SOUTHWESTERN ENERGY CO
Form 10-Q
May 07, 2018
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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 March 31, 2018

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

10000 Energy Drive

Spring, Texas (Address of principal executive offices)	77389 (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 April 30, 2018
Common Stock, Par Value $0.01	586,806,166

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SOUTHWESTERN ENERGY COMPANY

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FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2018

PART I – FINANCIAL INFORMATION

PART II – OTHER INFORMATION

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

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

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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 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.

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PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	For the three months ended March 31,	
(in millions, except share/per share amounts)	2018	2017
Operating Revenues:		
Gas sales	$ 540	$ 503
Oil sales	35	23
NGL sales	65	40
Marketing	253	253
Gas gathering	24	27
Other	3	–
	920	846
Operating Costs and Expenses:		
Marketing purchases	255	251
Operating expenses	189	147
General and administrative expenses	55	50
Depreciation, depletion and amortization	143	106
Taxes, other than income taxes	23	26
	665	580
Operating Income	255	266
Interest Expense:		
Interest on debt	65	58
Other interest charges	2	2
Interest capitalized	(28)	(28)
	39	32
Gain (Loss) on Derivatives	(7)	116
Other Income (Loss), Net	(1)	1
Income Before Income Taxes	208	351
Provision (Benefit) for Income Taxes:		
Current	–	–
Deferred	–	–
	–	–
Net Income	$ 208	$ 351
Mandatory convertible preferred stock dividend	–	27

Participating securities - mandatory convertible preferred stock	3	43
Net Income Attributable to Common Stock	$ 205	$ 281
Earnings Per Common Share:		
Basic	$ 0.36	$ 0.57
Diluted	$ 0.36	$ 0.57
Weighted Average Common Shares Outstanding:		
Basic	571,297,804	493,068,000
Diluted	573,844,459	494,494,995

The accompanying notes are an integral part of these

unaudited condensed consolidated financial statements.

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

(in millions)	For the three months ended March 31, 2018 (1)	2017
Net income	$ 208	$ 351
Change in value of pension and other postretirement liabilities:		
Amortization of prior service cost and net loss included in net periodic pension cost (2)	–	–
Comprehensive income	$ 208	$ 351

(1) In 2018, deferred tax activity incurred in other comprehensive income was offset by a valuation allowance.
(2) Net of $1 million in taxes for the three months ended March 31, 2017.

The accompanying notes are an integral part of these

unaudited condensed consolidated financial statements.

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

	March 31, 2018	December 31, 2017
ASSETS	(in millions)	
Current assets:		
Cash and cash equivalents	$ 958	$ 916
Accounts receivable, net	382	428
Derivative assets	110	130
Other current assets	38	35
Total current assets	1,488	1,509
Natural gas and oil properties, using the full cost method, including $1,822 million as of March 31, 2018 and $1,817 million as of December 31, 2017 excluded from amortization	24,224	23,890
Gathering systems	1,318	1,315
Other	562	564
Less: Accumulated depreciation, depletion and amortization	(20,136)	(19,997)
Total property and equipment, net	5,968	5,772
Other long-term assets	257	240
TOTAL ASSETS	$ 7,713	$ 7,521
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 555	$ 533
Taxes payable	50	62
Interest payable	64	70
Dividends payable	–	27
Derivative liabilities	40	64
Other current liabilities	23	24
Total current liabilities	732	780
Long-term debt	4,393	4,391
Pension and other postretirement liabilities	58	58
Other long-term liabilities	337	313
Total long-term liabilities	4,788	4,762
Commitments and contingencies (Note 10)		
Equity:		
Common stock, $0.01 par value; 1,250,000,000 shares authorized; issued 586,833,276 shares as of March 31, 2018 and 512,134,311 as of December 31, 2017	6	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 December 31, 2017, converted to common stock on January 12, 2018	–	–
Additional paid-in capital	4,703	4,698
Accumulated deficit	(2,471)	(2,679)

Accumulated other comprehensive loss	(44)	(44)
Common stock in treasury, 31,269 shares as of March 31, 2018 and December 31, 2017	(1)	(1)
Total equity	2,193	1,979
TOTAL LIABILITIES AND EQUITY	$ 7,713	$ 7,521

The accompanying notes are an integral part of these

unaudited condensed consolidated financial statements.

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

	For the three months ended March 31,	
	2018	2017
	(in millions)	
Cash Flows From Operating Activities:		
Net income	$ 208	$ 351
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	143	106
Amortization of debt issuance costs	2	2
Gain on derivatives, unsettled	(2)	(146)
Stock-based compensation	4	6
Other	3	(1)
Change in assets and liabilities:		
Accounts receivable	46	53
Accounts payable	(17)	(13)
Taxes payable	(12)	(8)
Interest payable	(4)	(24)
Other assets and liabilities	(7)	(14)
Net cash provided by operating activities	364	312
Cash Flows From Investing Activities:		
Capital investments	(302)	(340)
Proceeds from sale of property and equipment	6	2
Other	2	4
Net cash used in investing activities	(294)	(334)
Cash Flows From Financing Activities:		
Payments on current portion of long-term debt	–	(25)
Change in bank drafts outstanding	–	6
Preferred stock dividend	(27)	–
Cash paid for tax withholding	(1)	–
Net cash used in financing activities	(28)	(19)
Increase (decrease) in cash and cash equivalents	42	(41)
Cash and cash equivalents at beginning of year	916	1,423
Cash and cash equivalents at end of period	$ 958	$ 1,382

The accompanying notes are an integral part of these

unaudited condensed consolidated financial statements.

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

	Common Stock Shares Issued	Amount	Preferred Stock Shares Issued	Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Income	Common Stock in Treasury	
	(in millions, except share amounts)							
Balance at December 31, 2017	512,134,311	$ 5	1,725,000	$ 4,698	$ (2,679)	$ (44)	$ (1)	$
Comprehensive income:								
Net income	–	–	–	–	208	–	–	
Other comprehensive income	–	–	–	–	–	–	–	
Total comprehensive income	–	–	–	–	–	–	–	
Stock-based compensation	–	–	–	7	–	–	–	
Issuance of common stock	74,998,614	1	–	(1)	–	–	–	
Conversion of preferred stock	–	–	(1,725,000)	–	–	–	–	
Issuance of restricted stock	5,076	–	–	–	–	–	–	
Cancellation of restricted stock	(160,168)	–	–	–	–	–	–	
Performance units vested	214,866	–	–	–	–	–	–	
Tax withholding – stock compensation	(338,808)	–	–	(1)	–	–	–	
Balance at March 31, 2018	586,853,891	$ 6	–	$ 4,703	$ (2,471)	$ (44)	$ (1)	$

The accompanying notes are an integral part of these

unaudited condensed consolidated financial statements.

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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"). Southwestern conducts most of its businesses through subsidiaries and operates principally in two segments: E&P and Midstream.

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 on Form 10-K for the year ended December 31, 2017 ("2017 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 2017 Annual Report.

Certain reclassifications have been made to the prior year financial statements to conform to the 2018 presentation. The effects of the reclassifications were not material to the Company's unaudited condensed consolidated financial statements.

(2) REVENUE RECOGNITION

Effective January 1, 2018, the Company adopted Accounting Standards Codification ("ASC") 606, "Revenue from Contracts with Customers," using the modified retrospective method applied to those contracts which were not completed as of January 1, 2018. Under the modified retrospective method, the Company recognizes the cumulative effect of initially applying the new revenue standard as an adjustment to the opening balance of retained earnings; however, no material adjustment was required as a result of adopting ASC 606. Results for reporting periods beginning on January 1, 2018 are presented under the new revenue standard. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods. The Company performed an analysis of the impact of adopting ASC 606 across all revenue streams and did not identify any changes to its revenue recognition policies that would result in a material impact to its consolidated financial statements.

Revenues from Contracts with Customers

Natural gas and liquids. Natural gas, crude oil and natural gas liquid ("NGL") sales are recognized when control of the product is transferred to the customer at a designated delivery point. The pricing provisions of the Company's contracts are primarily tied to a market index with certain adjustments based on factors such as delivery, quality of the product and prevailing supply and demand conditions in the geographic areas in which the Company operates. Under the Company's sales contracts, the delivery of each unit of natural gas, crude oil and NGLs represents a separate performance obligation, and revenue is recognized at the point in time when the performance obligations are fulfilled. There is no significant financing component to the Company's revenues as payment terms are typically within 30 to 60 days of control transfer. Furthermore, consideration from a customer corresponds directly with the value to the customer of the Company's performance completed to date. As a result, the Company recognizes revenue in the amount to which the Company has a right to invoice and has not disclosed information regarding its remaining performance obligations.

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The Company records revenue from its natural gas and liquids production in the amount of its net revenue interest in sales from its properties. Accordingly, natural gas and liquid sales are not recognized for deliveries in excess of the Company's net revenue interest, while natural gas and liquid sales are recognized for any under-delivered volumes. Production imbalances are recorded as receivables and payables and not contract assets or contract liabilities as the imbalances are between the Company and other working interest owners, not the end customer.

Marketing.   The Company, through its marketing affiliate, generally markets natural gas, crude oil and NGLs for its affiliated E&P companies as well as other joint interest owners who choose to market with Southwestern. In addition, the Company markets some products purchased from third parties. Marketing revenues for natural gas, crude oil and NGL sales are recognized when control of the product is transferred to the customer at a designated delivery point. The pricing provisions of the Company's contracts are primarily tied to a market index with certain adjustments based on factors such as delivery, quality of the product and prevailing supply and demand conditions. Under the Company's marketing contracts, the delivery of each unit of natural gas, crude oil and NGLs represents a separate performance obligation, and revenue is recognized at the point in time when the performance obligations are fulfilled. Customers are invoiced and revenues are recorded each month as natural gas, crude oil and NGLs are delivered, and payment terms are typically within 30 to 60 days of control transfer. Furthermore, consideration from a customer corresponds directly with the value to the customer of the Company's performance completed to date. As a result, the Company recognizes revenue in the amount to which the Company has a right to invoice and has not disclosed information regarding its remaining performance obligations.

Gas gathering.   In certain areas, the Company, through its gathering affiliate, gathers natural gas pursuant to a variety of contracts with customers, including affiliated E&P companies. The performance obligations for gas gathering services include delivery of each unit of natural gas to the designated delivery point, which may include treating of certain natural gas units to meet interstate pipeline specifications. Revenue is recognized at the point in time when performance obligations are fulfilled. Under the Company's gathering contracts, customers are invoiced and revenue is recognized each month based on the volume of natural gas transported and treated at a contractually agreed upon price per unit. Payment terms are typically within 30 to 60 days of completion of the performance obligations. Furthermore, consideration from a customer corresponds directly with the value to the customer of the Company's performance completed to date. As a result, the Company recognizes revenue in the amount to which the Company has a right to invoice and has not disclosed information regarding its remaining performance obligations. Any imbalances are settled on a monthly basis by cashing-out with the respective shipper. Accordingly, there are no contract assets or contract liabilities related to the Company's gas gathering revenues.

Disaggregation of Revenues

The Company presents a disaggregation of E&P revenues by product on the condensed consolidated statements of operations net of intersegment revenues. The following table reconciles operating revenues as presented on the unaudited condensed consolidated statements of operations to the operating revenues by segment:

(in millions)	E&P	Midstream	Intersegment Revenues	Total
Three months ended March 31, 2018				
Gas sales	$ 535	$ –	$ 5	$ 540
Oil sales	34	–	1	35
NGL sales	65	–	–	65
Marketing	–	829	(576)	253
Gas gathering	–	67	(43)	24
Other (1)	3	–	–	3
Total	$ 637	$ 896	$ (613)	$ 920
Three months ended March 31, 2017				
Gas sales	$ 500	$ –	$ 3	$ 503
Oil sales	23	–	–	23
NGL sales	40	–	–	40
Marketing	–	777	(524)	253
Gas gathering	–	81	(54)	27
Other	–	–	–	–
Total	$ 563	$ 858	$ (575)	$ 846

(1) Other E&P revenues consists primarily of water sales to third-party operators.

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Associated E&P revenues are also disaggregated for analysis on a geographic basis by the core areas in which the Company operates, which are in Pennsylvania, West Virginia and Arkansas. Operations in northeast Pennsylvania are referred to as "Northeast Appalachia," operations in West Virginia and southwest Pennsylvania are referred to as "Southwest Appalachia" and operations in Arkansas are referred to as the "Fayetteville Shale."

	For the three months ended March 31,	
(in millions)	2018	2017
Northeast Appalachia	$ 327	$ 253
Southwest Appalachia	156	104
Fayetteville Shale	152	205
Other	2	1
Total	$ 637	$ 563

Receivables from Contracts with Customers

The following table reconciles the Company's receivables from contracts with customers to consolidated accounts receivable as presented on the unaudited condensed consolidated balance sheet:

(in millions)	March 31, 2018	December 31, 2017
Receivables from contracts with customers	$ 273	$ 322
Other accounts receivable	109	106
Total accounts receivable	$ 382	$ 428

Amounts recognized against the Company's allowance for doubtful accounts related to receivables arising from contracts with customers were immaterial for the three months ended March 31, 2018 and 2017. The Company has no contract assets or contract liabilities associated with its revenues from contracts with customers.

(3) CASH AND CASH EQUIVALENTS

The following table presents a summary of cash and cash equivalents as of March 31, 2018 and December 31, 2017:

(in millions)	March 31, 2018	December 31, 2017	
Cash	$ 267	$ 261	
Marketable securities (1)	691	605	
Other cash equivalents	–	50	(2)
Total	$ 958	$ 916	

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

(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.

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Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $3.00 per MMBtu, West Texas Intermediate oil of $49.94 per barrel and NGLs of $14.90 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 at March 31, 2018. The Company had no hedge positions that were designated for hedge accounting as of March 31, 2018. 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 $2.73 per MMBtu, West Texas Intermediate oil of $44.10 per barrel and NGLs of $10.17 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 at March 31, 2017. The Company had no hedge positions that were designated for hedge accounting as of March 31, 2017.

(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 January 2015, the Company issued 34,500,000 depositary shares that entitled the holder to a proportional fractional interest in the rights and preferences of the mandatory convertible preferred stock, including conversion, dividend, liquidation and voting rights. The mandatory convertible preferred stock had 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 has been 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 January 12, 2018, all outstanding shares of mandatory convertible preferred stock converted to 74,998,614 shares of the Company's common stock.

On December 18, 2017, the Company declared the quarterly dividend, which was paid to holders of the mandatory convertible preferred stock in cash on January 16, 2018. Dividends declared in the first, second and third quarters of 2017 were settled partially in common stock for a total of 10,040,306 shares.

The following table presents the computation of earnings per share for the three months ended March 31, 2018 and 2017:

	For the three months ended March 31,	
(in millions, except share/per share amounts)	2018	2017
Net income	$ 208	$ 351
Mandatory convertible preferred stock dividend	–	27
Participating securities - mandatory convertible preferred stock	3	43
Net income attributable to common stock	$ 205	$ 281
Number of common shares:		
Weighted average outstanding	571,297,804	493,068,000
Issued upon assumed exercise of outstanding stock options	–	82,845
Effect of issuance of non-vested restricted common stock	914,096	770,429
Effect of issuance of non-vested performance units	1,632,559	573,721
Weighted average and potential dilutive outstanding	573,844,459	494,494,995
Earnings per common share:		
Basic	$ 0.36	$ 0.57
Diluted	$ 0.36	$ 0.57

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The following table presents the common stock shares equivalent excluded from the calculation of diluted earnings per share for the three months ended March 31, 2018 and 2017, as they would have had an antidilutive effect:

	For the three months ended March 31,	
	2018	2017
Unexercised stock options	–	1,854,004
Unvested share-based payment	5,292,454	1,212,396
Performance units	574,944	–
Mandatory convertible preferred stock	9,999,815	74,999,895
Total	15,867,213	78,066,295

(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 March 31, 2018 and December 31, 2017, the Company's derivative financial instruments consisted of fixed price swaps, two-way costless collars, three-way costless collars, basis swaps, call options and interest rate swaps. A description of the Company's derivative financial instruments is provided below:

Fixed price swaps	If the Company sells a fixed price swap, the Company receives a fixed price for the contract and pays a floating market price to the counterparty. If the Company purchases a fixed price swap, the Company receives a floating market price for the contract and pays a fixed price to the counterparty.
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. If the Company sells a basis swap, 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. If the Company purchases a basis swap, the Company pays the counterparty if the price differential is greater than the stated terms of the contract and receives a payment from the counterparty if the price differential is less than the stated terms of the contract.
Call options	The Company purchases and sells call options in exchange for a premium. If the Company purchases a call option, the Company receives from the counterparty the excess (if any) of the market price over the strike price of the call option at the time of settlement, but if the market price is below the call's strike price, no payment is due from either party. If the Company sells a call option, the Company pays the counterparty the excess (if any) of the market price over the strike price of the call option at the time of settlement, but if the market price is below the call's strike price, no payment is due from either party.

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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.

The Company chooses 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, there can be no assurance that a counterparty will be able to meet its obligations to the Company.

The following tables provide 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 tables present the notional amount, the weighted average contract prices and the fair value by expected maturity dates as of March 31, 2018:

Financial Protection on Production		Weighted Average Price per MMBtu					Fair Value at March 31, 2018 ($ in millions)
	Volume (Bcf)	Swaps	Sold Puts	Purchased Puts	Sold Calls	Basis Differential	
Natural gas							
2018							
Fixed price swaps	215	$ 2.97	$ –	$ –	$ –	$ –	$ 33
Two-way costless collars	6	–	–	2.90	3.27	–	1
Three-way costless collars	213	–	2.40	2.97	3.37	–	39
Total	434						$ 73
2019							
Fixed price swaps	93	$ 3.00	$ –	$ –	$ –	$ –	$ 19
Two-way costless collars	53	–	–	2.80	2.98	–	6
Three-way costless collars	133	–	2.49	2.93	3.34	–	11
Total	279						$ 36
Basis swaps							
2018	73	$ –	$ –	$ –	$ –	$ (0.59)	$ –
2019	6	–	–	–	–	1.01	(1)
Total	79						$ (1)

	Volume (MBbls)	Weighted Average Strike Price per Bbl	Fair Value at March 31, 2018 ($ in millions)
Propane			
2018			
Fixed price swaps	1,100	$ 34.64	$ 3
Ethane			
2018			
Fixed price swaps	413	$ 11.19	$ –
2019			
Fixed price swaps	91	$ 11.61	$ –

Other Derivative Contracts

	Volume (Bcf)	Weighted Average Strike Price per MMBtu	Fair Value at March 31, 2018 ($ in millions)
Purchased call options			
2020	68	$ 3.63	$ 7
2021	57	3.52	11
Total	125		$ 18
Sold call options			
2018	47	$ 3.50	$ (1)
2019	52	3.50	(4)
2020	137	3.39	(21)
2021	114	3.33	(27)
Total	350		$ (53)

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	Volume (Bcf)	Weighted Average Strike Price per MMBtu	Basis Differential	Fair Value at March 31, 2018 ($ in millions)
Storage (1)				
2018				
Fixed price swaps	1	$ 2.76	$ –	$ –
Basis swaps	1	–	(0.88)	–
Total	2			$ –
2019				
Fixed price swaps	1	$ 3.03	$ –	$ –
Basis swaps	1	–	(0.44)	–
Total	2			$ –

(1) The Company has entered into certain derivatives to protect the value of volumes of natural gas injected into a storage facility that will be withdrawn at a later date.

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.

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 March 31, 2018 and December 31, 2017:

	Derivative Assets		
	Balance Sheet Classification	Fair Value	
		March 31, 2018	December 31, 2017
Derivatives not designated as hedging instruments:		(in millions)	
Fixed price swaps - natural gas	Derivative assets	$ 34	$ 38
Fixed price swaps - propane	Derivative assets	3	–
Two-way costless collars	Derivative assets	4	5
Three-way costless collars	Derivative assets	63	82

Basis swaps	Derivative assets	6	2	
Purchased call options	Derivative assets	–	2	
Fixed price swaps - natural gas	Other long-term assets	20	18	
Two-way costless collars	Other long-term assets	12	–	
Three-way costless collars	Other long-term assets	28	39	
Purchased call options	Other long-term assets	18	–	
Interest rate swaps	Other long-term assets	1	–	
Total derivative assets		$ 189	$ 186	(1)

	Derivative Liabilities		
	Balance Sheet Classification	Fair Value	
		March 31, 2018	December 31, 2017
Derivatives not designated as hedging instruments:		(in millions)	
Fixed price swaps - natural gas	Derivative liabilities	$ 2	$ –
Two-way costless collars	Derivative liabilities	3	1
Three-way costless collars	Derivative liabilities	25	36
Basis swaps	Derivative liabilities	7	23
Sold call options	Derivative liabilities	3	3
Interest rate swaps	Derivative liabilities	–	1
Fixed price swaps - natural gas	Other long-term liabilities	–	1
Two-way costless collars	Other long-term liabilities	6	–
Three-way costless collars	Other long-term liabilities	16	30
Sold call options	Other long-term liabilities	49	15
Total derivative liabilities		$ 111	$ 110

(1) Excludes $1 million in premiums paid related to certain call options recognized as a component of derivative assets within current assets on the condensed consolidated balance sheet at December 31, 2017. As certain call options settled, the premium was amortized and recognized as a component of gain (loss) on derivatives on the unaudited condensed statement of operations.

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At March 31, 2018, the net fair value of the Company's financial instruments related to commodities was a $77 million asset. The net fair value of the Company's interest rate swaps was a $1 million asset as of March 31, 2018.

Derivative Contracts Not Designated for Hedge Accounting

As of March 31, 2018, 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 statement 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 following tables summarize the before-tax effect of the Company's derivative instruments not designated for hedge accounting on the unaudited condensed consolidated statements of operations for the three months ended March 31, 2018 and 2017:

Derivative Instrument	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Unsettled	Gain (Loss) on Derivatives, Unsettled Recognized in Earnings For the three months ended March 31, 2018	2017
		(in millions)	
Fixed price swaps - natural gas	Gain (Loss) on Derivatives	$ (3)	$ 118
Fixed price swaps - propane	Gain (Loss) on Derivatives	3	–
Two-way costless collars	Gain (Loss) on Derivatives	3	31
Three-way costless collars	Gain (Loss) on Derivatives	(5)	57
Basis swaps	Gain (Loss) on Derivatives	20	(103)
Purchased call options	Gain (Loss) on Derivatives	16	–
Sold call options	Gain (Loss) on Derivatives	(34)	42
Interest rate swaps	Gain (Loss) on Derivatives	2	1
Total gain on unsettled derivatives		$ 2	$ 146

Derivative Instrument	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Settled	Gain (Loss) on Derivatives, Settled (1) Recognized in Earnings For the three months ended March 31, 2018	2017
		(in millions)	
Fixed price swaps - natural gas	Gain (Loss) on Derivatives	$ –	$ (16)
Two-way costless collars	Gain (Loss) on Derivatives	4	(3)
Three-way costless collars	Gain (Loss) on Derivatives	7	(4)
Basis swaps	Gain (Loss) on Derivatives	(21)	(1)
Purchased call options	Gain (Loss) on Derivatives	2 (2)	–
Sold call options	Gain (Loss) on Derivatives	(1)	(6)
Total loss on settled derivatives		$ (9)	$ (30)
Total gain (loss) on derivatives		$ (7)	$ 116

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

(2) Includes $1 million amortization of premiums paid related to certain call options for the three months ended March 31, 2018, which is included in gain (loss) on derivatives on the unaudited condensed consolidated statements of operations.

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(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 three months ended March 31, 2018:

(in millions)	Pension and Other Postretirement	Foreign Currency	Total
Beginning balance, December 31, 2017	$ (30)	$ (14)	$ (44)
Other comprehensive income (loss) before reclassifications (1)	–	–	–
Amounts reclassified from other comprehensive income (loss) (1) (2)	–	–	–
Net current-period other comprehensive income (loss)	–	–	–
Ending balance, March 31, 2018	$ (30)	$ (14)	$ (44)

(1) Deferred tax activity related to pension and other postretirement benefits was offset by a valuation allowance, resulting in no tax expense recorded for the period.
(2) See separate table below for details about these reclassifications.

Details about Accumulated Other Comprehensive Income	Affected Line Item in the Consolidated Statement of Operations	Amount Reclassified from Accumulated Other Comprehensive Income For the three months ended March 31, 2018 (in millions)
Pension and other postretirement:		
Amortization of prior service cost and net loss (1)	Other Income (Loss), Net	$ –
	Provision (benefit) for income taxes	–
	Net income	$ –
Total reclassifications for the period	Net income	$ –

(1) See Note 11 for additional details regarding the Company's pension and other postretirement benefit plans.

(8) FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company's financial instruments as of March 31, 2018 and December 31, 2017 were as follows:

	March 31, 2018		December 31, 2017	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 958	$ 958	$ 916	$ 916
2018 term loan facility due December 2020 (1)(2)	1,191	1,191	1,191	1,191
Senior notes (2)	3,242	3,199	3,242	3,358
Derivative instruments, net	78	78	76 (3)	76 (3)

(1) Concurrent with the closing of the new 2018 credit facility agreement, the Company repaid the $1,191 million secured term loan balance on April 26, 2018. See Note 16 – Subsequent Events for more information on the 2018 credit facility.

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

(3) Excludes $1 million in premiums paid related to certain call options recognized as a component of derivatives assets within current assets on the 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 market prices of the Company’s senior notes.

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The carrying values of the borrowings under the Company’s term loan facilities and unsecured revolving credit facility (to the extent utilized) 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.

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 natural gas 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 March 31, 2018 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, 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):

	March 31, 2018			
	Fair Value Measurements Using:			
(in millions)	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 - natural gas assets	$ –	$ 54	$ –	$ 54
Fixed price swap - propane assets	–	3	–	3
Two-way costless collar assets	–	–	16	16
Three-way costless collar assets	–	–	91	91
Basis swap assets	–	–	6	6
Purchased call option assets	–	–	18	18
Interest rate swap assets	–	1	–	1
Fixed price swap - natural gas liabilities	–	(2)	–	(2)
Two-way costless collar liabilities	–	–	(9)	(9)
Three-way costless collar liabilities	–	–	(41)	(41)
Basis swap liabilities	–	–	(7)	(7)
Sold call option liabilities	–	–	(52)	(52)
Total	$ –	$ 56	$ 22	$ 78

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	December 31, 2017			
	Fair Value Measurements Using:			
(in millions)	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	$ –	$ 56	$ –	$ 56
Two-way costless collar assets	–	–	5	5
Three-way costless collar assets	–	–	121	121
Purchased call option assets	–	–	2	2
Basis swap assets	–	–	2	2
Fixed price swap liabilities	–	(1)	–	(1)
Two-way costless collar liabilities	–	–	(1)	(1)
Three-way costless collar liabilities	–	–	(66)	(66)
Basis swap liabilities	–	–	(23)	(23)
Sold call option liabilities	–	–	(18)	(18)
Interest rate swap liabilities	–	(1)	–	(1)
Total	$ –	$ 54	$ 22	$ 76

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 months ended March 31, 2018 and 2017. 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 March 31, 2018 and 2017.

	For the three months ended March 31,	
(in millions)	2018	2017
Balance at beginning of period	$ 22	$ (195)
Total gains (losses):		
Included in earnings	(9)	13
Settlements (1)	9	14
Transfers into/out of Level 3	–	–

Balance at end of period	$ 22	$ (168)
Change in gains included in earnings relating to derivatives still held as of March 31	$ –	$ 27

(1) Includes $1 million amortization of premiums paid related to certain call options for the three months ended March 31, 2018.

(9) DEBT

The components of debt as of March 31, 2018 and December 31, 2017 consisted of the following:

	March 31, 2018			
(in millions)	Debt Instrument	Unamortized Issuance Expense	Unamortized Debt Discount	Total
Variable rate (4.240% at March 31, 2018) 2016 term loan facility, due December 2020 (1)	$ 1,191	$ (8)	$ –	$ 1,183
4.05% Senior Notes due January 2020 (2)	92	–	–	92
4.10% Senior Notes due March 2022	1,000	(6)	–	994
4.95% Senior Notes due January 2025 (2)	1,000	(8)	(2)	990
7.50 % Senior Notes due April 2026	650	(9)	–	641
7.75 % Senior Notes due October 2027	500	(7)	–	493
Total debt	$ 4,433	$ (38)	$ (2)	$ 4,393

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	December 31, 2017			
(in millions)	Debt Instrument	Unamortized Issuance Expense	Unamortized Debt Discount	Total
Variable rate (3.980% at December 31, 2017) 2016 term loan facility, due December 2020 (1)	$ 1,191	$ (8)	$ –	$ 1,183
4.05% Senior Notes due January 2020 (2)	92	–	–	92
4.10% Senior Notes due March 2022	1,000	(7)	–	993
4.95% Senior Notes due January 2025 (2)	1,000	(8)	(2)	990
7.50% Senior Notes due April 2026	650	(10)	–	640
7.75% Senior Notes due October 2027	500	(7)	–	493
Total debt	$ 4,433	$ (40)	$ (2)	$ 4,391

(1) Concurrent with the closing of the new 2018 credit facility agreement on April 26, 2018, the Company repaid the $1,191 million secured term loan balance with cash on hand and borrowings under the new credit facility. The Company's initial borrowings under the 2018 credit facility were $360 million, a portion of which related to other working capital needs. See Note 16 – Subsequent Events for more information on the 2018 credit facility.

(2) 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 5.80% for the 2020 Notes and 6.70% for the 2025 Notes.

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 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 5.80% 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 6.05% and 6.95%, respectively. The first coupon payment to the bondholders at the higher interest rates was paid in January 2017.

During the first half of 2017, the Company redeemed or repurchased (i) $38 million principal amount of its outstanding 2018 Notes, (ii) $212 million principal amount of its outstanding 7.50% Senior Notes due February 2018 and (iii) $26 million principal amount of its outstanding 7.15% Senior Notes due June 2018, and recognized an $11 million loss on the extinguishment of debt, $1 million of which was recognized in the three months ended March 31, 2017 and reported in other income (loss), net on the unaudited condensed consolidated statements of operations.

In September 2017, the Company completed a public offering of $650 million aggregate principal amount of its 7.50% senior notes due 2026 (the "2026 Notes") and $500 million aggregate principal amount of its 7.75% senior notes due 2027 (the "2027 Notes"), with net proceeds from the offering totaling approximately $1.1 billion after underwriting discounts and offering expenses. Both series of senior notes were sold to the public at face value. The proceeds from this offering were used to purchase $758 million of the Company's 2020 Notes in a tender offer and to repay the outstanding balance of $327 million on the Company's 2015 term loan. The Company recognized a loss on extinguishment of debt of $59 million, which included $53 million of premiums paid.

In October 2017, the Company retired $40 million principal amount outstanding on its 2017 senior notes.

In November 2017, the Company solicited and received consent to amend certain restrictive covenants contained in the indentures governing the Company's 2022 Notes and the 2025 Notes. These amendments conform certain covenants of the 2022 Notes and 2025 Notes to all other series of senior notes.

2018 Credit Facility

On April 26, 2018 the Company replaced its 2016 credit facility with a new credit facility. See Note 16 – Subsequent Events for more information on the new credit facility.

2016 Credit Facility

In June 2016, the Company reduced its existing $2.0 billion unsecured revolving credit facility entered into in December 2013 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, maturing in December 2020. At March 31, 2018 the $1,191 million secured term loan was fully drawn and there were no borrowings under either revolving credit facility; however, $323 million in letters of credit was outstanding under the 2016 revolving credit facility. Concurrent with the closing of the new 2018 credit facility agreement on April 26, 2018, the Company repaid the $1,191 million secured term loan balance. See Note 16 – Subsequent Events for more information on the 2018 credit facility.

Loans under the 2016 credit agreement were subject to varying rates of interest based on whether the loan was a Eurodollar loan or an alternate base rate loan. Eurodollar loans bore interest at the Eurodollar rate, which was adjusted LIBOR plus applicable margins ranging from 1.750% to 2.500%. Alternate base rate loans bore interest at the alternate base rate plus the applicable margin ranging from 0.750% to 1.500%. The interest rate on the term loan was determined based upon the Company's public debt ratings and was 250 basis points over LIBOR as of March 31, 2018.

The 2016 term loan and revolving credit facility contained financial covenants that imposed certain restrictions on the Company. In September 2017, the Company and the lenders amended the 2016 credit agreement to reflect the following:

- Increased the minimum interest coverage ratio to 2.00x commencing with the fiscal quarter ended June 30, 2017 and continued over the life of the 2016 Credit Agreement;

- Modified the minimum liquidity covenant such that either (1) if leverage was less than 4.00x or if the 2016 revolving credit facility has been terminated, there would be no minimum liquidity covenant, or (2) the Company could elect to replace the minimum liquidity covenant with a maximum leverage ratio of no more than 5.00x for the fiscal quarters ending March 31, 2018 and June 30, 2018 and 4.50x thereafter; and

· Modified the mandatory prepayment and commitment reduction provisions to permit the Company to retain the first $500 million of net cash proceeds from asset sales that would have otherwise been required to prepay amounts outstanding under the 2016 revolving credit facility and/or reduce commitments under the 2016 revolving credit facility.

As of March 31, 2018, the Company had not elected to replace the minimum liquidity covenant with a maximum leverage covenant. Therefore, under the credit agreement as amended in September 2017, should the leverage ratio have exceeded 4.00x, the Company would have been subject to a minimum liquidity requirement of $300 million. The financial covenant with respect to the maximum leverage ratio consisted of total debt divided by EBITDAX. The financial covenant with respect to minimum interest coverage consisted of EBITDAX divided by consolidated interest expense. EBITDAX, as defined in the Company's 2016 credit agreement, excluded 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 was 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 required a minimum collateral coverage ratio of 1.50x for the 2016 secured term loan. This collateral could also have supported all or a part of revolving credit extensions depending on restrictions in the Company's senior notes indentures.

As of March 31, 2018, the Company was in compliance with all of the covenants of this credit agreement.

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.

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The borrowing capacity of the original 2013 credit agreement was reduced from $2.0 billion to $66 million, remained unsecured and the maturity remained December 2018. As of March 31, 2018, 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 March 31, 2018, debt constituted 29% of the Company's adjusted book capital.

On April 26, 2018 the Company replaced its 2016 credit facility with a new credit facility. Concurrently, the 2013 credit facility was terminated. See Note 16 – Subsequent Events for more information on the new credit facility.

(10) COMMITMENTS AND CONTINGENCIES

Operating Commitments and Contingencies

As of March 31, 2018, 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 $9.1 billion, $3.1 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 $832 million of that amount. As of March 31, 2018, future payments under non-cancelable firm transportation and gathering agreements were as follows:

	Payments Due by Period					
(in millions)	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	5 to 8 Years	More than 8 Years
Infrastructure Currently in Service	$ 5,986	$ 639	$ 1,208	$ 894	$ 1,151	$ 2,094
Pending Regulatory Approval and/or Construction (1)	3,139	46	317	389	626	1,761
Total Transportation Charges	$ 9,125	$ 685	$ 1,525	$ 1,283	$ 1,777	$ 3,855

(1) Based on estimated in-service dates as of March 31, 2018.

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, employment matters, traffic accidents, pollution, contamination, encroachment on others' property 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, 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 trial court denied the plaintiff's motion for a new trial, and the plaintiff has filed a notice of appeal with the United States Court of Appeals for the Eighth Circuit. The court of appeals has not yet determined whether to hear oral argument. Independent of the plaintiff's appeal, several different parties sought to intervene in the Smith case prior to or shortly after trial, and have appealed the trial court's order denying their request to intervene. Briefing is complete in the intervenor's appeal, and oral argument is expected to occur sometime in the second quarter of 2018.

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 (one is set for trial during the third quarter of 2018; the other does not have a trial date) and three cases (all currently stayed) that were filed in Arkansas state court on behalf of a 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 material liabilities have 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 months ended March 31, 2018 and 2017:

(in millions)	Condensed Consolidated Statements of Operations Classification of Net Periodic Benefit Cost (1)	Pension Benefits For the three months ended March 31, 2018	2017

Service cost	General and administrative expenses	$ 3	$ 2
Interest cost	Other Income (Loss), Net	2	1
Expected return on plan assets	Other Income (Loss), Net	(2)	(1)
Amortization of prior service cost	Other Income (Loss), Net	–	–
Amortization of net loss	Other Income (Loss), Net	–	1
Net periodic benefit cost		$ 3	$ 3

(1) In the first quarter of 2018, the Company adopted Accounting Standards Update No. 2017-07, which requires the service cost component to be disaggregated from the other components of net benefit cost, which are to be presented outside of income from operations. See Note 15 – New Accounting Pronouncements for more information regarding this update.

The Company's other postretirement benefit plan had a net periodic benefit cost of $1 million for the three months ended March 31, 2018 and 2017.

As of March 31, 2018, the Company has contributed $3 million to the pension and other postretirement benefit plans in 2018. The Company expects to contribute an additional $9 million to its pension plan during the remainder of 2018. The Company recognized a liability of $41 million and $18 million related to its pension and other postretirement benefits, respectively, as of March 31, 2018, compared to a liability of $42 million and $17 million as of December 31, 2017.

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 31,269 shares at March 31, 2018 and December 31, 2017.

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(12) STOCK-BASED COMPENSATION

The Company recognized the following amounts in total employee stock-based compensation costs for the three months ended March 31, 2018 and 2017:

(in millions)	For the three months ended March 31, 2018	2017
Stock-based compensation cost – expensed	$ 5	$ 6
Stock-based compensation cost – capitalized	$ 3	$ 4

The Company's stock-based compensation is classified as either equity awards or liability awards in accordance with GAAP. The fair value of an equity-classified award is determined at the grant date and is amortized to general and administrative expense and capitalized expense on a straight-line basis over the vesting period of the award. The fair value of a liability-classified award is determined on a quarterly basis beginning at the grant date until final vesting. Changes in the fair value of liability-classified awards are recorded to general and administrative expense and capitalized expense over the vesting period of the award.

Equity Awards

The Company recognized the following amounts in employee equity-classified stock-based compensation costs for the three months ended March 31, 2018 and 2017:

(in millions)	For the three months ended March 31, 2018	2017
Equity-classified stock-based compensation cost – expensed	$ 4	$ 6

Equity-classified stock-based compensation cost – capitalized	$ 3	$ 4

As of March 31, 2018, there was $49 million of total unrecognized compensation cost related to the Company's unvested equity-classified stock option grants, equity-classified restricted stock grants and equity-classified performance units. This cost is expected to be recognized over a weighted-average period of 2 years.

Equity-Classified Stock Options

The following table summarizes equity-classified stock option activity for the three months ended March 31, 2018 and provides information for options outstanding and options exercisable as of March 31, 2018:

	Number of Options (in thousands)	Weighted Average Exercise Price
Outstanding at December 31, 2017	6,020	$ 19.43
Granted	–	–
Exercised	–	–
Forfeited or expired	(3)	38.65
Outstanding at March 31, 2018	6,017	$ 19.42
Exercisable at March 31, 2018	4,379	$ 23.80

Equity-Classified Restricted Stock

The following table summarizes equity-classified restricted stock activity for the three months ended March 31, 2018 and provides information for unvested shares as of March 31, 2018:

	Number of Shares (in thousands)	Weighted Average Fair Value
Unvested shares at December 31, 2017	6,254	$ 8.85

Granted	5	5.91
Vested	(1,033)	8.77
Forfeited	(160)	9.07
Unvested shares at March 31, 2018	5,066	$ 8.85

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Equity-Classified Performance Units

The following table summarizes equity-classified performance unit activity for the three months ended March 31, 2018 and provides information for unvested units as of March 31, 2018. The performance unit awards granted in 2015, 2016 and 2017 include a market condition based exclusively on the fair value of the Total Shareholder Return ("TSR"), as calculated by a Monte Carlo model. 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 grant date fair value is calculated using the closing price of the Company's common stock at the grant date.

	Number of Units (1) (in thousands)	Weighted Average Fair Value
Unvested units at December 31, 2017	1,084	$ 10.12
Granted	–	–
Vested	–	–
Forfeited	(18)	9.99
Unvested units at March 31, 2018	1,066	$ 10.12

(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 TSR. 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 Awards

The Company recognized the following amounts in employee liability-classified stock-based compensation costs for the three months ended March 31, 2018 and 2017:

For the three months ended March

(in millions)	31, 2018
Liability-classified stock-based compensation cost – expensed	$ 1
Liability-classified stock-based compensation cost – capitalized (1)	$ –

(1) For the three months ended March 31, 2018, the liability-classified stock-based compensation amount capitalized was less than $1 million.

Liability-Classified Restricted Stock

In the first quarter of 2018, the Company granted restricted stock units that vest over a period of four years and are payable in either cash or shares at the option of the Compensation Committee of the Company's Board of Directors. The Company has accounted for these as liability-classified awards and as such, changes in the market value of the instruments will be recorded to general and administrative expense and capitalized expense over the vesting period of the award. As of March 31, 2018, the Company had approximately 12 million unvested liability-classified restricted stock units with a total unrecognized compensation cost of $51 million. This cost is expected to be recognized over a weighted-average period of four years.

Liability-Classified Performance Units

In the first quarter of 2018, the Company granted performance units that vest over a three-year period and are payable in either cash or shares at the option of the Compensation Committee of the Company's Board of Directors. The Company has accounted for these as liability-classified awards and as such, changes in the fair market value of the instruments will be recorded to general and administrative expense and capitalized expense over the vesting period of the awards. The performance unit awards granted in 2018 include a performance condition based on cash flow per debt-adjusted share and two market conditions, one based on absolute TSR and the other on relative TSR as compared to a group of the Company's peers, collectively the "Performance Measures." The fair values of the two market conditions are calculated by Monte Carlo models on a quarterly basis. As of March 31, 2018, the Company had approximately 3 million unvested liability-classified performance units with a total unrecognized compensation cost of $14 million. This cost is expected to be recognized over a weighted-average period of three years. The final value of the performance unit awards is contingent upon the Company's actual performance against the Performance Measures.

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(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 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 2017 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 and other income (loss). The “Other” column includes items not related to the Company’s reportable segments, including real estate and corporate items.

	E&P	Midstream	Other	Total
Three months ended March 31, 2018:	(in millions)			
Revenues from external customers	$ 643	$ 277	$ –	$ 920
Intersegment revenues	(6)	619	–	613
Depreciation, depletion and amortization expense	117	26 (1)	–	143
Operating income	238	17	–	255
Interest expense (2)	39	–	–	39
Loss on derivatives	(7)	–	–	(7)
Other income (loss), net	–	(1)	–	(1)
Assets	5,346	1,217	1,150 (3)	7,713
Capital investments (4)	334	4	–	338
Three months ended March 31, 2017:				
Revenues from external customers	$ 566	$ 280	$ –	$ 846
Intersegment revenues	(3)	578	–	575
Depreciation, depletion and amortization expense	90	16	–	106
Operating income	225	41	–	266
Interest expense (2)	32	–	–	32
Gain on derivatives	116	–	–	116
Other income, net	2	–	(1)	1
Assets	4,413	1,268	1,515 (3)	7,196
Capital investments (4)	283	6	1	290

(1) Includes a $10 million impairment related to certain non-core gathering assets.

(2) Interest expense by segment is an allocation of corporate amounts as they are incurred at the corporate level.

(3) Other assets represent corporate assets not allocated to segments and assets for non-reportable segments. At March 31, 2018 and 2017, other assets includes approximately $958 million and $1.4 billion in cash and cash equivalents, respectively.

(4) Capital investments includes an increase of $33 million and a decrease of $52 million for the three months ended March 31, 2018 and 2017, respectively, relating to the change in capital accruals between periods.

Included in intersegment revenues of the Midstream segment are $576 million and $524 million for the three months ended March 31, 2018 and 2017, 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 taxes, are allocated to the segments.

(14) INCOME TAXES

The Company’s effective tax rate was approximately 0% for the three months ended March 31, 2018 and 2017 primarily as a result of the recognition 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 assets 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.

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The Company maintained its net deferred tax asset position at March 31, 2018 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 its valuation allowance of $51 million and $75 million for the three months ended March 31, 2018 and 2017, 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 assets 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.

On December 22, 2017 the Tax Cuts and Jobs Act (Tax Reform) was enacted, which made significant changes to the U.S. federal income tax law affecting the Company. Major changes in this legislation applicable to the Company relate to the reduction in tax rate for corporations to 21%, repeal of the corporate alternative minimum tax, interest deductibility and net operating loss carryforward limitations, changes to certain executive compensation and full expensing provisions related to business assets. The Company included tax reform impacts in its 2017 Annual Report and continues to examine the impact of this legislation and future regulations. The first quarter 2018 tax accrual calculated under the estimated annual effective tax rate method reflects the law changes that are effective January 1, 2018. Due to the tax valuation allowance currently in place, any adjustments required to deferred taxes in the current interim period would be fully offset by valuation allowance adjustments and are immaterial to the financial statements.

In February 2018, the FASB issued Accounting Standards Update No. 2018-02 amending the FASB Accounting Standards relating to tax effects in accumulated other comprehensive income. See Note 15 – New Accounting Pronouncements for more information regarding this update.

(15) NEW ACCOUNTING PRONOUNCEMENTS

New Accounting Standards Implemented

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, Revenue with Contracts from Customers (Topic 606) (ASC 606, as subsequently amended). ASC 606 supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and requires entities to recognize revenue when control of the promised goods or services is transferred to customers at an amount that reflects the consideration to which an entity expects to be entitled to in exchange for those goods and services. For public entities, ASC 606 became effective for fiscal years beginning after December 15, 2017. The Company adopted ASC 606 with an effective date of January 1, 2018 using the modified retrospective approach. The adoption of this standard did not have a material effect on the Company's unaudited condensed consolidated results of operations, financial position or cash flows. Additional disclosures regarding the nature, amount, timing and uncertainty of revenue and cash flow from contracts with customers are available in Note 2 –Revenue Recognition.

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 requires employers to disaggregate the service cost component from the other components of net benefit cost. The service cost component of the net periodic benefit cost shall be reported in the same line item as other compensation costs arising from services rendered by the employees during the period, except for amounts capitalized. All other components of net benefit cost shall be presented outside of a subtotal for income from operations. The Company adopted Update 2017-07 during the first quarter of 2018 resulting in no material impact to its unaudited condensed consolidated statements of operations, financial position or cash flows. The non-service cost components of net periodic benefit cost are presented as a component of Other Income (Loss), Net for the three months ended March 31, 2018 and 2017, and are disclosed in Note 11 – Pension Plan and Other Postretirement Benefits. The Company ceased capitalizing the non-service cost components of net periodic benefit costs prospectively as of the beginning of the first quarter of 2018.

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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. The Company adopted this Update during the first quarter of 2018 resulting in no impact on its unaudited condensed consolidated statements of cash flows.

In February 2018, the FASB issued Accounting Standards Update No. 2018-02 that will amend the FASB Accounting Standards relating to tax effects in accumulated other comprehensive income (Topic 220) ("Update 2018-02"). Update 2018-02 permits a company to reclassify the stranded income tax effects of the Tax Cuts and Jobs Act of 2017 on items within accumulated comprehensive income to retained earnings. Although the amendments in Update 2018-02 are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, the Company has elected to early adopt the amendments of Update 2018-02 for the current period. The implementation did not have a material impact on the Company's unaudited condensed consolidated statement of operations, financial position or cash flows due to the tax valuation allowance currently in place. Any adjustments required under this Update would be fully offset by valuation allowance adjustments for both continuing operations and accumulated other comprehensive income.

New Accounting Standards Not Yet Implemented

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. The codification was amended through additional ASUs. Through March 2018, 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 Update 2016-02 and related ASUs 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.

(16) SUBSEQUENT EVENTS

On April 26, 2018, as part of the Company's strategic effort to simplify the capital structure, increase financial flexibility and reduce costs, the Company replaced its 2016 credit facility (which consisted of a $1,191 million secured term loan and an unsecured $743 million revolving credit facility) with a new credit facility (the "2018 credit facility"), with initial aggregate commitments of $2,000 million, an initial borrowing base of $3,200 million and an aggregate maximum revolving credit amount of $3,500 million. The 2018 credit facility is secured by substantially all of the assets owned by the Company and its subsidiaries.

The 2018 credit facility matures on April 26, 2023, provided that if the Company has not amended, redeemed or refinanced at least $700 million of its 2022 Senior Notes on or before December 14, 2021, the 2018 credit facility will mature on December 14, 2021.

Loans under the 2018 credit facility 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 for such interest period plus the applicable margin (as those terms are defined in the 2018 credit facility documentation). The applicable margin for Eurodollar loans under the 2018 credit facility ranges from 1.50% to 2.50% based on the Company's utilization of the borrowing base under the 2018 credit facility. Alternate base rate loans bear interest at the alternate base rate plus the applicable margin. The applicable margin for alternate base rate loans under the 2018 credit facility ranges from 0.50% to 1.50% based on the Company's utilization of the borrowing base under the 2018 credit facility.

The 2018 credit facility contains customary representations and warranties and contains covenants including, among others, the following:

- a prohibition against incurring debt, subject to permitted exceptions;
- a restriction on creating liens on assets, subject to permitted exceptions;
- restrictions on mergers and asset dispositions;
- restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business; and
- maintenance of the following financial covenants, commencing with the fiscal quarter ending June 30, 2018:

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1. Minimum current ratio of no less than 1.00 to 1.00, whereby current ratio is defined as the Company's consolidated current assets (including unused commitments under the credit agreement, but excluding non-cash derivative assets) to consolidated current liabilities (excluding non-cash derivative obligations and current maturities of long-term debt).
2. Maximum total net leverage ratio of no less than (i) with respect to each fiscal quarter ending during the period from June 30, 2018 through March 31, 2019, 4.50 to 1.00, (ii) with respect to each fiscal quarter ending during the period from June 30, 2019 through March 31, 2020, 4.25 to 1.00, and (iii) with respect to each fiscal quarter ending on or after June 30, 2020, 4.00 to 1.00. Total net leverage ratio is defined as total debt less cash on hand (up to the lesser of 10% of credit limit or $150 million) divided by consolidated EBITDAX for the last four consecutive quarters. EBITDAX, as defined in the Company's 2018 credit agreement, excludes the effects of interest expense, depreciation, depletion and amortization, income tax, 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.

The 2018 credit facility contains customary events of default that include, among other things, the failure to comply with the financial covenants described above, non-payment of principal, interest or fees, violation of covenants, inaccuracy of representations and warranties, bankruptcy and insolvency events, material judgments and cross-defaults to material indebtedness. If an event of default occurs and is continuing, all amounts outstanding under the 2018 credit facility may become immediately due and payable.

The foregoing description of the 2018 credit facility is a summary only and is qualified in its entirety by reference to the Credit Agreement, a copy of which is attached as Exhibits 10.1, to the Company's Current Report on Form 8-K dated April 26, 2018, and is incorporated herein by reference.

Pursuant to requirements under the indentures governing its senior notes, the Company will cause each subsidiary that becomes a guarantor of the 2018 credit facility to also become a guarantor of each of the Company's senior notes.

Concurrent with the closing of the 2018 credit facility agreement, the Company repaid the $1,191 million secured term loan balance with cash on hand and borrowings under the new credit facility. The Company's initial borrowings under the 2018 credit facility were $360 million, a portion of which related to other working capital needs. Additionally, the $323 million in letters of credit outstanding under the 2016 revolving credit facility at March 31, 2018 were converted to letters of credit under the new 2018 credit facility.

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 2017 Annual Report and analyzes the changes in the results of operations between the three months ended March 31, 2018 and 2017. 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 2017 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 "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 2017 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.

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OVERVIEW

Background

Southwestern Energy Company (including its subsidiaries, collectively, “we,” “our,” “us,” “the Company” or “Southwestern”) 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.” We conduct most of our businesses through subsidiaries, and we currently operate exclusively in the United States.

E&P. Our primary business is the exploration for and production of natural gas, oil and NGLs, with our current operations 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. 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, and we provide certain oilfield products and services, principally serving our E&P operations.

Midstream. 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.

Recent Financial and Operating Results

Significant first quarter 2018 operating and financial highlights include:

Total Company

- Net income attributable to common stock of $205 million, or $0.36 per diluted share, declined 27% compared to net income attributable to common stock of $281 million, or $0.57 per diluted share, for the same period in 2017.

- Net cash provided by operating activities of $364 million increased 17% from $312 million for the same period in 2017.

- Total capital investing of $338 million increased 17% from $290 million for the same period in 2017.

E&P

- E&P segment operating income of $238 million improved from an operating income of $225 million for the same period in 2017.

- Total net production of 226 Bcfe, including 159 Bcfe from the Appalachian Basin and 67 Bcf from the Fayetteville Shale, increased 11% compared to the same period in 2017.

  - Comprised of 87% natural gas and 13% NGLs and condensate.

- Realized NGL price of $15.43 and realized oil price of $56.01, increased 16% and 28%, respectively, from the same period in 2017.

- E&P segment invested $334 million: drilling 32 wells, completing 29 wells and placing 33 wells to sales.

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Outlook

In 2018, we expect to continue to exercise capital discipline by aligning our 2018 capital investing program with our expected cash flow from operations, net of changes in working capital. We will also look for opportunities to maximize margins in each core area of our business and further develop our knowledge of our asset base. As announced in February 2018, this will include several strategic steps to reposition our portfolio, sharpen our focus on our highest return assets, strengthen our balance sheet and enhance financial performance. The initiatives include:

- Actively pursuing strategic alternatives for the Fayetteville Shale E&P and related Midstream gathering assets;

- Identifying and implementing structural, process and organizational changes to further reduce costs; and

- Utilizing funds realized from the foregoing to reduce debt, supplement Appalachian Basin development capital, potentially return capital to shareholders, and for general corporate purposes.

Subsequent to the end of the first quarter 2018, we replaced our 2016 credit facility. See Note 16 – Subsequent Events for more information on the new credit agreement.

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.

E&P

For the three months ended March 31,

(in millions)	2018	2017
Revenues	$ 637	$ 563
Operating costs and expenses	399	338
Operating income	$ 238	$ 225
Loss on derivatives, settled (1)	$ (9)	$ (30)

(1) Represents the loss on settled commodity derivatives.

Operating Income

- E&P segment operating income increased $13 million for the three months ended March 31, 2018, compared to the same period in 2017, primarily due to a $74 million increase in revenues, partially offset by a $61 million increase in operating costs.

Revenues

The following illustrates the effects on sales revenues associated with changes in commodity prices and production volumes:

	Three months ended March 31,			
(in millions except percentages)	Natural Gas	Oil	NGLs	Total
2017 sales revenues	$ 500	$ 23	$ 40	$ 563
Changes associated with prices	(2)	7	9	14
Changes associated with production volumes	37	4	16	57
2018 sales revenues (1)	$ 535	$ 34	$ 65	$ 634
Increase from 2017	7%	48%	63%	13%

(1) Excludes the impact of $3 million in other operating revenues, primarily related to water sales to third-party operators for the three months ended March 31, 2018.

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Production Volumes

	For the three months ended March 31,		Increase/
	2018	2017	(Decrease)
Natural gas (Bcf)			
Northeast Appalachia	108	87	24%
Southwest Appalachia	22	15	47%
Fayetteville Shale	67	81	(17%)
Other	–	–	–%
Total	197	183	8%
Oil (MBbls)			
Southwest Appalachia	594	495	20%
Other	19	24	(21%)
Total	613	519	18%
NGL (MBbls)			
Southwest Appalachia	4,218	2,996	41%
Other	12	12	–%
Total	4,230	3,008	41%
Production volumes by area (Bcfe):			
Northeast Appalachia	108	87	24%
Southwest Appalachia	51	36	42%
Fayetteville Shale	67	81	(17%)
Other	–	–	–%
Total	226	204	11%

- Production volumes for our E&P segment increased by 22 Bcfe for the three months ended March 31, 2018, compared to the same period in 2017, as increased production volumes from Northeast and Southwest Appalachia more than offset decreased natural gas production volumes in the Fayetteville Shale.

Commodity Prices

The price we expect to receive for our production is a critical factor in determining the capital investments we make to develop our properties. Commodity prices fluctuate due to a variety of factors we cannot control or predict, including 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. These factors impact supply and demand, which in turn determine the sales prices for our production. In addition to these factors, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices, including basis differentials. We will continue to evaluate the commodity price environments and adjust the pace of our activity to invest within cash flows in order to maintain appropriate liquidity and financial flexibility.

	For the three months ended March 31,		Increase/
Natural Gas Price:	2018	2017	(Decrease)
NYMEX Henry Hub price ($MMBtu) (1)	$ 3.00	$ 3.32	(10%)
Discount to NYMEX (2)	(0.28)	(0.59)	53%
Average realized gas price per MCF, excluding derivatives	$ 2.72	$ 2.73	–%
Loss on settled financial basis derivatives ($/Mcf)	(0.11)	(0.01)	
Gain (loss) on settled commodity derivatives ($/Mcf)	0.06	(0.15)	
Average realized gas price per Mcf, including derivatives	$ 2.67	$ 2.57	4%
Oil Price:			
WTI oil price ($/Bbl)	$ 62.87	$ 51.91	21%
Discount to WTI	(6.86)	(8.17)	16%
Average realized oil price per Bbl	$ 56.01	$ 43.74	28%
NGL Price:			
Average net realized NGL price per Bbl (3)	$ 15.43	$ 13.28	16%
Percentage of WTI	25%	26%	
Total Weighted Average Realized Price:			
Excluding derivatives	$ 2.81	$ 2.75	2%
Including derivatives	$ 2.77	$ 2.61	6%

(1) Based on last day settlement prices from monthly futures contracts.

(2) This discount includes a basis differential, a heating content adjustment, physical basis sales, third-party transportation charges and fuel charges, and excludes financial basis hedges.

(3) Includes the impact of transportation costs and $0.01 per Bbl and $0.02 per Bbl of settled derivative gains for the three months ended March 31, 2018 and 2017, respectively.

· Our average price realized for natural gas production, including the effect of derivatives, increased by $0.10 per Mcf for the three months ended March 31, 2018, compared to the same period in 2017, due to a $0.11 per Mcf improvement associated with our settled derivatives, partially offset by a $0.01 per Mcf decrease in the average realized price, excluding derivatives.

· The average price realized for our crude oil production increased by $12.27 per Bbl for the three months ended March 31, 2018, compared to the same period in 2017. We did not use derivatives to financially protect our 2018 or 2017 oil production.

· Our average price realized for NGL production, including the effect of derivatives, increased by $2.15 per Bbl for the three months ended March 31, 2018, compared to the same period in 2017. Settled derivative gains increased the realized NGL price by $0.01 per Bbl and $0.02 per Bbl for the three months ended March 31, 2018 and 2017, respectively.

Our E&P segment receives a sales price for our natural gas at a discount to average monthly NYMEX settlement prices based on heating content of the gas, locational basis differentials and 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, "Qualitative and Qualitative Disclosures About Market Risk" and Note 6 to the unaudited condensed consolidated financial statements, included in this Quarterly Report.

· As of March 31, 2018, we have protected basis on approximately 242 Bcf and 88 Bcf of our expected 2018 and 2019 natural gas production, respectively, through physical sales arrangements at a basis differential to NYMEX natural gas price of approximately ($0.38) per MMBtu and ($0.30) per MMBtu for 2018 and 2019, respectively.

- We have also financially protected basis on approximately 73 Bcf and 6 Bcf of our 2018 and 2019 expected natural gas production, respectively, through the use of derivatives at a basis differential to NYMEX natural gas price of approximately ($0.59) per MMBtu and $1.01 per MMBtu for 2018 and 2019, respectively.

- As of March 31, 2018 we have also financially protected 434 Bcf and 279 Bcf of our remaining expected 2018 and full year 2019 natural gas production, respectively, to limit our exposure to NYMEX price fluctuations.

- As of March 31, 2018 we have also financially protected 1,100 MBbls of our remaining expected 2018 propane production to limit our exposure to price fluctuations.

- As of March 31, 2018 we have also financially protected 413 MBbls and 91 MBbls of our remaining expected 2018 and full year 2019 ethane production, respectively, to limit our exposure to price fluctuations.

We refer you to Note 6 of the unaudited condensed consolidated financial statements included in this Quarterly Report for additional details about our derivative instruments.

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Operating Costs and Expenses

(in millions except percentages)	For the three months ended March 31, 2018	2017	Increase/ (Decrease)
Lease operating expenses	$ 213	$ 181	18%
General & administrative expenses	48	43	12%
Taxes, other than income taxes	21	24	(13%)
Full cost pool amortization	108	81	33%
Non-full cost pool DD&A	9	9	–%
Total operating costs	$ 399	$ 338	18%

Average unit costs per Mcfe:	For the three months ended March 31, 2018	2017	Increase/ (Decrease)
Lease operating expenses	$ 0.94	$ 0.89	6%
General & administrative expenses	$ 0.21	$ 0.21	–%
Taxes, other than income taxes	$ 0.09	$ 0.12	(25%)
Full cost pool amortization	$ 0.48	$ 0.40	20%

Lease Operating Expenses

· Lease operating expenses per Mcfe increased $0.05 for the three months ended March 31, 2018, compared to the same period of 2017, primarily due to additional transportation, NGL and gas processing costs associated with our production growth in the Appalachian Basin.

· Additionally, in the first quarter of 2018, we recorded additional charges related to preventative maintenance associated with extended severe winter weather and a $3.7 million one-time charge related to NGL processing fees.

General and Administrative Expenses

·

General and administrative expenses increased $5 million for the three months ended March 31, 2018, compared to the same period in 2017, primarily due to increased personnel costs, professional fees and information technology charges.

Taxes, Other than Income Taxes

- Taxes other than income taxes per Mcfe may 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. Taxes, other than income taxes, decreased $0.03 per Mcfe for the three months ended March 31, 2018, compared to the same period of 2017, due to favorable property tax assessments, reduced Pennsylvania impact fees which are based on lower current commodity prices than the same period in 2017, and property and sales tax refunds recorded in the first quarter of 2018.

Full Cost Pool Amortization

- Our full cost pool amortization rate increased $0.08 per Mcfe for the three months ended March 31, 2018, as compared to the same period in 2017. 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.

- 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.

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· Unevaluated costs excluded from amortization were $1.8 billion at March 31, 2018 and December 31, 2017. The unevaluated costs excluded from amortization remained unchanged as the impact of $87 million of unevaluated capital invested during the period was mostly offset by the evaluation of previously unevaluated properties totaling $82 million.

Midstream

(in millions except percentages)	For the three months ended March 31, 2018		2017	Increase/ (Decrease)
Marketing revenues	$ 829		$ 777	7%
Gas gathering revenues	67		81	(17%)
Marketing purchases	819		765	7%
Operating costs and expenses	60	(1)	52	15%
Operating income	$ 17		$ 41	(59%)
Volumes marketed (Bcfe)	265		245	8%
Volumes gathered (Bcf)	103		129	(20%)
Percent natural gas marketed from affiliated E&P operations	97 %		95 %	
Percent affiliated E&P oil and NGL production marketed by Midstream segment	67 %		67 %	

(1) Includes a $10 million impairment related to certain non-core gathering assets and a $1 million gain from the sale of certain compressor equipment.

Operating Income

· Operating income for the three months ended March 31, 2018 includes a $10 million impairment related to certain non-core gathering assets. Excluding this one-time charge, operating income from our Midstream segment decreased $14 million for the three months ended March 31, 2018, compared to the same period in 2017, primarily due to a $14 million decrease in gas gathering revenues and a $2 million decrease in marketing margin, partially offset by a $2 million decrease in operating costs and expenses.

- The margin generated from marketing activities was $10 million and $12 million for the three months ended March 31, 2018 and 2017, 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. Increases and decreases in marketing revenues due to changes in commodity prices and volumes marketed are largely offset by corresponding changes in marketing purchase expenses. We enter into derivative contracts from time to time with respect to our marketing activities to provide margin protection. For more information about our derivatives and risk management activities, we refer you to Item 3, "Qualitative and Qualitative Disclosures About Market Risks" and Note 6, in the unaudited condensed consolidated financial statements included in this Quarterly Report for additional information.

Revenues

- Revenues from our marketing activities increased $52 million for the three months ended March 31, 2018, compared to the same period in 2017, primarily due to a 20 Bcfe increase in the volumes marketed, partially offset by a 1% decrease in the price received for volumes marketed.

- The decrease in gas gathering revenues for the three months ended March 31, 2018, compared to the same period in 2017, was primarily due to decreasing volumes gathered in the Fayetteville Shale.

Operating Costs and Expenses

- Operating costs and expenses for the three months ended March 31, 2018 includes a $10 million impairment related to certain non-core gathering assets. Excluding this one-time charge, operating costs and expenses decreased $2 million for the three months ended March 31, 2018, compared to the same period in 2017, as decreases in compression expenses resulting from lower activity levels in the Fayetteville Shale were mostly offset by one-time compressor facility repair costs.

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Interest Expense

(in millions except percentages)	For the three months ended March 31, 2018	2017	Increase/ (Decrease)
Gross interest expense:			
Senior notes	$ 50	$ 44	14%
Credit arrangements	15	14	7%
Amortization of debt costs	2	2	–%
Total gross interest expense	67	60	12%
Less: capitalization	(28)	(28)	–%
Net interest expense	$ 39	$ 32	22%

- Interest expense related to our senior notes increased for the three months ended March 31, 2018 and 2017 due to a higher average interest rate.

- Capitalized interest remained unchanged but decreased as a percentage of gross interest expense for the three months ended March 31, 2018, compared to the same period in 2017, due to the continued evaluation of a portion of our Southwest Appalachia assets.

Gain (Loss) on Derivatives

(in millions)	For the three months ended March 31, 2018	2017
Gain on unsettled derivatives	$ 2	$ 146
Loss on settled derivatives	(9)	(30)
Gain (loss) on derivatives	$ (7)	$ 116

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.

Income Taxes

(in millions except percentages)	For the three months ended March 31, 2018	2017
Income tax expense (benefit)	$ –	$ –
Effective tax rate	0%	0%

- 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 revolving credit facility and capital markets as our primary sources of liquidity. Although we have financial flexibility to draw on our revolving credit facility as necessary, we continue to be committed to our capital discipline strategy of investing within our cash flow from operations net of changes in working capital, supplemented by $40 million in 2017 cash flow carried forward into 2018.

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

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commodity hedging activities. See "Quantitative and Qualitative Disclosures about Market Risks" in Item 3 and Note 6, in the unaudited condensed consolidated financial statements included in this Quarterly Report for further details.

Our derivative contracts allow us to ensure a certain level of cash flow to fund our operations. At March 31, 2018, we had NYMEX price derivatives in place on 434 Bcf and 279 Bcf on our targeted remaining 2018 and full year 2019 natural gas production, respectively, for protection against a decrease in natural gas prices. We also had commodity derivatives in place on 1,100 MBbls of our targeted remaining 2018 propane production as well as 413 MBbls and 91 MBbls of our targeted remaining 2018 and full year 2019 ethane production, respectively.

Our commodity hedging activities are subject to the credit risk of our counterparties being financially unable to settle 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.

Our short-term cash flows are also 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, rearrange or amend some or all of our outstanding debt or debt agreements 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.

Credit Arrangements and Financing Activities

As of March 31, 2018, the revolving credit facility component of our June 2016 credit agreement provided borrowing capacity of $743 million and the revolving credit facility we entered into in December 2013, as reduced in June 2016, provided borrowing capacity of $66 million. There were no borrowings under either revolving credit facility as of March 31, 2018; however, there was $323 million in letters of credit outstanding against the 2016 revolving credit facility.

As of March 31, 2018, we were in compliance with all of the covenants of the existing term loan and revolving credit facilities. We refer you to Note 9 of the unaudited condensed consolidated financial statements included in this Quarterly Report for additional discussion of the covenant requirements of our 2016 term loan and 2016 and 2013 revolving credit facilities.

On April 26, 2018, as part of our strategic effort to increase financial flexibility and reduce costs, we replaced our 2016 credit facility (which consisted of a $1,191 million secured term loan and an unsecured $743 million revolving credit facility) with a new credit facility. Although the 2018 credit facility has a maximum borrowing capacity of $3,500 million and currently has commitments of $2,000 million, it is subject to both a borrowing base that is determined semiannually in April and October by the lenders and the permitted lien limitations in our senior note indentures. The borrowing base is subject to change based primarily on drilling results, commodity prices, the level of capital investing and operating costs. The initial borrowing base under the 2018 credit facility is $3,200 million. The permitted lien provisions in the senior note indentures currently limit liens securing indebtedness to the greater of $2,000 million and 25% of adjusted consolidated net tangible assets. The 2018 credit facility matures in April 2023; however, the maturity date will accelerate to December 2021 if, by that date, we have not amended, redeemed or refinanced at least $700 million of our senior notes due March 2022.

By entering into the 2018 credit facility we expect to realize certain benefits, including:

- Reduction in debt outstanding and simplification of our capital structure by consolidating the components of the 2016 credit facility (consisting of the $1,191 million secured term loan and unsecured $743 million revolving credit facility) into a senior secured revolving credit facility. The 2013 credit facility (consisting of an unsecured $66 million revolving credit facility) was terminated.

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· Reduced interest expense due to both the termination of the $1,191 million secured term loan and lower interest margins associated with the 2018 credit facility.

· Greater access to liquidity by extending the maturity from December 2020 (under the 2016 credit facility) to April 2023 under the 2018 credit facility (subject to the acceleration as described above).

· Increased financial flexibility by eliminating certain provisions in the 2016 credit facility associated with minimum liquidity requirements and restrictions on asset sale proceeds.

See Note 16 – Subsequent Events of the unaudited condensed consolidated financial statements included in this Quarterly Report for more information on the new credit agreement, including an overview of key financial covenants.

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.

The credit status of the financial institutions participating in our revolving credit facility could adversely impact our ability to borrow funds under the revolving credit facility. Although we believe all of the lenders under the facility has the ability to provide funds, we cannot predict whether each will be able to meet their obligation to us. We refer you to Note 16 – Subsequent Events of the unaudited condensed consolidated financial statements included in this Quarterly Report for more information on the 2018 credit facility.

At April 30, 2018, 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.

Cash Flows

	For the three months ended March 31,	
(in millions)	2018	2017

Net cash provided by operating activities	$ 364	$ 312
Net cash used in investing activities	(294)	(334)
Net cash used in financing activities	(28)	(19)

Cash Flow from Operations

- Net cash provided by operating activities increased 17% or $52 million for the three months ended March 31, 2018, compared to the same period in 2017, primarily due to an 11% increase in production volumes, increases in realized oil and NGL pricing and a $21 million improvement in our settled derivatives.

- Net cash generated from operating activities provided 108% of our cash requirements for capital investments for the three months ended March 31, 2018 and 2017, reflecting our commitment to our capital discipline strategy of investing within our cash flow from operations, net of changes in working capital.

Cash Flow from Investing Activities

- Total E&P capital investing increased $51 million for the three months ended March 31, 2018, compared to the same period in 2017, due to a $50 million increase in direct E&P capital investing and a $1 million increase in capitalized interest and internal costs. Of the $334 million invested in our E&P segment for the three months ended March 31, 2018, 94% was invested in the Appalachian basin.

	For the three months ended March 31,	
(in millions)	2018	2017
Cash Flows from Investing Activities		
Additions to properties and equipment	$ 302	$ 340
Adjustments for capital investments		
Changes in capital accruals	33	(52)
Other	3	2
Total capital investing	$ 338	$ 290

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Capital Investing

(in millions except percentages)	For the three months ended March 31, 2018	2017	Increase/ (Decrease)
E&P capital investing	$ 334	$ 283	18%
Midstream capital investing	4	6	(33%)
Other capital investing	–	1	(100%)
Total capital investing	$ 338	$ 290	17%

(in millions)	For the three months ended March 31, 2018	2017
E&P Capital Investments by Type:		
Exploratory and development drilling, including workovers	$ 255	$ 208
Acquisitions of properties	20	21
Seismic expenditures	1	–
Drilling rigs, sand facility and other	5	2
Capitalized interest and other expenses	53	52
Total E&P capital investments	$ 334	$ 283
E&P Capital Investments by Area:		
Northeast Appalachia	$ 111	$ 112
Southwest Appalachia	202	121
Fayetteville Shale	15	39
New Ventures & Other	6	11
Total E&P capital investments	$ 334	$ 283

Gross Operated Well Count Summary:	For the three months ended March 31, 2018	2017

Drilled	32	33
Completed	29	49
Wells to sales	33	49

Actual capital expenditure levels may vary significantly from period to period due to many factors, including drilling results, natural gas, oil and NGL prices, industry conditions, the prices and availability of goods and services, and the extent to which properties are acquired or non-strategic assets are sold.

Cash Flow from Financing Activities

· Net cash used in financing activities for the three months ended March 31, 2018 was $28 million, compared to $19 million for the same period in 2017. During the three months ended March 31, 2018, $27 million of cash was paid for the preferred stock dividend declared in the fourth quarter of 2017 and $1 million was paid for tax withholding.

(in millions except percentages)	March 31, 2018	December 31, 2017	Increase/(Decrease)
Debt (1)	$ 4,393	$ 4,391	$ 2
Equity	2,193	1,979	214
Total debt to capitalization ratio	67%	69%	
Debt (1)	$ 4,393	$ 4,391	$ 2
Less: Cash and cash equivalents	958	916	42
Debt, net of cash and cash equivalents(2)	$ 3,435	$ 3,475	$ (40)

(1) The increase in total debt as of March 31, 2018, as compared to December 31, 2017, relates to the amortization of financing costs during the first quarter of 2018.

(2) Debt, net of cash and cash equivalents is a non-GAAP financial measure of a company's ability to repay its debt if it was all due today.

We refer you to Note 9 of the unaudited condensed consolidated financial statements included in this Quarterly Report for additional discussion of our outstanding debt and credit facilities.

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Working Capital

- We had positive working capital of $756 million at March 31, 2018 primarily due to $958 million of cash and cash equivalents resulting from the fully-drawn term loan that was part of our 2016 credit facility. That term loan was repaid on April 26, 2018 with cash on hand and borrowings under the new 2018 credit facility.

- At December 31, 2017, we had positive working capital of $729 million at December 31, 2017 primarily due to $916 million of cash and cash equivalents resulting from our fully-drawn 2016 term loan.

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 March 31, 2018, our material off-balance sheet arrangements and transactions include operating lease arrangements and $323 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 2017 Annual Report.

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 2017 Annual Report.

Contingent Liabilities and Commitments

As of March 31, 2018, 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 $9.1 billion, $3.1 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 $832 million. As of March 31, 2018, future payments under non-cancelable firm transportation and gathering agreements are as follows:

	Payments Due by Period					
(in millions)	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	5 to 8 years	More than 8 Years
Infrastructure Currently in Service	$ 5,986	$ 639	$ 1,208	$ 894	$ 1,151	$ 2,094
Pending Regulatory Approval and/or Construction (1)	3,139	46	317	389	626	1,761
Total Transportation Charges	$ 9,125	$ 685	$ 1,525	$ 1,283	$ 1,777	$ 3,855

(1) Based on the estimated in-service dates as of March 31, 2018.

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. For the three months ended March 31, 2018, we have contributed $3 million to the pension and postretirement benefit plans. We expect to contribute an additional $9 million to our pension and postretirement benefit plans during the remainder of 2018. We recognized liabilities of $59 million as of March 31, 2018 and December 31, 2017, 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, employment matters, traffic incidents, pollution, contamination, encroachment on others' property 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.

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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.

For further information, we refer you to "Litigation" and "Environmental Risk" in Note 10 to the unaudited condensed consolidated financial statements included in Item I of Part I of this Quarterly Report.

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, certain NGLs 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 risks 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 exposure to concentrations of credit risk consists 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 purchasers and their dispersion across geographic areas. During the three months ended March 31, 2018 and March 31, 2017, no single third-party purchaser accounted for 10% or more of our consolidated revenues. We believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, oil and NGL production. See "Commodities Risk" below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

As of March 31, 2018, we had approximately $3.2 billion of outstanding senior notes with a weighted average interest rate of 6.19%, and $1.2 billion of term loan facility debt with a variable interest rate of 4.24%. We currently have an interest rate swap in effect to mitigate a portion of our exposure to volatility in interest rates.

	Expected Maturity Date						
($ in millions)	2017	2018	2019	2020	2021	Thereafter	Total
Fixed Rate Payments (1)	$ –	$ –	$ –	$ 92	$ –	$ 3,150	$ 3,242
Weighted Average Interest Rate	– %	– %	– %	5.80 %	– %	6.21 %	6.19 %
Variable Rate Payments (1)	–	–	–	1,191 (2)	–	–	1,191 (2)
Weighted Average Interest Rate	– %	– %	– %	4.24 %	– %	– %	4.24 %

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

(2) Concurrent with the closing of the 2018 credit facility agreement, we repaid the $1,191 million secured term loan balance with cash on hand and borrowings under the new credit facility. See Note 16 – Subsequent Events for more information on the amended and restated agreement.

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).

The primary market risks relating to our derivative contracts are the volatility in market prices and basis differentials for our production. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the production 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. We refer you to Note 6 of the unaudited condensed consolidated financial statements included in this Quarterly Report for additional details about our derivative instruments.

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 March 31, 2018 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 March 31, 2018 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 2017 Annual Report.

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

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

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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

Not Applicable.

ITEM 6. EXHIBITS

(10.1)	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on March 8, 2018)
(10.2)	Southwestern Energy Company 2013 Incentive Plan Form of Performance Unit Award Agreement (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on March 8, 2018)
(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:	May 4, 2018	/s/ JULIAN M. BOTT
		Julian M. Bott Executive Vice President and Chief Financial Officer