CHESAPEAKE ENERGY CORP
Form 10-Q
August 04, 2016
TABLE OF CONTENTS

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q
[X] Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the Quarterly Period Ended June 30, 2016
[ ] 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 July 27, 2016, there were 776,956,037 shares of our $0.01 par value common stock outstanding.

CHESAPEAKE ENERGY CORPORATION
INDEX TO FORM 10-Q FOR THE QUARTER ENDED JUNE 30, 2016

TABLE OF CONTENTS
PART I. FINANCIAL INFORMATION

Item 1. Condensed Consolidated Financial Statements (Unaudited)
CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2016	December 31, 2015
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($1 and $1 attributable to our VIE)	$4	$825
Accounts receivable, net	952	1,129
Short-term derivative assets	30	366
Other current assets	218	160
Total Current Assets	1,204	2,480
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, at cost based on full cost accounting:		
Proved oil and natural gas properties ($488 and $488 attributable to our VIE)	64,547	63,843
Unproved properties	6,172	6,798
Other property and equipment	2,631	2,927
Total Property and Equipment, at Cost	73,350	73,568
Less: accumulated depreciation, depletion and amortization (($456) and ($428) attributable to our VIE)	(61,757)	(59,365)
Property and equipment held for sale, net	92	95
Total Property and Equipment, Net	11,685	14,298
LONG-TERM ASSETS:		
Long-term derivative assets	250	246
Other long-term assets	348	290
TOTAL ASSETS	$13,487	$17,314

The accompanying notes are an integral part of these condensed consolidated financial statements.
1

TABLE OF CONTENTS

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

	June 30, 2016	December 31, 2015
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$702	$944
Current maturities of long-term debt, net	1,028	381
Accrued interest	100	101
Short-term derivative liabilities	315	40
Other current liabilities ($0 and $8 attributable to our VIE)	1,632	2,219
Total Current Liabilities	3,777	3,685
LONG-TERM LIABILITIES:		
Long-term debt, net	8,621	10,311
Long-term derivative liabilities	41	60
Asset retirement obligations, net of current portion	400	452
Other long-term liabilities	419	409
Total Long-Term Liabilities	9,481	11,232
CONTINGENCIES AND COMMITMENTS (Note 4)		
EQUITY:		
Chesapeake Stockholders' Equity:		
Preferred stock, $0.01 par value, 20,000,000 shares authorized: 7,225,713 and 7,251,515 shares outstanding	3,036	3,062
Common stock, $0.01 par value, 1,500,000,000 and 1,000,000,000 shares authorized: 776,697,583 and 664,795,509 shares issued	8	7
Additional paid-in capital	12,930	12,403
Accumulated deficit	(15,873)	(13,202)
Accumulated other comprehensive loss	(104)	(99)
Less: treasury stock, at cost; 1,303,020 and 1,437,724 common shares	(29)	(33)
Total Chesapeake Stockholders' Equity (Deficit)	(32)	2,138
Noncontrolling interests	261	259
Total Equity	229	2,397
TOTAL LIABILITIES AND EQUITY	$13,487	$17,314

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

2

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	($ in millions except per share data)			
REVENUES:				
Oil, natural gas and NGL	$440	$1,216	$1,433	$2,759
Marketing, gathering and compression	1,182	2,305	2,142	3,980
Total Revenues	1,622	3,521	3,575	6,739
OPERATING EXPENSES:				
Oil, natural gas and NGL production	182	276	388	575
Oil, natural gas and NGL gathering, processing and transportation	481	488	963	946
Production taxes	19	34	37	62
Marketing, gathering and compression	1,207	2,096	2,149	3,796
General and administrative	61	69	109	125
Restructuring and other termination costs	3	(4)	3	(14)
Provision for legal contingencies	82	334	104	359
Oil, natural gas and NGL depreciation, depletion and amortization	265	601	536	1,285
Depreciation and amortization of other assets	29	34	58	69
Impairment of oil and natural gas properties	1,045	5,015	1,898	9,991
Impairments of fixed assets and other	6	84	44	88
Net (gains) losses on sales of fixed assets	(1)	1	(5)	4
Total Operating Expenses	3,379	9,028	6,284	17,286
LOSS FROM OPERATIONS	(1,757)	(5,507)	(2,709)	(10,547)
OTHER INCOME (EXPENSE):				
Interest expense	(62)	(71)	(124)	(122)
Losses on investments	(2)	(17)	(2)	(24)
Loss on sale of investment	—	—	(10)	—
Gains on purchases or exchanges of debt	68	—	168	—
Other income (expense)	3	(1)	6	5
Total Other Income (Expense)	7	(89)	38	(141)
LOSS BEFORE INCOME TAXES	(1,750)	(5,596)	(2,671)	(10,688)
INCOME TAX BENEFIT:				
Current income taxes	—	(6)	—	(6)
Deferred income taxes	—	(1,500)	—	(2,872)
Total Income Tax Benefit	—	(1,506)	—	(2,878)
NET LOSS	(1,750)	(4,090)	(2,671)	(7,810)
Net income attributable to noncontrolling interests	—	(18)	—	(37)
NET LOSS ATTRIBUTABLE TO CHESAPEAKE	(1,750)	(4,108)	(2,671)	(7,847)
Preferred stock dividends	(42)	(43)	(85)	(86)
NET LOSS AVAILABLE TO COMMON STOCKHOLDERS	$(1,792)	$(4,151)	$(2,756)	$(7,933)
LOSS PER COMMON SHARE:				
Basic	$(2.48)	$(6.27)	$(3.97)	$(11.99)
Diluted	$(2.48)	$(6.27)	$(3.97)	$(11.99)

CASH DIVIDEND DECLARED PER COMMON SHARE	$—	$—	$—	$0.0875
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	724	662	695	662
Diluted	724	662	695	662

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

3

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	($ in millions)			
NET LOSS	$(1,750)	$(4,090)	$(2,671)	$(7,810)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX:				
Unrealized gains (losses) on derivative instruments, net of income tax expense (benefit) of $2, $0, ($1) and ($1)	(15)	—	(19)	(1)
Reclassification of (gains) losses on settled derivative instruments, net of income tax expense (benefit) of ($4), $2, $3 and $9	10	3	14	13
Other Comprehensive Income (Loss)	(5)	3	(5)	12
COMPREHENSIVE LOSS	(1,755)	(4,087)	(2,676)	(7,798)
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	—	(18)	—	(37)
COMPREHENSIVE LOSS ATTRIBUTABLE TO CHESAPEAKE	$(1,755)	$(4,105)	$(2,676)	$(7,835)

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

TABLE OF CONTENTS

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

	Six Months Ended June 30, 2016	2015
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET LOSS	$(2,671)	$(7,810)
ADJUSTMENTS TO RECONCILE NET LOSS TO CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	594	1,354
Deferred income tax expense (benefit)	—	(2,872)
Derivative (gains) losses, net	278	(344)
Cash receipts on derivative settlements, net	386	631
Stock-based compensation	25	43
Impairment of oil and natural gas properties	1,898	9,991
Net (gains) losses on sales of fixed assets	(5)	4
Impairments of fixed assets and other	34	81
Losses on investments	2	24
Loss on sale of investment	10	—
Gains on purchases or exchanges of debt	(168)	—
Restructuring and other termination costs	3	(14)
Provision for legal contingencies	104	359
Other	(51)	9
Changes in assets and liabilities	(765)	(719)
Net Cash Provided By (Used In) Operating Activities	(326)	737
CASH FLOWS FROM INVESTING ACTIVITIES:		
Drilling and completion costs	(609)	(2,168)
Acquisitions of proved and unproved properties	(426)	(266)
Proceeds from divestitures of proved and unproved properties	964	14
Additions to other property and equipment	(25)	(93)
Proceeds from sales of other property and equipment	70	7
Cash paid for title defects	(69)	—
Additions to investments	—	(1)
Other	(4)	(5)
Net Cash Used In Investing Activities	(99)	(2,512)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Cash paid to purchase debt	(472)	—
Proceeds from credit facilities borrowings	2,477	—
Payments on credit facilities borrowings	(2,377)	—
Cash paid for common stock dividends	—	(118)
Cash paid for preferred stock dividends	—	(86)
Distributions to noncontrolling interest owners	(6)	(57)
Other	(18)	(21)
Net Cash Used In Financing Activities	(396)	(282)
Net decrease in cash and cash equivalents	(821)	(2,057)
Cash and cash equivalents, beginning of period	825	4,108

Cash and cash equivalents, end of period	$4	$2,051

The accompanying notes are an integral part of these condensed consolidated financial statements.
5

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:

	Six Months Ended June 30,	
	2016	2015
	($ in millions)	
SUPPLEMENTAL CASH FLOW INFORMATION:		
Interest paid, net of capitalized interest	$154	$65
Income taxes paid, net of refunds received	$(20)	$60
SUPPLEMENTAL DISCLOSURE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Change in accrued drilling and completion costs	$(13)	$(46)
Debt exchanged for common stock	$471	$—

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

6

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

	Six Months Ended June 30,	
	2016	2015
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning of period	$3,062	$3,062
Conversions of 25,802 and 0 shares of preferred stock for common stock	(26)	—
Balance, end of period	3,036	3,062
COMMON STOCK:		
Balance, beginning of period	7	7
Exchange of senior notes and contingent convertible notes	1	—
Balance, end of period	8	7
ADDITIONAL PAID-IN CAPITAL:		
Balance, beginning of period	12,403	12,531
Stock-based compensation	31	40
Exchange of contingent convertible notes for 55,427,782 and 0 shares of common stock	241	—
Exchange of senior notes for 53,923,925 and 0 shares of common stock	229	—
Conversion of preferred stock for 1,021,506 and 0 shares of common stock	26	—
Dividends on common stock	—	(59)
Dividends on preferred stock	—	(86)
Decrease in tax benefit from stock-based compensation	—	(6)
Balance, end of period	12,930	12,420
RETAINED EARNINGS (ACCUMULATED DEFICIT):		
Balance, beginning of period	(13,202)	1,483
Net loss attributable to Chesapeake	(2,671)	(7,847)
Balance, end of period	(15,873)	(6,364)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(99)	(143)
Hedging activity	(5)	12
Balance, end of period	(104)	(131)
TREASURY STOCK – COMMON:		
Balance, beginning of period	(33)	(37)
Purchase of 22,810 and 28,298 shares for company benefit plans	—	—
Release of 157,514 and 56,305 shares from company benefit plans	4	1
Balance, end of period	(29)	(36)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY (DEFICIT)	(32)	8,958
NONCONTROLLING INTERESTS:		
Balance, beginning of period	259	1,302
Net income attributable to noncontrolling interests	—	37
Distributions to noncontrolling interest owners	2	(54)
Balance, end of period	261	1,285
TOTAL EQUITY	$229	$10,243

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

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

1. Basis of Presentation

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements of Chesapeake Energy Corporation ("Chesapeake" or the "Company") and its subsidiaries were 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. These financial statements were prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with U.S. GAAP. This Form 10-Q relates to the three and six months ended June 30, 2016 (the "Current Quarter" and the “Current Period”, respectively) and the three and six months ended June 30, 2015 (the "Prior Quarter" and the “Prior Period”, respectively). Chesapeake's annual report on Form 10-K for the year ended December 31, 2015 ("2015 Form 10-K") includes certain definitions and a summary of significant accounting policies that should be read in conjunction with this Form 10-Q. All material adjustments (consisting solely of normal recurring adjustments) which, in the opinion of management, are necessary for a fair statement of the results for the interim periods have been reflected. The results for the Current Quarter and the Current Period are not necessarily indicative of the results to be expected for the full year.

Risks and Uncertainties

Our ability to grow, make capital expenditures and service our debt depends primarily upon the prices we receive for the oil, natural gas and natural gas liquids (NGL) we sell. Substantial expenditures are required to replace reserves, sustain production and fund our business plans. Historically, oil and natural gas prices have been very volatile, and may be subject to wide fluctuations in the future. The substantial decline in oil, natural gas and NGL prices from 2014 levels has negatively affected the amount of cash we have available for capital expenditures and debt service.

We face other significant risks to our business, including:

- In the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, capitalized costs of oil and natural gas properties exceeded our full cost ceiling, resulting in an impairment in the carrying value of our oil and natural gas properties of $1.045 billion, $5.015 billion, $1.898 billion and $9.991 billion, respectively. Based on the first-day-of-the-month prices we have received over the 11 months ended August 1, 2016, as well as the current strip price for September 2016, we expect to record downward reserve revisions and another write-down in the carrying value of our oil and natural gas properties in the third quarter of 2016, although the amount of impairment could be mitigated by the impact of anticipated divestitures in the third quarter of 2016 or other factors.
- Oil, natural gas and NGL prices have a material impact on our financial position, results of operations, cash flows and quantities of reserves that may be economically produced. If depressed prices persist throughout 2017 and we are unable to restructure or refinance our debt or generate additional liquidity through other actions, our ability to comply with the financial covenants under our revolving credit facility and to make scheduled debt payments could be adversely impacted.
- As of June 30, 2016, we had approximately $8.679 billion principal amount of debt outstanding, of which $1.382 billion matures or can be put to us in 2017 (including $337 million of maturities in January 2017, $730 million which can be put to us in May 2017 and $315 million that matures in August 2017) and $846 million that matures or can be put to us in 2018. See Note 3 for further discussion of our debt obligations, including principal and carrying amounts of our notes. As of June 30, 2016, we had $100 million of outstanding borrowings under our revolving credit facility and $3.087 billion of borrowing capacity available under our revolving credit facility.

- Since December 2015, Moody’s Investor Services, Inc. and Standard & Poor’s Rating Services have significantly lowered our credit ratings. Some of our counterparties have requested or required us to post collateral as financial assurance of our performance under certain contractual arrangements, such as gathering, processing, transportation and hedging agreements. As of August 1, 2016, we have received requests and posted approximately $274 million in collateral under such arrangements (excluding the supersedeas bond with respect to the 6.775% Senior Notes due 2019 (the 2019 Notes) litigation discussed in Note 4). We may be requested or required by other counterparties to post additional collateral in an aggregate amount of approximately $664 million, which may be in the form of additional letters of credit, cash or other acceptable collateral. Any posting of additional collateral consisting of cash or letters of credit, which would reduce availability under our revolving credit facility, will negatively impact our liquidity.
- We may seek to access the capital markets or otherwise incur debt to refinance a portion of our outstanding indebtedness and improve our liquidity.

We have taken measures to mitigate the risks and uncertainties facing us for the next 12 months, including mitigating a portion of our downside exposure to lower commodity prices through derivative contracts, the suspension of dividend payments on our convertible preferred stock, the April 2016 amendment to our revolving credit facility (discussed in Note 3) and divesting assets to increase our liquidity; however, there can be no assurance that these measures will satisfy our needs.

Reclassifications

In April 2015, the Financial Accounting Standards Board (FASB) issued guidance that requires debt issuance costs related to term debt to be presented in the balance sheet as a direct deduction from the associated debt liability. This standard requires retrospective application and is effective for annual reporting periods beginning after December 15, 2015. This change in accounting principle is preferable since it allows debt issuance costs and debt issuance discounts to be presented similarly in the consolidated balance sheets as a reduction to the face amount of our debt balances. A retrospective change to our consolidated balance sheet as of December 31, 2015, as previously presented, is required pursuant to the guidance. The retrospective adjustment to the December 31, 2015 consolidated balance sheet is shown below.

	As Previously Reported	December 31, 2015 Adjustment Effect	As Adjusted
	$ in millions		
Other long-term assets	$ 333	$ (43)	$ 290
Long-term debt, net	$ 10,354	$ (43)	$ 10,311

Beginning in the fourth quarter of 2015, we began presenting third party transportation and gathering costs as a component of operating expenses in our statement of operations. Previously, these costs were reflected as deductions to oil, natural gas and NGL sales. These costs have been reclassified in our condensed consolidated statement of operations for the Prior Quarter and the Prior Period to conform to the presentation used for the Current Quarter and the Current Period. The net effect of this reclassification did not impact our previously reported net loss, stockholders’ equity or cash flows; however, previously reported oil, natural gas and NGL sales have increased from the amounts previously reported, and total operating expenses have increased by those same amounts.

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 the issuance of common shares for all potentially dilutive securities, provided the effect is not antidilutive. For the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, 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.

For the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, shares of the following securities and associated adjustments to net income, representing dividends on preferred stock and allocated earnings on participating securities, were excluded from the calculation of diluted EPS as the effect was antidilutive.

	Net Income Adjustments ($ in millions)		Shares (in millions)
Three Months Ended June 30, 2016			
Common stock equivalent of our preferred stock outstanding:			
5.75% cumulative convertible preferred stock	$	21	58
5.75% cumulative convertible preferred stock (series A)	$	16	42
5.00% cumulative convertible preferred stock (series 2005B)	$	2	6
4.50% cumulative convertible preferred stock	$	3	6
Participating securities	$	—	1
Three Months Ended June 30, 2015			
Common stock equivalent of our preferred stock outstanding:			
5.75% cumulative convertible preferred stock	$	21	59
5.75% cumulative convertible preferred stock (series A)	$	16	42
5.00% cumulative convertible preferred stock (series 2005B)	$	3	6
4.50% cumulative convertible preferred stock	$	3	6
Participating securities	$	—	1
Six Months Ended June 30, 2016			
Common stock equivalent of our preferred stock outstanding:			
5.75% cumulative convertible preferred stock	$	42	58
5.75% cumulative convertible preferred stock (series A)	$	32	42
5.00% cumulative convertible preferred stock (series 2005B)	$	5	6
4.50% cumulative convertible preferred stock	$	6	6
Participating securities	$	—	1
Six Months Ended June 30, 2015			
Common stock equivalent of our preferred stock outstanding:			
5.75% cumulative convertible preferred stock	$	43	59
5.75% cumulative convertible preferred stock (series A)	$	32	42

5.00% cumulative convertible preferred stock (series 2005B)	$	5	6
4.50% cumulative convertible preferred stock	$	6	6
Participating securities	$	—	2

10

TABLE OF CONTENTS
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 June 30, 2016 and December 31, 2015:

	June 30, 2016		December 31, 2015	
	Principal Amount	Carrying Amount	Principal Amount	Carrying Amount
	($ in millions)			
3.25% senior notes due 2016	$—	$—	$381	$381
6.25% euro-denominated senior notes due 2017[(a)]	337	337	329	329
6.5% senior notes due 2017	315	315	453	453
7.25% senior notes due 2018	531	531	538	538
Floating rate senior notes due 2019	949	949	1,104	1,104
6.625% senior notes due 2020	822	822	822	822
6.875% senior notes due 2020	302	302	304	304
6.125% senior notes due 2021	584	584	589	589
5.375% senior notes due 2021	276	276	286	286
4.875% senior notes due 2022	607	607	639	639
8.00% senior secured second lien notes due 2022	2,425	3,501	2,425	3,584
5.75% senior notes due 2023	384	384	384	384
2.75% contingent convertible senior notes due 2035[(b)]	2	2	2	2
2.5% contingent convertible senior notes due 2037[(b)(c)]	730	694	1,110	1,027
2.25% contingent convertible senior notes due 2038[(b)(c)]	315	276	340	290
Revolving credit facility	100	100	—	—
Debt issuance costs	—	(35)	—	(43)
Discount on senior notes	—	(2)	—	(4)
Interest rate derivatives[(d)]	—	6	—	7
Total debt, net	8,679	9,649	9,706	10,692
Less current maturities of long-term debt, net[(e)]	(1,066)	(1,028)	(381)	(381)
Total long-term debt, net	$7,613	$8,621	$9,325	$10,311

(a) The principal and carrying amounts shown are based on the exchange rate of $1.1106 to €1.00 and $1.0862 to €1.00 as of June 30, 2016 and December 31, 2015, respectively. See Foreign Currency Derivatives in Note 8 for information on our related foreign currency derivatives.

(b) The repurchase, conversion, contingent interest and redemption provisions of our contingent convertible senior notes are as follows:

Holders’ Demand Repurchase Rights. 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.

Optional Conversion by Holders. At the holder's option, prior to maturity under certain circumstances, the notes are convertible into cash and, if applicable, shares of our common stock using a net share settlement process. One 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. During the specified period in the Current Quarter, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes and, as a result, the holders do not have the option to convert their notes into cash and common stock in the third quarter of 2016 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 during the Current Quarter and 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 the principal amount.

Contingent Interest. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years during certain periods if the average trading price of the notes exceeds the threshold defined in the indenture.

The holders' demand repurchase dates, the common stock price conversion threshold amounts (as adjusted to give effect to cash dividends on our common stock) 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	Holders' Demand Repurchase Dates	Common Stock Price Conversion Thresholds	Contingent Interest First Payable (if applicable)
2.75% due 2035	November 15, 2020, 2025, 2030	$ 45.02	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 59.44	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 100.20	June 14, 2019

Optional Redemption by the Company. We may redeem the contingent 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. In addition, we may redeem our 2.75% Contingent Convertible Senior Notes due 2035 at any time.

(c) The carrying amount associated with the equity component of our contingent convertible senior notes as of June 30, 2016 and December 31, 2015 is net of $75 million and $133 million, respectively. This amount is amortized based on an effective yield method.

(d) See Interest Rate Derivatives in Note 8 for further discussion related to these instruments.

(e) As of June 30, 2016, current maturities of long-term debt net includes our 6.25% Euro-denominated Senior Notes due 2017 and our 2.5% Contingent Convertible Senior Notes due 2037 (the 2037 Notes). As discussed in footnote (b) above, the holders of our 2037 Notes could exercise their individual demand repurchase rights on May 15, 2017, which would require us to repurchase all or a portion of the principal amount of the notes. As of June 30, 2016, there was $36 million associated with the equity component of the 2037 Notes.

Chesapeake Senior Notes and Contingent Convertible Senior Notes

In the Current Period, in addition to the repayment upon maturity of $259 million principal amount of our 3.25% Senior Notes due 2016, we repurchased in the open market approximately $181 million principal amount of our outstanding senior notes for $151 million and $118 million principal amount of our outstanding contingent convertible senior notes for $63 million. Additionally, we privately negotiated exchanges of approximately $290 million principal amount of our outstanding senior notes for 53,923,925 shares of common stock and $287 million principal amount of our outstanding contingent convertible senior notes for 55,427,782 shares of common stock. In the Current Period, we recorded an aggregate gain of approximately $168 million associated with the repurchases and exchanges (including $68 million in the Current Quarter).

Chesapeake Energy Corporation is a holding company and has no independent assets or operations. Our obligations under our outstanding senior notes and contingent convertible senior notes are fully and unconditionally guaranteed, jointly and severally, by certain of our 100% owned subsidiaries on a senior unsecured basis. Our non-guarantor subsidiaries are minor and, as such, we have not included condensed consolidating financial information.

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

Revolving Credit Facility

We have a $4.0 billion senior secured revolving credit facility that matures in December 2019. As of June 30, 2016, we had outstanding borrowings of $100 million under the credit facility and had used $813 million of the credit facility for various letters of credit (including the $461 million supersedeas bond with respect to the 2019 Notes litigation discussed in Note 4). The terms of the credit facility include covenants limiting, among other things, our ability to incur additional indebtedness, make investments or loans, create liens, consummate mergers and similar fundamental changes, make restricted payments, make investments in unrestricted subsidiaries and enter into transactions with affiliates. We were in compliance with all financial covenants under the agreement as of June 30, 2016.

In April 2016, we entered into the third amendment to our senior revolving credit facility. Pursuant to the amendment, our borrowing base was reaffirmed in the amount of $4.0 billion and the next scheduled borrowing base redetermination review was postponed until June 15, 2017, with the consenting lenders agreeing not to exercise their interim redetermination right prior to that date. The amendment also provides temporary financial covenant relief, with the credit facility's existing first lien secured leverage ratio and net debt to capitalization ratio suspended until September 30, 2017 and the interest coverage ratio maintenance covenant reduced as noted below. In addition, we agreed to grant liens and security interests on a majority of our assets, as well as maintain a minimum liquidity amount (defined as cash and cash equivalents and availability under our revolving credit facility) of $500 million until the suspension of the existing maintenance covenants ends.

The amendment reduces the interest coverage ratio from 1.1 to 1.0 to 0.65 to 1.0 through the first quarter of 2017, after which it will increase to 0.70 to 1.0 through the second quarter of 2017, 1.2 to 1.0 through the third quarter of 2017 and 1.25 to 1.0 thereafter. The amendment also includes a collateral value coverage test whereby if the collateral value coverage ratio, tested as of December 31, 2016, falls below 1.1 to 1.0, the $500 million minimum liquidity covenant increases to $750 million, and if the collateral value coverage ratio, tested as of March 31, 2017, falls below 1.25 to 1.0, our borrowing ability will be reduced in order to satisfy such ratio. The amendment also gives us the ability to incur up to $2.5 billion of first lien indebtedness secured on a pari passu basis with the existing obligations under the credit agreement, subject to payment priority in favor of the existing lenders and the other limitations on junior lien debt set forth in the credit agreement.

Fair Value of Debt

We estimate the fair value of our exchange-traded debt using quoted market prices (Level 1). The fair value of all other debt, including borrowings under our revolving credit facility, 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.

	June 30, 2016		December 31, 2015	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Short-term debt (Level 1)	$1,028	$984	$381	$ 366
Long-term debt (Level 1)	$8,515	$5,793	$10,304	$ 3,735
Long-term debt (Level 2)	$100	$83	$—	$ —

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.

2016 Shareholder Litigation. On April 19, 2016, a derivative action was filed in the U.S. District Court for the Western District of Oklahoma against the Company and current and former directors and officers of the Company alleging, among other things, violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act, breach of fiduciary duties, waste of corporate assets, gross mismanagement and violations of Sections 10(b) and Rule 10b-5 of the Exchange Act related to actions allegedly taken by such persons since 2008. The lawsuit seeks certification as a class action, damages, attorneys' fees and other costs.

Regulatory Proceedings. The Company has received, from the U.S. Department of Justice (DOJ) and certain state governmental agencies and authorities, subpoenas and demands for documents, information and testimony in connection with investigations into possible violations of federal and state antitrust laws relating to our purchase and lease of oil and natural gas rights in various states. The Company also has received DOJ, U.S. Postal Service and state subpoenas seeking information on the Company's royalty payment practices. Chesapeake has engaged in discussions with the DOJ, U.S. Postal Service and state agency representatives and continues to respond to such subpoenas and demands.

Redemption of 2019 Notes. As previously disclosed in the 2015 Form 10-K, in connection with the litigation related to the Company's notice issued on March 15, 2013 to redeem all of the 2019 Notes at par (plus accrued interest through the redemption date) pursuant to the special early redemption provision of the supplemental indenture governing the 2019 Notes, the Company filed a notice of appeal on July 27, 2015 of an amended judgment entered on July 17, 2015 by the U.S. District Court for the Southern District of New York awarding the Trustee for the 2019 Notes $380 million plus prejudgment interest in the amount of $59 million. The Company posted a supersedeas bond in the amount of $461 million (reflected as an outstanding letter of credit under the Company's credit facility) to stay execution of the judgment while appellate proceedings are pending. We accrued a loss contingency of $100 million for this matter in 2014, and we accrued an additional $339 million in 2015.

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 oil and natural gas interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The Company has successfully defended a number of these failure-to-close cases in various courts, has settled and resolved other such cases and disputes and believes that its remaining loss exposure for these claims will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Regarding royalty claims, Chesapeake and other natural gas producers have been named in various lawsuits alleging royalty underpayment. The suits against us allege, among other things, 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. Plaintiffs have varying royalty provisions in their respective leases, oil and gas law varies from state to state, and royalty owners and producers differ in their interpretation of the legal effect of lease provisions governing royalty calculations. The Company has resolved a number of these claims through negotiated settlements of past and future royalties and has prevailed in various other lawsuits. We are currently defending lawsuits seeking damages with respect to royalty underpayment in various states, including, but not limited to, Texas, Pennsylvania, Ohio, Louisiana, Oklahoma and Arkansas. These lawsuits include cases filed by individual royalty owners and putative class actions, some of which seek to certify a statewide class. The Company also has received DOJ, U.S. Postal Service and state subpoenas seeking information on the Company's royalty payment practices.

Chesapeake is defending numerous lawsuits filed by individual royalty owners alleging royalty underpayment with respect to properties in Texas. On April 8, 2015, Chesapeake obtained a transfer order from the Texas Multidistrict Litigation Panel to transfer a substantial portion of these lawsuits filed since June 2014 to the 348th District Court of Tarrant County for pre-trial purposes (the "MDL"). These lawsuits, which primarily relate to the Barnett Shale, generally allege that Chesapeake underpaid royalties by making improper deductions and using incorrect production volumes. In addition to allegations of breach of contract, a number of these lawsuits allege fraud, conspiracy, joint venture and antitrust violations by Chesapeake. The lawsuits seek direct damages in varying amounts, together with exemplary damages, attorneys' fees, costs and interest. Chesapeake entered into a settlement agreement with MDL plaintiffs representing over 97% of the hydrocarbons at issue by volume and, on July 22, 2016, the plaintiffs who accepted the settlement filed to dismiss such lawsuits. Chesapeake funded the settlement amount of approximately $29 million in cash and signed a $10 million, three-year promissory note in July 2016, which is accrued for as of June 30, 2016. Additional plaintiffs are continuing to accept the settlement on a rolling basis. Chesapeake expects that additional lawsuits filed by plaintiffs not participating in the settlement will continue to be pursued and that new plaintiffs will file other lawsuits making similar allegations.

On December 9, 2015, the Commonwealth of Pennsylvania, by the Office of Attorney General, filed a lawsuit in the Bradford County Court of Common Pleas related to royalty underpayment and lease acquisition and accounting practices with respect to properties in Pennsylvania. The lawsuit, which primarily relates to the Marcellus Shale and Utica Shale, alleges that Chesapeake violated the Pennsylvania Unfair Trade Practices and Consumer Protection Law (UTPCPL) by making improper deductions and entering into arrangements with affiliates that resulted in underpayment of royalties. The lawsuit seeks statutory restitution, civil penalties and costs, as well as temporary injunction from exploration and drilling activities in Pennsylvania until restitution, penalties and costs have been paid and permanent injunction from further violations of the UTPCPL. On February 8, 2016, the Office of Attorney General amended the complaint to, among other things, add an additional UTPCPL claim and antitrust claim alleging that a joint exploration agreement to which Chesapeake is a party established unlawful market allocation for the acquisition of leases. In response to Chesapeake's preliminary objections, the Office of Attorney General filed a second amended complaint on May 3, 2016, alleging further violations of the UTPCPL based upon alleged predicate violations of the federal Sherman Act and the Federal Trade Commission Act. Chesapeake removed the case to the United States District Court for the Middle District of Pennsylvania on May 27, 2016.

Putative statewide class actions in Pennsylvania and Ohio and purported class arbitrations in Pennsylvania have been filed on behalf of royalty owners asserting various claims for damages related to alleged underpayment of royalties as a result of the Company's divestiture of substantially all of its midstream business and most of its gathering assets in 2012 and 2013. These cases include claims for violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act and for an unlawful market allocation agreement for mineral rights. One of the cases includes claims of intentional interference with contractual relations and violations of antitrust laws related to purported markets for gas mineral rights, operating rights and gas gathering sources. We have not accrued a loss contingency for any of the Pennsylvania and Ohio matters seeking class certification.

We believe losses are reasonably possible in certain of the pending royalty cases for which we have not accrued a loss contingency, but we are currently unable to estimate an amount or range of loss or the impact the actions could have on our future results of operations or cash flows. Uncertainties in pending royalty cases generally include the complex

nature of the claims and defenses, the potential size of the class in class actions, the scope and types of the properties and agreements involved, and the applicable production years.
The Company is also defending lawsuits alleging various violations of the Sherman Antitrust Act and state antitrust laws. In 2016, putative class action lawsuits have been filed in the United States District Court for the Western District of Oklahoma and in Oklahoma state courts, and an individual lawsuit was filed in the United States District Court of Kansas, in each case against the Company and other defendants. The lawsuits generally allege that, since 2007 and continuing through April 2013, the defendants conspired to rig bids and depress the market for the purchases of oil and natural gas leasehold interests and properties in the Anadarko Basin containing producing oil and natural gas wells. The lawsuits seek damages, attorney’s fees, costs and interest, as well as enjoinment from adopting practices or plans which would restrain competition in a similar manner as alleged in the lawsuits.
In April 2016, a class action lawsuit on behalf of holders of the Company’s 6.875% Senior Notes due 2020 (the 2020 Notes) and 6.125% Senior Notes due 2021 (the 2021 Notes) was filed in the U.S. District Court for the Southern District of New York relating to the Company’s December 2015 debt exchange, whereby the Company privately exchanged newly issued 8.00% Senior Secured Second Lien Notes due 2022 (Second Lien Notes) for certain outstanding senior unsecured notes and contingent convertible notes. The lawsuit alleges that the Company violated the Trust Indenture Act of 1939 and the implied covenant of good faith and fair dealing by benefiting themselves and a minority of noteholders who are qualified institutional buyers (QIBs). According to the lawsuit, as a result of the Company’s private debt exchange in which only QIBs (and non-U.S. persons under Regulation S) were eligible to participate, the Company unjustly enriched itself at the expense of class members by reducing indebtedness and reducing the value of the 2020 Notes and the 2022 Notes. The lawsuit seeks damages and attorney’s fees, in addition to declaratory relief that the debt exchange and the liens created for the benefit of the Second Lien Notes are null and void and that the debt exchange effectively resulted in a default under the indentures for the 2020 Notes and the 2021 Notes. In June 2016, the lawsuit was transferred to the United States District Court for the Western District of Oklahoma.
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 future 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 Contingencies
The nature of the oil and gas business carries with it certain environmental risks for Chesapeake and its subsidiaries. Chesapeake has implemented various policies, programs, 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 address 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.

Commitments

Gathering, Processing and Transportation Agreements

We have contractual commitments with midstream service companies and pipeline carriers for future gathering, processing and transportation of oil, natural gas and NGL 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 in our estimates of proved reserves. The aggregate undiscounted commitments under our gathering, processing and transportation agreements, excluding any reimbursement from working interest and royalty interest owners, credits for third-party volumes or future costs under cost-of-service agreements, are presented below.

	June 30, 2016 ($ in millions)
2016	$ 925
2017	1,874
2018	1,670
2019	1,374
2020	1,046
2021 – 2099	6,572
Total	$ 13,461

In addition, we have entered into long-term agreements for certain natural gas gathering and related services within specified acreage dedication areas in exchange for cost-of-service based fees redetermined annually or tiered fees based on volumes delivered relative to scheduled volumes. Future gathering fees vary with the applicable agreement. One of these agreements (in the Anadarko Basin in northwestern Oklahoma) contains cost-of-service based fees that are redetermined annually through 2019. The annual upward or downward fee adjustment for this contract is capped at 15% of the then-current fees at the time of redetermination. To the extent the actual rate of return on capital expended by the counterparty over the term of the agreement differs from the applicable rate of return, a payment is due to (from) the midstream service company.

Drilling Contracts

We have contracts with various drilling contractors to utilize drilling services with terms ranging from three months to three years at market-based pricing. These commitments are not recorded in the accompanying condensed consolidated balance sheets. As of June 30, 2016, the aggregate undiscounted minimum future payments under these drilling service commitments were approximately $177 million.

Pressure Pumping Contracts

We have an agreement for pressure pumping services. Throughout the term of the agreement, which expires in June 2017, the services agreement requires us to utilize, at market-based pricing, the lesser of (i) three pressure pumping crews through June 30, 2017 or (ii) 50% of the total number of all pressure pumping crews working for us in all of our operating regions during the respective year. We are also required to utilize the pressure pumping services for a minimum number of fracture stages as set forth in the agreement. We are entitled to terminate the agreement in certain situations, including if the contractor fails to provide the overall quality of service provided by similar service providers. As of June 30, 2016, the aggregate undiscounted minimum future payments under this agreement were approximately $155 million.

15

Drilling Commitments

We previously committed to drill wells for the benefit of Chesapeake Granite Wash Trust (the Trust). In connection with the Trust's initial public offering, we conveyed royalty interests to the Trust that entitle the Trust to receive certain proceeds from the production of 69 then-producing wells, and 118 development wells that have been drilled 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 were obligated to drill and complete, or cause to be drilled and completed, the development wells at our own expense prior to June 30, 2016. As of June 30, 2016, we had fulfilled our drilling and completion commitment. See Note 10 for further discussion of the Trust.

Oil, Natural Gas and NGL Purchase Commitments

We commit to purchase oil, natural gas and NGL from other owners in the properties we operate, including owners associated with our volumetric production payment (VPP) transactions. Production purchases under these arrangements are based on market prices at the time of production, and the purchased oil, natural gas and NGL are resold at market prices. See Volumetric Production Payments in Note 9 for further discussion of our VPP transactions.

Net Acreage Maintenance Commitments

Under the terms of our Utica Shale joint venture agreements with Total S.A., we are required to extend, renew or replace expiring joint leasehold, at our cost, to ensure that the net acreage is maintained in certain designated areas as of a future measurement date.

Other Commitments

As part of our normal course of business, we enter into various agreements providing, or otherwise arranging for, 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 acquisitions and 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 and/or other specified matters. 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 entering into or consummating a particular transaction. For divestitures of oil and natural gas properties, our purchase and sale agreements may require the return of a portion of the proceeds we receive as a result of uncured title defects.

Certain of our oil and natural gas 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 these interests have been created, we have the responsibility to bear the cost of developing and producing the reserves attributable to these interests. See Volumetric Production Payments in Note 9 for further discussion of our VPP transactions.

While executing our strategic priorities, we have incurred certain cash charges, including contract termination charges, financing extinguishment costs and charges for unused natural gas transportation and gathering capacity. As we continue to focus on our strategic priorities, we may take certain actions that reduce financial leverage and complexity, and we may incur additional cash and noncash charges.

5. Other Liabilities

Other current liabilities as of June 30, 2016 and December 31, 2015 are detailed below.

	June 30, 2016	December 31, 2015
	($ in millions)	
Revenues and royalties due others	$430	$ 500
Accrued drilling and production costs	191	212
Joint interest prepayments received	84	169
Accrued compensation and benefits	173	264
Other accrued taxes	68	37
Bank of New York Mellon legal accrual	439	439
Minimum gathering volume commitment	—	201
Other	247	397
Total other current liabilities	$1,632	$ 2,219

Other long-term liabilities as of June 30, 2016 and December 31, 2015 are detailed below.

	June 30, 2016	December 31, 2015
	($ in millions)	
CHK Utica ORRI conveyance obligation[a]	$175	$ 190
Financing obligations	—	29
Unrecognized tax benefits	93	64
Other	151	126
Total other long-term liabilities	$419	$ 409

(a) The CHK Utica, L.L.C. investors' right to receive, proportionately, a 3% overriding royalty interest (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 through 2023. The liability represents the obligation to deliver future ORRIs. Approximately $29 million and $21 million of the total $204 million and $211 million obligations are recorded in other current liabilities as of June 30, 2016 and December 31, 2015, respectively.

6. Equity

Common Stock

A summary of the changes in our common shares issued for the Current Period and the Prior Period are detailed below.

	Six Months Ended June 30,	
	2016	2015
	(in thousands)	
Shares issued as of January 1	664,796	664,944
Exchange of convertible notes	55,428	—
Exchange of senior notes	53,924	—
Conversion of preferred stock	1,021	—
Restricted stock issuances (net of forfeitures and cancellations)	1,529	103
Stock option exercises	—	14
Shares issued as of June 30	776,698	665,061

On May 20, 2016, our shareholders approved an amendment to our certificate of incorporation to increase our authorized common stock from 1,000,000,000 shares to 1,500,000,000 shares, par value $0.01 per share.

Preferred Stock

Outstanding shares of our preferred stock for the Current Period and the Prior Period are detailed below.

	5.75%	5.75% (A)	4.50%	5.00% (2005B)
	(in thousands)			
Shares outstanding as of January 1, 2016	1,497	1,100	2,559	2,096
Preferred stock conversions[(a)]	(25)	(1)	—	—
Shares outstanding as of June 30, 2016	1,472	1,099	2,559	2,096
Shares outstanding as of January 1, 2015 and June 30, 2015	1,497	1,100	2,559	2,096

(a) In the Current Period, holders of our 5.75% Cumulative Convertible Preferred Stock converted 24,601 shares into 975,488 shares of common stock. Also in the Current Period, holders of our 5.75% (Series A) Cumulative Convertible Preferred Stock converted 1,201 shares into 46,018 shares of common stock.

Dividends

In January 2016, we announced that we were suspending dividend payments on each series of our outstanding convertible preferred stock. Suspension of the dividends did not constitute an event of default under our revolving credit facility or bond indentures. Our preferred stock dividends for the Current Period (paid in arrears) are detailed below.

	5.75%	5.75% (A)	4.50%	5.00% (2005B)
	($ in millions)			
Dividends in arrears	$42	$ 32	$ 6	$ 5

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

Accumulated Other Comprehensive Income (Loss)

For the Current Period and the Prior Period, changes in accumulated other comprehensive income (loss) for cash flow hedges, net of tax, are detailed below.

	Six Months Ended June 30,	
	2016	2015
	($ in millions)	
Balance, December 31	$(99)	$(143)
Other comprehensive income before reclassifications	(19)	(1)
Amounts reclassified from accumulated other comprehensive income	14	13
Net other comprehensive income (loss)	(5)	12
Balance, June 30	$(104)	$(131)

For the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, net losses on cash flow hedges for commodity contracts reclassified from accumulated other comprehensive income (loss), net of tax, to oil, natural gas and NGL revenues in the condensed consolidated statements of operations were $10 million, $3 million, $14 million and $13 million, respectively.

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 common stock and restricted stock granted to non-employee directors under our long term incentive plans. 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 units to employees and non-employee directors. Prior to 2014, we also granted restricted stock awards as equity compensation. We refer to both types of awards as restricted stock. A summary of the changes in unvested restricted stock during the Current Period is presented below.

	Shares of Unvested Restricted Stock (in thousands)	Weighted Average Grant Date Fair Value
Unvested restricted stock as of January 1, 2016	10,455	$ 17.31
Granted	2,882	$ 3.77
Vested	(3,713)	$ 17.35
Forfeited	(902)	$ 13.17
Unvested restricted stock as of June 30, 2016	8,722	$ 13.25

The aggregate intrinsic value of restricted stock that vested during the Current Period was approximately $16 million based on the stock price at the time of vesting.

As of June 30, 2016, there was approximately $76 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

1.57 years.

Stock Options. In the Current Period and the Prior Period, we granted members of senior management stock options that vest ratably over a three-year period. In January 2013, we also granted retention awards of stock options to certain officers that 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 expire seven to ten years from the date of grant.

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

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. 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 dividend policy, over the expected life of the option. The Company used the following weighted average assumptions to estimate the grant date fair value of the stock options granted in the Current Period.

Expected option life – years	6.0	
Volatility	46.07	%
Risk-free interest rate	1.70	%
Dividend yield	—	%

The following table provides information related to stock option activity in the Current Period.

	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 as of January 1, 2016	5,377	$ 19.37	5.80	$ —
Granted	4,932	$ 3.71		
Exercised	—	$ —		$ —
Expired	(477)	$ 19.06		
Forfeited	(945)	$ 5.66		
Outstanding as of June 30, 2016	8,887	$ 12.15	7.47	$ 2
Exercisable as of June 30, 2016	3,125	$ 19.62	5.32	$ —

(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 June 30, 2016, there was $10 million of total unrecognized compensation expense related to stock options. The expense is expected to be recognized over a weighted average period of approximately 2.00 years.

Restricted Stock and Stock Option Compensation. We recognized the following compensation costs related to restricted stock and stock options for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period.

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
	($ in millions)			
General and administrative expenses	$ 10	$ 12	$ 18	$ 24
Oil and natural gas properties	5	8	9	15

Oil, natural gas and NGL production expenses	3	6	6	10
Marketing, gathering and compression expenses	—	2	1	3
Total	$18	$ 28	$34	$ 52

TABLE OF CONTENTS

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

Liability-Classified Awards

Performance Share Units. We have granted PSUs to senior management that vest ratably over a three-year term and are settled in cash on the third anniversary of the awards. The ultimate amount earned is based on achievement of performance metrics established by the Compensation Committee of the Board of Directors, which include total shareholder return (TSR) and, for certain of the awards, operational performance goals such as finding and development costs and production levels.

For PSUs granted in 2016, the TSR component can range from 0% to 100% and the operational component can range from 0% to 100%, resulting in a maximum payout of 200%. The payout percentage of these PSUs is capped at 100% if the Company's absolute TSR is less than zero. For PSUs granted in 2015, the TSR component can range from 0% to 100%, and each of the two operational components can range from 0% to 50% resulting in a maximum total payout of 200%. The payout percentage for these PSUs is capped at 100% if the Company’s absolute TSR is less than zero. For PSUs granted in 2014, the TSR component can range from 0% to 200%, with no operational components.

Compensation expense associated with PSU grants is recognized over the service period based on the graded-vesting method. The number of units settled is dependent upon the Company’s estimates of the underlying performance measures. The Company utilized the Monte Carlo simulation for the TSR performance measure and the following assumptions to determine the grant date fair value of the PSUs.

Volatility	79.84	%
Risk-free interest rate	0.65	%
Dividend yield for value of awards	—	%

The following table presents a summary of our 2016, 2015 and 2014 PSU awards.

	Units	Grant Date Fair Value	June 30, 2016 Fair Value	June 30, 2016 Vested Liability
		($ in millions)		
2016 Awards:				
Payable 2019	2,348,893	$ 10	$ 11	$ 3
2015 Awards:				
Payable 2018	629,694	$ 13	$ 1	$ 1
2014 Awards:				
Payable 2017	561,215	$ 16	$ 1	$ 1

PSU Compensation. We recognized the following compensation costs (credits) related to PSUs for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period.

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
	($ in millions)			
General and administrative expenses	$ 1	$ (4)	$ 3	$ (14)
Restructuring and other termination costs	—	(5)	1	(15)

Marketing, gathering and compression	—	—	—	(1)
Oil and natural gas properties	—	—	—	(1)
Total	$1	$(9)	$4	$(31)

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

8. Derivative and Hedging Activities

Chesapeake uses derivative instruments to secure attractive pricing and margins on its share of expected 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 its exposure to foreign currency exchange rate fluctuations. All of our commodity 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.

Oil, Natural Gas and NGL Derivatives

As of June 30, 2016 and December 31, 2015, our oil, natural gas and NGL 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. In exchange for higher fixed prices on certain of our swap trades, we granted options that allow the counterparty to double the notional amount.
- 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 the excess on sold call options and Chesapeake receives the 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.
- 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.
- Basis Protection Swaps: These instruments are arrangements that guarantee a fixed price differential to NYMEX from a specified delivery point. Chesapeake receives the fixed price differential and pays the floating market price differential to the counterparty for the hedged commodity.

The estimated fair values of our oil, natural gas and NGL derivative instrument assets (liabilities) as of June 30, 2016 and December 31, 2015 are provided below.

	June 30, 2016		December 31, 2015	
	Volume	Fair Value ($ in millions)	Volume	Fair Value ($ in millions)
Oil (mmbbl):				
Fixed-price swaps	19.8	$ (78)	13.5	$ 144
Call options	12.3	(6)	19.2	(7)
Total oil	32.1	(84)	32.7	137
Natural gas (tbtu):				
Fixed-price swaps	577	(130)	500	229
Collars	38	(4)	—	—
Call options	205	(56)	295	(99)
Basis protection swaps	44	(8)	57	—
Total natural gas	864	(198)	852	130
NGL (mmgal):				
Fixed-price swaps	144	(10)	—	—

Total estimated fair value	$ (292)	$ 267

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 June 30, 2016 and December 31, 2015, there were no interest rate derivatives outstanding.

We have terminated fair value hedges related to certain of our 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 four years, we will recognize $6 million in net gains related to these transactions.

Foreign Currency Derivatives

We are party to cross currency swaps to mitigate our exposure to foreign currency exchange rate fluctuations. In December 2015, we exchanged in privately negotiated transactions and subsequently retired €42 million in aggregate principal amount of 6.25% Euro-denominated Senior Notes due 2017, and we simultaneously unwound the cross currency swaps for the same principal amount at a cost of $8 million. As a result, we realized a loss of $8 million in 2015 which was included in losses on purchases or exchanges of debt. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay us €9 million and we pay the counterparties $15 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay us €302 million and we will pay the counterparties $403 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. 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 sheets as liabilities of $64 million and $52 million as of June 30, 2016 and December 31, 2015, respectively. The euro-denominated debt in long-term debt has been adjusted to $337 million as of June 30, 2016, using an exchange rate of $1.1106 to €1.00.

Supply Contract Derivatives

From time to time and in the normal course of business, our marketing subsidiary enters into supply contracts under which we commit to deliver a predetermined quantity of natural gas to certain counterparties in an attempt to earn attractive margins. Under certain contracts, we receive a sales price that is based on the price of a product other than natural gas, thereby creating an embedded derivative requiring bifurcation. In one of these supply contracts, we are committed to supply a minimum of 90 bbtu per day of natural gas through March 2025. The bifurcated derivative is measured at fair value on a quarterly basis and resulted in an unrealized loss of $37 million in the Current Quarter and $17 million in the Current Period, respectively. Both settlements and mark-to-market gains (losses) are included in marketing, gathering and compression revenues in our condensed consolidated statements of operations.

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 June 30, 2016 and December 31, 2015 on a gross basis and after same-counterparty netting:

Balance Sheet Classification	Gross Fair Value	Amounts Netted in Condensed Consolidated Balance Sheet	Net Fair Value Presented in Condensed Consolidated Balance Sheet
	($ in millions)		
As of June 30, 2016			
Commodity Contracts:			
Short-term derivative asset	$27	$ (27)	$ —
Short-term derivative liability	(278)	27	(251)
Long-term derivative liability	(41)	—	(41)
Total commodity contracts	(292)	—	(292)
Foreign Currency Contracts:[a]			
Short-term derivative liability	(64)	—	(64)
Total foreign currency contracts	(64)	—	(64)
Supply Contracts:			
Short-term derivative asset	30	—	30
Long-term derivative asset	250	—	250
Total supply contracts	280	—	280
Total derivatives	$(76)	$ —	$ (76)
As of December 31, 2015			
Commodity Contracts:			
Short-term derivative asset	$381	$ (66)	$ 315
Short-term derivative liability	(106)	66	(40)
Long-term derivative liability	(8)	—	(8)
Total commodity contracts	267	—	267
Foreign Currency Contracts:[a]			
Long-term derivative liability	(52)	—	(52)
Total foreign currency contracts	(52)	—	(52)
Supply Contracts:			
Short-term derivative asset	51	—	51
Long-term derivative asset	246	—	246
Total supply contracts	297	—	297
Total derivatives	$512	$ —	$ 512

(a) Designated as cash flow hedging instruments.

As of June 30, 2016 and December 31, 2015, we did not have any cash collateral balances for these derivatives.

Effect of Derivative Instruments – Condensed Consolidated Statements of Operations

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	($ in millions)			
Oil, natural gas and NGL revenues	$884	$1,264	$1,696	$2,646
Gains (losses) on undesignated oil, natural gas and NGL derivatives	(438)	(43)	(246)	135
Losses on terminated cash flow hedges	(6)	(5)	(17)	(22)
Total oil, natural gas and NGL revenues	$440	$1,216	$1,433	$2,759

The components of marketing, gathering and compression revenues for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period are presented below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	($ in millions)			
Marketing, gathering and compression revenues	$1,219	$2,085	$2,159	$3,760
Gains (losses) on undesignated supply contract derivatives	(37)	220	(17)	220
Total marketing, gathering and compression revenues	$1,182	$2,305	$2,142	$3,980

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	($ in millions)			
Interest expense on senior notes	$107	$171	$222	$342
Amortization of loan discount, issuance costs and other	7	12	18	23
Interest expense on credit facilities	12	3	17	6
Gains on terminated fair value hedges	(1)	(1)	(1)	(2)
Gains on undesignated interest rate derivatives	—	—	—	(10)
Capitalized interest	(63)	(114)	(132)	(237)
Total interest expense	$62	$71	$124	$122

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 June 30,			
	2016		2015	
	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)			
Balance, beginning of period	$(156)	$(99)	$(216)	$(134)
Net change in fair value	(13)	(15)	—	—
Losses reclassified to income	6	10	5	3
Balance, end of period	$(163)	$(104)	$(211)	$(131)

	Six Months Ended June 30,			
	2016		2015	
	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)			
Balance, beginning of period	$(160)	$(99)	$(231)	$(143)
Net change in fair value	(20)	(19)	(2)	(1)
Losses reclassified to income	17	14	22	13
Balance, end of period	$(163)	$(104)	$(211)	$(131)

Approximately $99 million of the $104 million of accumulated other comprehensive loss as of June 30, 2016 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. Deferred gain or loss amounts will be recognized in earnings in the month in which the originally forecasted hedged production occurs. As of June 30, 2016, we expect to transfer approximately $20 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

Our 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 June 30, 2016, our oil, natural gas, NGL, foreign currency and supply contract derivative instruments were spread among 15 counterparties.

Hedging Arrangements

In 2015, we began entering into bilateral hedging agreements. The counterparties' and our obligations under certain of the bilateral hedging agreements must be secured by cash or letters of credit to the extent that any mark-to-market amounts owed to us or by us exceed defined thresholds.

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

Fair Value

The fair value of our derivatives is based on third-party pricing models which utilize inputs that are either readily available in the public market, such as oil, natural gas and NGL 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 oil, natural gas, NGL, 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.

The following table provides information for financial assets (liabilities) measured at fair value on a recurring basis as of June 30, 2016 and December 31, 2015:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
As of June 30, 2016				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ 27	$ —	$ 27
Commodity liabilities	—	(248)	(71)	(319)
Foreign currency liabilities	—	(64)	—	(64)
Supply contract assets	—	—	280	280
Total derivatives	$ —	$ (285)	$ 209	$ (76)
As of December 31, 2015				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ 372	$ 9	$ 381
Commodity liabilities	—	(14)	(100)	(114)
Foreign currency liabilities	—	(52)	—	(52)
Supply contract assets	—	—	297	297
Total derivatives	$ —	$ 306	$ 206	$ 512

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

	Commodity Derivatives	Supply Contracts
	($ in millions)	
Beginning balance as of December 31, 2015	$(91)	$ 297
Total gains (losses) (unrealized):		
Included in earnings[(a)]	(8)	13
Total purchases, issuances, sales and settlements:		
Settlements	28	(30)
Ending balance as of June 30, 2016	$(71)	$ 280
Beginning balance as of December 31, 2014	$(54)	$ 1
Total gains (losses) (unrealized):		
Included in earnings[(a)]	80	220
Total purchases, issuances, sales and settlements:		
Settlements	(108)	—
Ending balance as of June 30, 2015	$(82)	$ 221

(a)

	Oil, Natural Gas and NGL Sales		Marketing, Gathering and Compression Revenue	
	2016	2015	2016	2015
	($ in millions)			
Total gains (losses) included in earnings for the period	$(8)	$ 80	$(17)	$ 220
Change in unrealized gains (losses) related to assets still held at reporting date	$(20)	$ 69	$(17)	$ 220

Qualitative and Quantitative 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, market volatility and credit risk of counterparties. Changes in these inputs impact the fair value measurement of our derivative contracts. For example, an increase or decrease in the forward prices and volatility of oil and natural gas prices decreases or increases the fair value of oil and natural gas derivatives, and adverse changes to our counterparties' creditworthiness decreases the fair value of our derivatives. The following table presents quantitative information about Level 3 inputs used in the fair value measurement of our commodity derivative contracts at fair value as of June 30, 2016:

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value June 30, 2016
				($ in millions)
Oil trades[(a)]	Oil price volatility curves	21.20% – 33.68%	29.04%	$ (6)
Supply contracts[(b)]	Oil price volatility curves	19.94% – 37.25%	24.41%	$ 280
Natural gas trades[(a)]	Natural gas price volatility	19.97% – 53.48%	32.20%	$ (65)

curves

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

(b) Fair value is based on an estimate derived from industry standard methodologies which consider historical relationships among various commodities, modeled market prices, time value and volatility factors.

9. Oil and Natural Gas Property Transactions

Under full cost accounting rules, we accounted for the sales of oil and natural gas properties discussed below as adjustments to capitalized costs, with no recognition of gain or loss as the sales did not involve a significant change in proved reserves or significantly alter the relationship between costs and proved reserves.

In the Current Quarter and the Current Period, we sold certain of our noncore oil and natural gas properties for net proceeds of approximately $833 million and $964 million, respectively, after post-closing adjustments. In both the Current Quarter and the Current Period, additional consideration of approximately $106 million was withheld subject to certain title, environmental and other standard contingencies. In conjunction with certain of these sales, we purchased oil and natural gas interests previously sold to third parties in connection with four of our VPP transactions for approximately $259 million. A majority of the acquired interests were part of the asset divestitures discussed above and we no longer have any further commitments or obligations related to these VPPs. The asset divestitures cover various operating areas.

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 oil and natural gas 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 non-recourse 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 novated to each of the respective VPP buyers hedges that 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 these interests, which we include as a component of production expenses and production taxes in our condensed consolidated statements of operations in the periods these 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 the 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 oil and natural gas 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.

As of June 30, 2016, our outstanding VPPs consisted of the following:

VPP #	Date of VPP	Location	Proceeds	Volume Sold Oil	Natural Gas	NGL	Total
			($ in millions)	(mmbbl)	(bcf)	(mmbbl)	(bcfe)
9	May 2011	Mid-Continent	$ 853	1.7	138	4.8	177
1	December 2007	Kentucky and West Virginia	1,100	—	208	—	208
			$ 1,953	1.7	346	4.8	385

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

	Three Months Ended June 30, 2016				Three Months Ended June 30, 2015			
VPP #	Oil	Natural Gas	NGL	Total	Oil	Natural Gas	NGL	Total
	(mbbl)	(bcf)	(mbbl)	(bcfe)	(mbbl)	(bcf)	(mbbl)	(bcfe)
10[(a)]	42.0	1.2	146.0	2.3	78.0	2.2	268.7	4.3
9	38.5	3.3	87.6	4.1	42.5	3.5	94.9	4.4
8[(b)]	—	—	—	—	—	13.6	—	13.6
4[(a)]	9.9	1.9	—	2.0	10.7	2.0	—	2.1
3[(a)]	—	1.0	—	1.0	—	1.6	—	1.6
2[(a)]	—	0.6	—	0.6	—	1.0	—	1.0
1	—	3.1	—	3.1	—	3.3	—	3.3
	90.4	11.1	233.6	13.1	131.2	27.2	363.6	30.3

	Six Months Ended June 30, 2016				Six Months Ended June 30, 2015			
VPP #	Oil	Natural Gas	NGL	Total	Oil	Natural Gas	NGL	Total
	(mbbl)	(bcf)	(mbbl)	(bcfe)	(mbbl)	(bcf)	(mbbl)	(bcfe)
10[(a)]	108.0	3.0	368.7	5.8	161.0	4.4	545.0	8.7
9	77.9	6.7	176.9	8.2	86.1	7.2	191.9	8.9
8[(b)]	—	—	—	—	—	27.6	—	27.6
4[(a)]	20.0	3.8	—	3.9	21.7	4.1	—	4.2
3[(a)]	—	2.5	—	2.5	—	3.3	—	3.3
2[(a)]	—	1.5	—	1.5	—	2.1	—	2.1
1	—	6.4	—	6.4	—	6.8	—	6.8
	205.9	23.9	545.6	28.3	268.8	55.5	736.9	61.6

(a) In connection with certain divestitures in the Current Quarter, we purchased the remaining oil and natural gas interests previously sold in connection with VPP #10, VPP #4, VPP #3 and VPP #2. A majority of the oil and gas interests purchased were subsequently sold to the buyers of the assets.

(b) VPP #8 expired in August 2015.

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

The volumes remaining to be delivered on behalf of our VPP buyers as of June 30, 2016 were as follows:

		Volume Remaining as of June 30, 2016			
VPP #	Term Remaining	Oil	Natural Gas	NGL	Total
	(in months)	(mmbbl)	(bcf)	(mmbbl)	(bcfe)
9	56	0.6	52.4	1.4	64.2
1	78	—	71.9	—	71.9
		0.6	124.3	1.4	136.1

10. Variable Interest Entities

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 and because the royalty interest owners, other than Chesapeake, do not have the ability to exercise substantial liquidation rights. Our ownership in the Trust and our previous obligations under the development agreement 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 potentially could 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. As of June 30, 2016 and December 31, 2015, we had $261 million and $259 million, respectively, of noncontrolling interests on our condensed consolidated balance sheets attributable to the Trust. Net loss attributable to the Trust's noncontrolling interests is presented in our condensed consolidated statements of operations as a nominal amount in the Current Quarter, a loss of approximately $1 million in the Prior Quarter, a nominal amount in the Current Period and a loss of approximately $1 million in the Prior Period.

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. In consolidation, as of June 30, 2016, $1 million of cash and cash equivalents, $488 million of proved oil and natural gas properties and $456 million of accumulated depreciation, depletion and amortization 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.

11. Impairments

Impairments of Oil and Natural Gas Properties

Our proved oil and natural gas properties are subject to quarterly full cost ceiling tests. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. Estimated future net revenues for the quarterly ceiling limit are calculated using the average of commodity prices on the first day of the month over the trailing 12-month period. In the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, capitalized costs of oil and natural gas properties exceeded the ceiling, resulting in impairments in the carrying value of our oil and natural gas properties of $1.045 billion, $5.015 billion, $1.898 billion and $9.991 billion, respectively. Cash flow hedges which relate to future periods increased the ceiling test impairment by $160 million, $190 million, $326 million and $385 million in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. Based on the first-day-of-the-month prices we have received over the 11 months ended August 1, 2016, as well as the current strip price for September 2016, we expect to record another write-down in the carrying value of our oil and natural gas properties in the third quarter of 2016, although the amount of impairment could be mitigated by the impact of anticipated divestitures in the third quarter of 2016 or other factors. Further write-downs in subsequent quarters will occur if the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters.

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

Impairments of Fixed Assets and Other

We review our long-lived assets, other than oil and natural gas properties, for recoverability whenever events or changes in circumstances indicate that carrying amounts may not be recoverable. We 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, the Prior Quarter, the Current Period and the Prior Period is as follows:

	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
	($ in millions)			
Natural gas compressors	$ —	$ 21	$ 20	$ 21
Buildings and land	—	—	7	—
Other	6	63	17	67
Total impairments of fixed assets and other	$ 6	$ 84	$ 44	$ 88

Nonrecurring Fair Value Measurements. Fair value measurements for certain of the impairments discussed above were based on recent sales information for comparable 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, these values were classified as Level 2 in the fair value hierarchy. Other inputs used were not observable in the market; these values were classified as Level 3 in the fair value hierarchy.

12. Income Taxes

A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. To assess that likelihood, we use estimates and judgment regarding our future taxable income, and we consider the tax consequences in the jurisdiction where the taxable income is generated, to determine whether a valuation allowance is required. The evidence can include our current financial position, our results of operations, both actual and forecasted, the reversal of deferred tax liabilities, and tax planning strategies as well as the current and forecasted business economics of our industry.

Based on our estimated operating results for the subsequent quarters, we project being in a net deferred tax asset position as of December 31, 2016. We believe it is more likely than not that these deferred tax assets will not be realized. Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. A significant piece of objective negative evidence evaluated is the projected cumulative loss we expect to incur over the three-year period ending December 31, 2016. This objective negative evidence limits our ability to consider other subjective positive evidence, such as our projections for future growth. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as future expected growth.

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

13. Fair Value Measurements
Recurring Fair Value Measurements
Other Current Assets. Assets related to Chesapeake's deferred compensation plan 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.
Financial Assets (Liabilities). The following table provides fair value measurement information for the above-noted financial assets (liabilities) measured at fair value on a recurring basis as of June 30, 2016 and December 31, 2015:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
As of June 30, 2016				
Financial Assets (Liabilities):				
Other current assets	$ 45	$ —	$ —	$ 45
Other current liabilities	(46)	—	—	(46)
Total	$ (1)	$ —	$ —	$ (1)
As of December 31, 2015				
Financial Assets (Liabilities):				
Other current assets	$ 50	$ —	$ —	$ 50
Other current liabilities	(51)	—	—	(51)
Total	$ (1)	$ —	$ —	$ (1)

See Note 3 for information regarding fair value measurement of our debt instruments. See Note 8 for information regarding fair value measurement of our derivatives.
Nonrecurring Fair Value Measurements
See Note 11 regarding nonrecurring fair value measurements.
14. Segment Information
As of June 30, 2016, we have two reportable operating segments, each of which is managed separately because of the nature of its operations. The exploration and production operating segment is responsible for finding and producing oil, natural gas and NGL. The marketing, gathering and compression operating segment is responsible for marketing, gathering and compression of oil, natural gas and NGL.
Management evaluates the performance of our segments based upon income (loss) before income taxes. Revenues from the sale of oil, natural gas and NGL related to Chesapeake's ownership interests by our marketing, gathering and compression operating segment are reflected as revenues within our exploration and production operating segment. These amounts totaled $848 million, $1.204 billion, $1.631 billion and $2.437 billion for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively.
During the Current Period, we changed the structure of our internal organization to include certain assets in our Exploration and Production reportable segment instead of our Other segment. Accordingly, this change has been

reflected through retroactive revision of the segment information as of December 31, 2015, as shown in the tables below.

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

The following table presents selected financial information for Chesapeake's operating segments:

	Exploration and Production	Marketing, Gathering and Compression	Other	Intercompany Eliminations	Consolidated Total
	($ in millions)				
Three Months Ended June 30, 2016					
Revenues	$440	$ 2,030	$—	$ (848)	$ 1,622
Intersegment revenues	—	(848)	—	848	—
Total revenues	$440	$ 1,182	$—	$ —	$ 1,622
Income (Loss) Before Income Taxes	$(1,755)	$ (44)	$(8)	$ 57	$ (1,750)
Three Months Ended June 30, 2015					
Revenues	$1,187	$ 3,509	$—	$ (1,175)	$ 3,521
Intersegment revenues	29	(1,204)	—	1,175	—
Total revenues	$1,216	$ 2,305	$—	$ —	$ 3,521
Income (Loss) Before Income Taxes	$(5,785)	$ 134	$(31)	$ 86	$ (5,596)
Six Months Ended June 30, 2016					
Revenues	$1,433	$ 3,773	$—	$ (1,631)	$ 3,575
Intersegment revenues	—	(1,631)	—	1,631	—
Total revenues	$1,433	$ 2,142	$—	$ —	$ 3,575
Income (Loss) Before Income Taxes	$(2,650)	$ (4)	$(17)	$ —	$ (2,671)
Six Months Ended June 30, 2015					
Revenues	$2,707	$ 6,417	$—	$ (2,385)	$ 6,739
Intersegment revenues	52	(2,437)	—	2,385	—
Total revenues	$2,759	$ 3,980	$—	$ —	$ 6,739
Income (Loss) Before Income Taxes	$(11,134)	$ 138	$(45)	$ 353	$ (10,688)

As of June 30, 2016 Total Assets	$10,842	$ 1,421	$1,423	$ (199)	$ 13,487
As of December 31, 2015 Total Assets (as previously reported)	$11,776	$ 1,524	$4,325	$ (311)	$ 17,314
As of December 31, 2015 Total Assets (as revised)	$14,610	$ 1,524	$1,491	$ (311)	$ 17,314

34

15. Recently Issued Accounting Standards

In May 2014, the FASB issued updated revenue recognition guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for U.S. GAAP and international financial reporting standards. The new standard requires the recognition of revenue to depict the transfer of promised goods to customers in an amount reflecting the consideration the company expects to receive in the exchange. The accounting standards update is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016, with early application not permitted. In July 2015, the FASB approved a one-year deferral of the effective date as well as permission to early adopt the new revenue recognition standard as of the original effective date. In March 2016, the FASB issued an update clarifying the implementation guidance on principal versus agent considerations. In April 2016, the FASB issued an update clarifying the identification of performance obligations and licensing implementations guidance. In May 2016, the FASB issued an update clarifying guidance in a few narrow areas and added some practical expedients to the guidance. We are evaluating the impact of this guidance on our consolidated financial statements and related disclosures.

In August 2014, the FASB issued updated guidance that requires management, for each annual and interim reporting period, to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity’s ability to continue as a going concern within one year after the date that the consolidated financial statements are issued. If management concludes that conditions or events raise substantial doubt about the entity’s ability to continue as a going concern, certain disclosures are required to be made within the footnotes to the consolidated financial statements. The amendments in this update are effective for annual periods ending after December 15, 2016 and interim periods thereafter, with early adoption permitted. We are evaluating the impact of this guidance on our consolidated financial statements and related disclosures.

In February 2016, the FASB issued updated lease accounting guidance requiring companies to recognize the assets and liabilities for the rights and obligations created by long-term leases of assets on the balance sheet. The accounting standards update is effective for fiscal years, and interim periods within those years, beginning after December 15, 2018. We are evaluating the impact of this guidance on our consolidated financial statements and related disclosures.

In March 2016, the FASB issued guidance for improvements to employee share-based payment accounting to simplify the accounting for share-based compensation. The new standard requires all excess tax benefits and reductions from differences between the deduction for tax purposes and the compensation cost recorded for financial reporting purposes be recognized as income tax expense or benefit in the income statement and not recognized as additional paid-in capital. The new standard also requires all excess tax benefits and deficiencies to be classified as operating activity within the statement of cash flows. For public business entities, the amendments are effective for annual periods, including interim periods within those annual periods, beginning after December 15, 2016. Early adoption is permitted in any interim or annual period, with any adjustments reflected as of the beginning of the fiscal year of adoption. We have elected to early adopt the amendments effective January 1, 2016. The cumulative-effect adjustment to retained earnings for all excess tax benefits not previously recognized as of the beginning period is fully offset by a corresponding change in the valuation allowance resulting in no change. The implementation of this guidance did not have a material impact on our consolidated financial statements and related disclosures.

In March 2016, the FASB issued new guidance that will result in fewer put or call options embedded in debt instruments qualifying for separate derivative accounting because companies will not be required to assess whether the contingent event, such as change in control or an IPO, is related to interest rates or credit risks. This standard is effective for fiscal years beginning after December 15, 2016, including interim periods within those years. We are evaluating the impact of this guidance on our consolidated financial statements and related disclosures.

35

TABLE OF CONTENTS

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, oil, natural gas and NGL sales, average sales prices received, and other operating income and expenses for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net Production:				
Oil (mmbbl)	8	11	17	22
Natural gas (bcf)	269	275	546	539
NGL (mmbbl)	7	7	13	14
Oil equivalent (mmboe)[a]	60	64	121	126
Oil, Natural Gas and NGL Sales ($ in millions)[b]:				
Oil sales	$355	$594	$610	$1,080
Oil derivatives – realized gains (losses)[c]	11	182	84	417
Oil derivatives – unrealized gains (losses)[c]	(168)	(234)	(240)	(344)
Total oil sales	198	542	454	1,153
Natural gas sales	440	577	923	1,347
Natural gas derivatives – realized gains (losses)[c]	92	71	242	271
Natural gas derivatives – unrealized gains (losses)[c]	(365)	(67)	(335)	(231)
Total natural gas sales	167	581	830	1,387
NGL sales	89	93	163	219
NGL derivatives – realized gains (losses)[c]	(3)	—	(3)	—
NGL derivatives – unrealized gains (losses)[c]	(11)	—	(11)	—
Total NGL sales	75	93	149	219
Total oil, natural gas and NGL sales	$440	$1,216	$1,433	$2,759
Average Sales Price (excluding gains (losses) on derivatives):				
Oil ($ per bbl)	$43.00	$54.69	$35.98	$49.48
Natural gas ($ per mcf)	$1.63	$2.09	$1.69	$2.50
NGL ($ per bbl)	$13.37	$13.02	$12.43	$15.64
Oil equivalent ($ per boe)	$14.76	$19.77	$14.01	$21.04
Average Sales Price (including realized gains (losses) on derivatives):				
Oil ($ per bbl)	$44.31	$71.39	$40.93	$68.55
Natural gas ($ per mcf)	$1.97	$2.35	$2.14	$3.00
NGL ($ per bbl)	$12.88	$13.02	$12.17	$15.64
Oil equivalent ($ per boe)	$16.43	$23.72	$16.68	$26.51
Other Operating Income ($ in millions):				
Marketing, gathering and compression net margin[d][e]	$(25)	$209	$(7)	$184

TABLE OF CONTENTS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Expenses ($ per boe):				
Oil, natural gas and NGL production	$3.05	$4.32	$3.21	$4.58
Oil, natural gas and NGL gathering, processing and transportation	$8.04	$7.64	$7.96	$7.52
Production taxes	$0.32	$0.52	$0.31	$0.49
General and administrative[(f)]	$1.02	$1.08	$0.90	$1.00
Oil, natural gas and NGL depreciation, depletion and amortization	$4.43	$9.39	$4.43	$10.22
Depreciation and amortization of other assets	$0.48	$0.52	$0.48	$0.55
Interest expense[(g)]	$1.00	$1.12	$0.99	$1.05
Interest Expense ($ in millions):				
Interest expense	$63	$72	$125	$134
Interest rate derivatives – realized (gains) losses[(h)]	(3)	(1)	(6)	(2)
Interest rate derivatives – unrealized (gains) losses[(h)]	2	—	5	(10)
Total interest expense	$62	$71	$124	$122

(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.

(b) Beginning in the 2015 fourth quarter, we reclassified our presentation of third party oil, natural gas and NGL gathering, processing and transportation costs to report the costs as a component of operating expenses in the accompanying statements of operations. Previously, these costs were reflected as deductions to oil, natural gas and NGL sales. The net effect of this reclassification did not impact our previously reported net income, stockholders' equity or cash flows; however, previously reported oil, natural gas and NGL sales and consequently total revenues have increased from the previously reported amounts, and total operating expenses have increased by these same amounts.

(c) Realized gains (losses) include the following items: (i) settlements of undesignated 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 (losses) related to de-designated cash flow hedges originally designated to settle against current period production revenues. Unrealized gains (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 (losses) during the period.

(d) 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 segment.

(e) For the Current Quarter and the Current Period, we recorded unrealized losses of $37 million and $17 million, respectively, on the fair value of our supply contract derivative. 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 this instrument.

(f) Excludes restructuring and other termination costs.

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

(h) Realized (gains) losses include interest rate derivative settlements related to current period interest 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.

37

TABLE OF CONTENTS

Overview

We own interests in approximately 32,400 oil and natural gas wells and produced an average of approximately 657 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 Anadarko Basin in northwestern Oklahoma and the Texas Panhandle; and the Niobrara Shale in the Powder River Basin in Wyoming. Our natural gas resource plays are the Haynesville/Bossier Shales in northwestern Louisiana and East Texas; the Marcellus Shale in the northern Appalachian Basin in Pennsylvania; and the Barnett Shale in the Fort Worth Basin of north-central Texas. We also own oil and natural gas marketing and natural gas gathering and compression businesses.

Our Strategy

Chesapeake's strategy is focused on maximizing liquidity, improving margins and improving the value of our significant positions in premier U.S. onshore resource plays. We continue to apply financial discipline to all aspects of our business with the goal of increasing financial and operational flexibility through lower spending. Our capital program is focused on efficient investments that can improve our cash flow generating ability in a depressed commodity price environment. We are utilizing fewer rigs in 2016 than we utilized in 2015; however, to improve cash flow, we are increasing completion crews to capitalize on prior investments and generate revenues from initial production on new wells. We expect the suspension of dividend payments on our convertible preferred stock, the recent amendment to our senior revolving credit facility and the sale of assets that do not fit in our strategic priorities will provide additional liquidity. In addition, we are strengthening our balance sheet and improving our liquidity position by continuing to exchange or repurchase, at a discount, certain of our debt instruments.

Our substantial inventory of hydrocarbon resources, including our undeveloped acreage, provides a strong foundation to create future value. We have seen and continue to see increased efficiencies and operational improvements, including increased well productivity from larger completions and lower production declines due to a greater focus on strengthening our base production. Building on our strong and diverse asset base, we believe that our dedication to financial discipline, the flexibility of our capital program, and our continued focus on safety and environmental stewardship will provide opportunities to create value for Chesapeake and its stakeholders.

Operating Results

Our Current Quarter production of 60 mmboe consisted of 8 mmbbls of oil (14% on an oil equivalent basis), 269 bcf of natural gas (75% on an oil equivalent basis) and 7 mmbbls of NGL (11% on an oil equivalent basis). Our daily production for the Current Quarter averaged approximately 657 mboe, a decrease of 7% from the Prior Quarter. Compared to the Prior Quarter, average daily oil production decreased by 24%, or approximately 29 mbbls per day; average daily natural gas production decreased by 2%, or approximately 66 mmcf per day; and average daily NGL production decreased by 8%, or approximately 6 mbbls per day. Our oil and NGL production decreased primarily as a result of the sale of certain of our Cleveland and Tonkawa assets in 2015 and a significant reduction in drilling activity. Adjusted for asset sales, our total daily production was flat in the Current Quarter compared to the Prior Quarter. Our oil, natural gas and NGL revenues (excluding gains or losses on oil and natural gas derivatives) decreased approximately $380 million to $884 million in the Current Quarter compared to $1.264 billion in the Prior Quarter, primarily due to significant decreases in the prices received for oil, natural gas and NGL sold in addition to lower volumes sold. See Results of Operations below for additional details.

Our Current Period production of 121 mmboe consisted of 17 mmbbls of oil (14% on an oil equivalent basis), 546 bcf of natural gas (75% on an oil equivalent basis), and 13 mmbbls of NGL (11% on an oil equivalent basis). Our daily production for the Current Period averaged approximately 665 mboe, a decrease of 4% from the Prior Period. Compared to the Prior Period, average daily oil production decreased by 23% or approximately 28 mbbls per day; average daily natural gas production increased by 1%, or approximately 19 mmcf per day; and average daily NGL production decreased by 7%, or approximately 6 mbbls per day. Our oil and NGL production decreased primarily as a result of the sale of certain of our Cleveland and Tonkawa assets in 2015 and a significant reduction in drilling activity. Adjusted for asset sales, our total daily production increased 1% in the Current Period compared to the Prior Period. Our oil, natural gas and NGL revenues (excluding gains or losses on oil and natural gas derivatives) decreased approximately $950 million to $1.696 billion in the Current Period compared to $2.646 billion in the Prior Period, primarily due to significant decreases in the prices received for oil, natural gas and NGL sold in addition to lower volumes sold. See Results of Operations below for additional details.

Capital Expenditures

Our drilling and completion capital expenditures during the Current Quarter were approximately $337 million and capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property and equipment were approximately $56 million, for a total of approximately $393 million. In the Current Quarter, we operated an average of nine rigs, a decrease of 17 rigs, or 65%, compared to the Prior Quarter. As a result of lower drilling and completion activity, drilling and completion expenditures decreased approximately $450 million in the Current Quarter compared to the Prior Quarter.

Our capitalized interest was approximately $63 million and $114 million in the Current Quarter and the Prior Quarter, respectively. Including capitalized interest, total capital investments were approximately $456 million in the Current Quarter compared to $957 million for the Prior Quarter, a decrease of 52%.

Our drilling and completion capital expenditures during the Current Period were approximately $618 million and capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property and equipment were approximately $70 million, for a total of approximately $688 million. In the Current Period, we operated an average of nine rigs, a decrease of 31 rigs, or 78%, compared to the Prior Period. As a result of lower drilling and completion activity, drilling and completion expenditures decreased approximately $1.5 billion in the Current Period compared to the Prior Period. The level of capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property and equipment decreased approximately $49 million compared to the Prior Period.

Our capitalized interest was approximately $132 million and $237 million in the Current Period and the Prior Period, respectively. Including capitalized interest, total capital investments were approximately $820 million in the Current Period compared to $2.4 billion for the Prior Period, a decrease of 66%.

Based on planned activity levels for the remainder of 2016, we project that 2016 capital expenditures for drilling and completions, leasehold, geological and geophysical and other property and equipment will be $1.3 - $1.8 billion, inclusive of capitalized interest. The decrease from the $3.6 billion spent in 2015 is primarily driven by reduced activity as a result of continued lower forecasted oil and natural gas prices for the remainder of 2016. See Liquidity and Capital Resources for additional information on how we plan to fund our capital budget.

Strategic Developments

In the Current Quarter, we further amended our revolving credit facility agreement. Pursuant to the amendment, our borrowing base was reaffirmed in the amount of $4.0 billion and our next scheduled borrowing base redetermination date was postponed until June 15, 2017, with the consenting lenders agreeing not to exercise their interim redetermination right prior to that date. The amendment also modifies the credit agreement to provide for, among other things, (i) the suspension or modification of certain financial covenants, and (ii) the granting of liens and security interests on substantially all of our assets, including mortgages encumbering 90% of our proved oil and gas properties that constitute borrowing base properties, all hedge contracts and personal property subject to certain agreed upon carve outs. See Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I for further discussion of the terms of our revolving credit facility.

In the Current Period, in addition to the repayment upon maturity of $259 million principal amount of our 3.25% Senior Notes due 2016, we repurchased in the open market approximately $181 million principal amount of our outstanding senior notes for $151 million and $118 million principal amount of our outstanding contingent convertible senior notes for $63 million. Additionally, we privately negotiated exchanges of approximately $290 million principal amount of our outstanding senior notes for 53,923,925 shares of our common stock and $287 million principal amount of our outstanding contingent convertible senior notes for 55,427,782 shares of our common stock. We recorded a gain of approximately $168 million associated with these purchases and exchanges.

In the Current Period, we amended certain of our firm transportation agreements in the Haynesville, Barnett and Eagle Ford operating areas, which will reduce our firm transportation volume commitments and fees. We estimate a benefit of approximately $650 million gross ($415 million net) over the term of the contracts, including $80 million gross ($50 million net) in lower unused demand charges for the underutilized capacity and lower transportation fees in 2016.

TABLE OF CONTENTS

In the Current Period, we sold certain of our noncore assets for net proceeds of approximately $964 million after post-closing adjustments. Additional consideration of approximately $106 million was withheld subject to certain title, environmental and other standard contingencies. In conjunction with certain of these sales, we purchased four of our VPP transactions for approximately $259 million. A majority of the acquired interests were part of the asset divestitures discussed above and we no longer have any further commitments or obligations related to these VPPs. The asset divestitures cover various operating areas. We continue to pursue the sale of assets that do not fit in our strategic priorities.

In the Current Period, we suspended dividend payments on our convertible preferred stock to provide additional liquidity in the currently depressed commodity environment.

Liquidity and Capital Resources

Liquidity Overview

Our ability to grow, make capital expenditures and service our debt depends primarily upon the prices we receive for the oil, natural gas and NGL we sell. Substantial expenditures are required to replace reserves, sustain production and fund our business plans. Historically, oil and natural gas prices have been very volatile, and may be subject to wide fluctuations in the future. The substantial decline in oil, natural gas and NGL prices from 2014 levels has negatively affected the amount of cash we have available for capital expenditures and debt service.

As of June 30, 2016, we had a cash balance of approximately $4 million compared to $825 million as of December 31, 2015, and we had a net working capital deficit of approximately $2.573 billion, compared to a net working capital deficit of approximately $1.205 billion as of December 31, 2015. Based on our cash balance, forecasted cash flows from operating activities and availability under our revolving credit facility, we expect to be able to fund our planned capital expenditures budget, meet our debt service requirements and fund our other commitments and obligations for the next 12 months. Oil, natural gas and NGL prices have a material impact on our financial position, results of operations, cash flows and quantities of reserves that may be economically produced. If depressed prices persist throughout 2017 and we are unable to restructure or refinance our debt or generate additional liquidity through other actions, our ability to comply with the financial covenants under our revolving credit facility and to make scheduled debt payments could be adversely impacted.

As discussed in Strategic Developments above and in Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report, we further amended our revolving credit agreement in April 2016 to reaffirm our borrowing base, postpone our next scheduled borrowing base redetermination date and modify or suspend certain credit agreement financial covenants.

As of June 30, 2016, we had approximately $8.679 billion principal amount of debt outstanding, of which $1.382 billion matures or can be put to us in 2017 (including $337 million of maturities in January 2017, $730 million which can be put to us in May 2017 and $315 million of maturities in August 2017) and $846 million that matures or can be put to us in 2018. As of June 30, 2016, we had $100 million of outstanding borrowings under our revolving credit facility and had utilized approximately $813 million of the credit facility for various letters of credit (including the $461 million supersedeas bond with respect to the 2019 Notes litigation). As of June 30, 2016, we had $3.087 billion of borrowing capacity available under our revolving credit facility. 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 our debt obligations, including principal and carrying amounts of our notes.

As operator of a substantial portion of our oil and natural gas properties under development, we have significant control and flexibility over the development plan and the associated timing, enabling us to reduce at least a portion of our capital spending as needed. We have reduced our budgeted 2016 capital expenditures, inclusive of capitalized interest, to $1.3 - $1.8 billion, a significant reduction from our 2015 capital spending level of $3.6 billion. We currently plan to use cash flow from operations, cash on hand, proceeds from assets sales and our revolving credit facility to fund our capital expenditures during 2016. We expect to generate additional liquidity with proceeds from future sales of assets that we determine do not fit our strategic priorities. Management continues to review operational plans for the remainder of 2016 and beyond, which could result in changes to projected capital expenditures and revenues from sales of oil, natural gas and NGL. We closely monitor the amounts and timing of our sources and uses of funds, particularly as they affect our ability to maintain compliance with the financial covenants of our revolving credit facility.

TABLE OF CONTENTS

Since December 2015, Moody's Investor Services, Inc. and Standard & Poor's Rating Services have significantly lowered our credit ratings. Some of our counterparties have requested or required us to post collateral as financial assurance of our performance under certain contractual arrangements, such as gathering, processing, transportation and hedging agreements. As of August 1, 2016, we have received requests and posted approximately $274 million in collateral under such arrangements (excluding the supersedeas bond with respect to the 2019 Notes). We may be requested or required by other counterparties to post additional collateral in an aggregate amount of approximately $664 million, which may be in the form of additional letters of credit, cash or other acceptable collateral. However, we have substantial long-term business relationships with each of these counterparties, and we may be able to mitigate any collateral requests through ongoing business arrangements and by offsetting amounts that the counterparty owes us. Any posting of additional collateral consisting of cash or letters of credit, which would further reduce availability under our revolving credit facility, will negatively impact our liquidity.

In addition, during 2016, we may be required to pay up to $439 million in connection with the judgment against us related to the redemption at par value of our 6.775% Senior Notes due 2019. In connection with our appeal of the decision by the U.S. District Court for the Southern District of New York regarding the redemption, we posted a supersedeas bond in the amount of $461 million in July 2015, which is reflected as an outstanding letter of credit under our credit facility. This contingent payment is fully accrued on our condensed consolidated balance sheet.

We may seek to access the capital markets or otherwise incur debt to refinance a portion of our outstanding indebtedness and improve our liquidity.

To add more certainty to our future estimated cash flows by mitigating our downside exposure to lower commodity prices, as of August 1, 2016, we have downside price protection, through open swaps, on approximately 71% of our projected remaining 2016 oil production at an average price of $46.60 per bbl. We also have downside price protection, through open swaps and collars, on approximately 74% of our projected remaining 2016 natural gas production at an average price of $2.77 per mcf, of which 3% is hedged under two-way collar arrangements based on an average bought put NYMEX price of $3.00 per mcf. In addition, in exchange for a higher price on certain of our oil and natural gas swaps, we have sold certain call options that allow the counterparty to double the notional amount on existing fixed-price swaps. We also have downside price protection, through open swaps, on approximately 32% of our projected remaining 2016 NGL production at average prices of $0.17 per gallon of ethane and $0.46 per gallon of propane.

We have taken measures to mitigate the liquidity concerns facing us for the next 12 months, including mitigating a portion of our downside exposure to lower commodity prices through derivative contracts, the suspension of dividend payments on our convertible preferred stock, the April 2016 amendment to our revolving credit facility and divesting assets to increase our liquidity; however, there can be no assurance that these measures will satisfy our needs.

Sources of Funds

The following table presents the sources of our cash and cash equivalents for the Current Period and the Prior Period.

	Six Months Ended June 30,	
	2016	2015
	($ in millions)	
Cash Provided by (Used In) Operating Activities	$(326)	$737
Proceeds from credit facility borrowings, net	100	—
Divestitures of proved and unproved properties	964	14
Sales of other property and equipment	70	7
Total sources of cash and cash equivalents	$808	$758

Cash used in operating activities was $326 million in the Current Period compared to $737 million of cash provided by operating activities in the Prior Period. The decrease in cash provided by operating activities from the Current Period to the Prior Period is primarily the result of lower realized prices for the oil, natural gas and NGL we sold, partially offset by decreases in certain of our operating expenses. 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, gains or losses on sales of fixed assets, deferred income taxes and mark-to-market changes in our derivative instruments. See further discussion below under Results of Operations.

TABLE OF CONTENTS

We currently plan to use cash flow from operations, cash on hand, proceeds from asset sales and our revolving credit facility to fund our capital expenditures for the remainder of 2016. We expect to generate additional liquidity with proceeds from future sales of assets that we have determined are noncore or do not fit our long-term plans. We borrowed $2.477 billion and repaid $2.377 billion under our revolving credit facility in the Current Period and had no borrowings or repayments in the Prior Period.

Uses of Funds

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

	Six Months Ended June 30,	
	2016	2015
	($ in millions)	
Oil and Natural Gas Expenditures:		
Drilling and completion costs[(a)]	$608	$2,150
Acquisitions of proved and unproved properties	303	54
Interest capitalized on unproved leasehold	124	230
Total oil and natural gas expenditures	1,035	2,434
Other Uses of Cash and Cash Equivalents:		
Cash paid to repurchase debt	472	—
Cash paid for title defects	69	—
Additions to other property and equipment	25	93
Dividends paid	—	204
Distributions to noncontrolling interest owners	6	57
Additions to investments	—	1
Other	22	26
Total other uses of cash and cash equivalents	594	381
Total uses of cash and cash equivalents	$1,629	$2,815

(a) Net of $51 million in drilling and completion carries received from our joint venture partners during the Prior Period.

Our primary use of funds is for capital expenditures for drilling and completion costs on our oil and natural gas properties. Our drilling and completion costs decreased primarily as a result of significantly decreased activity. During the Current Period, our average operated rig count was nine rigs compared to an average operated rig count of 40 rigs in the Prior Period.

In the Current Period, we used $472 million of cash to reduce $558 million principal amount of debt. In addition to the repayment at maturity of $259 million principal amount of our 3.25% Senior Notes due 2016, we repurchased in the open market approximately $118 million principal amount of our 2037 Notes (that could have been put to us in May 2017) for $63 million, $122 million principal amount of our 3.25% Senior Notes due 2016 for $115 million (prior to maturity) and $59 million principal amount of our 6.5% Senior Notes due 2017 for $36 million.

We paid dividends on our preferred stock of $86 million in the Prior Period and we paid dividends on our common stock of $118 million in the Prior Period. We eliminated common stock dividends effective in the 2015 third quarter and suspended preferred stock dividends effective in the 2016 first quarter.

Revolving Credit Facility

We have a $4.0 billion senior secured revolving credit facility that matures in December 2019. As of June 30, 2016, we had $100 million of outstanding borrowings under the credit facility and had used $813 million of the credit facility for various letters of credit (including the $461 million supersedeas bond with respect to the 2019 Notes litigation). See Liquidity Overview above for additional information on our collateral postings. Borrowings under the facility bear interest at a variable rate. We are required to secure our obligations under the facility with liens on certain of our oil and natural gas properties, with the liens to be released upon the satisfaction of specific conditions. The applicable interest rates under the facility fluctuate based on the percentage of the borrowing base used. In April 2016, we amended

TABLE OF CONTENTS

our credit facility to provide covenant relief and affirm our $4.0 billion borrowing base. See Note 3 of the notes to our condensed consolidated financial statements included in Item I of Part 1 for further discussion of the terms of the credit facility and the April 2016 amendment. As of June 30, 2016, our interest rate coverage ratio was approximately 2.02 to 1.0. As of June 30, 2016, we were in compliance with all financial covenants under the credit agreement.

Hedging Arrangements

In February 2016, our multi-counterparty secured hedging facility was terminated and all liens on the collateral securing the hedging facility were released. In April 2015, we began using bilateral hedging arrangements. For discussion of our bilateral hedging agreements, see Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report.

Senior Note Obligations

Our senior note obligations consisted of the following as of June 30, 2016:

	June 30, 2016	
	Principal Amount	Carrying Amount
	($ in millions)	
6.25% euro-denominated senior notes due 2017[(a)]	$337	$337
6.5% senior notes due 2017	315	315
7.25% senior notes due 2018	531	531
Floating rate senior notes due 2019	949	949
6.625% senior notes due 2020	822	822
6.875% senior notes due 2020	302	302
6.125% senior notes due 2021	584	584
5.375% senior notes due 2021	276	276
4.875% senior notes due 2022	607	607
8.00% senior secured second lien notes due 2022	2,425	3,501
5.75% senior notes due 2023	384	384
2.75% contingent convertible senior notes due 2035[(b)]	2	2
2.5% contingent convertible senior notes due 2037[(b)(c)]	730	694
2.25% contingent convertible senior notes due 2038[(b)(c)]	315	276
Debt issuance costs	—	(35)
Discount on senior notes	—	(2)
Interest rate derivatives[(d)]	—	6
Total senior notes, net	8,579	9,549
Less current maturities of senior notes, net[(e)]	(1,066)	(1,028)
Total long-term senior notes, net	$7,513	$8,521

(a) The principal amount shown is based on the exchange rate of $1.1106 to €1.00 as of June 30, 2016. 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.

(b) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder's option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. We may redeem our 2.75% Contingent Convertible Senior Notes due 2035 at any time.

(c) The carrying amount associated with the equity component of our contingent convertible senior notes as of June 30, 2016 is net of $75 million.

TABLE OF CONTENTS

(d) 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.

(e) As of June 30, 2016, current maturities of long-term debt, net includes our 6.25% Euro-denominated Senior Notes due January 2017 and our 2037 Notes. As discussed in footnote (b) above and in Note 3 of the notes to our condensed consolidated financial statements included in Item I of Part 1 of this report, the holders of our 2037 Notes could exercise their individual demand repurchase rights on May 15, 2017, which would require us to repurchase all or a portion of the principal amount of the notes. As of June 30, 2016, there was $36 million of discount associated with the equity component of the 2037 Notes.

For further discussion and details regarding our senior notes and contingent convertible 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 oil, natural gas and NGL prices, as well as to 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 June 30, 2016, our oil, natural gas, NGL, interest rate and supply contract derivative instruments were spread among 15 counterparties. Additionally, the counterparties under our commodity hedging arrangements are required to secure their obligations in excess of defined thresholds.

Our accounts receivable are primarily from purchasers of oil, natural gas and NGL ($697 million as of June 30, 2016) and exploration and production companies that own interests in properties we operate ($172 million as of June 30, 2016). 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, the Prior Quarter, the Current Period and the Prior Period, we recognized $3 million, $1 million, $4 million and $2 million, respectively, 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 contractual obligations and off-balance sheet commitments. As of June 30, 2016, these arrangements and transactions included (i) operating lease agreements, (ii) volumetric production payments (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. See Notes 4 and 9 of the notes to our condensed consolidated financial statements included in Item 1 of this report for further discussion of commitments and VPPs, respectively.

Results of Operations – Three Months Ended June 30, 2016 vs. June 30, 2015

General. For the Current Quarter, Chesapeake had a net loss of $1.750 billion, or $2.48 per diluted common share, on total revenues of $1.622 billion. This compares to a net loss of $4.090 billion, or $6.27 per diluted common share, on total revenues of $3.521 billion for the Prior Quarter. The net losses in the Current Quarter and the Prior Quarter were primarily driven by impairments of our oil and natural gas properties. See Impairment of Oil and Natural Gas Properties below. The decrease in total revenues in the Current Quarter and the Prior Quarter was primarily driven by unrealized hedging losses of $544 million and $301 million, respectively. Additionally, the decrease in total revenues in the Current Quarter was driven by decreases in the prices we received for our oil, natural gas and NGL production and the prices our marketing affiliate received for oil, natural gas and NGL production sold on behalf of third-party producers.

Oil, Natural Gas and NGL Sales. During the Current Quarter, oil, natural gas and NGL sales were $440 million compared to $1.216 billion in the Prior Quarter. In the Current Quarter, Chesapeake sold 60 mmboe for $884 million at a weighted average price of $14.76 per boe (excluding the effect of derivatives), compared to 64 mmboe sold in the Prior Quarter for $1.264 billion at a weighted average price of $19.77 per boe (excluding the effect of derivatives). The decrease in the price received per boe in the Current Quarter compared to the Prior Quarter resulted in a $297 million decrease in revenues, and decreased sales volumes resulted in an $83 million decrease in revenues, for a total decrease in revenues of $380 million (excluding the effect of derivatives).

For the Current Quarter, our average price received per barrel of oil (excluding the effect of derivatives) was $43.00, compared to $54.69 in the Prior Quarter. Natural gas prices received per mcf (excluding the effect of derivatives) were $1.63 in the Current Quarter and $2.09 in the Prior Quarter. NGL prices received per barrel (excluding the effect of derivatives) were $13.37 in the Current Quarter and $13.02 in the Prior Quarter.

Losses from our oil and natural gas derivatives resulted in a net decrease in oil, natural gas and NGL revenues of $444 million in the Current Quarter and a net decrease of $48 million in the Prior Quarter, respectively. See Item 3. Quantitative and Qualitative Disclosures About Market Risk in Part I of this report for a complete listing of all of our derivative instruments as of June 30, 2016.

A change in oil, natural gas 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 $1.00 per barrel of oil sold would result in an increase or decrease in Current Quarter revenues of approximately $8 million, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in Current Quarter revenues of approximately $27 million and an increase or decrease of $1.00 per barrel of NGL sold would result in an increase or decrease Current Quarter revenues of $7 million.

TABLE OF CONTENTS

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

	Three Months Ended June 30, 2016								
	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[a]	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b]	6.3	44.29	140.8	1.72	3.1	14.78	32.8	55	17.26
Northern[c]	1.9	38.83	128.6	1.53	3.6	12.16	27.2	45	11.71
Total	8.2	43.00	269.4	1.63	6.7	13.37	60.0	100%	14.76

	Three Months Ended June 30, 2015								
	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[a]	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b]	8.8	56.81	147.6	2.41	4.0	13.98	37.4	58	24.36
Northern[c]	2.1	45.73	127.8	1.73	3.2	11.80	26.6	42	13.30
Total	10.9	54.69	275.4	2.09	7.2	13.02	64.0	100%	19.77

(a) Average sales prices exclude gains (losses) on derivatives. The decrease in the average sales price for our oil sold in the Current Quarter as compared to the Prior Quarter was primarily driven by lower crude oil prices. The decrease in the average sales price for our natural gas sold in the Current Quarter as compared to the Prior Quarter was primarily driven by lower natural gas prices. The decrease in the average sales price for our NGL sold in the Current Quarter as compared to the Prior Quarter was primarily driven by lower NGL prices.

(b) Our Southern Division includes the Eagle Ford and Anadarko Basin liquids plays and the Haynesville/Bossier and Barnett natural gas shale plays. The Eagle Ford Shale accounted for approximately 24% of our estimated proved reserves by volume as of December 31, 2015. Eagle Ford Shale production for the Current Quarter and the Prior Quarter was 8.3 mmboe and 9.6 mmboe, respectively.

(c) Our Northern Division includes the Utica and Niobrara liquids plays and the Marcellus natural gas play. The Utica Shale accounted for approximately 18% of our estimated proved reserves by volume as of December 31, 2015. Utica Shale production for the Current Quarter and the Prior Quarter was 12.4 mmboe and 11.3 mmboe, respectively. The Marcellus Shale accounted for approximately 17% of our estimated proved reserves by volume as of December 31, 2015. Marcellus Shale production for the Current Quarter and the Prior Quarter was 12.3 mmboe, and 12.7 mmboe, respectively.

Our average daily production of 657 mboe for the Current Quarter consisted of approximately 91 mbbls of oil (14% on an oil equivalent basis), approximately 3 bcf of natural gas (75% on an oil equivalent basis) and approximately 73 mbbls of NGL (11% on an oil equivalent basis). Oil production decreased by 24% year over year primarily as a result of the sale of certain of our Cleveland and Tonkawa assets in 2015 and a significant reduction in drilling activity. Natural gas production decreased by 2% and NGL production decreased by 8%.

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

	Three Months Ended June 30,	
	2016	2015
Oil	40%	47%
Natural gas	50%	46%
NGL	10%	7%
Total	100%	100%

46

TABLE OF CONTENTS

Marketing, Gathering and Compression Revenues and Expenses. Marketing, gathering and compression revenues consist of third-party revenues as well as fair value adjustments on our supply contract derivatives (see Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for additional information on our supply contract derivatives). Expenses related to our marketing, gathering and compression operations consist of third-party expenses 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 $1.182 billion in marketing, gathering and compression revenues in the Current Quarter, of which $37 million related to unrealized losses on the fair value of our supply contract derivative, with corresponding expenses of $1.207 billion, for a net loss before depreciation of $25 million. This compares to revenues of $2.305 billion, of which $220 million related to unrealized gains on the fair value of our supply contract derivative, with corresponding expenses of $2.096 billion, for a net margin before depreciation of $209 million in the Prior Quarter. Revenues and expenses decreased in the Current Quarter compared to the Prior Quarter primarily as a result of lower oil, natural gas and NGL prices paid and received in our marketing operations. The margin decrease in the Current Quarter as compared to the Prior Quarter was primarily the result of an unrealized gain on the fair value adjustment on our supply contract derivative in the Prior Quarter as well as lower compression margins as a result of the sale of a significant portion of our compression assets in 2015.

Oil, Natural Gas and NGL Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $182 million in the Current Quarter, compared to $276 million in the Prior Quarter. On a unit-of-production basis, production expenses were $3.05 per boe in the Current Quarter compared to $4.32 per boe in the Prior Quarter. The absolute and per unit decrease in the Current Quarter was primarily the result of operating efficiencies across most of our operating areas. Production expenses in the Current Quarter and the Prior Quarter included approximately $15 million and $31 million, or $0.25 and $0.48 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 operating efficiencies generally improve. Additionally, in connection with certain divestitures in the Current Quarter, we purchased the remaining oil and natural gas interests previously sold in connection with four of our VPPs and a majority of the oil and gas interests purchased were subsequently sold and one of our VPPs expired in 2015.

Oil, Natural Gas, and NGL Gathering, Processing and Transportation Expenses. Oil, natural gas and NGL gathering, processing and transportation expenses were $481 million in the Current Quarter compared to $488 million in the Prior Quarter. On a unit-of-production basis, gathering, processing and transportation expenses were $8.04 per boe in the Current Quarter compared to $7.64 per boe in the Prior Quarter. Certain of our gathering agreements require us to pay the service provider a fee for any production shortfall below certain annual minimum gathering volume commitments and we anticipate incurring shortfall fees in the 2016 fourth quarter based on current production estimates. A summary of oil, natural gas and NGL gathering, processing and transportation expenses by product is shown below.

	Three Months Ended June 30,	
	2016	2015
Oil ($ per bbl)	$3.64	$3.49
Natural gas ($ per mcf)	$1.48	$1.45
NGL ($ per bbl)	$7.61	$7.01

Production Taxes. Production taxes were $19 million in the Current Quarter compared to $34 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.32 per boe in the Current Quarter compared to $0.52 per boe in the Prior Quarter. In general, production taxes are calculated using value-based formulas that produce lower per unit costs when oil, natural gas and NGL prices are lower. The absolute and per unit decrease in production taxes in the Current Quarter was primarily due to lower prices received for oil, natural gas and NGL. Production taxes in both the Current Quarter and the Prior Quarter included approximately $1 million, or $0.02 per boe, associated with VPP production volumes. We anticipate a continued decrease in production tax expenses associated with VPP production volumes as the contractually scheduled volumes under our VPP agreements decrease.

General and Administrative Expenses. General and administrative expenses were $61 million in the Current Quarter and $69 million in the Prior Quarter, or $1.02 and $1.08 per boe, respectively. The absolute and per unit expense decrease in the Current Quarter was primarily due to reduced overhead as a result of our workforce reduction in the 2015 third quarter and our continuing efforts to reduce other administrative expenses.

TABLE OF CONTENTS

Chesapeake follows the full cost method of accounting under which all costs associated with oil and natural gas property acquisition, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with the acquisition of leasehold, as well as drilling and completion activities, and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $35 million and $65 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our leasehold acquisition and drilling and completion efforts.

Restructuring and Other Termination Costs. We recorded expense of $3 million in the Current Quarter and credits of $4 million in the Prior Quarter for restructuring and other termination costs. The Current Quarter amount primarily related to the reduction in workforce in connection with the restructuring of our compressor manufacturing subsidiary and approximately $1 million was related to PSU fair value adjustments. The Prior Quarter amount was primarily related to negative fair value adjustments to PSUs granted to former executives of the Company, which corresponded to a decrease in the trading price of our common stock.

Provision for Legal Contingencies. In the Current Quarter and the Prior Quarter, we recorded $82 million and $334 million, respectively, for legal contingencies. The Current Quarter provision consists of accruals for loss contingencies primarily related to royalty claims. See Note 4 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of royalty claims. The Prior Quarter amount relates to the $339 million charge for litigation regarding our early redemption of our 2019 Notes, partially offset by $5 million related to certain royalty claimants that opted out of a settlement agreement.

Oil, Natural Gas and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of oil, natural gas and NGL properties was $265 million and $601 million in the Current Quarter and the Prior Quarter, respectively. 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 $4.43 and $9.39 in the Current Quarter and the Prior Quarter, respectively. The absolute and per unit decrease in the Current Quarter was the result of a lower amortization base, which is due to the 2015 and 2016 impairments of our oil and natural gas properties.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $29 million in the Current Quarter compared to $34 million in the Prior Quarter. On a unit-of-production basis, depreciation and amortization of other assets was $0.48 per boe in the Current Quarter compared to $0.52 per boe in the Prior Quarter. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. 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 June 30,		Estimated Useful Life
	2016	2015	
	($ in millions)		(in years)
Buildings and improvements	$ 10	$ 9	10 – 39
Natural gas compressors[a]	7	11	3 – 20
Computers and office equipment	5	6	3 – 7
Vehicles	1	3	0 – 7
Natural gas gathering systems and treating plants[a]	3	3	20
Other	3	2	2 – 20
Total depreciation and amortization of other assets	$ 29	$ 34	

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

Impairment of Oil and Natural Gas Properties. Our oil and natural gas properties are subject to quarterly full cost ceiling tests. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. For the Current Quarter and the Prior Quarter, capitalized costs of oil and natural gas properties exceeded the ceiling, resulting in impairments of the carrying value of our oil and natural gas properties of $1.045 billion and $5.015 billion, respectively. Cash flow hedges related to future periods increased the ceiling test impairment by $160 million and $190 million in the Current Quarter and the Prior Quarter, respectively.

TABLE OF CONTENTS

As of June 30, 2016, the present value of estimated future net revenue of our proved reserves, discounted at an annual rate of 10%, was $3.055 billion. Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, gathering, processing, transportation and future development costs, using prices and costs under existing economic conditions as of that date. The prices used in the present value calculation as of June 30, 2016 were $43.12 per bbl of oil and $2.24 per mcf of natural gas, before price differential adjustments. Based on the first-day-of-the-month index prices we have received over the 11 months ended August 1, 2016, as well as the current strip price for September 2016, we reasonably expect a decrease of approximately $1.44 per barrel of oil and increase of $0.04 per mcf of natural gas in the prices we will be using to calculate the estimated future net revenue of our proved reserves as of September 30, 2016, and such decreases and increases are expected to reduce the present value of estimated future net revenue of our proved reserves by less than $150 million in the 2016 third quarter (including the effects of expected negative price-related revisions to reserve volumes discussed below). This decrease is expected to result in a write-down in the third quarter of 2016. The actual impairment in the third quarter of 2016 could be greater or less than the decrease in estimated discounted future net revenues, or mitigated by the impact of anticipated divestitures or other factors. Further write-downs in subsequent quarters could occur if the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters.

Deterioration in commodity prices also impacts estimated quantities of proved reserves. In the Current Quarter, we recognized negative reserve revisions to our year-end 2015 estimated proved reserves of approximately 12% due to lower commodity prices. Based on first-of-the-month index prices for July and August 2016, as well as the current strip prices for September 2016, we reasonably expect negative price-related revisions to our September 30, 2016 estimated total proved reserves (developed and undeveloped) of approximately 2.5%, and if prices continue to decline we expect to have additional negative price-related revisions in the future. We do not expect these negative price-related revisions and 2016 production to be fully offset by reserve additions.

Impairments of Fixed Assets and Other. In the Current Quarter and the Prior Quarter, we recognized $6 million and $84 million, respectively, of fixed asset impairment losses and other charges. The Current Quarter amount primarily related to charges incurred for terminating drilling contracts as a result of the decline in oil and natural gas prices. The Prior Quarter amount consisted of a loss contingency related to contract disputes, an impairment related to third-party rental compressors, an impairment of a note receivable and charges incurred for terminating drilling contracts.

Net (Gains) Losses on Sales of Fixed Assets. In the Current Quarter, net gains on sales of fixed assets were $1 million compared to net losses of $1 million in the Prior Quarter. The Current Quarter and the Prior Quarter amounts primarily related to the sale of buildings, land and other property and equipment.

Interest Expense. Interest expense was $62 million in the Current Quarter compared to $71 million in the Prior Quarter as follows:

	Three Months Ended June 30,	
	2016	2015
	($ in millions)	
Interest expense on senior notes	$107	$171
Amortization of loan discount, issuance costs and other	7	12
Interest expense on credit facilities	12	3
Realized gains on interest rate derivatives[a]	(3)	(1)
Unrealized (gains) losses on interest rate derivatives[b]	2	—
Capitalized interest	(63)	(114)
Total interest expense	$62	$71
Average senior notes borrowings	$8,926	$11,798
Average credit facility borrowings	$457	$—

(a) Includes settlements related to the interest accrual for the current period 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 current period.

The decrease in capitalized interest resulted from a lower average balance of our unproved oil and natural gas properties, the primary asset on which interest is capitalized. The decrease in senior note interest expense is primarily due to interest on our second lien notes being accounted for as a reduction in the carrying value of debt instead of interest expense as a result of troubled debt restructuring accounting rules. Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $1.00 per boe in the Current Quarter and $1.12 in the Prior Quarter.

Losses on Investments. Losses on investments of $2 million in the Current Quarter were related to our equity investment in Sundrop Fuels, Inc. Losses on investments of $17 million in the Prior Quarter were primarily related to our equity investments in FTS International, Inc. and Sundrop Fuels, Inc.

Gains on Purchases or Exchanges of Debt. In the Current Quarter, we privately negotiated exchanges of approximately $275 million principal amount of our outstanding senior notes for 51,367,946 shares of our common stock and $197 million principal amount of our outstanding contingent convertible senior notes for 40,728,414 shares of our common stock. We recorded a gain of approximately $68 million associated with these debt exchanges.

Other Income (Expense). Other income was $3 million in the Current Quarter and consisted of miscellaneous income. In the Prior Quarter, we recorded $1 million of other expense that consisted of $1 million of interest income and $2 million of miscellaneous expense.

Income Tax Benefit. Chesapeake recorded an income tax benefit of $1.506 billion in the Prior Quarter. Our effective income tax rate was 0.0% in the Current Quarter and 26.9% in the Prior Quarter. The decrease in the effective income tax rate from the Prior Quarter to the Current Quarter is primarily due to the tax benefit at expected rates being fully offset by a change in our valuation allowance. Further, our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences. 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 income taxes.

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded net income attributable to noncontrolling interests of $18 million in the Prior Quarter. This amount was primarily related to dividends paid on preferred stock of our CHK C-T subsidiary. The decrease from the Prior Quarter to the Current Quarter is due to the repurchase of all of the preferred shares of CHK C-T from third-party shareholders in August 2015.

TABLE OF CONTENTS

Results of Operations – Six Months Ended June 30, 2016 vs. June 30, 2015

General. For the Current Period, Chesapeake had a net loss of $2.671 billion, or $3.97 per diluted common share, on total revenues of $3.575 billion. This compares to a net loss of $7.810 billion, or $11.99 per diluted common share, on total revenues of $6.739 billion for the Prior Period. The net losses in the Current Period and the Prior Period were primarily driven by impairments of our oil and natural gas properties. See Impairment of Oil and Natural Gas Properties below. The decrease in total revenues in the Current Period and the Prior Period was primarily driven by unrealized hedging losses of $586 million and $575 million, respectively. Additionally, the decrease in total revenues in the Current Period was driven by decreases in the prices we received for our oil, natural gas and NGL production and the prices our marketing affiliate received for oil, natural gas and NGL production sold on behalf of third-party producers.

Oil, Natural Gas and NGL Sales. During the Current Period, oil, natural gas and NGL sales were $1.433 billion compared to $2.759 billion in the Prior Period. In the Current Period, Chesapeake sold 121 mmboe for $1.696 billion at a weighted average price of $14.01 per boe (excluding the effect of derivatives), compared to 126 mmboe sold in the Prior Period for $2.646 billion at a weighted average price of $21.04 per boe (excluding the effect of derivatives). The decrease in the price received per boe in the Current Period compared to the Prior Period resulted in a $100 million decrease in revenues, and decreased sales volumes resulted in an $850 million decrease in revenues, for a total decrease in revenues of $950 million (excluding the effect of derivatives).

For the Current Period, our average price received per barrel of oil (excluding the effect of derivatives) was $35.98, compared to $49.48 in the Prior Period. Natural gas prices received per mcf (excluding the effect of derivatives) were $1.69 in the Current Period and $2.50 in the Prior Period. NGL prices received per barrel (excluding the effect of derivatives) were $12.43 in the Current Period and $15.64 in the Prior Period.

Gains and losses from our oil and natural gas derivatives resulted in a net decrease in oil, natural gas and NGL revenues of $263 million in the Current Period and a net increase of $113 million in the Prior Period, respectively. See Item 3. Quantitative and Qualitative Disclosures About Market Risk in Part I of this report for a complete listing of all of our derivative instruments as of June 30, 2016.

A change in oil, natural gas and NGL prices has a significant impact on our revenues and cash flows. Assuming our Current Period production levels and without considering the effect of derivatives, an increase or decrease of $1.00 per barrel of oil sold would result in an increase or decrease in Current Period revenues of approximately $17 million, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in Current Period revenues of approximately $55 million and an increase or decrease of $1.00 per barrel of NGL sold would result in an increase or decrease Current Period revenues of $13 million.

TABLE OF CONTENTS

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

	Six Months Ended June 30, 2016								
	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[a]	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	(%)	($/boe)[a]
Southern[b]	12.9	37.12	282.2	1.77	6.2	12.50	66.1	55	15.96
Northern[c]	4.1	32.38	263.4	1.61	6.9	12.36	54.9	45	11.67
Total	17.0	35.98	545.6	1.69	13.1	12.43	121.0	100%	14.01

	Six Months Ended June 30, 2015								
	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[a]	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	(%)	($/boe)[a]
Southern[b]	18.1	51.26	289.3	2.64	7.9	14.61	74.5	59	24.31
Northern[c]	3.8	41.07	249.9	2.33	6.1	16.98	51.5	41	16.33
Total	21.9	49.48	539.2	2.50	14.0	15.64	126.0	100%	21.04

(a) Average sales prices exclude gains (losses) on derivatives. The decrease in the average sales price for our oil sold in the Current Period as compared to the Prior Period was primarily driven by lower crude oil prices. The decrease in the average sales price for our natural gas sold in the Current Period as compared to the Prior Period was primarily driven by lower natural gas prices. The decrease in the average sales price for our NGL sold in the Current Period as compared to the Prior Period was primarily driven by lower NGL prices.

(b) Our Southern Division includes the Eagle Ford and Anadarko Basin liquids plays and the Haynesville/Bossier and Barnett natural gas shale plays. The Eagle Ford Shale accounted for approximately 24% of our estimated proved reserves by volume as of December 31, 2015. Eagle Ford Shale production for the Current Period and the Prior Period was 16.6 mmboe and 19.8 mmboe, respectively.

(c) Our Northern Division includes the Utica and Niobrara liquids plays and the Marcellus natural gas play. The Utica Shale accounted for approximately 18% of our estimated proved reserves by volume as of December 31, 2015. Utica Shale production for the Current Period and the Prior Period was 25.0 mmboe and 21.2 mmboe, respectively. The Marcellus Shale accounted for approximately 17% of our estimated proved reserves by volume as of December 31, 2015. Marcellus Shale production for the Current Period and the Prior Period was 25.4 mmboe, and 25.2 mmboe, respectively.

Our average daily production of 665 mboe for the Current Period consisted of approximately 93 mbbls of oil (14% on an oil equivalent basis), approximately 3 bcf of natural gas (75% on an oil equivalent basis) and approximately 72 mbbls of NGL (11% on an oil equivalent basis). Oil production decreased by 23% year over year primarily as a result of the sale of certain of our Cleveland and Tonkawa assets in 2015 and a significant reduction in drilling activity. Natural gas production increased by 1% and NGL production decreased by 7%.

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

	Six Months Ended June 30,	
	2016	2015
Oil	36%	41%
Natural gas	54%	51%
NGL	10%	8%
Total	100%	100%

Marketing, Gathering and Compression Revenues and Expenses. Marketing, gathering and compression revenues consist of third-party revenues as well as fair value adjustments on our supply contract derivatives (see Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for additional information on our supply contract derivatives). Expenses related to our marketing, gathering and compression operations consist of third-party expenses 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 $2.142 billion in marketing, gathering and compression revenues in the Current Period, of which $17 million related to unrealized losses on the fair value of our supply contract derivative, with corresponding expenses of $2.149 billion, for a net loss before depreciation of $7 million. This compares to revenues of $3.980 billion, of which $220 million related to unrealized gains on the fair value of our supply contract derivative, with corresponding expenses of $3.796 billion, for a net margin before depreciation of $184 million in the Prior Period. Revenues and expenses decreased in the Current Period compared to the Prior Period primarily as a result of lower oil, natural gas and NGL prices paid and received in our marketing operations. The margin decrease in the Current Period as compared to the Prior Period was primarily the result of an unrealized gain on the fair value adjustment on our supply contract derivative in the Prior Period as well as lower compression margins as a result of the sale of a significant portion of our compression assets in 2015.

Oil, Natural Gas and NGL Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $388 million in the Current Period, compared to $575 million in the Prior Period. On a unit-of-production basis, production expenses were $3.21 per boe in the Current Period compared to $4.58 per boe in the Prior Period. The absolute and per unit decrease in the Current Period was primarily the result of operating efficiencies across most of our operating areas. Production expenses in the Current Period and the Prior Period included approximately $28 million and $63 million, or $0.23 and $0.50 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 operating efficiencies generally improve. Additionally, in connection with certain divestitures in the Current Quarter, we purchased the remaining oil and natural gas interests previously sold in connection with four of our VPPs and a majority of the oil and gas interests repurchased were subsequently sold and one of our VPPs expired in 2015.

Oil, Natural Gas, and NGL Gathering, Processing and Transportation Expenses. Oil, natural gas and NGL gathering, processing and transportation expenses were $963 million in the Current Period compared to $946 million in the Prior Period. On a unit-of-production basis, gathering, processing and transportation expenses were $7.96 per boe in the Current Period compared to $7.52 per boe in the Prior Period. Certain of our gathering agreements require us to pay the service provider a fee for any production shortfall below certain annual minimum gathering volume commitments and we anticipate incurring shortfall fees in the 2016 fourth quarter based on current production estimates. A summary of oil, natural gas and NGL gathering, processing and transportation expenses by product is shown below.

	Six Months Ended June 30,	
	2016	2015
Oil ($ per bbl)	$3.46	$3.32
Natural gas ($ per mcf)	$1.47	$1.44
NGL ($ per bbl)	$7.60	$7.00

Production Taxes. Production taxes were $37 million in the Current Period compared to $62 million in the Prior Period. On a unit-of-production basis, production taxes were $0.31 per boe in the Current Period compared to $0.49 per boe in the Prior Period. In general, production taxes are calculated using value-based formulas that produce lower per unit costs when oil, natural gas and NGL prices are lower. The absolute and per unit decrease in production taxes in the Current Period was primarily due to lower prices received for oil, natural gas and NGL. Production taxes in the Current Period and the Prior Period included approximately $2 million and $3 million, or $0.02 and $0.03 per boe,

respectively, associated with VPP production volumes. We anticipate a continued decrease in production tax expenses associated with VPP production volumes as the contractually scheduled volumes under our VPP agreements decrease.
General and Administrative Expenses. General and administrative expenses were $109 million in the Current Period and $125 million in the Prior Period, or $0.90 and $1.00 per boe, respectively. The absolute and per unit expense decrease in the Current Period was primarily due to reduced overhead as a result of our workforce reduction in the 2015 third quarter and our continuing efforts to reduce other administrative expenses.

TABLE OF CONTENTS

Chesapeake follows the full cost method of accounting under which all costs associated with oil and natural gas property acquisition, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with the acquisition of leasehold, as well as drilling and completion activities, and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $72 million and $113 million of internal costs in the Current Period and the Prior Period, respectively, directly related to our leasehold acquisition and drilling and completion efforts.

Restructuring and Other Termination Costs. We recorded expense of $3 million in the Current Period and credits of $14 million in the Prior Period, respectively, for restructuring and other termination costs. The Current Period amount was primarily related to the reduction in workforce in connection with the restructuring of our compressor manufacturing subsidiary and approximately $1 million was related to PSU fair value adjustments. The Prior Quarter amount was primarily related to negative fair value adjustments to PSUs granted to former executives of the Company, which corresponded to a decrease in the trading price of our common stock.

Provision for Legal Contingencies. In the Current Period and the Prior Period, we recorded $104 million and $359 million, respectively, for legal contingencies. The Current Period provision consists of accruals for loss contingencies primarily related to royalty claims. See Note 4 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of royalty claims. The Prior Period amount includes $25 million related to the resolution in April 2015 of litigation we were defending against the state of Michigan and $339 million related to litigation involving our early redemption of our 2019 notes, partially offset by $5 million related to certain royalty claimants that opted out of a settlement agreement.

Oil, Natural Gas and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of oil, natural gas and NGL properties was $536 million and $1.285 billion in the Current Period and the Prior Period, respectively. 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 $4.43 and $10.22 in the Current Period and the Prior Period, respectively. The absolute and per unit decrease in the Current Period was the result of a lower amortization base, which is due to the 2015 and 2016 impairments of our oil and natural gas properties.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $58 million in the Current Period compared to $69 million in the Prior Period. On a unit-of-production basis, depreciation and amortization of other assets was $0.48 per boe in the Current Period compared to $0.55 per boe in the Prior Period. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. The following table shows depreciation expense by asset class for the Current Period and the Prior Period and the estimated useful lives of these assets.

	Six Months Ended June 30,		Estimated Useful Life
	2016	2015	
	($ in millions)		(in years)
Buildings and improvements	$ 20	$ 19	10 – 39
Natural gas compressors[(a)]	15	21	3 – 20
Computers and office equipment	9	13	3 – 7
Vehicles	2	6	0 – 7
Natural gas gathering systems and treating plants[(a)]	5	5	20
Other	7	5	2 – 20
Total depreciation and amortization of other assets	$ 58	$ 69	

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

TABLE OF CONTENTS

Impairment of Oil and Natural Gas Properties. Our oil and natural gas properties are subject to quarterly full cost ceiling tests. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. For the Current Period and the Prior Period, capitalized costs of oil and natural gas properties exceeded the ceiling, resulting in impairments of the carrying value of our oil and natural gas properties of $1.898 billion and $9.991 billion, respectively. Cash flow hedges related to future periods increased the ceiling test impairment by $326 million and $385 million in the Current Period and the Prior Period, respectively.

As of June 30, 2016, the present value of estimated future net revenue of our proved reserves, discounted at an annual rate of 10%, was $3.055 billion. Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, gathering, processing, transportation and future development costs, using prices and costs under existing economic conditions as of that date. The prices used in the present value calculation as of June 30, 2016 were $43.12 per bbl of oil and $2.24 per mcf of natural gas, before price differential adjustments. Based on the first-day-of-the-month index prices we have received over the 11 months ended August 1, 2016, as well as the current strip price for September 2016, we reasonably expect a decrease of approximately $1.44 per barrel of oil and increase of $0.04 per mcf of natural gas in the prices we will be using to calculate the estimated future net revenue of our proved reserves as of September 30, 2016, and such decreases and increases are expected to reduce the present value of estimated future net revenue of our proved reserves by less than $150 million in the 2016 third quarter (including the effects of expected negative price-related revisions to reserve volumes discussed below). This decrease is expected to result in a write-down in the third quarter of 2016. The actual impairment in the third quarter of 2016 could be greater or less than the decrease in estimated discounted future net revenues, or mitigated by the impact of anticipated divestitures or other factors. Further write-downs in subsequent quarters could occur if the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters.

Deterioration in commodity prices also impacts estimated quantities of proved reserves. In the Current Period, we recognized negative reserve revisions to our year-end 2015 estimated proved reserves of approximately 22% due to lower commodity prices. Based on first-of-the-month index prices for July and August 2016, as well as the current strip prices for September 2016, we reasonably expect negative price-related revisions to our September 30, 2016 estimated total proved reserves (developed and undeveloped) of approximately 2.5%, and if prices continue to decline we expect to have additional negative price-related revisions in the future. We do not expect these negative price-related revisions and 2016 production to be fully offset by reserve additions.

Impairments of Fixed Assets and Other. In the Current Period and the Prior Period, we recognized $44 million and $88 million, respectively, of fixed asset impairment losses and other charges. The Current Period amount primarily related to impairments of certain of our buildings, land and compressors as well as charges incurred for terminating drilling contracts as a result of the decline in oil and natural gas prices. The Prior Period amount consisted of a loss contingency related to contract disputes, an impairment related to third-party rental compressors, an impairment of a note receivable and charges incurred for terminating drilling contracts.

Net (Gains) Losses on Sales of Fixed Assets. In the Current Period, net gains on sales of fixed assets were $5 million compared to net losses of $4 million in the Prior Period. The Current Period and the Prior Period amounts primarily related to the sale of gathering systems, buildings, land and other property and equipment.

TABLE OF CONTENTS

Interest Expense. Interest expense was $124 million in the Current Period compared to $122 million in the Prior Period as follows:

	Six Months Ended June 30,	
	2016	2015
	($ in millions)	
Interest expense on senior notes	$222	$342
Amortization of loan discount, issuance costs and other	18	23
Interest expense on credit facilities	17	6
Realized gains on interest rate derivatives[(a)]	(6)	(2)
Unrealized (gains) losses on interest rate derivatives[(b)]	5	(10)
Capitalized interest	(132)	(237)
Total interest expense	$124	$122
Average senior notes borrowings	$9,246	$11,798
Average credit facilities borrowings	$263	$—

(a) Includes settlements related to the interest accrual for the current period 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 current period.

The decrease in capitalized interest resulted from a lower average balance of our unproved oil and natural gas properties, the primary asset on which interest is capitalized. The decrease in senior note interest expense is primarily due to interest on our second lien notes being accounted for as a reduction in the carrying value of debt instead of interest expense as a result of troubled debt restructuring accounting rules. Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.99 per boe in the Current Period and $1.05 per boe in the Prior Period.

Losses on Investments. Losses on investments of $2 million in the Current Period were primarily related to our equity investment in Sundrop Fuels, Inc. Losses on investments of $24 million in the Prior Period were primarily related to our equity investments in FTS International, Inc. and Sundrop Fuels, Inc.

Loss on Sale of Investment. In the Current Period, we sold certain of our mineral interests and assigned our partnership interest in Mineral Acquisition Company I, L.P. to KKR Royalty Aggregator LLC. As a result of the transaction, we wrote off our equity investment and recognized a $10 million loss.

Gains on Purchases or Exchanges of Debt. In the Current Period, we repurchased in the open market approximately $181 million principal amount of our senior notes for $151 million and $118 million principal amount of our contingent convertible senior notes for $63 million. Additionally, in the Current Period, we privately negotiated exchanges of approximately $290 million principal amount of our outstanding senior notes for 53,923,925 shares of our common stock and $287 million principal amount of our outstanding contingent convertible senior notes for 55,427,782 shares of our common stock. We recorded a gain of approximately $168 million associated with these debt purchases and exchanges.

Other Income. Other income was $6 million in the Current Period, consisting of $1 million of interest income and $5 million of miscellaneous income. In the Prior Period, other income was $5 million and consisted of $3 million of interest income and $2 million of miscellaneous income.

Income Tax Benefit. Chesapeake recorded an income tax benefit of $2.878 billion in the Prior Period. Our effective income tax rate was 0.0% in the Current Period and 26.9% in the Prior Period. The decrease in the effective income tax rate from the Prior Period to the Current Period is primarily due to the tax benefit at expected rates being fully offset by a change in our valuation allowance. Further, our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences. 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 income tax expenses.

TABLE OF CONTENTS

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded net income attributable to noncontrolling interests of $37 million in the Prior Period. This amount was primarily related to dividends paid on preferred stock of our CHK C-T subsidiary. The decrease from the Prior Period to the Current Period is due to the repurchase of all of the preferred shares of CHK C-T from third-party shareholders in August 2015.

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 oil, natural gas and NGL production and future expenses, estimated operating costs, assumptions regarding future oil, natural gas and NGL prices, planned drilling activity, estimates of future drilling and completion and other capital expenditures (including the use of joint venture drilling carries), potential future write-downs of our oil and natural gas assets, anticipated sales, and the adequacy of our provisions for legal contingencies, as well as statements concerning anticipated cash flow and liquidity, ability to comply with financial maintenance covenants and meet contractual cash commitments to third parties, debt repurchases, operating and capital efficiencies, business strategy, and other plans and objectives for future operations. Disclosures concerning the fair values of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility.

Although we believe the expectations and forecasts reflected in 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 annual report on Form 10-K for the year ended December 31, 2015 (2015 Form 10-K) and include:

- the volatility of oil, natural gas and NGL prices;
- the limitations our level of indebtedness may have on our financial flexibility;
- our inability to access the capital markets on favorable terms or at all;
- the availability of cash flows from operations and other funds to finance reserve replacement costs or satisfy our debt obligations;
- a further downgrade in our credit rating requiring us to post more collateral under certain commercial arrangements;
- write-downs of our oil and natural gas asset carrying values due to low commodity prices;
- our ability to replace reserves and sustain production;
- uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and projecting future rates of production and the amount and timing of development expenditures;
- 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 oil, natural gas and NGL sales;
- the need to secure derivative liabilities and the inability of counterparties to satisfy their obligations;
- adverse developments or losses from pending or future litigation and regulatory proceedings, including royalty claims;
- charges incurred in response to market conditions and in connection with our ongoing actions to reduce financial leverage and complexity;
- drilling and operating risks and resulting liabilities;
- effects of environmental protection laws and regulation on our business;
- legislative and regulatory initiatives further regulating hydraulic fracturing;
- our need to secure adequate supplies of water for our drilling operations and to dispose of or recycle the water used;
- impacts of potential legislative and regulatory actions addressing climate change;
- federal and state tax proposals affecting our industry;

- potential OTC derivatives regulation limiting our ability to hedge against commodity price fluctuations;
- competition in the oil and gas exploration and production industry;
- a deterioration in general economic, business or industry conditions;
- negative public perceptions of our industry;
- limited control over properties we do not operate;
- pipeline and gathering system capacity constraints and transportation interruptions;
- terrorist activities and/or cyber-attacks adversely impacting our operations;
- potential challenges of our spin-off of Seventy Seven Energy Inc. (SSE) in connection with SSE's recently completed bankruptcy under Chapter 11 of the U.S. Bankruptcy Code;
- an interruption in operations at our headquarters due to a catastrophic event;
- the continuation of suspended dividend payments on our common stock and preferred stock;
- certain anti-takeover provisions that affect shareholder rights; and
- our inability to increase or maintain our liquidity through debt repurchases, capital exchanges, asset sales, joint ventures, farmouts or other means.

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

Oil, Natural Gas and NGL Derivatives

Our results of operations and cash flows are impacted by changes in market prices for oil, natural gas 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 oil, natural gas and NGL price changes is to hedge into strengthening oil and natural gas 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, oil and natural gas storage inventory levels, industry decline rates for base production and weather trends.

We use derivative instruments to achieve our risk management objectives, including swaps and options. All of these are described in more detail below. We typically use swaps for a large portion of the oil and natural gas price risk we hedge. We have also sold calls, taking advantage of premiums associated with market price volatility. In 2012 and 2013, we bought oil and natural gas calls to, in effect, lock in sold call positions. Due to lower oil, natural gas 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.

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 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 volumes in excess of our share of 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 commodity 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.

58

TABLE OF CONTENTS

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 this 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 review 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. This 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 commodity hedging arrangements which require 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 this report for further discussion of the fair value measurements associated with our derivatives.
As of June 30, 2016, our oil and natural gas 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. In exchange for higher fixed prices on certain of our swap trades, we granted options that allow the counterparty to double the notional amount.
- 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 the excess on sold call options, and Chesapeake receives the 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.
- 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.
- Basis Protection Swaps: These instruments are arrangements that guarantee a fixed price differential to NYMEX from a specified delivery point. Chesapeake receives the fixed price differential and pays the floating market price differential to the counterparty for the hedged commodity.

As of June 30, 2016, we had the following open oil, natural gas and NGL derivative instruments:

		Weighted Average Price				Fair Value
	Volume	Fixed	Call	Put	Differential	Asset (Liability)
	(mmbbl)	($ per bbl)				($ in millions)
Oil:						
Swaps[a]:						
Short-term	15.9	$46.79	$ —	$ —	$ —	$ (58)
Long-term	3.9	47.54	—	—	—	(20)
Call Options (sold):						
Short-term	9.6	—	86.23	—	—	(4)
Long-term	2.7	—	83.50	—	—	(2)
Total Oil						$ (84)

59

	Volume	Weighted Average Price Fixed	Call	Put	Differential	Fair Value Asset (Liability)
	(tbtu)	($ per mmbtu)				($ in millions)
Natural Gas:						
Swaps[b]:						
Short-term	470	$2.82	$ —	$ —	$ —	$ (115)
Long-term	107	2.98	—	—	—	(15)
Collars:						
Short-term	38	—	3.48	3.00	—	(4)
Call Options (sold):						
Short-term	210	—	6.08	—	—	(17)
Long-term	90	—	11.31	—	—	—
Call Options (bought)[c]:						
Short-term	(95)	—	6.02	—	—	(39)
Basis Protection Swaps:						
Short-term	31	—	—	—	(0.57)	(4)
Long-term	13	—	—	—	(0.51)	(4)
Total Natural Gas						$ (198)

	Volume	Weighted Average Price Fixed	Call	Put	Differential	Fair Value Asset (Liability)
	(mmgal)	($ per mgal)				($ in millions)
NGL:						
Ethane Swaps:						
Short-term	77	$0.17	$ —	$ —	$ —	$ (5)
Propane Swaps:						
Short-term	67	0.46	—	—	—	(5)
Total NGL						$ (10)
Total Oil, Natural Gas and NGL						$ (292)

(a) Certain hedging arrangements include a sold option to double the volume at an average price of $53.67/bbl covering 1.5 mmbbls, which are included in the sold call options.

(b) Certain hedging arrangements include a sold option to double the volume at an average price of $2.80/mmbtu covering 52 tbtus, which are included in the sold call options.

(c) Included in the fair value are deferred premiums of $39 million which will be included in oil, natural gas and NGL sales as realized gains (losses) in the remainder of 2016.

TABLE OF CONTENTS

In addition to the open derivative positions disclosed above, as of June 30, 2016, we had $5 million of net derivative gains related to settled contracts for future production periods that will be recorded within oil, natural gas 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.

	June 30, 2016
	($ in millions)
Short-term	$ 44
Long-term	(39)
Total	$ 5

The table below reconciles the changes in fair value of our oil and natural gas derivatives during the Current Period. Of the $292 million fair value liability as of June 30, 2016, a $251 million liability relates to contracts maturing in the next 12 months and a $41 million liability relates to contracts maturing after 12 months. All open derivative instruments as of June 30, 2016 are expected to mature by December 31, 2022.

	June 30, 2016
	($ in millions)
Fair value of contracts outstanding, as of January 1, 2016	$ 267
Change in fair value of contracts	(246)
Contracts realized or otherwise settled	(318)
Fair value of contracts closed	5
Fair value of contracts outstanding, as of June 30, 2016	$ (292)

The change in oil and natural gas prices during the Current Period decreased the liability related to our derivative instruments by $246 million. This unrealized loss is recorded in oil, natural gas and NGL sales. We settled contracts in the Current Period that were in an asset position for $318 million. We terminated contracts that were in a liability position for $5 million. Realized gains and losses will be recorded in oil, natural gas 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, using the earliest demand repurchase date for contingent convertible senior notes. As of June 30, 2016, we had total debt of $8.679 billion, including $7.630 billion of fixed rate debt at interest rates averaging 6.25% and $1.049 billion of floating rate debt at an interest rate of 3.81%.

	Years of Maturity						
	2016	2017	2018	2019	2020	Thereafter	Total
	($ in millions)						
Liabilities:							
Debt – fixed rate[(a)]	$—	$1,382	$846	$—	$1,126	$4,276	$7,630
Average interest rate	—%	4.32 %	5.39 %	— %	6.69 %	6.93 %	6.25 %
Debt – variable rate	$—	$—	$—	$1,049	$—	$—	$1,049
Average interest rate	—%	— %	— %	3.81 %	— %	— %	3.81 %

(a) This amount does not include the premium and deferred financing costs included in debt of $964 million and interest rate derivatives of $6 million.

TABLE OF CONTENTS

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 credit facility and our floating rate senior notes. 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.

From time to time, 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 revolving credit facility borrowings. As of June 30, 2016, there were no interest rate derivatives outstanding.

As of June 30, 2016, we had $33 million of net gains related to settled derivative contracts that will be recorded within interest expense as realized gains or losses once they are transferred from our senior note liability or within interest expense as unrealized gains or 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 senior 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. In December 2015, we exchanged and subsequently retired €42 million in aggregate principal amount of these senior notes, 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 €9 million and we pay the counterparties $15 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay us €302 million and we will pay the counterparties $403 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 sheets as liabilities of $64 million and $52 million as of June 30, 2016 and December 31, 2015, respectively. The euro-denominated debt in long-term debt has been adjusted to $337 million as of June 30, 2016, using an exchange rate of $1.1106 to €1.00.

Supply Contract Derivatives

As discussed in Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report, we enter into supply contracts in the normal course of business under which we commit to deliver a predetermined quantity of natural gas to certain counterparties in an attempt to earn attractive margins. Under certain contracts, we receive a sales price that is based on the price of a product other than natural gas thereby creating an embedded derivative. The prices of the products other than natural gas are unobservable. We engage an independent third-party valuation firm to value these supply contracts. The products being valued other than natural gas are sensitive to pricing fluctuations and some of these fluctuations could be material. Changes to the value of these contracts are recorded as mark-to-market adjustments to marketing, gathering and compression revenues in our condensed consolidated financial statements.

TABLE OF CONTENTS

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 our 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 our Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2016.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the quarter ended June 30, 2016, which materially affected, or was reasonably likely to materially affect, our internal control over financial reporting.

PART II

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.

2016 Shareholder Litigation. On April 19, 2016, a derivative action was filed in the U.S. District Court for the Western District of Oklahoma against the Company and current and former directors and officers of the Company alleging, among other things, violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act, breach of fiduciary duties, waste of corporate assets, gross mismanagement and violations of Sections 10(b) and Rule 10b-5 of the Exchange Act related to actions allegedly taken by such persons since 2008. The lawsuit seeks certification as a class action, damages, attorneys’ fees and other costs.

Regulatory Proceedings. The Company has received, from the U.S. Department of Justice (DOJ) and certain state governmental agencies and authorities, subpoenas and demands for documents, information and testimony in connection with investigations into possible violations of federal and state antitrust laws relating to our purchase and lease of oil and natural gas rights in various states. The Company also has received DOJ, U.S. Postal Service and state subpoenas seeking information on the Company’s royalty payment practices. Chesapeake has engaged in discussions with the DOJ, U.S. Postal Service and state agency representatives and continues to respond to such subpoenas and demands.

Redemption of 2019 Notes. See Note 4 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a description of pending litigation regarding our redemption in May 2013 of our 6.775% Senior Notes due 2019 (the 2019 Notes).

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 oil and natural gas interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The Company has successfully defended a number of these failure-to-close cases in various courts, has settled and resolved other such cases and disputes and believes that its remaining loss exposure for these claims will not have a material adverse effect on the Company’s financial position, results of operations or cash flows.

63

Regarding royalty claims, Chesapeake and other natural gas producers have been named in various lawsuits alleging royalty underpayment. The suits against us allege, among other things, 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 has resolved a number of these claims through negotiated settlements of past and future royalties and has prevailed in various other lawsuits. We are currently defending lawsuits seeking damages with respect to royalty underpayment in various states, including, but not limited to, Texas, Pennsylvania, Ohio, Louisiana, Oklahoma and Arkansas. These lawsuits include cases filed by individual royalty owners and putative class actions, some of which seek to certify a statewide class. The Company also has received DOJ, U.S. Postal Service and state subpoenas seeking information on the Company's royalty payment practices.

Chesapeake is defending numerous lawsuits filed by individual royalty owners alleging royalty underpayment with respect to properties in Texas. On April 8, 2015, Chesapeake obtained a transfer order from the Texas Multidistrict Litigation Panel to transfer a substantial portion of these lawsuits filed since June 2014 to the 348th District Court of Tarrant County for pre-trial purposes (the "MDL"). These lawsuits, which primarily relate to the Barnett Shale, generally allege that Chesapeake underpaid royalties by making improper deductions and using incorrect production volumes. In addition to allegations of breach of contract, a number of these lawsuits allege fraud, conspiracy, joint venture and antitrust violations by Chesapeake. The lawsuits seek direct damages in varying amounts, together with exemplary damages, attorneys' fees, costs and interest. Chesapeake has entered into a settlement agreement with MDL plaintiffs representing over 97% of the hydrocarbons at issue by volume and, on July 22, 2016, the plaintiffs who accepted the settlement filed to dismiss such lawsuits. Chesapeake funded the settlement amount of approximately $29 million in cash and signed a $10 million, three-year promissory note in July 2016, which is accrued for as of June 30, 2016. Additional plaintiffs are continuing to accept the settlement on a rolling basis. Chesapeake expects that additional lawsuits filed by plaintiffs not participating in the settlement will continue to be pursued and that new plaintiffs will file other lawsuits making similar allegations.

On December 9, 2015, the Commonwealth of Pennsylvania, by the Office of Attorney General, filed a lawsuit in the Bradford County Court of Common Pleas related to royalty underpayment and lease acquisition and accounting practices with respect to properties in Pennsylvania. The lawsuit, which primarily relates to the Marcellus Shale and Utica Shale, alleges that Chesapeake violated the Pennsylvania Unfair Trade Practices and Consumer Protection Law (UTPCPL) by making improper deductions and entering into arrangements with affiliates that resulted in underpayment of royalties. The lawsuit seeks statutory restitution, civil penalties and costs, as well as temporary injunction from exploration and drilling activities in Pennsylvania until restitution, penalties and costs have been paid and permanent injunction from further violations of the UTPCPL. On February 8, 2016, the Office of Attorney General amended the complaint to, among other things, add an additional UTPCPL claim and antitrust claim alleging that a joint exploration agreement to which Chesapeake is a party established unlawful market allocation for the acquisition of leases. In response to Chesapeake's preliminary objections, the Office of Attorney General filed a second amended complaint on May 3, 2016, alleging further violations of the UTPCPL based upon alleged predicate violations of the federal Sherman Act and the Federal Trade Commission Act. Chesapeake removed the case to the United States District Court for the Middle District of Pennsylvania on May 27, 2016.

Putative statewide class actions in Pennsylvania and Ohio and purported class arbitrations in Pennsylvania have been filed on behalf of royalty owners asserting various claims for damages related to alleged underpayment of royalties as a result of the Company's divestiture of substantially all of its midstream business and most of its gathering assets in 2012 and 2013. These cases include claims for violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act and for an unlawful market allocation agreement for mineral rights. One of the cases includes claims of intentional interference with contractual relations and violations of antitrust laws related to purported markets for gas mineral rights, operating rights and gas gathering sources.

The Company is also defending lawsuits alleging various violations of the Sherman Antitrust Act and state antitrust laws. In 2016, putative class action lawsuits have been filed in the United States District Court for the Western District of Oklahoma and in Oklahoma state courts, and an individual lawsuit was filed in the United States District Court of

Kansas, in each case against the Company and other defendants. The lawsuits generally allege that, since 2007 and continuing through April 2013, the defendants conspired to rig bids and depress the market for the purchases of oil and natural gas leasehold interests and properties in the Anadarko Basin containing producing oil and natural gas wells. The lawsuits seek damages, attorney's fees, costs and interest, as well as enjoinment from adopting practices or plans which would restrain competition in a similar manner as alleged in the lawsuits.

TABLE OF CONTENTS

In April 2016, a class action lawsuit on behalf of holders of the Company's 6.875% Senior Notes due 2020 (the 2020 Notes) and 6.125% Senior Notes due 2021 (the 2021 Notes) was filed in the U.S. District Court for the Southern District of New York relating to the Company's December 2015 debt exchange, whereby the Company privately exchanged newly issued 8.00% Senior Secured Second Lien Notes due 2022 (Second Lien Notes) for certain outstanding senior unsecured notes and contingent convertible notes. The lawsuit alleges that the Company violated the Trust Indenture Act of 1939 and the implied covenant of good faith and fair dealing by benefiting themselves and a minority of noteholders who are qualified institutional buyers (QIBs). According to the lawsuit, as a result of the Company's private debt exchange in which only QIBs (and non-U.S. persons under Regulation S) were eligible to participate, the Company unjustly enriched itself at the expense of class members by reducing indebtedness and reducing the value of the 2020 Notes and the 2022 Notes. The lawsuit seeks damages and attorney's fees, in addition to declaratory relief that the debt exchange and the liens created for the benefit of the Second Lien Notes are null and void and that the debt exchange effectively resulted in a default under the indentures for the 2020 Notes and the 2021 Notes. In June 2016, the lawsuit was transferred to the United States District Court for the Western District of Oklahoma.

Environmental Proceedings

Our subsidiary Chesapeake Appalachia, LLC (CALLC) is engaged in discussions with the U.S. Environmental Protection Agency, the U.S. Army Corps of Engineers and the Pennsylvania Department of Environmental Protection (PADEP) regarding potential violations of the permitting requirements of the federal Clean Water Act, the Pennsylvania Clean Streams Law and the Pennsylvania Dam Safety and Encroachments Act in connection with the placement of dredge and fill material during construction of certain sites in Pennsylvania. CALLC identified the potential violations in connection with an internal review of its facilities siting and construction processes and voluntarily reported them to the regulatory agencies. Resolution of the matter may result in monetary sanctions of more than $100,000.

CALLC and the PADEP are also engaged in discussions regarding alleged violations of the Pennsylvania Oil and Gas Act and the Pennsylvania Clean Streams Law in connection with contamination in the vicinity of one of CALLC's well pads in Sullivan County, Pennsylvania. Resolution of the matter may result in monetary sanctions of more than $100,000.

On January 12, 2016, we were named as a defendant in a putative class action filed in state district court in Logan County, Oklahoma alleging that we and the other defendants, all exploration and production companies have operated produced water disposal wells in a manner that has caused earthquakes. The proposed class would consist of all Oklahoma residents whose property has been so damaged. The petition sought an unspecified amount of actual and punitive damages. The case was subsequently moved to the U.S. District Court for the Western District of Oklahoma. On July 21, 2016, the plaintiffs dismissed the case.

On February 16, 2016, we were named as a defendant in a lawsuit brought in the U.S. District Court for the Western District of Oklahoma by the Sierra Club. The complaint alleges that we and the other defendants, all exploration and production companies, have violated the federal Resource Conservation and Recovery Act by operating produced water disposal wells in a manner that has caused earthquakes. It requests a court order requiring substantial reduction of the amounts of produced water disposed of in such manner, the creation of an earthquake prediction center, and the reinforcement of purportedly vulnerable structures that could be impacted by earthquakes.

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 2015 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.

TABLE OF CONTENTS

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 June 30, 2016:

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 Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs[(b)] ($ in millions)
April 1, 2016 through April 30, 2016	21,578	$ 5.04	—	$ —
May 1, 2016 through May 31, 2016	4,976	$ 4.29	—	$ —
June 1, 2016 through June 30, 2016	129,856	$ 4.51	—	$ —
Total	156,410	$ 4.57	—	

(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. Also includes shares of common stock purchased on behalf of Chesapeake's deferred compensation plan related to participant deferrals and Company matching contributions.

(b) In December 2014, the Company's Board of Directors authorized the repurchase of up to $1 billion in value of its common stock from time to time. The repurchase program does not have an expiration date. As of June 30, 2016, no repurchases had been made under the program.

ITEM 3. Defaults Upon Senior Securities

In January 2016, our Board of Directors determined to suspend dividend payments on our preferred stock. Suspension of the dividends did not constitute an event of default under our revolving credit facility or bond indentures. However, as a result of such suspension, we are in arrears in the payment of dividends with respect to our 5.75% Cumulative Convertible Preferred Stock, 5.75% Cumulative Convertible Preferred Stock (series A), 5.00% Cumulative Convertible Preferred Stock (series 2005B) and 4.50% Cumulative Convertible Preferred Stock. The table below details our preferred stock dividends as of June 30, 2016 (paid in arrears).

	5.75%	5.75% (A)	4.50%	5.00% (2005B)
	($ in millions)			
Dividends in arrears	$42	$ 32	$ 6	$ 5

ITEM 4. Mine Safety Disclosures

Not applicable.

ITEM 5. Other Information

Not applicable.

ITEM 6. Exhibits

The exhibits listed below in the Index of Exhibits (following the signatures page) are filed, furnished or incorporated by reference pursuant to the requirements of Item 601 of Regulation S-K.

TABLE OF CONTENTS

SIGNATURES

Pursuant to the requirements 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: August 4, 2016	By:	/s/ ROBERT D. LAWLER Robert D. Lawler, President and Chief Executive Officer
Date: August 4, 2016	By:	/s/ DOMENIC J. DELL'OSSO, JR. Domenic J. Dell'Osso, Jr. Executive Vice President and Chief Financial Officer

TABLE OF CONTENTS

INDEX OF EXHIBITS

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed or Furnished Herewith
		Form	SEC File Number	Exhibit	Filing Date	
3.1.1	Chesapeake's Restated Certificate of Incorporation.	10-Q	001-13726	3.1.1	8/6/2014	
3.1.2	Certificate of Amendment to Restated Certificate of Incorporation	8-K	001-13726	3.1.2	5/20/2016	
3.1.3	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008	
3.1.4	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	8/11/2008	
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	5/20/2010	
3.1.6	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	6/9/2014	
4.1	Credit Agreement dated December 15, 2014 by and among: Chesapeake Energy Corporation, as borrower; MUFG Union Bank N.A., as administrative agent, co-syndication agent, a swingline lender and a letter of credit issuer; Wells Fargo Bank and National Association, as co-syndication agent, a swingline lender and a letter of credit issuer; Bank of America, N.A., Crèdit Argicole Corporate and Investment Bank and JPMorgan Chase Bank, N.A., as co-documentation agents and letter of credit issuers; and certain other lenders named therein.					X
4.2†	Third Amendment to Credit Agreement dated April 8, 2016 among Chesapeake Energy Corporation, as borrower; MUFG Union Bank N.A., as administrative agent, a swingline lender and a letter of credit issuer; and certain other lenders named therein.					X
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.					X
31.1	Robert D. Lawler, President and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X

31.2	Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	X
32.1	Robert D. Lawler, President and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	X

TABLE OF CONTENTS

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

† Confidential treatment has been requested for portions of this exhibit. These portions have been omitted and submitted separately to the Securities and Exchange Commission.