our senior notes, contingent convertible senior notes and COO senior notes, see Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report.

Credit Risk

Derivative instruments that enable us to manage our exposure to natural gas, oil and NGL prices, interest rate and foreign currency 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. As of March 31, 2014, our natural gas, oil and interest rate derivative instruments were spread among 16 counterparties. Additionally, the counterparties under our multi-counterparty secured hedging facility are required to secure their obligations in excess of defined thresholds. We use this facility for substantially all of our natural gas, oil and NGL derivatives.

Our accounts receivable are primarily from purchasers of natural gas, oil and NGL ($1.940 billion as of March 31, 2014) and exploration and production companies that own interests in properties we operate ($472 million as of March 31, 2014). 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.

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, 2014, these arrangements and transactions included (i) operating lease agreements, (ii) VPPs (to purchase production and pay related production expenses and taxes in the future), (iii) open purchase commitments, (iv) open delivery commitments, (v) open drilling commitments, (vi) undrawn letters of credit, (vii) open gathering and transportation commitments and (viii) various other commitments we enter into in the ordinary course of business that could result in a future cash obligation.

As the operator of the properties from which VPP volumes have been sold, we bear the cost of producing the reserves attributable to such interests, which we include as a component of production expenses and production taxes in our condensed consolidated statements of operations in the periods such costs are incurred. As with all non-expense-bearing royalty interests, volumes conveyed in a VPP transaction are excluded from our estimated proved reserves; however, the estimated production expenses and taxes associated with VPP volumes expected to be delivered in future periods are included as a reduction of the future net cash flows attributable to our proved reserves for purposes of determining our full cost ceiling test for impairment purposes and in determining our standardized measure. Our commitment to bear the costs on any future production of VPP volumes is not reflected as a liability on our balance sheet. The costs that will apply in the future will depend on the actual production volumes as well as the production costs and taxes in effect during the periods in which such production actually occurs, which could differ materially from our current and historical costs, and production may not occur at the times or in the quantities projected, or at all. We have committed to purchase natural gas and liquids produced that are associated with our VPP transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices.

See Notes 4 and 9 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of commitments and VPPs, respectively.

Results of Operations – Three Months Ended March 31, 2014 vs. March 31, 2013

General. For the Current Quarter, Chesapeake had net income of $466 million, or $0.54 per diluted common share, on total revenues of $5.046 billion. This compares to net income of $102 million, or $0.02 per diluted common share, on total revenues of $3.424 billion during the Prior Quarter. The increase in the Current Quarter was primarily driven by an increase in our natural gas, oil and NGL sales as discussed below.

Natural Gas, Oil and NGL Sales. During the Current Quarter, natural gas, oil and NGL sales were $1.766 billion compared to $1.453 billion in the Prior Quarter. In the Current Quarter, Chesapeake produced and sold 61 mmboe for $2.148 billion at a weighted average price of $35.35 per boe, compared to 60 mmboe produced and sold in the Prior Quarter for $1.595 billion at a weighted average price of $26.71 per boe. The increase in the price received per boe in the Current Quarter compared to the Prior Quarter resulted in an increase in revenues of $525 million, and increased sales volumes resulted in a $28 million increase in revenues, for a total increase in revenues of $553 million (excluding the effect of derivatives).

For the Current Quarter, our average price received per mcf of natural gas was $3.86 compared to $2.10 in the Prior Quarter (excluding the effect of derivatives). Oil prices received per barrel (excluding the effect of derivatives) were $93.60 and $95.23 in the Current Quarter and the Prior Quarter, respectively. NGL prices received per barrel (excluding the effect of derivatives) were $29.23 and $28.25 in the Current Quarter and the Prior Quarter, respectively.

Gains and losses from our natural gas, oil and NGL derivatives resulted in a net decrease in natural gas, oil and NGL revenues of $382 million in the Current Quarter and a net decrease of $142 million in the Prior Quarter. See Item 3 of Part I of this report for a complete listing of all of our derivative instruments as of March 31, 2014.

A change in natural gas, oil and NGL prices has a significant impact on our revenues and cash flows. Assuming our Current Quarter production levels and without considering the effect of derivatives, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in the Current Quarter revenues and cash flows of approximately $26 million, and an increase or decrease of $1.00 per barrel of liquids sold would result in an increase or decrease in the Current Quarter revenues and cash flows of approximately $17 million.

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

	Three Months Ended March 31, 2014								
	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b]	139.8	3.18	8.5	94.77	4.3	29.77	36.0	59	38.08
Northern[c]	120.2	4.66	1.4	86.66	3.3	28.53	24.8	41	31.38
Total[d]	260.0	3.86	9.9	93.60	7.6	29.23	60.8	100 %	35.35

	Three Months Ended March 31, 2013								
	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b]	192.5	1.94	8.8	95.69	4.2	26.28	45.1	76	29.47
Northern[c]	80.6	2.48	0.5	85.85	0.7	39.64	14.6	24	18.19
Total[d]	273.1	2.10	9.3	95.23	4.9	28.25	59.7	100 %	26.71

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

(b) Our Southern Division includes the Eagle Ford, Granite Wash/Hogshooter, Cleveland, Tonkawa and Mississippi Lime unconventional liquids plays and the Haynesville/Bossier and Barnett unconventional natural gas shale plays. The Eagle Ford Shale accounted for approximately 19% of our estimated proved reserves by volume as of December 31, 2013. Production for the Eagle Ford Shale for the Current Quarter and the Prior Quarter was 7.9 mmboe and 6.8 mmboe, respectively. The Barnett Shale accounted for approximately 16% of our estimated proved reserves by volume as of December 31, 2013. Production for the Barnett Shale for the Current Quarter and the Prior Quarter was 6.4 mmboe and 7.2 mmboe, respectively.

(c) Our Northern Division includes the Utica and Niobrara unconventional liquids plays and the Marcellus unconventional natural gas play. The Marcellus Shale accounted for approximately 25% of our estimated proved reserves by volume as of December 31, 2013. Production for the Marcellus Shale for the Current Quarter and the Prior Quarter was 18.8 mmboe and 12.8 mmboe, respectively.

(d) Current Quarter and Prior Quarter production levels reflect the impact of various asset sales and joint ventures. See Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for information on our natural gas and oil property divestitures and joint ventures.

Our average daily production of 675 mboe for the Current Quarter consisted of approximately 2.9 bcf of natural gas (71% on an oil equivalent basis) and approximately 193,700 bbls of liquids, consisting of approximately 109,500 bbls of oil (16% on an oil equivalent basis) and approximately 84,200 bbls of NGL (13% on an oil equivalent basis). Our year-over-year growth rate of oil production was 6% and our year-over-year growth rate of NGL production was 55%. Natural gas production declined 5% year over year primarily as a result of asset sales.

Excluding the impact of derivatives, our percentage of revenues from natural gas, oil and NGL is shown in the following table.

	Three Months Ended March 31,	
	2014	2013
Natural gas	47%	36%
Oil	43%	55%
NGL	10%	9%
Total	100%	100%

64

We are defending against claims by royalty owners alleging that we used below-market prices, made improper deductions, used improper measurement techniques and/or entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sale of natural gas and NGL. Adverse results in these matters would cause our obligations to royalty owners to increase, which would result in a decrease in our future revenues.

Marketing, Gathering and Compression Revenues and Expenses. Marketing, gathering and compression revenues and expenses consist of third-party revenues and expenses related to our marketing, gathering and compression operations and exclude depreciation and amortization, general and administrative expenses, impairments of fixed assets and other, net gains or losses on sales of fixed assets and interest expense. See Depreciation and Amortization of Other Assets below for the depreciation and amortization recorded on our marketing, gathering and compression assets. Chesapeake recognized $3.015 billion in marketing, gathering and compression revenues in the Current Quarter with corresponding expenses of $2.980 billion, for a net margin before depreciation of $35 million. This compares to revenues of $1.781 billion, expenses of $1.745 billion and a net margin before depreciation of $36 million in the Prior Quarter. Our revenues and operating expenses from our marketing business increased substantially in the Current Quarter compared to the Prior Quarter. In the Current Quarter, the prices received for marketing natural gas and NGL were significantly higher than in the Prior Quarter. In addition, in the Current Quarter we marketed significantly more oil and NGL from both Chesapeake-operated wells and for third parties. Our marketing revenues and operating expenses also increased because of a variety of purchase and sales contracts we entered into with third parties for various commercial purposes, including credit risk mitigation and to help meet certain of our pipeline delivery commitments. In addition, compression services increased in the Current Quarter compared to the Prior Quarter.

Oilfield Services Revenues and Expenses. Oilfield services consists of third-party revenues and expenses related to our oilfield services operations and excludes depreciation and amortization, general and administrative expenses, impairments of fixed assets and other, net gains or losses on sales of fixed assets and interest expense. See Depreciation and Amortization of Other Assets below for the depreciation and amortization recorded on our oilfield services assets. Chesapeake recognized $265 million in oilfield services revenues in the Current Quarter with corresponding expenses of $220 million, for a net margin before depreciation of $45 million. This compares to revenues of $190 million, expenses of $155 million and a net margin before depreciation of $35 million in the Prior Quarter. Oilfield services revenues and expenses increased in the Current Quarter compared to the Prior Quarter primarily as a result of increased third-party utilization for all of our oilfield services.

Natural Gas, Oil and NGL Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $288 million in the Current Quarter, compared to $307 million in the Prior Quarter. On a unit-of-production basis, production expenses were $4.73 per boe in the Current Quarter compared to $5.14 in the Prior Quarter. The per unit expense decrease in the Current Quarter was primarily the result of a general improvement in operating efficiencies across most of our operating areas. Production expenses in the Current Quarter and the Prior Quarter included approximately $41 million and $45 million, or $0.68 and $0.75 per boe, respectively, associated with VPP production volumes. We anticipate a continued decrease in production expenses associated with VPP production volumes as the contractually scheduled volumes under our VPP agreements decrease and as operating efficiencies generally improve.

Production Taxes. Production taxes were $50 million in the Current Quarter compared to $53 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.83 per boe in the Current Quarter compared to $0.89 per boe in the Prior Quarter. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas, oil and NGL prices are higher. Even with the increase in prices in the Current Quarter compared to the Prior Quarter, total production taxes declined as a result of production tax credits received in both Oklahoma and Texas. Production taxes in the Current Quarter and the Prior Quarter included approximately $4 million and $7 million, or $0.07 and $0.11 per boe, respectively, associated with VPP production volumes.

General and Administrative Expenses. General and administrative expenses were $79 million in the Current Quarter and $110 million in the Prior Quarter, or $1.30 and $1.84 per boe, respectively. The absolute and per unit expense decrease in the Current Quarter was primarily due to our efforts to reduce costs and increased emphasis on operational efficiencies. In addition, the workforce reduction described in Restructuring and Other Termination Costs below resulted in cost savings and is expected to contribute to more profitable and efficient growth. Included in general and administrative expenses is stock-based compensation of $12 million in the Current Quarter and $20 million in the Prior Quarter. See Note 7 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion 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 acquisition of leasehold and drilling and completion activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $57 million and $92 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our natural gas and oil property acquisition and drilling and completion efforts. The decrease was primarily due to lower costs and increased emphasis on operational efficiencies in support of our current business strategy.

Restructuring and Other Termination Costs. We recorded $7 million of income in the Current Quarter and $133 million of restructuring and other termination costs in the Prior Quarter. The Current Quarter amount primarily related to negative fair value adjustments to PSUs granted to former executives of the Company. The Prior Quarter amount primarily related to our voluntary separation plan and senior management separations. See Note 14 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion.

Natural Gas, Oil and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of natural gas, oil and NGL properties was $628 million and $648 million in the Current Quarter and the Prior Quarter, respectively. The $20 million decrease in the Current Quarter is primarily driven by efficiencies in our drilling program as a result of lower development costs and higher estimated reserve recoveries in addition to upward price revisions to our estimated proved reserves. The average DD&A rate per boe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $10.33 and $10.86 in the Current Quarter and the Prior Quarter, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $78 million in both the Current Quarter and the Prior Quarter. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. To the extent company-owned oilfield services equipment is used to drill and complete our wells, a substantial portion of the depreciation (i.e., the portion related to our utilization of the equipment) is capitalized in natural gas and oil properties as drilling and completion costs. The following table shows depreciation expense by asset class for the Current Quarter and the Prior Quarter and the estimated useful lives of these assets.

	Three Months Ended March 31,		Estimated
	2014	2013	Useful Life
	($ in millions)		(in years)
Oilfield services equipment[(a)]	$37	$26	3 - 15
Buildings and improvements	11	13	10 - 39
Natural gas compressors[(b)]	8	9	3 - 20
Computers and office equipment	9	12	3 - 7
Vehicles	7	11	0 - 7
Natural gas gathering systems and treating plants[(b)]	4	3	20
Other	2	4	2 - 20
Total depreciation and amortization of other assets	$78	$78	

(a) Included in our oilfield services operating segment.

(b) Included in our marketing, gathering and compression operating segment.

Impairments of Fixed Assets and Other. In the Current Quarter and the Prior Quarter, we recognized $20 million and $27 million, respectively, of fixed asset impairment losses and other charges. The Current Quarter losses primarily related to drilling rigs and equipment. The Prior Quarter losses primarily related to buildings and land. See Note 13 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of our impairments of fixed assets and other.

Net Gains on Sales of Fixed Assets. In the Current Quarter, net gains on sales of fixed assets were $23 million compared to $49 million in the Prior Quarter. The Current Quarter amount primarily related to the sale of natural gas compressors. The Prior Quarter amount primarily consisted of gains on sales of gathering assets partially offset by losses on the sales of buildings and land. See Note 12 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of our net gains on sales of fixed assets.

Interest Expense. Interest expense was $39 million in the Current Quarter compared to $21 million in the Prior Quarter as follows:

	Three Months Ended March 31,	
	2014	2013
	($ in millions)	
Interest expense on senior notes	$180	$186
Interest expense on term loans	29	29
Amortization of loan discount, issuance costs and other	19	19
Interest expense on credit facilities	8	12
Realized (gains) losses on interest rate derivatives[(a)]	(3)	(2)
Unrealized (gains) losses on interest rate derivatives[(b)]	(16)	6
Capitalized interest	(178)	(229)
Total interest expense	$39	$21
Average senior notes borrowings	$10,809	$10,283
Average term loan borrowings	$2,000	$2,000
Average credit facilities borrowings	$440	$1,095

(a) Includes settlements related to the current period interest accrual and the effect of gains (losses) on early terminated trades. Settlements of early-terminated trades are reflected in realized (gains) losses over the original life of the hedged item.

(b) Includes changes in the fair value of open interest rate derivatives offset by amounts reclassified to realized (gains) losses during the period.

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.90 per boe in the Current Quarter compared to $0.25 per boe in the Prior Quarter. The increase in Current Quarter interest expense is primarily due to a decrease in the amount of interest capitalized as a result of a lower average balance of unevaluated natural gas and oil properties, the primary asset on which interest is capitalized.

Losses on Investments. Losses on investments were $21 million in the Current Quarter compared to losses of $37 million in the Prior Quarter. The Current Quarter and the Prior Quarter losses primarily related to our equity in the net loss of FTS International, Inc.

Net Gain on Sales of Investments. We recorded net gains on sales of investments of $67 million in the Current Quarter. We sold all of our interest in Chaparral Energy, Inc. for cash proceeds of $215 million and recorded a $73 million gain related to the sale. We also sold an equity investment in a natural gas trading and management firm for cash proceeds of $30 million and recorded a loss of $6 million associated with the transaction.

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

Income Tax Expense. Chesapeake recorded income tax expense of $280 million and $63 million in the Current Quarter and the Prior Quarter, respectively. Our effective income tax rate was 37.5% in the Current Quarter and 38% in the Prior Quarter. Our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences.

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded net income attributable to noncontrolling interests of $41 million and $44 million in the Current Quarter and the Prior Quarter, respectively. Net income attributable to noncontrolling interests is primarily driven by the dividends paid on our CHK Utica and CHK C-T preferred stock in addition to income or loss related to the Chesapeake Granite Wash Trust. See Note 6 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of these entities.

67

Recently Issued Accounting Standards

In February 2013, the Financial Accounting Standards Board issued guidance on the recognition, measurement and disclosure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. We adopted this standard on January 1, 2014, and it did not have a material impact on our financial statements.

Forward-Looking Statements

This report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 (the “Exchange Act”). Forward-looking statements give our current expectations or forecasts of future events. They include expected natural gas, oil and NGL production and future expenses, estimated operating costs, assumptions regarding future natural gas, oil and NGL prices, planned drilling activity, estimates of future drilling and completion and other capital expenditures (including the use of joint venture drilling carries), and anticipated sales, as well as statements concerning anticipated cash flow and liquidity, covenant compliance, debt reduction, operating and capital efficiencies, business strategy and other plans and objectives for future operations. Our ability to generate sufficient operating cash flow to fund future capital expenditures is subject to all the risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time. Further, asset dispositions we are evaluating as we focus on our strategic priorities are subject to market conditions and other factors beyond our control. Our plans to reduce financial leverage and complexity may take longer to implement if such dispositions are delayed or do not occur as expected. 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 our 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 2013 Form 10-K and include:

- the volatility of natural gas, oil and NGL prices;
- the limitations our level of indebtedness may have on our financial flexibility;
- the availability of capital on an economic basis to fund reserve replacement costs;
- our ability to replace reserves and sustain production;
- uncertainties inherent in estimating quantities of natural gas, oil and NGL reserves and projecting future rates of production and the amount and timing of development expenditures;
- declines in the prices of natural gas and oil potentially resulting in a write-down of our asset carrying values;
- our ability to generate profits or achieve targeted results in drilling and well operations;
- leasehold terms expiring before production can be established;
- commodity derivative activities resulting in lower prices realized on natural gas, oil and NGL sales;
- the need to secure derivative liabilities and the inability of counterparties to satisfy their obligations;
- charges incurred in connection with actions to reduce financial leverage and complexity;
- competition in the oil and gas exploration and production industry;
- drilling and operating risks, including potential environmental liabilities;
- our need to acquire adequate supplies of water for our drilling operations and to dispose of or recycle the water used;
- legislative and regulatory changes adversely affecting our industry and our business, including initiatives related to hydraulic fracturing, air emissions and endangered species;
- a deterioration in general economic, business or industry conditions;

- oilfield services shortages, gathering system and transportation capacity constraints and various transportation interruptions that could adversely affect our revenues and cash flow;
- adverse developments or losses from pending or future litigation and regulatory investigations;
- cyber attacks adversely impacting our operations; and
- an interruption in operations at our headquarters due to a catastrophic event.

We caution you not to place undue reliance on the forward-looking statements contained in this report, which speak only as of the filing date, and we undertake no obligation to update this information except as required by applicable law. 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.

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

Natural Gas, Oil and NGL Derivatives

Our results of operations and cash flows are impacted by changes in market prices for natural gas, oil and NGL. To mitigate a portion of our exposure to adverse price 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 share of production. We believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

Our general strategy for protecting short-term cash flow and attempting to mitigate exposure to adverse natural gas, oil and NGL price changes is to hedge into strengthening natural gas and oil futures markets when prices reach levels that management believes are unsustainable for the long term, have material downside risk in the short term or provide reasonable rates of return on our invested capital. 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, collars and options. All of these are described in more detail below. We typically use collars, three-way collars and swaps for a large portion of the natural gas and oil price risk we hedge. We have also sold calls, taking advantage of premiums associated with market price volatility. In the second half of 2011 and in 2012 and 2013, we bought natural gas and oil calls to, in effect, lock in sold call positions. Due to lower natural gas, oil and NGL prices, we were able to achieve this at a low cost to us. In some cases, we deferred the payment of the premium on these trades to the related month of production. 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 condensed consolidated statements of cash flows.

We determine the volume potentially subject to derivative contracts by reviewing our overall 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 enter into derivative contracts for more volumes than our forecasted production, and if production estimates were lowered for future periods and derivative instruments are already executed for some volume above the new production forecasts, the positions would be reversed. The actual fixed price on our derivative instruments is derived from 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 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 negotiating a cash settlement with our counterparty, restructuring the position or 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 recognized 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 counterparty valuations for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. Future risk related to counterparties not being able to meet their obligations has been partially mitigated under our multi-counterparty 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 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of the fair value measurements associated with our derivatives.

As of March 31, 2014, 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.
- Collars: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike prices, no payments are due from either party. Three-way collars include an additional put option in exchange for a more favorable strike price on the call option. This eliminates the counterparty's downside exposure below the second put option.
- 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.
- Basis Protection Swaps: These instruments are arrangements that guarantee a price differential to NYMEX from a specified delivery point. Our current natural gas basis protection swaps 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. Our current oil basis protection swaps have positive differentials to NYMEX. Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

As of March 31, 2014, we had the following open natural gas and oil derivative instruments:

		Weighted Average Price				Fair Value
	Volume	Fixed	Call	Put	Differential	Asset (Liability)
	(tbtu)	($ per mmbtu)				($ in millions)
Natural Gas:						
Swaps:						
Short-term	394	4.17	—	—	—	$(125)
3-Way Collars:						
Short-term	280	—	4.47	3.47 / 4.21	—	(56)
Long-term	107	—	4.37	3.38 / 4.17	—	8
Call Options (sold):						
Short-term	305	—	6.41	—	—	(15)
Long-term	563	—	7.44	—	—	(26)
Call Options (bought)[a]:						
Short-term	(305)	—	6.41	—	—	(36)
Long-term	(370)	—	6.15	—	—	(125)
Basis Protection Swaps:						
Short-term	119	—	—	—	(0.51)	(10)
Long-term	32	—	—	—	(0.52)	(4)
Total Natural Gas						$(389)

	Volume	Weighted Average Price Fixed	Call	Put	Differential	Fair Value Asset (Liability)
	(mmbbl)	($ per bbl)				($ in millions)
Oil:						
Swaps:						
Short-term	22.4	94.23	—	—	—	$(81)
Long-term	0.4	89.15	—	—	—	—
Call Options (sold):						
Short-term	16.2	—	97.74	—	—	(84)
Long-term	42.8	—	100.23	—	—	(162)
Call Options (bought)[b]:						
Short-term	(10.4)	—	102.02	—	—	(7)
Long-term	(6.7)	—	113.54	—	—	(4)
Basis Protection Swaps:						
Short-term	0.3	—	—	—	6.00	1
	Total Oil					$(337)
	Total Natural Gas and Oil					$(726)

(a) Included in the fair value are deferred premiums of $31 million, $82 million and $85 million which will be included in natural gas, oil and NGL sales as realized gains (losses) in 2014, 2015 and 2016, respectively.

(b) Included in the fair value are deferred premiums of $35 million and $13 million which will be included in natural gas, oil and NGL sales as realized gains (losses) in 2014 and 2015, respectively.

In addition to the open derivative positions disclosed above, as of March 31, 2014 we had $107 million of net derivative gains related to settled contracts for future production periods that will be recorded within natural gas, oil and NGL sales as realized gains (losses) on derivatives once they are transferred from either accumulated other comprehensive income or unrealized gains (losses) on derivatives in the month of related production, based on the terms specified in the original contract as noted below.

	March 31, 2014 ($ in millions)
Short-term	$(79)
Long-term	186
Total	$107

The table below reconciles the changes in fair value of our natural gas and oil derivatives during the Current Quarter. Of the $726 million fair value liability as of March 31, 2014, $412 million related to contracts maturing in the next 12 months and $314 million related to contracts maturing after 12 months. All open derivative instruments as of March 31, 2014 are expected to mature by December 31, 2022.

	2014 ($ in millions)
Fair value of contracts outstanding, as of January 1	$(551)
Change in fair value of contracts	(364)
Fair value of new contracts when entered into	—
Contracts realized or otherwise settled	189
Fair value of contracts when closed	—
Fair value of contracts outstanding, as of March 31	$(726)

The change in natural gas and oil prices during the Current Quarter increased the liability related to our derivative instruments by $364 million. This unrealized gain is recorded in natural gas, oil and NGL sales. We settled contracts in the Current Quarter that were in a liability position for $189 million. The realized losses will be recorded in natural gas, oil and NGL sales in the month of related production.

Interest Rate Derivatives

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

	Years of Maturity						
	2014	2015	2016	2017	2018	Thereafter	Total
	($ in millions)						
Liabilities:							
Debt – fixed rate[(a)]	$—	$1,661	$500	$2,302	$1,112	$5,250	$10,825
Average interest rate	— %	7.89 %	3.25 %	4.42 %	5.66 %	6.20 %	5.89 %
Debt – variable rate[(b)]	$—	$—	$464	$2,000	$—	$—	$2,464
Average interest rate	— %	— %	2.90 %	5.75 %	— %	— %	5.21 %

(a) This amount does not include the discount included in debt of $303 million and interest rate derivatives of $13 million.

(b) This amount does not include the discount included in debt of $30 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 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.

We enter into interest rate derivatives, including 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 and floating-to-fixed interest rate swaps (we receive a floating market rate and pay a fixed interest rate) to manage our interest rate exposure related to our bank credit facility borrowings. As of March 31, 2014, the following interest rate derivatives were outstanding:

	Notional Amount ($ in millions)	Weighted Average Rate Fixed	Weighted Average Rate Floating[(a)]	Fair Value Hedge	Fair Value Asset (Liability) ($ in millions)
Fixed to Floating:					
Swaps					
Mature 2020 – 2023	$1,200	6.06 %	1 – 3 mL 430 bp	No	$(66)
Floating to Fixed:					
Swaps					
Mature 2014 – 2015	$1,050	2.13 %	1 – 6 mL	No	(14)
					$(80)

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

72

In addition to the open derivative positions disclosed above, as of March 31, 2014 we had $62 million of net gains related to settled derivative contracts that will be recorded within interest expense as realized gains (losses) once they are transferred from our senior note liability or within interest expense as unrealized gains (losses) over the remaining seven-year term of our related senior notes.

Realized and unrealized gains or losses from interest rate derivative transactions are reflected as adjustments to interest expense on the condensed consolidated statements of operations.

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. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay us €11 million and we pay the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay us €344 million and we 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 our expected cash flows related to changes in foreign exchange rates and therefore the swaps are designated as cash flow hedges. The fair values of the cross currency swaps are recorded on the condensed consolidated balance sheet as an asset of $7 million as of March 31, 2014. The euro-denominated debt in long-term debt has been adjusted to $473 million as of March 31, 2014 using an exchange rate of $1.3769 to €1.00.

ITEM 4. Controls and Procedures

Evaluation of Disclosure 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. As of 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, 2014.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the period ended March 31, 2014 which materially affected, or was reasonably likely to materially affect, our internal control over financial reporting.

PART II OTHER INFORMATION

ITEM 1. Legal Proceedings

Litigation and Regulatory Proceedings

The Company is involved in a number of litigation and regulatory proceedings (including those described below). Many of these proceedings are in early stages, and many of them seek or may seek damages and penalties, the amount of which is currently indeterminate. See Note 4 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for information regarding our estimation and provision for potential losses related to litigation and regulatory proceedings.

July 2008 Common Stock Offering. On February 25, 2009, a putative class action was filed in the U.S. District Court for the Southern District of New York against the Company and certain of its officers and directors along with certain underwriters of the Company's July 2008 common stock offering. The 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. Chesapeake and the officer and director defendants moved for summary judgment on grounds of loss causation and materiality on December 28, 2011, and the motion was granted as to all claims as a matter of law on March 29, 2013. Final judgment in favor of Chesapeake and the officer and director defendants was entered on June 21, 2013, and the plaintiff filed a notice of appeal on July 19, 2013 in the U.S. Court of Appeals for the Tenth Circuit. The appeal has been fully briefed and oral argument is scheduled for May 14, 2014.
A derivative action relating to the July 2008 offering filed in the U.S. District Court for the Western District of Oklahoma on September 6, 2011 is pending. Following the denial on September 28, 2012 of its motion to dismiss and pursuant to court order, nominal defendant Chesapeake filed an answer in the case on October 12, 2012. By stipulation between the parties, the case is stayed pending resolution of the Tenth Circuit appeal.
2012 Securities and Shareholder Litigation. A putative class action was filed in the U.S. District Court for the Western District of Oklahoma on April 26, 2012 against the Company and its former Chief Executive Officer (CEO), Aubrey K. McClendon. On July 20, 2012, the court appointed a lead plaintiff, which filed an amended complaint on October 19, 2012 against the Company, Mr. McClendon and certain other officers. The amended complaint asserted claims under Sections 10(b) (and Rule 10b-5 promulgated thereunder) and 20(a) of the Securities Exchange Act of 1934 based on alleged misrepresentations regarding the Company’s asset monetization strategy, including liabilities associated with its volumetric production payment (VPP) transactions, as well as Mr. McClendon’s personal loans and the Company’s internal controls. On December 6, 2012, the Company and other defendants filed a motion to dismiss the action. On April 10, 2013, the Court granted the motion, and on April 16, 2013 entered judgment against the plaintiff and dismissed the complaint with prejudice. The plaintiff filed a notice of appeal on June 14, 2013 in the U.S. Court of Appeals for the Tenth Circuit. Briefing on the appeal was complete on August 2, 2013, and on November 18, 2013, argument was heard.
A related federal consolidated derivative action and an Oklahoma state court derivative action are stayed pursuant to the parties' stipulation pending resolution of the appeal in the federal securities class action.
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. On August 21, 2012, the District Court granted the Company's motion to dismiss for lack of derivative standing, and the plaintiff appealed the ruling on December 6, 2012.

2014 Shareholder Litigation. On April 10, 2014, a derivative action was filed in the District Court of Oklahoma County, Oklahoma against current and former directors and officers of the Company alleging, among other things, breach of fiduciary duties, waste of corporate assets, gross mismanagement and unjust enrichment related to the Company's payment of shareholder dividends since October 2012.

Regulatory Proceedings. On May 2, 2012, Chesapeake and Mr. McClendon received notice from the SEC that its Fort Worth Regional Office had commenced an informal inquiry into, among other things, certain of the matters alleged in the foregoing 2012 securities and shareholder lawsuits. On December 21, 2012, the SEC's Fort Worth Regional Office advised Chesapeake that its inquiry was continuing as an investigation. The Company provided information and testimony to the SEC pursuant to subpoenas and otherwise in connection with this matter and is also responding to related inquiries from other governmental and regulatory agencies and self-regulatory organizations. On April 8, 2014, the SEC's Fort Worth Regional Office advised Chesapeake that it had concluded its investigation and, based on the information it had as of that date, did not intend to recommend an enforcement action by the SEC.

The Company has received, from the Antitrust Division of the U.S. Department of Justice (DOJ) and certain state governmental agencies, subpoenas and demands for documents, information and testimony in connection with investigations into possible violations of federal and state laws relating to our purchase and lease of oil and gas rights in various states. Chesapeake has engaged in discussions with the DOJ and state agencies and continues to respond to such subpoenas and demands. On March 5, 2014, the Attorney General of the state of Michigan filed a criminal complaint against Chesapeake in Michigan state court alleging misdemeanor antitrust violations and attempted antitrust violations under state law arising out of the Company's leasing activities in Michigan during 2010.

Business Operations. Chesapeake is involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions. With regard to contract actions, 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. Regarding royalty claims, Chesapeake and other natural gas producers have been named in various lawsuits alleging royalty underpayment. The suits allege that we used below-market prices, made improper deductions, used improper measurement techniques and/or entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sale of natural gas and NGL. The Company is defending against certain pending claims, has resolved a number of claims through negotiated settlements of past and future royalties and has prevailed in various other lawsuits.

Environmental Proceedings

On December 19, 2013, our subsidiary Chesapeake Appalachia, LLC (CALLC) entered into a consent decree with the Environmental Protection Agency (EPA), the U.S. Department of Justice (DOJ) and the West Virginia Department of Environmental Protection (WVDEP) to resolve alleged violations of the Clean Water Act (CWA) and the West Virginia Water Pollution Control Act at 27 sites in West Virginia. In a complaint filed against CALLC the same day in the U.S. District Court for the Northern District of West Virginia, the EPA and WVDEP alleged that CALLC impounded streams and discharged sand, dirt, rocks and other fill material into streams and wetlands without a federal permit in order to construct well pads, impoundments, road crossings and other facilities related to natural gas extraction. The consent decree was approved and entered by the court on March 11, 2014.

In accordance with the consent decree, CALLC paid a civil penalty of $3.2 million, which was divided evenly between the U.S. and the state of West Virginia. The consent decree settlement also requires that CALLC restore the affected wetlands and streams in accordance with an agreed plan, monitor the restored sites for up to 10 years to assure the success of the restoration, and implement a comprehensive compliance program to ensure future compliance with the CWA and applicable West Virginia law. To offset the impacts to sites, CALLC is required by the consent decree to perform compensatory mitigation, which will likely involve purchasing credits from a wetland mitigation bank located in a local watershed. We believe that compliance with the consent decree will not have a material adverse impact on our business.

In a related case, in December 2012, CALLC pled guilty to three misdemeanor violations of the CWA for unauthorized discharge at one of the sites subject to the consent decree of crushed stone and gravel into a local stream to create a roadway to improve access to a drilling site. CALLC paid a $600,000 penalty and is subject to a two-year probation ending in December 2014. CALLC has fully restored the site, and we believe that CALLC is in compliance with the terms of probation. By operation of law, a CWA conviction triggers “disqualification”, by which the disqualified entity is prohibited from receiving federal contracts or benefits until the EPA certifies that the conditions giving rise to the conviction have been corrected. Disqualification of CALLC has not had, and we do not expect it to have, a material adverse impact on our business.

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 2013 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.

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

The following table presents information about repurchases of our common stock during the quarter ended March 31, 2014:

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, 2014 through January 31, 2014	845,892	$26.35	—	—
February 1, 2014 through February 28, 2014	11,874	$25.86	—	—
March 1, 2014 through March 31, 2014	22,235	$25.56	—	—
Total	880,001	$26.32	—	—

(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 that 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.

ITEM 6. Exhibits

The following exhibits are filed or furnished herewith pursuant to the requirements of Item 601 of Regulation S-K:

		Incorporated by Reference					
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
3.1.1	Chesapeake's Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	8/10/2009		
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	8/11/2008		
3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	5/20/2010		
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	8/9/2010		
3.2	Chesapeake's Amended and Restated Bylaws.	8-K	001-13726	3.2	6/8/2012		
4.1.1	Indenture, dated as of April 24, 2014, by and among the Company, the subsidiaries signatory thereto, as Subsidiary Guarantors, and Deutsche Bank Trust Company Americas, as Trustee.	8-K	001-13726	4.1	4/29/2014		
4.1.2	First Supplemental Indenture, dated as of April 24, 2014, to Indenture dated as of April 24, 2014 with respect to	8-K	001-13726	4.2	4/29/2014		

	Floating Rate Senior Notes due 2019.					
4.1.3	Second Supplemental Indenture, dated as of April 24, 2014, to Indenture dated as of April 24, 2014 with respect to 4.875% Senior Notes due 2022.	8-K	001-13726	4.3	4/29/2014	
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.					X
31.1	Robert D. Lawler, 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	Robert D. Lawler, Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.		X
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	

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 7, 2014	By: /s/ ROBERT D. LAWLER Robert D. Lawler, President and Chief Executive Officer
Date: May 7, 2014	By: /s/ DOMENIC J. DELL'OSSO, JR. Domenic J. Dell'Osso, Jr. Executive Vice President and Chief Financial Officer

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3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	5/20/2010		
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	8/9/2010		
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