SOUTHWESTERN ENERGY CO
Form 10-Q
August 03, 2017
Table of Contents

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

Form 10-Q

(Mark One)
[X] Quarterly Report pursuant to Section 13 or 15(d) of the Securities

Exchange Act of 1934

For the quarterly period ended June 30, 2017

Or

[ ] Transition Report pursuant to Section 13 or 15(d) of the Securities

Exchange Act of 1934

For the transition period from __________ to __________

Commission file number: 001-08246
Southwestern Energy Company
(Exact name of registrant as specified in its charter)

Delaware	71-0205415
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

10000 Energy Drive

Spring, Texas	77389
(Address of principal executive offices)	(Zip Code)

(832) 796-1000
(Registrant’s telephone number, including area code)

Not Applicable
(Former name, former address and former fiscal year, if changed since last report)
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 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 No

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

Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company	Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No
Indicate the number of shares outstanding of each of the issuer’s classes of common stock, as of the latest practicable date:

Class	Outstanding as of August 1, 2017
Common Stock, Par Value $0.01	509,168,651

Table of Contents

SOUTHWESTERN ENERGY COMPANY

INDEX TO FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2017

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

All statements, other than historical fact or present financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements, except as may be required by law.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Quarterly Report on Form 10-Q identified by words such as “anticipate,” “intend,” “plan,” “project,” “estimate,” “continue,” “potential,” “should,” “could,” “may,” “will,” “
“guidance,” “outlook,” “effort,” “expect,” “believe,” “predict,” “budget,” “projection,” “goal,” “forecast,” “target” or similar w

Table of Contents

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- the timing and extent of changes in market conditions and prices for natural gas, oil and natural gas liquids (“NGLs”) (including regional basis differentials);
- our ability to fund our planned capital investments;
- a change in our credit rating;
- the extent to which lower commodity prices impact our ability to service or refinance our existing debt;
- the impact of volatility in the financial markets or other global economic factors;
- difficulties in appropriately allocating capital and resources among our strategic opportunities;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- our ability to maintain leases that may expire if production is not established or profitably maintained;
- our ability to realize the expected benefits from recent acquisitions;
- our ability to transport our production to the most favorable markets or at all;
- availability and costs of personnel and of products and services provided by third parties;
- the impact of government regulation, including the ability to obtain and maintain permits, any increase in severance or similar taxes, and legislation relating to hydraulic fracturing, climate and over-the-counter derivatives;
- the impact of the adverse outcome of any material litigation against us;
- the effects of weather;
- increased competition and regulation;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties; and
- any other factors listed in the reports we have filed and may file with the Securities and Exchange Commission (“SEC”).

Should one or more of the risks or uncertainties described above or elsewhere in this Quarterly Report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

Table of Contents

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	For the three months ended June 30,		For the six months ended June 30,	
	2017	2016	2017	2016
	(in millions, except share/per share amounts)			
Operating Revenues:				
Gas sales	$ 471	$ 251	$ 974	$ 566
Oil sales	23	20	46	31
NGL sales	37	20	77	37
Marketing	250	196	503	394
Gas gathering	30	35	57	73
	811	522	1,657	1,101
Operating Costs and Expenses:				
Marketing purchases	253	197	504	393
Operating expenses	164	151	311	316
General and administrative expenses	58	56	108	110
Restructuring charges	–	11	–	75
Depreciation, depletion and amortization	123	107	229	250
Impairment of natural gas and oil properties	–	470	–	1,504
Taxes, other than income taxes	25	22	51	45
	623	1,014	1,203	2,693
Operating Income (Loss)	188	(492)	454	(1,592)
Interest Expense:				
Interest on debt	59	56	117	109
Other interest charges	3	2	5	4
Interest capitalized	(28)	(41)	(56)	(82)
	34	17	66	31
Gain (Loss) on Derivatives	134	(85)	250	(99)
Loss on Early Extinguishment of Debt	(10)	–	(11)	–
Other Income (Loss), Net	6	–	8	(3)
Income (Loss) Before Income Taxes	284	(594)	635	(1,725)

Benefit for Income Taxes:				
Deferred	–	(1)	–	–
Net Income (Loss)	$ 284	$ (593)	$ 635	$ (1,725)
Mandatory convertible preferred stock dividend	27	27	54	54
Participating securities - mandatory convertible preferred stock	33	–	76	–
Net Income (Loss) Attributable to Common Stock	$ 224	$ (620)	$ 505	$ (1,779)
Earnings (Loss) Per Common Share:				
Basic	$ 0.45	$ (1.61)	$ 1.02	$ (4.63)
Diluted	$ 0.45	$ (1.61)	$ 1.02	$ (4.63)
Weighted Average Common Shares Outstanding:				
Basic	496,419,815	385,594,815	494,753,391	384,232,831
Diluted	498,224,599	385,594,815	496,627,843	384,232,831

The accompanying notes are an integral part of these

unaudited condensed consolidated financial statements.

3

Table of Contents

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	For the three months ended June 30,		For the six months ended June 30,	
	2017	2016	2017	2016
	(in millions)			
Net income (loss)	$ 284	$ (593)	$ 635	$ (1,725)
Change in value of pension and other postretirement liabilities:				
Amortization of prior service cost and net loss included in net periodic pension cost (1)	1	(1)	1	–
Net gain incurred in period (1)	–	4	–	4
Change in currency translation adjustment	–	–	–	3
Comprehensive income (loss)	$ 285	$ (590)	$ 636	$ (1,718)

(1) Net of tax for the three and six months ended June 30, 2017 and 2016.

The accompanying notes are an integral part of these

unaudited condensed consolidated financial statements.

Table of Contents

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2017	December 31, 2016
ASSETS	(in millions)	
Current assets:		
Cash and cash equivalents	$ 1,111	$ 1,423
Accounts receivable, net	351	363
Derivative assets	83	51
Other current assets	34	35
Total current assets	1,579	1,872
Natural gas and oil properties, using the full cost method, including $2,034 million as of June 30, 2017 and $2,105 million as of December 31, 2016 excluded from amortization	23,248	22,653
Gathering systems	1,307	1,299
Other	553	537
Less: Accumulated depreciation, depletion and amortization	(19,767)	(19,534)
Total property and equipment, net	5,341	4,955
Other long-term assets	230	249
TOTAL ASSETS	$ 7,150	$ 7,076
LIABILITIES AND EQUITY		
Current liabilities:		
Short-term debt	$ 40	$ 41
Accounts payable	473	473
Taxes payable	64	59
Interest payable	67	74
Dividends payable	27	27
Derivative liabilities	127	355
Other current liabilities	23	35
Total current liabilities	821	1,064
Long-term debt	4,341	4,612
Pension and other postretirement liabilities	46	49
Other long-term liabilities	369	434
Total long-term liabilities	4,756	5,095
Commitments and contingencies (Note 10)		
Equity:		
Common stock, $0.01 par value; 1,250,000,000 shares authorized; issued 505,893,345 shares as of June 30, 2017 (does not include 3,346,738 shares issued on July 17, 2017 on account of a dividend declared on June 21, 2017) and 495,248,369 as of December 31, 2016	5	5
	–	–

Preferred stock, $0.01 par value, 10,000,000 shares authorized, 6.25% Series B Mandatory Convertible, $1,000 per share liquidation preference, 1,725,000 shares issued and outstanding as of June 30, 2017 and December 31, 2016, conversion in January 2018		
Additional paid-in capital	4,697	4,677
Accumulated deficit	(3,090)	(3,725)
Accumulated other comprehensive loss	(38)	(39)
Common stock in treasury, 31,269 shares as of June 30, 2017 and December 31, 2016	(1)	(1)
Total equity	1,573	917
TOTAL LIABILITIES AND EQUITY	$ 7,150	$ 7,076

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

Table of Contents

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	For the six months ended June 30,	
	2017	2016
	(in millions)	
Cash Flows From Operating Activities:		
Net income (loss)	$ 635	$ (1,725)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	229	250
Impairment of natural gas and oil properties	–	1,504
Amortization of debt issuance costs	4	4
(Gain) loss on derivatives, unsettled	(319)	129
Stock-based compensation	12	17
Restructuring charges	–	29
Loss on early extinguishment of debt	11	–
Other	(4)	7
Change in assets and liabilities:		
Accounts receivable	12	92
Accounts payable	2	(139)
Taxes payable	5	(3)
Interest payable	(4)	–
Other assets and liabilities	(5)	–
Net cash provided by operating activities	578	165
Cash Flows From Investing Activities:		
Capital investments	(619)	(241)
Proceeds from sale of property and equipment	12	54
Other	1	1
Net cash used in investing activities	(606)	(186)
Cash Flows From Financing Activities:		
Payments on short-term debt	(287)	(1)
Payments on revolving credit facility	–	(3,268)
Borrowings under revolving credit facility	–	3,152
Payments on commercial paper	–	(242)
Borrowings under commercial paper	–	242

Change in bank drafts outstanding	3	(21)
Proceeds for issuance of long-term debt	–	1,191
Debt issuance costs	–	(16)
Preferred stock dividend	–	(27)
Other	–	(6)
Net cash provided by (used in) financing activities	(284)	1,004
Increase (decrease) in cash and cash equivalents	(312)	983
Cash and cash equivalents at beginning of year	1,423	15
Cash and cash equivalents at end of period	$ 1,111	$ 998

The accompanying notes are an integral part of these

unaudited condensed consolidated financial statements.

Table of Contents

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Unaudited)

	Common Stock Shares Issued	Common Stock Amount	Preferred Stock Shares Issued	Additional Paid-In Capital	Accumulated Deficit (1)	Accumulated Other Comprehensive Income (Loss)	Common Stock in Treasury	Total
	(in millions, except share amounts)							
Balance at December 31, 2016	495,248,369	$ 5	1,725,000	$ 4,677	$ (3,725)	$ (39)	$ (1)	$ 917
Comprehensive income:								
Net income	–	–	–	–	635	–	–	635
Other comprehensive income	–	–	–	–	–	1	–	1
Total comprehensive income	–	–	–	–	–	–	–	636
Stock-based compensation	–	–	–	20	–	–	–	20
Preferred stock dividend (2)	6,098,275	–	–	–	–	–	–	–
Issuance of restricted stock	4,902,925	–	–	–	–	–	–	–
Cancellation of restricted stock	(416,320)	–	–	–	–	–	–	–
Performance units vested	121,208	–	–	–	–	–	–	–
Tax withholding – stock compensation	(61,184)	–	–	–	–	–	–	–
Issuance of stock awards	72	–	–	–	–	–	–	–
Balance at June 30, 2017	505,893,345	$ 5	1,725,000	$ 4,697	$ (3,090)	$ (38)	$ (1)	$ 1,573

(1) Includes a net cumulative-effect adjustment of $59 million related to the recognition of previously unrecognized windfall tax benefits resulting from the adoption of ASU 2016-09 as of the beginning of 2017. This adjustment was offset by an increase in net deferred tax assets and the related income tax valuation allowance of the same amount.

(2)

Does not include 3,346,738 shares issued on July 17, 2017 and distributed to holders of the Company's mandatory convertible preferred stock.

The accompanying notes are an integral part of these

unaudited condensed consolidated financial statements.

Table of Contents

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(1) BASIS OF PRESENTATION

Southwestern Energy Company (including its subsidiaries, collectively "Southwestern" or the "Company") is an independent energy company engaged in natural gas, oil and NGL exploration, development and production ("E&P"). The Company is also focused on creating and capturing additional value through its natural gas gathering and marketing businesses ("Midstream Services"). Southwestern conducts most of its businesses through subsidiaries and operates principally in two segments: E&P and Midstream Services.

Exploration and Production. Southwestern's primary business is the exploration for and production of natural gas, oil and NGLs, with current operations principally focused on the development of unconventional natural gas reservoirs located in Pennsylvania, West Virginia and Arkansas. The Company's operations in northeast Pennsylvania, herein referred to as "Northeast Appalachia," are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale. Operations in West Virginia and southwest Pennsylvania, herein referred to as "Southwest Appalachia," are focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs. Collectively, Southwestern refers to its properties located in Pennsylvania and West Virginia as the "Appalachian Basin." The Company's operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale. Southwestern has activities ongoing in Colorado and Louisiana, along with other areas in which it is currently assessing new development opportunities. The Company also has drilling rigs located in Pennsylvania, West Virginia and Arkansas, as well as in other operating areas, and provides oilfield products and services, principally serving its E&P operations.

Midstream Services. Through the Company's affiliated midstream subsidiaries, Southwestern engages in natural gas gathering activities in Arkansas and Louisiana. These activities primarily support the Company's E&P operations and generate revenue from fees associated with the gathering of natural gas. Southwestern's marketing activities capture opportunities that arise through the marketing and transportation of the natural gas, oil and NGLs produced in its E&P operations.

The accompanying unaudited condensed consolidated financial statements were prepared using accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and in accordance with the rules and regulations of the Securities and Exchange Commission. Certain information relating to the Company's organization and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been appropriately condensed or omitted in this Quarterly Report. The Company believes the disclosures made are adequate to make the information presented not misleading.

The unaudited condensed consolidated financial statements contained in this report include all normal and recurring material adjustments that, in the opinion of management, are necessary for a fair statement of the financial position, results of operations and cash flows for the interim periods presented herein. It is recommended that these unaudited condensed consolidated financial statements be read in conjunction with the consolidated financial statements and the notes thereto included in the Company's Annual Report for the year ended December 31, 2016 ("2016 Annual Report").

The Company's significant accounting policies, which have been reviewed and approved by the Audit Committee of the Company's Board of Directors, are summarized in Note 1 in the Notes to the Consolidated Financial Statements included in the Company's 2016 Annual Report.

Table of Contents

(2) CASH AND CASH EQUIVALENTS

The following table presents a summary of cash and cash equivalents as of June 30, 2017 and December 31, 2016:

	June 30, 2017	December 31, 2016
	(in millions)	
Cash	$ 263	$ 254
Marketable securities (1)	798	1,169
Other cash equivalents (2)	50	–
Total cash and cash equivalents	$ 1,111	$ 1,423

(1) Consists of government stable value money market funds.
(2) Consists of time deposits.

(3) REDUCTION IN WORKFORCE

In January 2016, the Company announced a 40% workforce reduction as a result of lower anticipated drilling activity. This reduction was substantially completed in the first quarter of 2016. In April 2016, the Company also partially restructured executive management, which was substantially completed in the second quarter of 2016.

The following table presents a summary of the restructuring charges for the three and six months ended June 30, 2016:

	For the three months ended June 30,	For the six months ended June 30,

	2016	2016
	(in millions)	
Severance (including payroll taxes) (1)	$ 2	$ 44
Stock-based compensation (2)	6	24
Pension and other postretirement benefits (3)	3	3
Other benefits	–	3
Outplacement services, other	–	1
Total restructuring charges (4)	$ 11	$ 75

(1) Includes $1 million related to executive management restructuring for the three and six months ended June 30, 2016.

(2) Includes $3 million related to executive management restructuring for the three and six months ended June 30, 2016.

(3) Includes non-cash charges related to the curtailment and settlement of the pension and other postretirement benefit plans. See Note 11 for additional details regarding the Company's retirement and employee benefit plans.

(4) Total restructuring charges were $11 million and less than $1 million for the Company's E&P and Midstream Services segments, respectively, for the three months ended June 30, 2016. For the six months ended June 30, 2016, restructuring charges were $72 million and $3 million for the Company's E&P and Midstream Services segments, respectively.

Severance payments and other separation costs related to restructuring were substantially completed by the end of 2016.

(4) NATURAL GAS AND OIL PROPERTIES

The Company utilizes the full cost method of accounting for costs related to the exploration, development and acquisition of natural gas and oil properties. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities are capitalized on a country-by-country basis and amortized over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test that limits such pooled costs, net of applicable deferred taxes, to the aggregate of the present value of future net revenues attributable to proved natural gas, oil and NGL reserves discounted at 10% (standardized measure). Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas, oil and NGL prices may subsequently increase the ceiling. Companies using the full cost method are required to use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives designated for hedge accounting, to calculate the ceiling value of their reserves.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $3.01 per MMBtu, West Texas Intermediate oil of $45.42 per barrel and NGLs of $10.90 per barrel, adjusted for differentials, the Company's net book value of its United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at June 30, 2017. The Company had no hedge positions that were designated for hedge accounting as of June 30, 2017. Decreases in market prices as well as changes in production rates, levels of reserves, evaluation of costs excluded from amortization, future development costs and production costs could result in future ceiling test impairments.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.24 per MMBtu, West Texas Intermediate oil of $39.63 per barrel and NGLs of $5.87 per barrel, adjusted for differentials, the net book value of the Company's United States natural gas and oil properties resulted in a non-cash ceiling test impairment of $470 million for the three months ended June 30, 2016. In the first quarter of 2016, the Company recognized a non-cash ceiling test impairment of $1,034 million. The Company had no hedge positions that were designated for hedge accounting as of June 30, 2016.

(5) EARNINGS PER SHARE

Basic earnings per common share is computed by dividing net income (loss) attributable to common stock by the weighted average number of common shares outstanding during the reportable period. The diluted earnings per share calculation adds to the weighted average number of common shares outstanding: the incremental shares that would have been outstanding assuming the exercise of dilutive stock options, the vesting of unvested restricted shares of common stock, performance units and the assumed conversion of mandatory convertible preferred stock. An antidilutive impact is an increase in earnings per share or a reduction in net loss per share resulting from the conversion, exercise, or contingent issuance of certain securities.

In July 2016, the Company completed an underwritten public offering of 98,900,000 shares of its common stock, with an offering price to the public of $13.00 per share. Net proceeds from the common stock offering were approximately $1,247 million, after underwriting discount and offering expenses. The proceeds from the offering were used to repay $375 million of the $750 million term loan entered into in November 2015 and to settle certain tender offers by purchasing an aggregate principal amount of approximately $700 million of the Company's outstanding senior notes due in the first quarter of 2018. The remaining proceeds of the offering have been used for general corporate purposes.

The depositary shares issued in January 2015 entitles the holder to a proportional fractional interest in the rights and preferences of the convertible preferred stock, including conversion, dividend, liquidation and voting rights. Unless converted earlier at the option of the holders, on or around January 15, 2018 each share of convertible preferred stock will automatically convert into between 37.0028 and 43.4782 shares of the Company's common stock (correspondingly, each depositary share will convert into between 1.85014 and 2.17391 shares of the Company's common stock), subject to customary anti-dilution adjustments, depending on the volume-weighted average price of the Company's common stock over a 20 trading day averaging period immediately prior to that date. The total potential shares of common stock resulting from the conversion will range from 63,829,830 to 74,999,895 shares.

The mandatory convertible preferred stock has the non-forfeitable right to participate on an as-converted basis at the conversion rate then in effect in any common stock dividends declared and as such, is considered a participating security. Accordingly, it is included in the computation of basic and diluted earnings per share, pursuant to the two-class method. In the calculation of basic earnings per share attributable to common shareholders, participating securities are allocated earnings based on actual dividend distributions received plus a proportionate share of undistributed net income attributable to common shareholders, if any, after recognizing distributed earnings. The Company's participating securities do not participate in undistributed net losses because they are not contractually obligated to do so.

On June 21, 2017, the Company declared its quarterly dividend, payable to holders of the mandatory convertible preferred stock, and announced that it would pay the quarterly dividend in stock, in lieu of cash, to the extent permitted by the certificate of designations for the Series B preferred stock. The Company issued 3,346,738 shares of common stock on July 17, 2017 in payment for the dividend.

Table of Contents

The following table presents the computation of earnings per share for the three and six months ended June 30, 2017 and 2016:

	For the three months ended June 30,		For the six months ended June 30,	
	2017	2016	2017	2016
	(in millions, except share/per share amounts)			
Net income (loss)	$ 284	$ (593)	$ 635	$ (1,725)
Mandatory convertible preferred stock dividend	27	27	54	54
Participating securities - mandatory convertible preferred stock	33	–	76	–
Net income (loss) attributable to common stock	$ 224	$ (620)	$ 505	$ (1,779)
Number of common shares:				
Weighted average outstanding	496,419,815	385,594,815	494,753,391	384,232,831
Issued upon assumed exercise of outstanding stock options	–	–	3,317	–
Effect of issuance of non-vested restricted common stock	761,311	–	707,576	–
Effect of issuance of non-vested performance units	1,043,473	–	1,163,559	–
Effect of issuance of mandatory convertible preferred stock	–	–	–	–
Weighted average and potential dilutive outstanding	498,224,599	385,594,815	496,627,843	384,232,831
Earnings (loss) per common share:				
Basic	$ 0.45	$ (1.61)	$ 1.02	$ (4.63)
Diluted	$ 0.45	$ (1.61)	$ 1.02	$ (4.63)

The following table presents the common stock shares equivalent excluded from the calculation of diluted earnings per share for the three and six months ended June 30, 2017 and 2016, as they would have had an antidilutive effect:

	For the three months ended	For the six months ended

	June 30,		June 30,	
	2017	2016	2017	2016
Unvested stock options	–	4,028,819	1,344,942	4,781,109
Unvested share-based payment	6,106,322	3,353,371	3,504,222	2,844,365
Performance units	1,268,040	780,920	980,836	577,624
Mandatory convertible preferred stock	74,999,895	74,999,895	74,999,895	74,999,895
Total	82,374,257	83,163,005	80,829,895	83,202,993

Table of Contents

(6) DERIVATIVES AND RISK MANAGEMENT

The Company is exposed to volatility in market prices and basis differentials for natural gas, oil and NGLs which impacts the predictability of its cash flows related to the sale of those commodities. These risks are managed by the Company's use of certain derivative financial instruments. As of June 30, 2017 and December 31, 2016, the Company's derivative financial instruments consisted of fixed price swaps, two-way costless collars, three-way costless collars, basis swaps, put and call options, and interest rate swaps. A description of the Company's derivative financial instruments is provided below:

Fixed price swaps	The Company receives a fixed price for the contract and pays a floating market price to the counterparty.
Purchased put options	The Company purchases put options based on an index price from the counterparty by payment of a cash premium. If the index price is lower than the put's strike price at the time of settlement, the Company receives from the counterparty such difference between the index price and the purchased put strike price. If the market price settles above the put's strike price, no payment is due from either party.
Two-way costless collars	Arrangements that contain a fixed floor price (purchased put option) and a fixed ceiling price (sold call option) based on an index price which, in aggregate, have no net cost. At the contract settlement date, (1) if the index price is higher than the ceiling price, the Company pays the counterparty the difference between the index price and ceiling price, (2) if the index price is between the floor and ceiling prices, no payments are due from either party, and (3) if the index price is below the floor price, the Company will receive the difference between the floor price and the index price.
Three-way costless collars	Arrangements that contain a purchased put option, a sold call option and a sold put option based on an index price which, in aggregate, have no net cost. At the contract settlement date, (1) if the index price is higher than the sold call strike price, the Company pays the counterparty the difference between the index price and sold call strike price, (2) if the index price is between the purchased put strike price and the sold call strike price, no payments are due from either party, (3) if the index price is between the sold put strike price and the purchased put strike price, the Company will receive the difference between the purchased put strike price and the index price, and (4) if the index price is below the sold put strike price, the Company will receive the difference between the purchased put strike price and the sold put strike price.
Basis swaps	Arrangements that guarantee a price differential for natural gas from a specified delivery point. The Company receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.
Sold call options	The Company sells call options in exchange for a premium. If the market price exceeds the strike price of the call option at the time of settlement, the Company pays the counterparty such excess on sold call options. If the market price settles below the call's strike price, no payment is due from either party.

Interest rate swaps	Interest rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to unfavorable interest rate changes.

Table of Contents

The Company utilizes counterparties for its derivative instruments that it believes are creditworthy at the time the transactions are entered into, and the Company closely monitors the credit ratings of these counterparties. Additionally, the Company performs both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. However, the events in the financial markets in recent years demonstrate there can be no assurance that a counterparty will be able to meet its obligations to the Company.

The following table provides information about the Company's financial instruments that are sensitive to changes in commodity prices and that are used to protect the Company's exposure. None of the financial instruments below are designated for hedge accounting treatment. The table presents the notional amount in Bcf, the weighted average contract prices and the fair value by expected maturity dates as of June 30, 2017:

		Weighted Average Price per MMBtu					
	Volume (Bcf)	Swaps	Sold Puts	Purchased Puts	Sold Calls	Basis Differential	Fair Value at June 30, 2017 (in millions)
Financial protection on production							
2017							
Fixed price swaps	168	$ 3.07	$ –	$ –	$ –	$ –	$ (2)
Two-way costless-collars	48	–	–	2.93	3.35	–	–
Three-way costless-collars	68	–	2.29	2.97	3.30	–	–
Total	284						$ (2)
2018							
Fixed price swaps	94	$ 3.00	$ –	$ –	$ –	$ –	$ 1
Two-way costless-collars	23	–	–	2.97	3.56	–	(2)
Three-way costless-collars	272	–	2.40	2.97	3.37	–	9
Total	389						$ 8
2019							
Three-way costless-collars	108	$ –	$ 2.50	$ 2.95	$ 3.32	$ –	$ (2)
Total	108						$ (2)
Basis Swaps							
2017	86	$ –	$ –	$ –	$ –	$ (1.03)	$ (13)
2018	20	–	–	–	–	(0.95)	(15)

Total	106		$ (28)

	Volume (Bcf)	Weighted Average Price per MMBtu Sold Calls	Fair Value at June 30, 2017 (in millions)	
Call options				
2017	43	$ 3.68	$ (2)	(1)
2018	63	3.50	(11)	
2019	52	3.50	(10)	
2020	32	3.75	(5)	
Total	190		$ (28)	

(1) Excludes $5 million in premiums paid related to certain call options recognized as a component of derivative assets within current assets on the unaudited condensed consolidated balance sheet. As certain call options settle, the premium will be amortized and recognized as a component of gain (loss) on derivatives on the unaudited condensed consolidated statements of operations.

13

Table of Contents

The balance sheet classification of the assets and liabilities related to derivative financial instruments (none of which are designated for hedge accounting treatment) are summarized below as of June 30, 2017 and December 31, 2016:

	Derivative Assets Balance Sheet Classification	Fair Value June 30, 2017	December 31, 2016
		(in millions)	
Derivatives not designated as hedging instruments:			
Fixed price swaps	Derivative assets	$ 10	$ –
Two-way costless collars	Derivative assets	11	8
Three-way costless collars	Derivative assets	45	11
Basis swaps	Derivative assets	7	32
Call options	Derivative assets	5	–
Fixed price swaps	Other long-term assets	5	1
Two-way costless collars	Other long-term assets	–	2
Three-way costless collars	Other long-term assets	100	100
Basis swaps	Other long-term assets	–	1
Total derivative assets		$ 183 (1)	$ 155

	Derivative Liabilities Balance Sheet Classification	Fair Value June 30, 2017	December 31, 2016
		(in millions)	
Derivatives not designated as hedging instruments:			
Fixed price swaps	Derivative liabilities	$ 15	$ 175
Two-way costless collars	Derivative liabilities	14	49
Three-way costless collars	Derivative liabilities	48	70
Basis swaps	Derivative liabilities	35	13
Call options	Derivative liabilities	14	46
Interest rate swaps	Derivative liabilities	1	2
Fixed price swaps	Other long-term liabilities	–	3
Two-way costless collars	Other long-term liabilities	–	9
Three-way costless collars	Other long-term liabilities	90	122
Basis swaps	Other long-term liabilities	–	5
Call options	Other long-term liabilities	19	35
Interest rate swaps	Other long-term liabilities	1	1
Total derivative liabilities		$ 237	$ 530

(1) Excludes $5 million in premiums paid related to certain call options currently recognized as a component of derivative assets within current assets on the unaudited condensed consolidated balance sheet. As certain call options settle, the premium will be amortized and recognized as a component of gain (loss) on derivatives on the

unaudited condensed consolidated statements of operations.

At June 30, 2017, the net fair value of the Company's financial instruments related to natural gas was a $52 million liability. The net fair value of the Company's interest rate swaps was a $2 million liability as of June 30, 2017. The Company had ethane fixed price swaps with an immaterial fair value as of June 30, 2017.

Derivative Contracts Not Designated for Hedge Accounting

As of June 30, 2017, the Company had no positions designated for hedge accounting treatment. Gains and losses on derivatives that are not designated for hedge accounting treatment, or that do not meet hedge accounting requirements, are recorded as a component of gain (loss) on derivatives on the unaudited condensed consolidated statements of operations. Accordingly, the gain (loss) on derivatives component of the statements of operations reflects the gains and losses on both settled and unsettled derivatives. The Company calculates gains and losses on settled derivatives as the summation of gains and losses on positions which have settled within the reporting period. Only the settled gains and losses are included in the Company's realized commodity price calculations.

The Company is a party to interest rate swaps that were entered into to mitigate the Company's exposure to volatility in interest rates. The interest rate swaps have a notional amount of $170 million and expire in June 2020. The Company did not designate the interest rate swaps for hedge accounting treatment. Changes in the fair value of the interest rate swaps are included in gain (loss) on derivatives on the unaudited condensed consolidated statements of operations.

Table of Contents

Table of Contents

The following tables summarize the before-tax effect of fixed price swaps, purchased put options, two-way costless collars, three-way costless collars, basis swaps, call options and interest rate swaps not designated for hedge accounting on the unaudited condensed consolidated statements of operations for the three and six months ended June 30, 2017 and 2016:

		Gain (Loss) on Derivatives, Unsettled Recognized in Earnings			
		For the three months ended June 30,		For the six months ended June 30,	
Derivative Instrument	Consolidated Statements of Operations Classification of Gain (Loss) on Derivatives, Unsettled	2017	2016	2017	2016
		(in millions)			
Fixed price swaps (1)	Gain (Loss) on Derivatives	$ 58	$ (60)	$ 176	$ (40)
Purchased put options	Gain (Loss) on Derivatives	–	(15)	–	–
Two-way costless collars	Gain (Loss) on Derivatives	14	(5)	45	(5)
Three-way costless collars	Gain (Loss) on Derivatives	31	(2)	88	(2)
Basis swaps	Gain (Loss) on Derivatives	60	(1)	(43)	(4)
Call options	Gain (Loss) on Derivatives	11	(25)	53	(75)
Interest rate swaps	Gain (Loss) on Derivatives	(1)	–	–	(3)
Total gain (loss) on unsettled derivatives		$ 173	$ (108)	$ 319	$ (129)

		Gain (Loss) on Derivatives, Settled (2) Recognized in Earnings			
		For the three months ended June 30,		For the six months ended June 30,	
Derivative Instrument	Consolidated Statements of Operations Classification of Gain (Loss) on Derivatives, Settled	2017	2016	2017	2016
		(in millions)			
Fixed price swaps (1)	Gain (Loss) on Derivatives	$ (9)	$ 12	$ (25)	$ 16
Purchased put options	Gain (Loss) on Derivatives	–	11	–	11
Two-way costless collars	Gain (Loss) on Derivatives	–	–	(3)	–
Three-way costless collars	Gain (Loss) on Derivatives	(1)	–	(5)	–
Basis swaps	Gain (Loss) on Derivatives	(29)	–	(30)	4
Call options	Gain (Loss) on Derivatives	–	–	(6)	–
Interest rate swaps	Gain (Loss) on Derivatives	–	–	–	(1)
Total gain (loss) on settled derivatives (3)		$ (39)	$ 23	$ (69)	$ 30

Total gain (loss) on derivatives	$ 134	$ (85)	$ 250	$ (99)

(1) Includes the Company's fixed price swaps on natural gas and ethane. As of June 30, 2017, the amount of unsettled and settled fixed price swaps related to ethane was immaterial.

(2) The Company calculates gain (loss) on derivatives, settled, as the summation of gains and losses on positions that have settled within the period.

(3) Excluding interest rate swaps and settled ethane fixed price swaps, these amounts are included, along with gas sales revenues, in the calculation of the Company's realized natural gas price. Settled ethane fixed price swaps are included, along with NGL sales revenues, in the calculation of the Company's realized NGL price.

Derivative Contracts Designated for Hedge Accounting

All derivatives are recognized in the balance sheet as either an asset or liability and are measured at fair value, other than transactions for which normal purchase/normal sale is applied. Certain criteria must be satisfied in order for derivative financial instruments to be designated for hedge accounting. Unrealized gains and losses related to unsettled derivatives that have been designated for hedge accounting treatment are recorded in either earnings or as a component of other comprehensive income until settled. In the period of settlement, the Company recognizes the gains and losses from these qualifying hedges in gas sales revenues. As of June 30, 2017 and 2016, the Company had no positions designated for hedge accounting treatment.

Table of Contents

(7) RECLASSIFICATIONS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The following tables detail the components of accumulated other comprehensive income (loss) and the related tax effects for the six months ended June 30, 2017:

	Pension and Other Postretirement	Foreign Currency	Total
	(in millions)		
Beginning balance, December 31, 2016	$ (19)	$ (20)	$ (39)
Other comprehensive income before reclassifications	–	–	–
Amounts reclassified from other comprehensive income (1)	1	–	1
Net current-period other comprehensive income	1	–	1
Ending balance, June 30, 2017	$ (18)	$ (20)	$ (38)

(1) See separate table below for details about these reclassifications.

1

Details about Accumulated Other Comprehensive Income	Affected Line Item in the Consolidated Statement of Operations	Amount Reclassified from Accumulated Other Comprehensive Income For the six months ended June 30, 2017 (in millions)

Pension and other postretirement:			
Amortization of prior service cost and net loss (1)	General and administrative expenses	$	1
	Provision for income taxes		–
	Net income (loss)	$	1
Total reclassifications for the period	Net income (loss)	$	1

(1) See Note 11 for additional details regarding the Company's retirement and employee benefit plans.

(8) FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company's financial instruments as of June 30, 2017 and December 31, 2016 were as follows:

	June 30, 2017		December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Cash and cash equivalents	$ 1,111	$ 1,111	$ 1,423	$ 1,423
Term loan facility due December 2020 (1)	327	327	327	327
Term loan facility due December 2020 (1)	1,191	1,191	1,191	1,191
Senior notes	2,890	2,821	3,166	3,182
Derivative instruments, net (2)	(54)	(54)	(375)	(375)

(1) The maturity date will accelerate to October 2019 if, by that date, the Company has not amended, redeemed or refinanced at least $765 million of its senior notes due in January 2020.
(2) Excludes $5 million in premiums paid related to certain call options currently recognized as a component of derivative assets within current assets on the unaudited condensed consolidated balance sheet.

The carrying values of cash and cash equivalents, accounts receivable, other current assets, accounts payable and other current liabilities on the unaudited condensed consolidated balance sheets approximate fair value because of their short-term nature. For debt and derivative instruments, the following methods and assumptions were used to estimate fair value:

Debt: The fair values of the Company's senior notes were based on the market value of the Company's publicly traded debt as determined based on the yield of the Company's senior notes.

The carrying values of the borrowings under the Company's term loan facilities and unsecured revolving credit facility approximate fair value because the interest rate is variable and reflective of market rates. The Company considers the fair value of its debt to be a Level 2 measurement on the fair value hierarchy.

Table of Contents

Derivative Instruments: The fair value of all derivative instruments is the amount at which the instrument could be exchanged currently between willing parties. The amounts are based on quoted market prices, best estimates obtained from counterparties and an option pricing model, when necessary, for price option contracts.

The fair value hierarchy prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

Level 1 valuations - Consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority.

Level 2 valuations - Consist of quoted market information for the calculation of fair market value.

Level 3 valuations - Consist of internal estimates and have the lowest priority.

The Company has classified its derivatives into these levels depending upon the data utilized to determine their fair values. The Company's fixed price swaps (Level 2) are estimated using third-party discounted cash flow calculations using the NYMEX futures index. The Company utilized discounted cash flow models for valuing its interest rate derivatives (Level 2). The net derivative values attributable to the Company's interest rate derivative contracts as of June 30, 2017 are based on (i) the contracted notional amounts, (ii) active market-quoted London Interbank Offered Rate ("LIBOR") yield curves and (iii) the applicable credit-adjusted risk-free rate yield curve. The Company's call options, purchased put options, two-way costless collars and three-way costless collars (Level 3) are valued using the Black-Scholes model, an industry standard option valuation model that takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the NYMEX futures index, interest rates, volatility and credit worthiness. The Company's basis swaps (Level 3) are estimated using third-party calculations based upon forward commodity price curves.

Inputs to the Black-Scholes model, including the volatility input, which is the significant unobservable input for Level 3 fair value measurements, are obtained from a third-party pricing source, with independent verification of the most significant inputs on a monthly basis. An increase (decrease) in volatility would result in an increase (decrease) in fair value measurement, respectively.

Assets and liabilities measured at fair value on a recurring basis are summarized below (in millions):

	June 30, 2017			
	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) at Fair Value
Fixed price swap assets	$ –	$ 15	$ –	$ 15
Two-way costless collars assets	–	–	11	11
Three-way costless collars assets	–	–	145	145
Basis swap assets	–	–	7	7
Call option assets (1)	–	–	5	5
Fixed price swap liabilities	–	(15)	–	(15)
Two-way costless collars liabilities	–	–	(14)	(14)
Three-way costless collars liabilities	–	–	(138)	(138)
Basis swap liabilities	–	–	(35)	(35)
Call option liabilities	–	–	(33)	(33)
Interest rate swap liabilities	–	(2)	–	(2)
Total	$ –	$ (2)	$ (52)	$ (54)

(1) Excludes $5 million in premiums paid related to certain call options currently recognized as a component of derivative assets within current assets on the unaudited condensed consolidated balance sheet.

Table of Contents

	December 31, 2016			
	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) at Fair Value
Fixed price swap assets	$ –	$ 1	$ –	$ 1
Two-way costless collars assets	–	–	10	10
Three-way costless collars assets	–	–	111	111
Basis swap assets	–	–	33	33
Fixed price swap liabilities	–	(178)	–	(178)
Two-way costless collars liabilities	–	–	(58)	(58)
Three-way costless collars liabilities	–	–	(192)	(192)
Basis swap liabilities	–	–	(18)	(18)
Call option liabilities	–	–	(81)	(81)
Interest rate swap liabilities	–	(3)	–	(3)
Total	$ –	$ (180)	$ (195)	$ (375)

The table below presents reconciliations for the change in net fair value of derivative assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the three and six months ended June 30, 2017 and 2016. The fair values of Level 3 derivative instruments are estimated using proprietary valuation models that utilize both market observable and unobservable parameters. Level 3 instruments presented in the table consist of net derivatives valued using pricing models incorporating assumptions that, in the Company’s judgment, reflect reasonable assumptions a marketplace participant would have used as of June 30, 2017 and 2016.

	For the three months ended June 30,		For the six months ended June 30,	
	2017	2016	2017	2016
	(in millions)		(in millions)	
Balance at beginning of period	$ (168)	$ (35)	$ (195)	$ 3
Total gains (losses):				
Included in earnings	86	(37)	99	(71)
Settlements	30	(11)	44	(15)
Transfers into/out of Level 3	–	–	–	–
Balance at end of period	$ (52)	$ (83)	$ (52)	$ (83)
Change in gains (losses) included in earnings relating to derivatives still held as of June 30	$ 116	$ (48)	$ 143	$ (86)

(9) DEBT

The components of debt as of June 30, 2017 and December 31, 2016 consisted of the following:

	June 30, 2017			
	Debt Instrument	Unamortized Issuance Expense	Unamortized Debt Discount	Total
	(in millions)			
Short-term debt:				
7.35% Senior Notes due October 2017	$ 15	$ –	$ –	$ 15
7.125% Senior Notes due October 2017	25	–	–	25
Total short-term debt	$ 40	$ –	$ –	$ 40
Long-term debt:				
Variable rate (3.690% at June 30, 2017) term loan facility, due December 2020 (3)	327	(2)	–	325
Variable rate (3.690% at June 30, 2017) term loan facility, due December 2020 (3)	1,191	(9)	–	1,182
4.05% Senior Notes due January 2020 (1)	850	(3)	–	847
4.10% Senior Notes due March 2022	1,000	(4)	(1)	995
4.95% Senior Notes due January 2025 (1)	1,000	(6)	(2)	992

Total long-term debt	$ 4,368	$ (24)	$ (3)	$ 4,341
Total debt	$ 4,408	$ (24)	$ (3)	$ 4,381

Table of Contents

	December 31, 2016			
	Debt Instrument	Unamortized Issuance Expense	Unamortized Debt Discount	Total
	(in millions)			
Short-term debt:				
7.35% Senior Notes due October 2017	$ 15	$ –	$ –	$ 15
7.125% Senior Notes due October 2017	25	–	–	25
7.15% Senior Notes due June 2018	1	–	–	1
Total short-term debt	$ 41	$ –	$ –	$ 41
Long-term debt:				
Variable rate (3.220% at December 31, 2016) term loan facility, due December 2020 (3)	327	(2)	–	325
Variable rate (3.220% at December 31, 2016) term loan facility, due December 2020 (3)	1,191	(10)	–	1,181
3.30% Senior Notes due January 2018 (1) (2)	38	–	–	38
7.50% Senior Notes due February 2018 (2)	212	–	–	212
7.15% Senior Notes due June 2018 (2)	25	–	–	25
4.05% Senior Notes due January 2020 (1)	850	(5)	–	845
4.10% Senior Notes due March 2022	1,000	(4)	(1)	995
4.95% Senior Notes due January 2025 (1)	1,000	(7)	(2)	991
Total long-term debt	$ 4,643	$ (28)	$ (3)	$ 4,612
Total debt	$ 4,684	$ (28)	$ (3)	$ 4,653

(1) In February and June 2016, Moody’s and S&P downgraded certain senior notes, increasing the interest rates by 175 basis points effective July 2016. As a result of the downgrades, interest rates increased to 5.05% for the 2018 Notes, 5.80% for the 2020 Notes and 6.70% for the 2025 Notes.

(2) In March 2017, the Company repurchased $25 million of its 7.50% Senior Notes due February 2018 and recognized a $1 million loss on the extinguishment of debt. In May 2017, the Company redeemed all (i) $187 million principal amount of its outstanding 7.50% Senior Notes due February 2018, (ii) $38 million principal amount of its outstanding 3.30% Senior Notes due January 2018 and (iii) $26 million principal amount of its outstanding 7.15% Senior Notes due June 2018 and recognized a $10 million loss on the extinguishment of debt.

(3) The maturity date will accelerate to October 2019 if, by that date, the Company has not amended, redeemed or refinanced at least $765 million of its senior notes due in January 2020.

2016 Credit Facility

In June 2016, the Company reduced its existing $2.0 billion unsecured revolving credit facility to $66 million and entered into a new credit agreement for $1,934 million, consisting of a $1,191 million secured term loan and a new $743 million unsecured revolving credit facility, which matures in December 2020. The maturity date will accelerate to October 2019 if, by that date, the Company has not amended, redeemed or refinanced at least $765 million of its senior notes due January 2020. The $1,191 million secured term loan is fully drawn, with approximately $285 million of this balance used to pay down the previous revolving credit facility balance in its entirety. As of June 30, 2017, there were no borrowings under either revolving credit facility; however, $326 million in letters of credit was outstanding against the 2016 revolving credit facility.

Loans under the 2016 credit agreement are subject to varying rates of interest based on whether the loan is a Eurodollar loan or an alternate base rate loan. Eurodollar loans bear interest at the Eurodollar rate, which is adjusted LIBOR plus applicable margins ranging from 1.750% to 2.500%. Alternate base rate loans bear interest at the alternate base rate plus the applicable margin ranging from 0.750% to 1.500%. The interest rate on the term loan facility is determined based upon the Company's public debt ratings and was 250 basis points over LIBOR as of June 30, 2017.

The 2016 term loan and revolving credit facility contain financial covenants that impose certain restrictions on the Company. Under the credit agreement, the Company must maintain a minimum interest coverage of 1.00x in 2017, increasing by 0.25x increments per year to 1.50x in 2019 and 2020. The Company is also subject to a minimum liquidity requirement of $300 million, which could be increased up to $500 million upon certain conditions, as well as an anti-hoarding provision, requiring unrestricted cash in excess of $100 million to pay down any amounts borrowed under the revolving credit facility. The financial covenant with respect to minimum interest coverage consists of EBITDAX divided by consolidated interest expense. EBITDAX, as defined in our 2016 credit agreement, excludes the effects of interest expense, income taxes, depreciation, depletion and amortization, any non-cash impacts from impairments, certain non-cash hedging activities, stock-based compensation expense, non-cash gains or losses on asset sales, unamortized issuance cost, unamortized debt discount and certain restructuring costs. Collateral for the secured term loan is principally the Company's E&P properties in the Fayetteville Shale area, the equity of its subsidiaries and cash and marketable securities on hand, and the credit agreement requires a minimum collateral coverage ratio of 1.50x for the 2016 secured term loan. This collateral also may support all or a part of revolving credit extensions depending on restrictions in the Company's senior notes indentures.

As of June 30, 2017, the Company was in compliance with all of the covenants of this credit agreement. Although the Company does not anticipate any violations of the financial covenants, its ability to comply with these covenants is dependent upon the success of its exploration and development program and upon factors beyond the Company's control, such as the market prices for natural gas, oil and NGLs.

2013 Credit Facility

In December 2013, the Company entered into a credit agreement that exchanged its previous revolving credit facility. Under the revolving credit facility, the Company had a borrowing capacity of $2.0 billion. The revolving credit facility was unsecured and was not guaranteed by any subsidiaries. In June 2016, this credit facility was substantially exchanged for a new credit facility comprised of a $1,191 million secured term loan and a new $743 million revolving credit facility. The borrowing capacity of the original 2013 credit agreement was reduced from $2.0 billion to $66 million, remains unsecured and the maturity remains December 2018. As of June 30, 2017, there were no borrowings under this facility.

The existing unsecured 2013 revolving credit facility includes a financial covenant under which the Company may not have total debt in excess of 60% of its total adjusted book capital. This financial covenant with respect to capitalization percentages excludes the effects of any full cost ceiling impairments, certain hedging activities and the Company's pension and other postretirement liabilities. At June 30, 2017, debt constituted 32% of the Company's adjusted book capital.

2015 Term Facility

In November 2015, the Company entered into a $750 million unsecured three-year term loan credit agreement with various lenders that was utilized to repay borrowings under the revolving credit facility. The interest rate on the term loan facility is determined based upon the Company's public debt ratings from Moody's and S&P and was 250 basis points over LIBOR as of June 30, 2017. The term loan facility requires prepayment under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business. In June 2016, this term loan agreement was amended to extend the maturity date upon a repayment threshold. From the net proceeds of the July 2016 equity offering, the Company repaid $375 million of the $750 million unsecured term loan, which had the effect of extending the term loan maturity from November 2018 to December 2020, which will accelerate to October 2019 if, by that date, the Company has not amended, redeemed or refinanced at least $765 million of its senior notes due in January 2020. In September 2016, the Company repaid an additional $48 million from the proceeds received from the closing of the sale of approximately 55,000 net acres in West Virginia.

Senior Notes

In January 2015, the Company completed a public offering of $350 million aggregate principal amount of its 3.30% senior notes due 2018 (the "2018 Notes"), $850 million aggregate principal amount of its 4.05% senior notes due 2020 (the "2020 Notes") and $1.0 billion aggregate principal amount of its 4.95% senior notes due 2025 (the "2025 Notes" together with the 2018 and 2020 Notes, the "Notes"), with net proceeds from the offering totaling approximately $2.2 billion after underwriting discounts and offering expenses. The Notes were sold to the public at a price of 99.949% of their face value for the 2018 Notes, 99.897% of their face value for the 2020 Notes and 99.782% of their face value for the 2025 Notes. The interest rates on the Notes are determined based upon the public bond ratings from Moody's and S&P. Downgrades on the Notes from either rating agency increase interest costs by 25 basis points per downgrade level and upgrades decrease interest costs by 25 basis points per upgrade level, up to the stated coupon rate, on the following semi-annual bond interest payment. In February and June 2016, Moody's and S&P downgraded the Notes, increasing the interest rates by 175 basis points effective July 2016. As a result of these downgrades, interest rates increased to 5.05% for the 2018 Notes, 5.80% for the 2020 Notes and 6.70% for the 2025 Notes. In the event of future downgrades, the coupons for this series of notes are capped at 5.30%, 6.05% and 6.95%, respectively. The first coupon payment at the higher interest rates was paid in January 2017.

In July 2016, the Company used a portion of the proceeds from the July 2016 equity offering to settle certain tender offers by purchasing an aggregate principal amount of approximately $700 million of its outstanding senior notes due in the first quarter of 2018.

Table of Contents

In March 2017, the Company repurchased $25 million of its 7.50% Senior Notes due February 2018 and recognized a $1 million loss on the extinguishment of debt. In May 2017, the Company redeemed all (i) $187 million principal amount of its outstanding 7.50% Senior Notes due February 2018, (ii) $38 million principal amount of its outstanding 3.30% Senior Notes due January 2018 and (iii) $26 million principal amount of its outstanding 7.15% Senior Notes due June 2018 and recognized a $10 million loss on the extinguishment of debt.

(10) COMMITMENTS AND CONTINGENCIES

Operating Commitments and Contingencies

As of June 30, 2017, the Company's contractual obligations for demand and similar charges under firm transportation and gathering agreements to guarantee access capacity on natural gas and liquids pipelines and gathering systems totaled approximately $8.6 billion, $3.6 billion of which related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and additional construction efforts. The Company also had guarantee obligations of up to $822 million of that amount. As of June 30, 2017, future payments under non-cancelable firm transportation and gathering agreements were as follows:

	Payments Due by Period					
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	5 to 8 Years	More than 8 Years
	(in millions)					
Infrastructure currently in service	$ 4,944	$ 580	$ 1,128	$ 766	$ 843	$ 1,627
Pending regulatory approval and/or construction (1)	3,608	46	398	464	714	1,986
Total transportation charges	$ 8,552	$ 626	$ 1,526	$ 1,230	$ 1,557	$ 3,613

(1) Based on the estimated in-service dates as of June 30, 2017.

Environmental Risk

The Company is subject to laws and regulations relating to the protection of the environment. Environmental and cleanup related costs of a non-capital nature are accrued when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on the financial position or results of operations of the Company.

Litigation

The Company is subject to various litigation, claims and proceedings that have arisen in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties and pollution, contamination or nuisance. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. Management believes that current litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on the Company's financial position, results of operations or cash flows, although it is possible that adverse outcomes could have a material adverse effect on the Company's results of operations or cash flows for the period in which the effect of that outcome becomes reasonably estimable. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and are all subject to inherent uncertainties; therefore, management's view may change in the future.

Arkansas Royalty Litigation

In June 2017 the jury returned a verdict in favor of the Company on all counts in Smith v. SEECO, Inc. et al., a class action in the United States District Court for the Eastern District of Arkansas. The plaintiff had alleged that the Company had underpaid lessors of lands in Arkansas by deducting from royalty payments costs for gathering, transportation and compression of natural gas in excess of what is permitted by the relevant leases and asserted claims for, among other things, breach of contract, fraud, civil conspiracy, unjust enrichment and violation of certain Arkansas statutes. Following the verdict, the court entered judgment in favor of the Company on all claims. The plaintiff has moved for a new trial, and the court has not yet ruled on that motion.

The plaintiff class in Smith comprises the vast majority of lessors of lands in Arkansas for which leases permit deductions for these types of costs. Most of the remaining lessors are named plaintiffs or members of classes in other pending lawsuits; in particular, two actions on behalf of certified classes of only Arkansas residents pending in state courts in Arkansas (no trial date set) and three cases (all currently stayed) that were filed in Arkansas state court on behalf of a

Table of Contents

total of 248 individually named plaintiffs, two of which have been removed to federal court have been assigned to the same court that held the Smith trial. Management believes that, as the Smith jury concluded, the deductions from royalty payments were calculated in accordance with the leases. The Company currently does not anticipate that these other cases are likely to have a material adverse effect on the results of operations, financial position or cash flows of the Company.

Indemnifications

The Company provides certain indemnifications in relation to dispositions of assets. These indemnifications typically relate to disputes, litigation or tax matters existing at the date of disposition. No liability has been recognized in connection with these indemnifications.

(11) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company maintains defined pension and postretirement benefit plans which cover substantially all of the Company's employees. Net periodic pension costs include the following components for the three and six months ended June 30, 2017 and 2016:

	Pension Benefits			
	For the three months ended June 30,		For the six months ended June 30,	
	2017	2016	2017	2016
	(in millions)			
Service cost	$ 3	$ 2	$ 5	$ 6
Interest cost	1	1	2	3
Expected return on plan assets	(2)	(1)	(3)	(3)
Amortization of prior service cost	–	–	–	–
Amortization of net loss	–	1	1	1
Curtailment loss	–	1	–	1
Settlement loss	–	8	–	8
Net periodic benefit cost	$ 2	$ 12	$ 5	$ 16

The Company's other postretirement benefit plan had a marginal net periodic benefit cost for the three months ended June 30, 2017, a net periodic benefit gain of $6 million for the three months ended June 30, 2016 and a net periodic benefit cost (gain) of $1 million and ($5) million for the six months ended June 30, 2017 and 2016, respectively. Included in the net periodic benefit cost for the three and six months ended June 30, 2016 is a curtailment gain of $6 million, which more than offset the other components of net periodic benefit cost.

As of June 30, 2017, the Company has contributed $8 million to the pension and other postretirement benefit plans in 2017. The Company expects to contribute an additional $6 million to its pension plan during the remainder of 2017. The Company recognized a liability of $33 million and $14 million related to its pension and other postretirement benefits, respectively, as of June 30, 2017, compared to a liability of $36 million and $13 million as of December 31, 2016. The Company updated the discount rate currently used in the measurement of the benefit obligation of the pension plan and other postretirement benefits plan to 4.20% in the second quarter of 2016. The Company used a discount rate of 4.60% during the first quarter of 2016 for the measurement of the benefit obligation of both the pension and other postretirement benefit plans. In January 2016, the Company initiated a reduction in workforce that was substantially completed by the end of the first quarter of 2016. The impact of the workforce reduction on the Company's pension and other postretirement benefit costs was not recognized until subsequent quarters in 2016 due to the delayed timing of actuarial data available.

The Company maintains a non-qualified deferred compensation supplemental retirement savings plan ("Non-Qualified Plan") for certain key employees who may elect to defer and contribute a portion of their compensation, as permitted by the Non-Qualified Plan. Shares of the Company's common stock purchased under the terms of the Non-Qualified Plan are presented as treasury stock and totaled 11,686 shares at June 30, 2017, compared to 31,269 shares at December 31, 2016.

Table of Contents

(12) STOCK-BASED COMPENSATION

The Company recognized the following amounts in employee stock-based compensation costs for the three and six months ended June 30, 2017 and 2016:

	For the three months ended June 30,		For the six months ended June 30,	
	2017	2016	2017	2016
	(in millions)			
Stock-based compensation cost – expensed (1) (2)	$ 6	$ 14	$ 12	$ 37
Stock-based compensation cost – capitalized	$ 4	$ 2	$ 8	$ 5

(1) Includes $2 million and $16 million related to the reduction in workforce for the three and six months ended June 30, 2016, respectively.
(2) Includes $3 million related to executive management restructuring for the three and six months ended June 30, 2016, respectively.

In January 2016, the Company announced a 40% workforce reduction that was substantially completed by the end of March 2016. In April 2016, the Company also partially restructured executive management, which was substantially completed in the second quarter of 2016. Affected employees were offered a severance package that included, if applicable, amendments to certain outstanding equity awards that modified forfeiture provisions on separation from the Company. As a result, certain unvested stock-based equity awards became fully vested at the time of separation. These shares were revalued and recognized immediately as a component of restructuring charges on the Company's unaudited condensed consolidated statements of operations. The unvested portion of equity-based performance units was forfeited upon separation from the Company.

As of June 30, 2017, there was $78 million of total unrecognized compensation cost related to the Company's unvested stock option grants, restricted stock grants and performance units. This cost is expected to be recognized over a weighted-average period of 3 years.

Stock Options

The following table summarizes stock option activity for the six months ended June 30, 2017 and provides information for options outstanding and options exercisable as of June 30, 2017:

	Number of Options (in thousands)	Weighted Average Exercise Price (per share)
Outstanding at December 31, 2016	5,416	$ 23.46
Granted	1,322	8.59
Exercised	–	–
Forfeited or expired	(454)	12.99
Outstanding at June 30, 2017	6,284	21.09
Exercisable at June 30, 2017	3,582	$ 29.21

Restricted Stock

The following table summarizes restricted stock activity for the six months ended June 30, 2017 and provides information for unvested shares as of June 30, 2017:

	Number of Shares (in thousands)	Weighted Average Fair Value (per share)
Unvested shares at December 31, 2016	3,321	$ 11.85
Granted	4,903	8.48
Vested	(147)	11.44
Forfeited	(416)	10.29
Unvested shares at June 30, 2017	7,661	$ 9.79

Table of Contents

Equity-Classified Performance Units

The following table summarizes performance unit activity for the six months ended June 30, 2017 and provides information for unvested units as of June 30, 2017. The performance units awarded in 2014 included a market condition based on relative Total Shareholder Return ("TSR") and a performance condition based on the Company's Present Value Index ("PVI"), collectively the "Performance Measures." The fair value of the TSR market condition is based on a Monte Carlo model and the fair value of the PVI performance condition is based on economic analysis for each investment opportunity based upon the expected present value added for each dollar to be invested. The total fair value of the performance units is amortized to compensation expense on a straight line basis over the vesting period of the award. The performance unit awards granted in 2015, 2016 and during the first half of 2017 include a market condition based exclusively on TSR. The grant date fair value is calculated using the applicable Performance Measures and the closing price of the Company's common stock at the grant date.

	Number of Units (1) (in thousands)	Weighted Average Fair Value (per share)
Unvested units at December 31, 2016	719	$ 11.46
Granted	1,197	10.47
Vested	(2)	13.88
Forfeited	(332)	10.93
Unvested units at June 30, 2017	1,582	$ 10.82

(1) These amounts reflect the number of performance units granted in thousands. The actual payout of shares may range from a minimum of zero shares to a maximum of two shares per unit contingent upon the actual performance against the Performance Measures. The performance units have a three-year vesting term and the actual disbursement of shares, if any, is determined during the first quarter following the end of the three-year vesting period.

Liability-Classified Performance Units

Prior to 2013, certain employees were awarded performance units which vested equally over three years and which were settled in cash. The payout of these units was based on certain metrics, such as total shareholder return and reserve replacement efficiency, compared to a predetermined group of peer companies and Company goals. At the end of each performance period, the value of the vested performance units, if any, would be paid in cash. In the first quarter of 2016, the Company completed the final payout with respect to these performance units.

(13) SEGMENT INFORMATION

The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the E&P segment are derived from the production and sale of natural gas and liquids. The Midstream Services segment generates revenue through the marketing of both Company and third-party produced natural gas and liquids volumes and through gathering fees associated with the transportation of natural gas to market.

Summarized financial information for the Company's reportable segments is shown in the following table. The accounting policies of the segments are the same as those described in Note 1 of the Notes to Consolidated Financial Statements included in Item 8 of the 2016 Annual Report. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs. Income before income taxes, for the purpose of reconciling the operating income amount shown below to consolidated income before income taxes, is the sum of operating income, interest expense, gain (loss) on derivatives, loss on early extinguishment of debt and other income (loss). The "Other" column includes items not related to the Company's reportable segments, including real estate and corporate items.

Table of Contents

	Exploration and Production (in millions)		Midstream Services	Other		Total
Three months ended June 30, 2017:						
Revenues from external customers	$ 531		$ 280	$ –		$ 811
Intersegment revenues	(5)		542	–		537
Depreciation, depletion and amortization expense	107		16	–		123
Operating income	146		42	–		188
Interest expense (1)	34		–	–		34
Gain on derivatives	134		–	–		134
Loss on early extinguishment of debt	–		–	(10)		(10)
Other income, net	2		4	–		6
Assets	4,633		1,281	1,236	(2)	7,150
Capital investments (3)	318		6	1		325
Three months ended June 30, 2016:						
Revenues from external customers	$ 291		$ 231	$ –		$ 522
Intersegment revenues	(7)		328	–		321
Depreciation, depletion and amortization expense	90		17	–		107
Impairment of natural gas and oil properties	470		–	–		470
Operating income (loss)	(549)	(4)	57	–		(492)
Interest expense (1)	16		1	–		17
Loss on derivatives	(85)		–	–		(85)
Other income (loss), net	3		(2)	(1)		–
Benefit for income taxes (1)	(1)		–	–		(1)
Assets	5,000		1,227	1,150	(2)	7,377
Capital investments (3)	73		–	1		74

	Exploration and Production (in millions)	Midstream Services	Other	Total
Six months ended June 30, 2017:				
Revenues from external customers	$ 1,097	$ 560	$ –	$ 1,657
Intersegment revenues	(8)	1,120	–	1,112
Depreciation, depletion and amortization expense	197	32	–	229

Operating income	371	83	–	454
Interest expense (1)	66	–	–	66
Gain on derivatives	250	–	–	250
Loss on early extinguishment of debt	–	–	(11)	(11)
Other income, net	4	4	–	8
Assets	4,633	1,281	1,236 (2)	7,150
Capital investments (3)	601	12	2	615
Six months ended June 30, 2016:				
Revenues from external customers	$ 634	$ 467	$ –	$ 1,101
Intersegment revenues	(14)	713	–	699
Depreciation, depletion and amortization expense	217	33	–	250
Impairment of natural gas and oil properties	1,504	–	–	1,504
Operating income (loss)	(1,709) (4)	117 (5)	–	(1,592)
Interest expense (1)	30	1	–	31
Loss on derivatives	(98)	(1)	–	(99)
Other income (loss), net	1	(3)	(1)	(3)
Assets	5,000	1,227	1,150 (2)	7,377
Capital investments (3)	193	2	1	196

(1) Interest expense and the benefit for income taxes by segment are an allocation of corporate amounts as they are incurred at the corporate level.

(2) Other assets represent corporate assets not allocated to segments and assets for non-reportable segments. At June 30, 2017 and 2016, other assets includes approximately $1.1 billion and $998 million in cash and cash equivalents, respectively.

(3) Capital investments includes increases of $41 million and $27 million for the three months ended June 30, 2017 and 2016, respectively, and decreases of $11 million and $51 million for the six months ended June 30, 2017 and 2016, respectively, relating to the change in accrued expenditures between periods.

(4) Operating income (loss) for the E&P segment includes $11 million and $72 million related to restructuring charges for the three and six months ended June 30, 2016, respectively.

(5) Operating income (loss) for the Midstream services segment includes $3 million related to restructuring charges for the six months ended June 30, 2016.

Included in intersegment revenues of the Midstream Services segment are $490 million and $267 million for the three months ended June 30, 2017 and 2016, respectively and $1,014 million and $586 million for the six months ended June 30, 2017 and 2016, respectively, for marketing of the Company’s E&P sales. Corporate assets include cash and cash equivalents, furniture and fixtures and other costs. Corporate general and administrative costs, depreciation expense and taxes other than income are allocated to the segments.

(14) INCOME TAXES

The Company’s effective tax rate was approximately 0% for the three and six months ended June 30, 2017 and 2016, primarily as a result of the existence of a valuation allowance. 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, the Company uses estimates and judgment regarding future taxable income, and considers the tax consequences in the jurisdiction where such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include current financial position, 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 the oil and gas industry.

The Company maintained its net deferred tax asset position at June 30, 2017 primarily due to the write-downs of the carrying value of natural gas and oil properties in 2015 and 2016. The Company recorded decreases in our valuation allowance of $107 million and $182 million for the three and six months ended June 30, 2017, respectively. For the three and six months ended June 30, 2016, there were increases in our valuation allowance of $216 million and $647 million, respectively. 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. In management’s view, the cumulative loss incurred over recent years outweighs any positive factors, such as the possibility of 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.

(15) NEW ACCOUNTING PRONOUNCEMENTS

New Accounting Standards Implemented

In March 2016, the FASB issued Accounting Standards Update No. 2016-09, Compensation – Stock Compensation (Topic 718) ("Update 2016-09"), to simplify accounting for share-based payment transactions including income tax consequences, classification of awards as either equity or liabilities, and the classification on the statement of cash flows. For public entities, Update 2016-09 became effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years, with early adoption permitted. The Company adopted Update 2016-09 during the first quarter with an effective date of January 1, 2017. The recognition of previously unrecognized windfall tax benefits resulted in a net cumulative-effect adjustment of $59 million, which increased net deferred tax assets and the related income tax valuation allowance by the same amount as of the beginning of 2017. The amendments within Update 2016-09 related to the recognition of excess tax benefits and tax shortfalls in the income statement and presentation within the operating section of the statement of cash flows were adopted prospectively, with no adjustments made to prior periods. The Company has elected to account for forfeitures as they occur. The remaining provisions of this amendment did not have a material effect on its unaudited condensed consolidated results of operations, financial position or cash flows.

New Accounting Standards Not Yet Implemented

In March 2017, the FASB issued Accounting Standards Update No. 2017-07, Compensation - Retirement Benefits (Topic 715) ("Update 2017-07"), which provides additional guidance on the presentation of net benefit cost in the statement of operations and on the components eligible for capitalization in assets. The guidance is effective for annual periods beginning after December 15, 2017, including interim periods within those annual periods. The amendments in this update should be applied retrospectively for the presentation of the service cost component and the other components of net periodic postretirement benefit cost in the income statement and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic benefit cost in assets. The Company is evaluating the impact of the adoption of Update 2017-07 on its consolidated financial statements and related disclosures.

Table of Contents

In August 2016, the FASB issued Accounting Standards Update No. 2016-15, Statement of Cash Flows (Topic 230) ("Update 2016-15"), which seeks to reduce the existing diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. For public entities, Update 2016-15 becomes effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted. The Company does not expect the impact of adopting Update 2016-15 to have a material effect on its consolidated financial statements and related disclosures.

In February 2016, the FASB issued Accounting Standards Update No. 2016-02, Leases (Topic 842) ("Update 2016-02"), which seeks to increase transparency and comparability among organizations by, among other things, recognizing lease assets and lease liabilities on the balance sheet for leases classified as operating leases under previous GAAP and disclosing key information about leasing arrangements. Through June 2017, the Company made progress on contract reviews, drafting its accounting policies and evaluating the new disclosure requirements. The Company will continue assessing the effect that the updated standard may have on its consolidated financial statements and related disclosures, and anticipates that its assessment will be complete in 2018. For public entities, Update 2016-02 becomes effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted.

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("Update 2014-09"), which seeks to provide clarity for recognizing revenue. The new standard removes inconsistencies in existing standards, changes the way companies recognize revenue from contracts with customers and increases disclosure requirements. The codification was amended through additional ASUs and, as amended, requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The standard is required to be adopted using either the full retrospective approach, with all prior periods presented adjusted, or the modified retrospective approach, with a cumulative adjustment to retained earnings on the opening balance sheet. The Company has not yet selected a transition method. The Company has a team in place to analyze the impact of Update 2014-09, and the related ASU's, across all revenue streams to evaluate the impact of the new standard on revenue contracts. This includes reviewing current accounting policies and practices to identify potential differences that would result from applying the requirements under the new standard. Through June 2017, the Company made progress on contract reviews, drafting its accounting policies and evaluating the new disclosure requirements. The Company expects to complete its evaluations of the impacts of the accounting and disclosure requirements on its business processes, controls and systems in the second half of 2017. For public entities, the new standard is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

The following updates information as to Southwestern Energy Company's financial condition provided in our 2016 Annual Report and analyzes the changes in the results of operations between the three and six months ended June 30, 2017 and 2016. For definitions of commonly used natural gas and oil terms used in this Quarterly Report, please refer to the "Glossary of Certain Industry Terms" provided in our 2016 Annual Report.

The following discussion contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in forward-looking statements for many reasons, including the risks described in the "Cautionary Statement About Forward-Looking Statements" in the forepart of this Quarterly Report, in Item 1A, "Risk Factors" in Part I and elsewhere in our 2016 Annual Report, and Item 1A, "Risk Factors" in Part II in this Quarterly Report and any other quarterly report on Form 10-Q filed during the fiscal year. You should read the following discussion with our unaudited condensed consolidated financial statements and the related notes included in this Quarterly Report.

OVERVIEW

Background

Southwestern Energy Company (including its subsidiaries, collectively, “we”, “our”, “us” or “Southwestern”) is an independent energy company engaged in natural gas, oil and NGL exploration, development and production, which we refer to as “E&P.” We are also focused on creating and capturing additional value through our natural gas gathering and marketing businesses, which we refer to as “Midstream Services.” We conduct most of our businesses through subsidiaries and we operate principally in two segments: E&P and Midstream Services. Currently we operate only in the United States.

Exploration and Production. Our primary business is the exploration for and production of natural gas, oil and NGLs, with our current operations principally focused on the development of unconventional natural gas reservoirs located in Pennsylvania, West Virginia and Arkansas. Our operations in northeast Pennsylvania, which we refer to as “Northeast Appalachia,” are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale. Our operations in West Virginia and southwest Pennsylvania, which we refer to as “Southwest Appalachia,” are focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs. Collectively, we refer to our properties located in Pennsylvania and West Virginia as the “Appalachian Basin.” Our operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale. We have smaller holdings in Colorado and Louisiana, along with other areas in which we are testing potential new resources. We also have drilling rigs located in Pennsylvania, West Virginia and Arkansas, as well as in other operating areas, and provide oilfield products and services, principally serving our E&P operations.

Midstream Services. Through our affiliated midstream subsidiaries, we engage in natural gas gathering activities in Arkansas and Louisiana. These activities primarily support our E&P operations and generate revenue from fees associated with the gathering of natural gas. Our marketing activities capture opportunities that arise through the marketing and transportation of natural gas, oil and NGLs produced in our E&P operations.

We are focused on providing long-term growth in the net asset value per share of our business. Historically, the vast majority of our operating income and cash flow has been derived from the production associated with our E&P business. However, beginning in 2015 and continuing into 2017, a challenging commodity price environment significantly decreased our cash flow from our E&P operations. As a result of our commitment to capital discipline, we have adjusted the pace of our activity to invest within cash flows. The price we expect to receive for our production is a critical factor in the capital investments we make to develop our properties. Commodity prices fluctuate due to a variety of factors we cannot control or predict. These factors, which include increased supplies of natural gas, oil or NGLs due to greater exploration and development activities, weather conditions, political and economic events, and competition from other energy sources, impact supply and demand, which in turn determines the sales prices for our production. In addition to the factors identified above, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices, including basis differentials. Our 2016 results also reflected reduced costs of third-party services we were able to negotiate during the downturn in the industry. As industry activity increases, demand for these services also increases, and these service providers are likely to seek higher rates than we were able to obtain in 2016.

With the successful implementation of our debt reduction strategy in 2016, along with improving forward pricing, we began increasing our activity in the third quarter of 2016, continuing into 2017. We made additional progress on our debt reduction strategy by redeeming all of our outstanding 2018 Senior Notes in the first half of 2017.

Three Months Ended June 30, 2017 Compared with Three Months Ended June 30, 2016

We reported net income attributable to common stock of $224 million for the three months ended June 30, 2017, or $0.45 per diluted share, compared to a net loss attributable to common stock of $620 million, or ($1.61) per diluted share, for the same period in 2016.

Our natural gas and liquids production was 222 Bcfe for the three months ended June 30, 2017, down from 225 Bcfe for the same period in 2016. The 3 Bcfe decrease was due to a 15 Bcfe decrease in net production from our Fayetteville Shale and other properties, partially offset by increases of 7 Bcf in net production from our Northeast Appalachia properties and 5 Bcfe in net production from our Southwest Appalachia properties, compared to the same period in 2016. The average price realized for our gas production, including the effects of derivatives, increased 63% to $2.15 per Mcf for the three months ended June 30, 2017, compared to $1.32 per Mcf for the same period in 2016. The average price realized for our oil production increased 25% to $40.56 per barrel for the three months ended June 30, 2017, compared to

$32.46 per barrel for the same period in 2016. We did not use derivatives to financially protect our 2017 or 2016 oil production. The average price realized for our NGL production, including the effects of derivatives, increased 76% to $11.25 per barrel for the three months ended June 30, 2017, compared to $6.41 per barrel for the same period in 2016.

Our E&P segment operating income was $146 million for the three months ended June 30, 2017, an increase from an operating loss of $549 million for the same period in 2016. This increase was primarily due to the impairment of natural gas and oil properties of $470 million for the three months ended June 30, 2016. Excluding the 2016 impairment, our E&P segment operating income increased $225 million for the three months ended June 30, 2017, compared to the same period in 2016, primarily due to a $247 million increase in revenue related to increased realized natural gas, oil and NGL prices (excluding derivatives), partially offset by a $17 million increase in depreciation, depletion and amortization expense and a $5 million decrease in revenue resulting from a 3 Bcfe decrease in production.

Operating income for our Midstream Services segment was $42 million for the three months ended June 30, 2017, a decrease from $57 million for the same period in 2016, primarily due to a $15 million decrease in gas gathering revenues.

Capital investments were $325 million for the three months ended June 30, 2017 (including $28 million in capitalized interest and $26 million in capitalized expenses), of which $318 million was invested in our E&P segment, compared to $74 million for the same period of 2016, of which $73 million was invested in our E&P segment.

Six Months Ended June 30, 2017 Compared with Six Months Ended June 30, 2016

We reported net income attributable to common stock of $505 million for the six months ended June 30, 2017, or $1.02 per diluted share, compared to a net loss attributable to common stock of $1.8 billion, or ($4.63) per diluted share, for the same period in 2016.

Our natural gas and liquids production was 426 Bcfe for the six months ended June 30, 2017, a decrease of 8% from 462 Bcfe for the same period in 2016. The 36 Bcfe decrease was due to a 37 Bcfe decrease in net production from our Fayetteville Shale and other properties, partially offset by a 1 Bcfe increase in net production from our Southwest Appalachia properties, compared to the same period in 2016. Production from our Northeast Appalachia properties for the six months ended June 30, 2017 was flat compared to the same period in 2016. The average price realized for our gas production, including the effects of derivatives, increased 68% to $2.35 per Mcf for the six months ended June 30, 2017, compared to $1.40 per Mcf for the same period in 2016. The average price realized for our oil production increased 65% to $42.08 per barrel for the six months ended June 30, 2017, compared to $25.43 per barrel for the same period in 2016. We did not use derivatives to financially protect our 2017 or 2016 oil production. The average price realized for our NGL production, including the effects of derivatives, increased 116% to $12.22 per barrel for the six months ended June 30, 2017, compared to $5.67 per barrel for the same period in 2016.

Our E&P segment operating income was $371 million for the six months ended June 30, 2017, an increase from an operating loss of $1.7 billion for the same period in 2016. This increase was primarily due to the impairment of natural gas and oil properties of $1.5 billion for the six months ended June 30, 2016. Excluding the 2016 impairment, our E&P segment operating income increased $576 million for the six months ended June 30, 2017, compared to the same period in 2016, primarily due to a $518 million increase in revenue related to increased realized natural gas, oil and NGL prices (excluding derivatives) and a $107 million decrease in operating costs and expenses, partially offset by a $49 million decrease in revenue resulting from a 36 Bcfe decrease in production.

Operating income for our Midstream Services segment was $83 million for the six months ended June 30, 2017, a decrease from $117 million for the same period in 2016, primarily due to a $37 million decrease in gas gathering revenues and a $4 million decrease in our marketing margin, partially offset by a $7 million decrease in operating costs and expenses.

Capital investments were $615 million for the six months ended June 30, 2017 (including $56 million in capitalized interest and $51 million in capitalized expenses), of which $601 million was invested in our E&P segment, compared to $196 million for the same period of 2016, of which $193 million was invested in our E&P segment.

Table of Contents

RESULTS OF OPERATIONS

The following discussion of our results of operations for our segments is presented before intersegment eliminations. We evaluate our segments as if they were stand-alone operations and accordingly discuss their results prior to any intersegment eliminations. Interest expense and income tax expense are discussed on a consolidated basis.

Exploration and Production

	For the three months ended June 30,		For the six months ended June 30,	
	2017	2016	2017	2016
Revenues (in millions)	$ 526	$ 284	$ 1,089	$ 620
Impairment of natural gas and oil properties (in millions)	$ –	$ 470	$ –	$ 1,504
Operating costs and expenses (in millions) (1)	$ 380	$ 363	$ 718	$ 825
Operating income (loss) (in millions)	$ 146	$ (549)	$ 371	$ (1,709)
Gain (loss) on derivatives, settled (in millions) (2)	$ (39)	$ 23	$ (69)	$ 31
Gas production (Bcf)	199	203	382	416
Oil production (MBbls)	565	586	1,084	1,193
NGL production (MBbls)	3,316	3,136	6,324	6,512
Total production (Bcfe)	222	225	426	462
Average realized gas price per Mcf, including derivatives (3)	$ 2.15	$ 1.32	$ 2.35	$ 1.40
Average realized gas price per Mcf, excluding derivatives	$ 2.35	$ 1.21	$ 2.53	$ 1.33
Average realized oil price per Bbl	$ 40.56	$ 32.46	$ 42.08	$ 25.43
Average realized NGL price per Bbl, including derivatives (3)	$ 11.25	$ 6.41	$ 12.22	$ 5.67
Average unit costs per Mcfe:				
Lease operating expenses	$ 0.89	$ 0.87	$ 0.89	$ 0.88
General & administrative expenses (4)	$ 0.23	$ 0.21	$ 0.22	$ 0.20
Taxes, other than income taxes (5)	$ 0.10	$ 0.09	$ 0.11	$ 0.09
Full cost pool amortization	$ 0.44	$ 0.35	$ 0.42	$ 0.42

(1) Includes $11 million and $72 million of restructuring charges for the three and six months ended June 30, 2016, respectively.

(2) Represents the gain (loss) on settled commodity derivatives.

(3) Includes the gain (loss) on settled commodity derivatives.

(4) Excludes $11 million and $69 million of restructuring charges for the three and six months ended June 30, 2016, respectively.

(5) Excludes $3 million of restructuring charges for the six months ended June 30, 2016.

Revenues

Revenues for our E&P segment were $526 million, an increase of 85%, for the three months ended June 30, 2017, compared to $284 million for the same period in 2016. Revenues increased by $247 million as a result of increased natural gas, oil and NGL pricing, excluding the effects of derivatives, partially offset by a decrease of $5 million as a result of decreased production volumes. E&P segment revenues were $1,089 million, an increase of 76%, for the six months ended June 30, 2017, compared to $620 million for the same period in 2016. Revenues increased by $518 million as a result of increased natural gas, oil and NGL pricing, excluding the effects of derivatives, partially offset by a decrease of $49 million as a result of decreased production volumes. Natural gas, oil and NGL prices are difficult to predict and are subject to wide price fluctuations. Excluding basis swaps, as of June 30, 2017 we had financially protected 284 Bcf of our remaining 2017 natural gas production to limit our exposure to price fluctuations. We refer you to Note 6 to the unaudited condensed consolidated financial statements included in this Quarterly Report and to the discussion of "Commodity Prices" provided below for additional information.

Production

For the three months ended June 30, 2017, our natural gas and liquids production decreased 1% to 222 Bcfe, from 225 Bcfe for the same period in 2016, and was produced entirely by our properties in the United States. The 3 Bcfe decrease was due to a 15 Bcfe decrease in net production from our Fayetteville Shale and other properties, partially offset by a 7 Bcf increase in net production from our Northeast Appalachia properties and a 5 Bcfe increase in net production from our Southwest Appalachia properties, compared to the same period in 2016. Net production from our Northeast Appalachia, Southwest Appalachia and Fayetteville Shale properties was 97 Bcf, 43 Bcfe and 82 Bcf, respectively, for the three months ended June 30, 2017, compared to 90 Bcf, 38 Bcfe, and 96 Bcf, respectively, for the same period in

Table of Contents

2016. For the six months ended June 30, 2017, our natural gas and liquids production decreased 8% to 426 Bcfe, from 462 Bcfe for the same period in 2016, and was produced entirely by our properties in the United States. The 36 Bcfe decrease was due to a 37 Bcfe decrease in net production from our Fayetteville Shale and other properties, partially offset by a 1 Bcfe increase in net production from our Southwest Appalachia properties, compared to the same period in 2016. Production from our Northeast Appalachia properties for the six months ended June 30, 2017 was flat compared to the same period in 2016. Net production from our Northeast Appalachia, Southwest Appalachia and Fayetteville Shale properties was 184 Bcf, 79 Bcfe and 163 Bcf, respectively, for the six months ended June 30, 2017, compared to 184 Bcf, 78 Bcfe, and 199 Bcf, respectively, for the same period in 2016.

Commodity Prices

The average price realized for our natural gas production, including the effects of derivatives, increased to $2.15 per Mcf for the three months ended June 30, 2017, compared to $1.32 per Mcf for the same period in 2016. The increase was primarily due to the $1.14 per Mcf increase in the average realized natural gas price, excluding the effects of derivatives, partially offset by a loss from our derivative program during the three months ended June 30, 2017, compared to a gain for the same period in 2016. The average price realized for our natural gas production, excluding the effects of derivatives, increased 94% to $2.35 per Mcf for the three months ended June 30, 2017, compared to the same period in 2016. Our derivatives decreased the average realized natural gas price by $0.20 per Mcf for the three months ended June 30, 2017, compared to an increase of $0.11 per Mcf for the same period in 2016.

The average price realized for our natural gas production, including the effects of derivatives, increased to $2.35 per Mcf for the six months ended June 30, 2017, compared to $1.40 per Mcf for the same period in 2016. The increase was primarily due to the $1.20 per Mcf increase in the average realized natural gas price, excluding the effects of derivatives, partially offset by a loss from our derivative program during the six months ended June 30, 2017, compared to a gain for the same period in 2016. The average price realized for our natural gas production, excluding the effects of derivatives, increased 90% to $2.53 per Mcf for the six months ended June 30, 2017, compared to the same period in 2016. Our derivatives decreased the average realized natural gas price by $0.18 per Mcf for the six months ended June 30, 2017, compared to an increase of $0.07 per Mcf for the same period in 2016.

Our E&P segment receives a sales price for our natural gas at a discount to average monthly NYMEX settlement prices due to heating content of the gas, locational basis differentials, transportation and fuel charges. Additionally, we receive a sales price for our oil and NGLs at a difference to average monthly West Texas Intermediate settlement and Mont Belvieu NGL composite prices, respectively, due to a number of factors including product quality, composition and types of NGLs sold, locational basis differentials, transportation and fuel charges.

We regularly enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational market differentials. We refer you to Item 3, "Quantitative and Qualitative Disclosures About Market Risks" and Note 6 to the unaudited condensed consolidated financial statements included in this Quarterly Report for additional discussion about our derivatives and risk management activities.

Excluding the impact of derivatives, the average price received for our natural gas production for the six months ended June 30, 2017 of $2.53 per Mcf was approximately $0.72 per Mcf lower than the average monthly NYMEX settlement price, primarily due to locational basis differentials and transportation charges. We protected approximately 64% of our natural gas production for the six months ended June 30, 2017 from the impact of widening basis differentials through our sales arrangements and financial derivatives. As of June 30, 2017, we have physically protected basis on approximately 116 Bcf and 96 Bcf of our remaining 2017 and 2018 expected natural gas production, respectively, through physical sales arrangements at a basis differential to NYMEX natural gas price of approximately ($0.49) per MMBtu and ($0.44) per MMBtu for the remainder of 2017 and 2018, respectively. We have also financially protected basis on approximately 86 Bcf and 20 Bcf of our remaining 2017 and 2018 expected natural gas production, respectively, at a basis differential to NYMEX natural gas price of approximately ($1.03) per MMBtu and ($0.95) per MMBtu for the remainder of 2017 and 2018, respectively. We refer you to Note 6 to the unaudited condensed consolidated financial statements included in this Quarterly Report for additional details about our derivative instruments.

We realized an average sales price of $40.56 per barrel for our oil production for the three months ended June 30, 2017, an increase of approximately 25% from $32.46 per barrel for the same period in 2016. Oil accounted for 1% and 2% of our total production for the three months ended June 30, 2017 and 2016, respectively. We realized an average sales price of $42.08 per barrel for our oil production for the six months ended June 30, 2017, an increase of approximately 65% from $25.43 per barrel for the same period in 2016. Oil accounted for 1% and 2% of our total production for the six

Table of Contents

months ended June 30, 2017 and 2016, respectively. We did not use derivatives to financially protect our 2017 or 2016 oil production.

We realized an average sales price of $11.25 per barrel for our NGL production, including the effect of derivatives, for the three months ended June 30, 2017, an increase of approximately 76% from $6.41 per barrel for the same period in 2016. Our derivatives increased the average realized NGL price by $0.04 per barrel for the three months ended June 30, 2017. NGLs accounted for 9% and 8% of our total production for the three months ended June 30, 2017 and 2016, respectively. We realized an average sales price of $12.22 per barrel for our NGL production, including the effect of derivatives, for the six months ended June 30, 2017, an increase of approximately 116% from $5.67 per barrel for the same period in 2016. Our derivatives increased the average realized NGL price by $0.03 per barrel for the six months ended June 30, 2017. NGLs accounted for 9% and 8% of our total production for the six months ended June 30, 2017 and 2016, respectively. We did not financially protect our NGL production in 2016.

Operating Income

Our E&P segment operating income was $146 million for the three months ended June 30, 2017, an increase from an operating loss of $549 million for the same period in 2016. The E&P segment recorded a $470 million impairment of natural gas and oil properties for the three months ended June 30, 2016. Excluding the 2016 impairment, our E&P segment operating income increased $225 million for the three months ended June 30, 2017, compared to the same period in 2016, primarily due to a $247 million increase in revenue related to increased realized natural gas, oil and NGL prices (excluding derivatives), partially offset by a $17 million increase in depreciation, depletion and amortization expense and a $5 million decrease in revenue resulting from a 3 Bcfe decrease in production. For the three months ended June 30, 2016, general and administrative expenses included $11 million related to restructuring charges.

Our E&P segment operating income was $371 million for the six months ended June 30, 2017, an increase from an operating loss of $1.7 billion for the same period in 2016. The E&P segment recorded a $1.5 billion impairment of natural gas and oil properties for the six months ended June 30, 2016. Excluding the 2016 impairment, our E&P segment operating income increased $576 million for the six months ended June 30, 2017, compared to the same period in 2016, primarily due to a $518 million increase in revenue related to increased realized natural gas, oil and NGL prices (excluding derivatives) and a $107 million decrease in operating costs and expenses, partially offset by a $49 million decrease in revenue resulting from a 36 Bcfe decrease in production. For the six months ended June 30, 2016, general and administrative expenses and taxes other than income taxes included $69 million and $3 million, respectively, related to restructuring charges.

Operating Costs and Expenses

Lease operating expenses per Mcfe for the E&P segment were $0.89 for the three months ended June 30, 2017, compared to $0.87 for the same period in 2016. Lease operating expenses per Mcfe increased for the three months ended June 30, 2017, compared to the same period of 2016, primarily due to the impact of increased prices for natural gas used as compressor fuel. In total, lease operating expenses for the E&P segment were $200 million and $196 million for the three months ended June 30, 2017 and 2016, respectively. Lease operating expenses per Mcfe for the E&P segment were $0.89 for the six months ended June 30, 2017, compared to $0.88 for the same period in 2016. Lease operating expenses per Mcfe increased for the six months ended June 30, 2017, compared to the same period of 2016, primarily due to the impact of increased prices for natural gas used as compressor fuel. In total, lease operating expenses for the E&P segment were $381 million and $405 million for the six months ended June 30, 2017 and 2016, respectively.

General and administrative expenses for the E&P segment increased to $0.23 per Mcfe for the three months ended June 30, 2017, compared to $0.21 per Mcf for the same period in 2016, excluding the restructuring charges associated with our 2016 workforce reduction, primarily as a result of increased professional fees. In total, general and administrative expenses for the E&P segment were $50 million and $46 million for the three months ended June 30, 2017 and 2016, respectively, excluding the 2016 restructuring charges. Including restructuring charges, general and administrative costs for three months ended June 30, 2016 were $57 million for our E&P segment. General and administrative expenses for the E&P segment increased to $0.22 per Mcfe for the six months ended June 30, 2017, compared to $0.20 per Mcf for the same period in 2016, excluding the 2016 restructuring charges, primarily as a result of decreased production volumes and increased professional fees. In total, general and administrative expenses for the E&P segment were $93 million and $91 million for the six months ended June 30, 2017 and 2016, respectively, excluding the 2016 restructuring charges. Including restructuring charges, general and administrative costs for six months ended June 30, 2016 were $160 million for our E&P segment.

Taxes other than income taxes per Mcfe were $0.10 for the three months ended June 30, 2017, compared to $0.09 per Mcfe for the same period in 2016. Taxes other than income taxes per Mcfe were $0.11 for the six months ended June 30, 2017, compared to $0.09 per Mcfe for the same period in 2016, excluding $3 million relating to restructuring charges in the first quarter of 2016. Taxes other than income taxes per Mcfe vary from period to period due to changes in ad valorem and severance taxes that result from the mix of our production volumes and fluctuations in commodity prices.

Our full cost pool amortization rate averaged $0.44 per Mcfe and $0.35 per Mcfe for the three months ended June 30, 2017 and 2016, respectively. The increase in the average amortization rate resulted primarily from the addition of future development costs associated with proved undeveloped reserves recognized as a result of improved commodity prices. Our full cost pool amortization rate averaged $0.42 per Mcfe for the six months ended June 30, 2017 and 2016. The amortization rate is impacted by the timing and amount of reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from full cost ceiling impairments, proceeds from the sale of properties that reduce the full cost pool and the levels of costs subject to amortization. We cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as other factors, including but not limited to the uncertainty of the amount of future reserve changes. In total, depreciation, depletion and amortization expense for the E&P segment was $107 million and $90 million for the three months ended June 30, 2017 and 2016, respectively and $197 million and $217 million for the six months ended June 30, 2017 and 2016, respectively.

Unevaluated costs excluded from amortization were $2.0 billion at June 30, 2017, compared to $2.1 billion at December 31, 2016. The unevaluated costs excluded from amortization remained relatively flat as the evaluation of previously unevaluated properties totaling $284 million in the first half of 2017 was partially offset by the impact of $204 million of unevaluated capital invested during the same period.

Midstream Services

	For the three months ended June 30,		For the six months ended June 30,	
	2017	2016	2017	2016
	($ in millions, except volumes)			
Marketing revenues	$ 740	$ 462	$ 1,517	$ 980
Gas gathering revenues	$ 82	$ 97	$ 163	$ 200
Marketing purchases	$ 731	$ 452	$ 1,496	$ 955
Operating costs and expenses (1)	$ 49	$ 50	$ 101	$ 108
Operating income	$ 42	$ 57	$ 83	$ 117
Volumes marketed (Bcfe)	264	271	509	550
Volumes gathered (Bcf)	128	154	257	318

(1) Includes less than $1 million and $3 million of restructuring charges for the three and six months ended June 30, 2016.

Revenues

Revenues from our marketing activities increased 60% to $740 million for the three months ended June 30, 2017, compared to the same period in 2016, and were up 55% to $1,517 million for the six months ended June 30, 2017, compared to the same period in 2016. For the three months ended June 30, 2017, the price received for volumes marketed increased 64% and the volumes marketed decreased 3%, compared to the same period in 2016. For the six months ended June 30, 2017, the price received for volumes marketed increased 67% and the volumes marketed decreased 7%, compared to the same period in 2016. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in marketing purchase expenses. Of the total natural gas volumes marketed, production from our affiliated E&P operated wells accounted for 96% and 94% of the natural gas marketed volumes for the three months ended June 30, 2017 and 2016, respectively. For the six months ended June 30, 2017 and 2016, production from our affiliated E&P operated wells accounted for 96% and 95%, respectively, of our total natural gas volumes marketed. Our Midstream Services segment marketed approximately 62% and 65% of our combined oil and NGL production for the three months ended June 30, 2017 and 2016, respectively, and 64% and 66% of our combined oil and NGL production for the six months ended June 30, 2017 and 2016, respectively.

Revenues from our gathering activities decreased 15% to $82 million for the three months ended June 30, 2017, compared to the same period in 2016, and decreased 19% to $163 million for the six months ended June 30, 2017, compared to the same period in 2016. The decreases in the gathering revenues for the three and six months ended June 30, 2017 were primarily due to the decreased volumes in the Fayetteville Shale, compared to the same periods in 2016.

Table of Contents

Operating Income

Operating income from our Midstream Services segment decreased to $42 million for the three months ended June 30, 2017, compared to $57 million for the same period in 2016, primarily due to a $15 million decrease in gas gathering revenues and a $1 million decrease in marketing margin, partially offset by a $1 million decrease in operating costs and expenses. Operating income from our Midstream Services segment decreased to $83 million for the six months ended June 30, 2017, compared to $117 million for the same period in 2016, primarily due to a $37 million decrease in gas gathering revenues and a $4 million decrease in marketing margin, partially offset by a $7 million decrease in operating costs and expenses.

The margin generated from marketing activities was $9 million and $10 million for the three months ended June 30, 2017 and 2016, respectively. The margin generated from marketing activities was $21 million and $25 million for the six months ended June 30, 2017 and 2016, respectively. Margins are driven primarily by volumes marketed and may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. We enter into derivative contracts from time to time with respect to our natural gas marketing activities to provide margin protection. For more information about our derivatives and risk management activities, we refer you to Item 3, "Quantitative and Qualitative Disclosures About Market Risks" included in this Quarterly Report for additional information.

Restructuring Charges

In January 2016, we announced a 40% workforce reduction, which was substantially concluded by the end of March 2016. In April 2016, we also partially restructured executive management. Affected employees were offered a severance package that included a one-time cash payment depending on length of service and, if applicable, accelerated vesting of outstanding stock-based equity awards. As a result of the workforce reduction and executive management restructuring, we recognized restructuring charges of $11 million and $75 million for the three and six months ended June 30, 2016, respectively.

Interest Expense

Interest expense, net of capitalization, was $34 million and $17 million for the three months ended June 30, 2017 and 2016, respectively, and $66 million and $31 million of interest expense, net of capitalization, for the six months ended June 30, 2017 and 2016, respectively. Gross interest expense was $62 million and $58 million for the three months ended June 30, 2017 and 2016, respectively, and $122 million and $113 million for the six months ended June 30, 2017 and 2016, respectively. The increase in gross interest expense was primarily due to an increase in our cost of debt. We capitalized interest of $28 million and $41 million for the three months ended June 30, 2017 and 2016, respectively and capitalized interest of $56 million and $82 million for the six months ended June 30, 2017 and 2016, respectively. The decrease in capitalized interest for the three and six months ended June 30, 2017, compared to the same periods in 2016, was primarily due to the evaluation of a portion of our Southwest Appalachia assets acquired in December 2014.

Gain (Loss) on Derivatives

Our current derivatives are not designated for hedge accounting treatment. Changes in the fair value of derivatives that are not designated for hedge accounting are recorded in gain (loss) on derivatives. We recorded a $134 million net gain on our derivatives for the three months ended June 30, 2017, consisting of a $173 million gain on unsettled derivatives, partially offset by a $39 million loss on settled derivatives. For the three months ended June 30, 2016, we recorded an $85 million net loss on our derivatives, consisting of a $108 million loss on unsettled derivatives, partially offset by a $23 million gain on settled derivatives. We recorded a $250 million net gain on our derivatives for the six months ended June 30, 2017, consisting of a $319 million gain on unsettled derivatives, partially offset by a $69 million loss on settled derivatives. For the six months ended June 30, 2016, we recorded a $99 million net loss on our derivatives, consisting of a $129 million loss on unsettled derivatives, partially offset by a $30 million gain on settled derivatives. We refer you to Note 6 to the unaudited condensed consolidated financial statements included in this Quarterly Report for additional details about our gain (loss) on derivatives. In general and without consideration of volatility or duration, as natural gas prices increase from June 30, 2017 levels, we will recognize losses in future periods and, likewise, as natural gas prices decline from June 30, 2017 levels, we will recognize gains in future periods on our derivative contracts not designated for hedge accounting treatment prior to settlement.

Table of Contents

Income Taxes

Our effective tax rate was approximately 0% for the six months ended June 30, 2017 and 2016. We recorded income tax expense of less than $1 million for the three months ended June 30, 2017, and a $1 million income tax benefit for the three months ended June 30, 2016. We recorded an income tax benefit of less than $1 million for the six months ended June 30, 2017. Our low effective tax rate is the result of our recognition of a valuation allowance that reduced the deferred tax asset primarily related to our current net operating loss carryforward. 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.

New Accounting Standards Implemented in this Report

Refer to Note 15 to the unaudited condensed consolidated financial statements of this Quarterly Report for a discussion of new accounting standards which have been implemented.

New Accounting Standards Not Yet Implemented in this Report

Refer to Note 15 to the unaudited condensed consolidated financial statements of this Quarterly Report for a discussion of new accounting standards which have not yet been implemented.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on funds generated from our operations, our cash and cash equivalents balance, our $809 million revolving credit facilities and capital markets as our primary sources of liquidity.

During 2016, we took significant steps in managing our maturities and liquidity. In June 2016, we refinanced approximately 97% of our principal credit facility, which was due in December 2018, including extending the maturity by two years until December 2020, granting liens on certain assets and modifying borrowing rates and covenants. We simultaneously modified borrowing rates and covenants under our $750 million unsecured term loan facility and extended its maturity by two years also until December 2020. The maturity dates of our principle credit facility and our term loan facilities will accelerate to October 2019 if, by that date, we have not amended, redeemed or refinanced at least $765 million of our senior notes due in January 2020. In July 2016, we completed a public offering of 98,900,000 shares of our common stock, with net proceeds totaling approximately $1,247 million after underwriting discounts and offering expenses. Of the funds received from the common stock offering, $375 million was used to pay down a portion of our $750 million unsecured term loan and $750 million was used to settle certain tender offers by purchasing an aggregate principal amount of approximately $700 million of our outstanding senior notes due in the first quarter of 2018. The repayment of $375 million on the $750 million unsecured term loan had the effect of extending its maturity date to December 2020 subject to the conditions described above. In September 2016, we completed the sale of 55,000 net acres in West Virginia for $422 million, subject to customary post-closing adjustments, and used $48 million of the proceeds to further decrease the balance of this term loan. We earmarked the remaining funds from the equity issuance and the sale of the West Virginia acreage for capital activity. In March 2017, we repurchased $25 million of our 7.50% Senior Notes due February 2018, and in May 2017, we redeemed the remaining $251 million principal amount outstanding of our 2018 Senior Notes. We recognized a loss on the extinguishment of debt of $10 million and $11 million for the three and six months ended June 30, 2017, respectively.

During the first half of 2016, we suspended drilling and completion activity in the Appalachian Basin and Fayetteville Shale as a result of the commodity price environment. After the successful implementation of our debt reduction strategy along with our equity offering, we began increasing our activity in the third quarter of 2016, which has continued throughout the first half of 2017. Although we have the financial flexibility to draw on the funds available under our cash balance and revolving credit facility as necessary, we continue to be committed to our capital discipline strategy of investing within our cash flow from operations, supplemented by the remaining funds from the July 2016 equity issuance and asset sale in West Virginia. We refer you to Note 9 of the unaudited condensed consolidated financial statements included in this Quarterly Report and the section below under "Financing Requirements" for additional discussion of our credit facilities.

The credit status of the financial institutions participating in our revolving credit facilities could adversely impact our ability to borrow funds under the revolving credit facilities. Although we believe all of the lenders under the facilities have the ability to provide funds, we cannot predict whether each will be able to meet their obligation to us. We refer you to the section below under "Financing Requirements" for additional discussion of our compliance with the covenants of our term loans and revolving credit facilities.

Net cash provided by operating activities increased 250% to $578 million for the six months ended June 30, 2017, from $165 million for the same period in 2016, primarily due to an increase in net income adjusted for non-cash expenses and changes in working capital accounts. During the six months ended June 30, 2017, requirements for our capital investments were funded primarily from our cash generated by operating activities and cash and cash equivalents. Net cash generated from operating activities was 94% of our cash requirements for capital investments for the six months ended June 30, 2017, compared to net cash from operating activities being 84% of our cash requirements for capital investments for the same period in 2016, reflecting our commitment to our capital discipline strategy of investing within our cash flow from operations, supplemented by the 2016 equity issuance and asset sales, during the current commodity price environment.

Our cash flow from operating activities is highly dependent upon the sales prices that we receive for our natural gas and liquids production. Natural gas, oil and NGL prices are subject to wide fluctuations and are driven by market supply and demand, which is impacted by many factors. The sales price we receive for our production is also influenced by our commodity hedging activities. See "Quantitative and Qualitative Disclosures about Market Risks" in Item 3 and Note 6 to the unaudited condensed consolidated financial statements included in this Quarterly Report for further details. Our commodity hedging activities are subject to the credit risk of our counterparties being financially unable to complete the transaction. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. However, any future failures by one or more counterparties could negatively impact our cash flow from operating activities.

Additionally, our short-term cash flows are dependent on the timely collection of receivables from our customers and joint interest partners. We actively manage this risk through credit management activities and, through the date of this filing, have not experienced any significant write-offs for non-collectable amounts. However, any sustained inaccessibility of credit by our customers and joint interest partners could adversely impact our cash flows.

Due to these above factors, we are unable to forecast with certainty our future level of cash flow from operations. Accordingly, we expect to adjust our discretionary uses of cash depending upon available cash flow. Further, we may from time to time seek to retire or rearrange some or all of our outstanding debt or preferred stock through cash purchases, and/or exchanges, open market purchases, privately negotiated transactions, tender offers or otherwise. Such transactions, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Capital Investments

Our capital investments were $325 million and $74 million for the three months ended June 30, 2017 and 2016, respectively, and $615 million and $196 million for the six months ended June 30, 2017 and 2016, respectively. Our E&P segment investments were $318 million and $73 million for the three months ended June 30, 2017 and 2016, respectively, and $601 million and $193 million for the six months ended June 30, 2017 and 2016, respectively. Our E&P segment capitalized internal costs of $36 million for the three months ended June 30, 2017 compared to $22 million for the same period in 2016. For the six months ended June 30, 2017, our E&P segment capitalized internal costs of $68 million compared to $49 million for the same period in 2016. These internal costs were directly related to acquisition, exploration and development activities and are included as part of the cost of natural gas and oil properties.

Although our 2017 capital investment program is expected to be funded through cash flow from operations along with our cash and cash equivalents, we have the financial flexibility to utilize borrowings under our revolving credit facilities.

Financing Requirements

Our total debt outstanding was $4.4 billion and $4.6 billion as of June 30, 2017 and December 31, 2016, respectively. Our total debt, net of cash and cash equivalents of $1.1 billion, was $3.3 billion at June 30, 2017, compared to $3.2 billion, net of $1.4 billion of cash and cash equivalents, at December 31, 2016. Our actions to reduce and extend maturities on our total debt outstanding are further discussed below.

At August 1, 2017, we had a long-term issuer credit rating of Ba3 by Moody’s, a long-term debt rating of BB- by S&P and a long-term issuer default rating of BB by Fitch Ratings. Any downgrades in our public debt ratings by Moody’s or S&P could increase our cost of funds and decrease our liquidity under our revolving credit facilities.

Table of Contents

At June 30, 2017, our capital structure consisted of 74% debt (excluding $1.1 billion in cash and cash equivalents) and 26% equity, compared to 84% debt (excluding $1.4 billion in cash and cash equivalents) and 16% equity at December 31, 2016.

In July 2016, we consummated an underwritten offering of 98,900,000 shares of our common stock pursuant to an effective registration statement filed with the Securities and Exchange Commission, with net proceeds of the offering totaling approximately $1,247 million after underwriting discounts and offering expenses. A portion of the proceeds from the offering were used to repay $375 million of the $750 million term loan entered into in November 2015 and to settle certain tender offers by purchasing an aggregate principal amount of approximately $700 million of our outstanding senior notes due in the first quarter of 2018. The remaining net proceeds of the offering were used for general corporate purposes, including the completion of wells already drilled or the funding of other capital projects.

In June 2016, we reduced our existing $2.0 billion unsecured revolving credit facility to $66 million and entered into a new credit agreement for $1,934 million, consisting of a $1,191 million secured term loan and a new unsecured $743 million revolving credit facility, which matures in December 2020. The maturity date will accelerate to October 2019 if, by that date, we have not amended, redeemed or refinanced at least $765 million of our senior notes due in January 2020. The $1,191 million secured term loan is fully drawn, with approximately $285 million of this balance used to pay down the existing revolving credit facility balance in its entirety. As of June 30, 2017, there were no borrowings under either revolving credit facility; however, there was $326 million in letters of credit outstanding against the 2016 revolving credit facility.

Loans under the 2016 credit agreement are subject to varying rates of interest based on whether the loan is a Eurodollar loan or an alternate base rate loan. Eurodollar loans bear interest at the Eurodollar rate, which is adjusted London Interbank Offer Rate ("LIBOR") plus applicable margins ranging from 1.750% to 2.500%. Alternate base rate loans bear interest at the alternate base rate plus the applicable margin ranging from 0.750% to 1.500%. The interest rate on the term loan facility is determined based upon our public debt ratings and was 250 basis points over LIBOR as of June 30, 2017.

Our 2016 credit agreement contains financial covenants that impose certain restrictions on us. Under our revolving credit and term loan facilities, we must keep a minimum interest coverage of 1.00x in 2017, increasing by 0.25x increments per year to 1.50x in 2019 and 2020. We are also subject to a minimum liquidity requirement of $300 million, which could be increased up to $500 million upon certain conditions, as well as an anti-hoarding provision, requiring unrestricted cash in excess of $100 million to pay down any amounts borrowed under the new revolving credit facility. The financial covenant with respect to minimum interest coverage consists of EBITDAX divided by consolidated interest expense. EBITDAX, as defined in our 2016 credit agreement, excludes the effects of interest expense, income taxes, depreciation, depletion and amortization, any non-cash impacts from impairments, certain non-cash hedging activities, stock-based compensation expense, non-cash gains or losses on asset sales, unamortized issuance cost, unamortized debt discount and certain restructuring costs. Collateral for the new secured term loan is principally our E&P properties in the Fayetteville Shale area, the equity of its subsidiaries and cash and marketable securities on hand. This collateral also may support all or a part of revolving credit extensions depending on restrictions in our senior notes indentures, and requires a minimum collateral coverage ratio of 1.50x.

The existing unsecured 2013 revolving credit facility includes a financial covenant under which we may not issue total debt in excess of 60% of our total adjusted book capital, as defined in that agreement. This financial covenant with respect to capitalization percentages excludes the effects of any full cost ceiling impairments, certain hedging activities and our pension and other postretirement liabilities. We are in compliance with this covenant. As of June 30, 2017, the maximum amount available under this credit facility was $66 million, with no amounts outstanding.

In November 2015, we entered into a $750 million unsecured three-year term loan credit agreement with various lenders that was used to repay borrowings under the existing revolving credit facility. The interest rate on the term loan facility is determined based upon our public debt ratings from Moody's and S&P and was 250 basis points over LIBOR as of June 30, 2017. The term loan facility requires prepayment under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business. In June 2016, the 2015 term loan agreement was amended to extend the maturity date, provided at least 50% would be paid down by June 2017. After our July 2016 equity offering, we repaid $375 million of the $750 million term loan, which had the effect of extending its maturity from November 2018 to December 2020. The maturity date will accelerate to October 2019 if, by that date, we have not amended, redeemed or refinanced at least $765 million of our senior notes due January 2020. In September 2016, we repaid an additional $48 million of the term loan with proceeds from the sale of our West Virginia acreage.

Table of Contents

As of June 30, 2017, we were in compliance with all of the covenants of the term loans and revolving credit facilities. Although we do not anticipate any violations of the financial covenants, our ability to comply with these covenants is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and liquids.

Our mandatory convertible preferred stock, issued in January 2015, entitles the holders to a proportional fractional interest in the rights and preferences of the convertible preferred stock, including conversion, dividend, liquidation and voting rights. Dividends are to be paid at a rate of 6.25% per annum on the liquidation preference of $1,000 per share and can be paid in cash, common stock or a combination of both. Since inception, and as of August 1, 2017, we have made four of the quarterly dividend payments in cash and six of the quarterly dividend payments in stock. Unless converted earlier at the option of the holders, on or around January 15, 2018 each share of convertible preferred stock will automatically convert into between 37.0028 and 43.4782 shares of our common stock (correspondingly, each depositary share will convert into between 1.85014 and 2.17391 shares of our common stock), subject to customary anti-dilution adjustments, depending on the volume-weighted average price of our common stock over a 20 trading-day period immediately prior to that date.

Our mandatory convertible preferred stock has the non-forfeitable right to participate on an as-converted basis at the conversion rate then in effect in any common stock dividends declared and as such, is considered a participating security. As such, it is included in the computation of basic and diluted earnings per share, pursuant to the two-class method. In the calculation of basic earnings per share attributable to common shareholders, participating securities are allocated earnings based on actual dividend distributions received plus a proportionate share of undistributed net income attributable to common shareholders, if any, after recognizing distributed earnings.

In January 2015, we completed a public offering of $350 million aggregate principal amount of our 3.30% senior notes due 2018 (the “2018 Notes”), $850 million aggregate principal amount of our 4.05% senior notes due 2020 (the “2020 Notes”) and $1.0 billion aggregate principal amount of our 4.95% senior notes due 2025 (the “2025 Notes” and together with the 2018 and 2020 Notes, the “Notes”), with net proceeds from the offering totaling approximately $2.2 billion after underwriting discounts and offering expenses. The interest rates on the Notes are determined based on our public bond ratings from Moody’s and S&P. Downgrades on the Notes from either rating agency increase our interest costs by 25 basis points per downgrade level on the following semi-annual bond interest payment. Based on the February and June 2016 downgrades from Moody’s and S&P, our interest rates on these Notes increased by 175 basis points in July 2016. In July 2016, we used a portion of the proceeds from the July 2016 equity offering to settle certain tender offers by purchasing an aggregate principal amount of approximately $700 million of our outstanding senior notes due in the first quarter of 2018. In March 2017, we repurchased $25 million of our 7.50% Senior Notes due February 2018. In May 2017, the Company redeemed all (i) $187 million principal amount of its outstanding 7.50% Senior Notes due February 2018, (ii) $38 million principal amount of its outstanding 3.30% Senior Notes due January 2018 and (iii) $26 million principal amount of its outstanding 7.15% Senior Notes due June 2018. As of June 30, 2017, we have retired all of our 2018 Senior Notes.

Our derivative contracts allow us to ensure a certain level of cash flow to fund our operations. Excluding basis swaps, at June 30, 2017, we had commodity price derivatives in place on 284 Bcf of our remaining targeted 2017 natural gas production, and 389 Bcf and 108 Bcf on our targeted 2018 and 2019 natural gas production, respectively. We also had commodity derivatives in place on 92 MBbls of our remaining targeted 2017 ethane production and 183 MBbls of our targeted 2018 ethane production.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of June 30, 2017, our material off-balance sheet arrangements and transactions include operating lease arrangements and $326 million in letters of credit outstanding against our 2016 revolving credit facility. There are no other transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of our capital resources. For more information regarding off-balance sheet arrangements, we refer you to “Contractual Obligations and Contingent Liabilities and Commitments” in our 2016 Annual Report.

Table of Contents

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. Other than the firm transportation and gathering agreements discussed below, there have been no material changes to our contractual obligations from those disclosed in our 2016 Annual Report on Form 10-K.

Contingent Liabilities and Commitments

As of June 30, 2017, our contractual obligations for demand and similar charges under firm transport and gathering agreements to guarantee access capacity on natural gas and liquids pipelines and gathering systems totaled approximately $8.6 billion, $3.6 billion of which related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and/or additional construction efforts. This amount also included guarantee obligations of up to $822 million. As of June 30, 2017, future payments under non-cancelable firm transportation and gathering agreements are as follows:

	Payments Due by Period					
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	5 to 8 Years	More than 8 Years
	(in millions)					
Infrastructure Currently in Service	$ 4,944	$ 580	$ 1,128	$ 766	$ 843	$ 1,627
Pending Regulatory Approval and/or Construction (1)	3,608	46	398	464	714	1,986
Total Transportation Charges	$ 8,552	$ 626	$ 1,526	$ 1,230	$ 1,557	$ 3,613

(1) Based on the estimated in-service dates as of June 30, 2017.

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. For the six months ended June 30, 2017, we have contributed $8 million to the pension and postretirement benefit plans. We expect to contribute an additional $6 million to our pension and postretirement benefit plans during the remainder of 2017. As of June 30, 2017 and December 31, 2016, we recognized liabilities of $47 million and $49 million, respectively, as a result of the underfunded status of our pension and other postretirement benefit plans. See Note 11 to the unaudited condensed consolidated financial statements included in this Quarterly Report for additional discussion about our pension and other postretirement benefits.

We are subject to various litigation, claims and proceedings that arise in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties and pollution, contamination or nuisance. We accrue for such items when a liability is both probable and the amount can be reasonably estimated. Management believes that current litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on our financial position, results of operations or cash flows, although it is possible that adverse outcomes could have a material adverse effect on our results of operations or cash flows for the period in which the effect of that outcome becomes reasonably estimable. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and are all subject to inherent uncertainties; therefore, management's view may change in the future. For further information, we refer you to "Litigation" and "Environmental Risk" in Note 10 to the unaudited condensed consolidated financial statements included in Item 1 of Part I of this Quarterly Report.

We are also subject to laws and regulations relating to the protection of the environment. Environmental and cleanup related costs of a non-capital nature are accrued when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on our financial position or results of operations.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our cash and cash equivalents and our revolving credit facilities, described in "Financing Requirements" above. We had positive working capital of $758 million at June 30, 2017 and positive working capital of $808 million at December 31, 2016. The positive working capital as of June 30, 2017 and December 31, 2016 was primarily due to $1.1 billion and $1.4 billion of cash and cash equivalents, respectively.

Table of Contents

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Market risks relating to our operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as service costs and credit risk concentrations. We use fixed price swap agreements, fixed price options, basis swaps and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and interest rates. Our Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price risk. Utilization of financial products for the reduction of interest rate risk is also overseen by our Board of Directors. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of our physical commodity purchasers and their dispersion across geographic areas. No single purchaser accounted for greater than 10% of revenues for the six months ended June 30, 2017. See "Commodities Risk" below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

As of June 30, 2017, we had approximately $2.9 billion of outstanding senior notes with a weighted average interest rate of 5.54% and $1.5 billion of term loan facility debt with a variable interest rate of 3.69%. We currently have an interest rate swap in effect to mitigate a portion of our exposure to volatility in interest rates.

	Expected Maturity Date						
	2017	2018	2019	2020	2021	Thereafter	Total
Fixed Rate Payments (1)	$ 40	$ –	$ –	$ 850	$ –	$ 2,000	$ 2,890
Weighted Average Interest Rate	7.21 %	– %	– %	5.80 %	– %	5.40 %	5.54 %
Variable Rate Payments (1)	–	–	–	1,518(2)	–	–	1,518
	– %	– %	– %	3.69 %	– %	– %	3.69 %

Weighted Average Interest
Rate

(1) Excludes unamortized debt issuance costs and debt discounts.

(2) The maturity date will accelerate to October 2019 if, by that date, we have not amended, redeemed or refinanced at least $765 million of our 2020 Senior Notes.

Commodities Risk

We use over-the-counter fixed price swap agreements and options to protect sales of our production against the inherent risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX futures market. These swaps and options include transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps) and transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps). For additional information on our derivatives and risk management, see Note 6 in the unaudited condensed consolidated financial statements included in this Quarterly Report.

The primary market risks relating to our derivative contracts are the volatility in market prices and basis differentials for natural gas. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas that is financially protected. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major banks and integrated energy companies that management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure we have to each counterparty are closely monitored to limit our credit risk exposure. Additionally, we perform both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. We have not incurred any counterparty losses related to non-performance and do not anticipate any losses given the information we have currently. However, we cannot be certain that we will not experience such losses in the future.

Table of Contents

Item 4. Controls and Procedures.

Disclosure Controls and Procedures

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act. Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submission within the time periods specified in the SEC's rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a level of reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of June 30, 2017 at a reasonable assurance level.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended June 30, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS.

Refer to "Litigation" and "Environmental Risk" in Note 10 to the unaudited condensed consolidated financial statements included in Item 1 of Part I of this Quarterly Report for a discussion of the Company's legal proceedings.

ITEM 1A. RISK FACTORS.

There were no additions or material changes to our risk factors as disclosed in Item 1A of Part I in the Company's 2016 Annual Report.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS.

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES.

Our sand mining operations in support of our E&P business are subject to regulation by the Federal Mine Safety and Health Administration under the Federal Mine Safety and Health Act of 1977. Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.106) is included in Exhibit 95.1 to this Quarterly Report.

ITEM 5. OTHER INFORMATION.

The Company is combining its activities fostering innovative solutions for responsible development of natural resources with its broader technological innovation programs. Mark K. Boling, Executive Vice President and President, V+ Development Solutions, will be leaving the Company in August 2017. Mr. Boling has been offered benefits similar to those offered to other executives affected by recent restructurings.

Table of Contents

ITEM 6. EXHIBITS.

(10.1)*	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Award Agreement for Directors
(31.1)*	Certification of CEO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
(31.2)*	Certification of CFO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
(32.1)*	Certification of CEO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
(32.2)*	Certification of CFO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
(95.1)*	Mine Safety Disclosure
(101.INS)	Interactive Data File Instance Document
(101.SCH)	Interactive Data File Schema Document
(101.CAL)	Interactive Data File Calculation Linkbase Document
(101.LAB)	Interactive Data File Label Linkbase Document
(101.PRE)	Interactive Data File Presentation Linkbase Document
(101.DEF)	Interactive Data File Definition Linkbase Document

*Filed herewith

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.

SOUTHWESTERN ENERGY COMPANY
Registrant

Dated:	August 3, 2017	/s/ JENNIFER STEWART
		Jennifer Stewart Senior Vice President and Chief Financial Officer – Interim

43