SM Energy Co
Form 10-Q
May 02, 2019

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2019

OR

o 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 001-31539
SM ENERGY COMPANY
(Exact name of registrant as specified in its charter)

Delaware	41-0518430
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1775 Sherman Street, Suite 1200, Denver, Colorado	80203
(Address of principal executive offices)	(Zip Code)

(303) 861-8140
(Registrant's telephone number, including area code)
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o
Indicate by check mark whether the registrant has submitted electronically, every Interactive Data File required to be submitted 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 such files). Yes þ No o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a 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 þ	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o
	Emerging growth company o

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. o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading symbol(s)	Name of each exchange on which registered
Common stock, $0.01 par value	SM	New York Stock Exchange

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

As of April 25, 2019, the registrant had 112,244,545 shares of common stock outstanding.

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PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(in thousands, except share data)

	March 31, 2019	December 31, 2018
ASSETS		
Current assets:		
Cash and cash equivalents	$ 14	$ 77,965
Accounts receivable	145,299	167,536
Derivative assets	67,567	175,130
Prepaid expenses and other	8,454	8,632
Total current assets	221,334	429,263
Property and equipment (successful efforts method):		
Proved oil and gas properties	7,578,976	7,278,362
Accumulated depletion, depreciation, and amortization	(3,586,650)	(3,417,953)
Unproved oil and gas properties	1,529,825	1,581,401
Wells in progress	345,507	295,529
Properties held for sale, net	—	5,280
Other property and equipment, net of accumulated depreciation of $59,720 and $57,102, respectively	86,732	88,546
Total property and equipment, net	5,954,390	5,831,165
Noncurrent assets:		
Derivative assets	27,202	58,499
Other noncurrent assets	83,692	33,935
Total noncurrent assets	110,894	92,434
Total assets	$ 6,286,618	$ 6,352,862
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 426,550	$ 403,199
Derivative liabilities	95,269	62,853
Other current liabilities	23,523	—
Total current liabilities	545,342	466,052
Noncurrent liabilities:		
Revolving credit facility	46,500	—
Senior Notes, net of unamortized deferred financing costs	2,449,588	2,448,439
Senior Convertible Notes, net of unamortized discount and deferred financing costs	150,199	147,894
Asset retirement obligations	94,026	91,859
Deferred income taxes	176,348	223,278
Derivative liabilities	13,332	12,496
Other noncurrent liabilities	68,058	42,522
Total noncurrent liabilities	2,998,051	2,966,488
Commitments and contingencies (note 6)		
Stockholders’ equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 112,244,545 and 112,241,966 shares, respectively	1,122	1,122
Additional paid-in capital	1,771,558	1,765,738

Retained earnings	982,662	1,165,842
Accumulated other comprehensive loss	(12,117)	(12,380)
Total stockholders’ equity	2,743,225	2,920,322
Total liabilities and stockholders’ equity	$ 6,286,618	$ 6,352,862

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)
(in thousands, except per share data)

	For the Three Months Ended March 31, 2019	2018
Operating revenues and other income:		
Oil, gas, and NGL production revenue	$340,476	$382,886
Net gain on divestiture activity	61	385,369
Other operating revenues	393	1,340
Total operating revenues and other income	340,930	769,595
Operating expenses:		
Oil, gas, and NGL production expense	121,305	120,879
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	177,746	130,473
Exploration	11,348	13,727
Abandonment and impairment of unproved properties	6,338	5,625
General and administrative	32,086	27,682
Net derivative loss	177,081	7,529
Other operating expenses, net	335	4,612
Total operating expenses	526,239	310,527
Income (loss) from operations	(185,309)	459,068
Interest expense	(37,980)	(43,085)
Other non-operating income (expense), net	(317)	409
Income (loss) before income taxes	(223,606)	416,392
Income tax (expense) benefit	46,038	(98,991)
Net income (loss)	$(177,568)	$317,401
Basic weighted-average common shares outstanding	112,252	111,696
Diluted weighted-average common shares outstanding	112,252	112,879
Basic net income (loss) per common share	$(1.58)	$2.84
Diluted net income (loss) per common share	$(1.58)	$2.81
Dividends per common share	$0.05	$0.05

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) (UNAUDITED)
(in thousands)

	For the Three Months Ended March 31,	
	2019	2018
Net income (loss)	$(177,568)	$317,401
Other comprehensive income, net of tax:		
Pension liability adjustment	263	260
Total other comprehensive income, net of tax	263	260
Total comprehensive income (loss)	$(177,305)	$317,661

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (UNAUDITED)
(in thousands, except share data and dividends per share)

	Common Stock		Additional Paid-in	Retained	Accumulated Other Comprehensive	Total Stockholders'
	Shares	Amount	Capital	Earnings	Loss	Equity
Balances, December 31, 2018	112,241,966	$ 1,122	$ 1,765,738	$ 1,165,842	$ (12,380)	$ 2,920,322
Net loss	—	—	—	(177,568)	—	(177,568)
Other comprehensive income	—	—	—	—	263	263
Cash dividends declared, $0.05 per share	—	—	—	(5,612)	—	(5,612)
Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings	2,579	—	(18)	—	—	(18)
Stock-based compensation expense	—	—	5,838	—	—	5,838
Balances, March 31, 2019	112,244,545	$ 1,122	$ 1,771,558	$ 982,662	$ (12,117)	$ 2,743,225

	Common Stock		Additional Paid-in	Retained	Accumulated Other Comprehensive	Total Stockholders'
	Shares	Amount	Capital	Earnings	Loss	Equity
Balances, December 31, 2017	111,687,016	$ 1,117	$ 1,741,623	$ 665,657	$ (13,789)	$ 2,394,608
Net income	—	—	—	317,401	—	317,401
Other comprehensive income	—	—	—	—	260	260
Cash dividends declared, $0.05 per share	—	—	—	(5,584)	—	(5,584)
Stock-based compensation expense	—	—	5,412	—	—	5,412
Cumulative effect of accounting change	—	—	—	2,969	(2,969)	—
Other	—	—	—	1	(1)	—
Balances, March 31, 2018	111,687,016	$ 1,117	$ 1,747,035	$ 980,444	$ (16,499)	$ 2,712,097

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)
(in thousands)

	For the Three Months Ended March 31, 2019	2018
Cash flows from operating activities:		
Net income (loss)	$(177,568)	$317,401
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Net gain on divestiture activity	(61)	(385,369)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	177,746	130,473
Abandonment and impairment of unproved properties	6,338	5,625
Stock-based compensation expense	5,838	5,412
Net derivative loss	177,081	7,529
Derivative settlement loss	(4,969)	(24,528)
Amortization of debt discount and deferred financing costs	3,789	3,866
Deferred income taxes	(47,003)	98,366
Other, net	(2,530)	(2,527)
Net change in working capital	(20,159)	(16,113)
Net cash provided by operating activities	118,502	140,135
Cash flows from investing activities:		
Net proceeds from the sale of oil and gas properties	6,114	490,780
Capital expenditures	(249,340)	(301,521)
Other, net	291	—
Net cash provided by (used in) investing activities	(242,935)	189,259
Cash flows from financing activities:		
Proceeds from credit facility	172,000	—
Repayment of credit facility	(125,500)	—
Other, net	(18)	—
Net cash provided by financing activities	46,482	—
Net change in cash, cash equivalents, and restricted cash	(77,951)	329,394
Cash, cash equivalents, and restricted cash at beginning of period	77,965	313,943
Cash, cash equivalents, and restricted cash at end of period	$14	$643,337
Supplemental schedule of additional cash flow information and non-cash activities:		
Operating activities:		
Cash paid for interest, net of capitalized interest	$(39,957)	$(40,060)
Investing activities:		
Changes in capital expenditure accruals and other	$62,185	$60,299
Supplemental non-cash investing activities:		
Carrying value of properties exchanged	$65,788	$—

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

SM ENERGY COMPANY AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Note 1 - Summary of Significant Accounting Policies

Description of Operations

SM Energy Company, together with its consolidated subsidiaries ("SM Energy" or the "Company"), is an independent energy company engaged in the acquisition, exploration, development, and production of crude oil and condensate, natural gas, and natural gas liquids (also respectively referred to as "oil," "gas," and "NGLs" throughout this report) in onshore North America.

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements include the accounts of the Company and have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") for interim financial information, the instructions to Quarterly Report on Form 10-Q, and Regulation S-X. These financial statements do not include all information and notes required by GAAP for annual financial statements. However, except as disclosed herein, there has been no material change in the information disclosed in the notes to the consolidated financial statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2018 (the "2018 Form 10-K"). In the opinion of management, all adjustments, consisting of normal recurring adjustments considered necessary for a fair presentation of interim financial information, have been included. Operating results for the periods presented are not necessarily indicative of expected results for the full year.
In connection with the preparation of the Company's unaudited condensed consolidated financial statements, the Company evaluated events subsequent to the balance sheet date of March 31, 2019, and through the filing of this report. Certain prior period amounts have been reclassified to conform to the current presentation on the accompanying unaudited condensed consolidated financial statements.

Significant Accounting Policies

The significant accounting policies followed by the Company are set forth in Note 1 - Summary of Significant Accounting Policies in the 2018 Form 10-K and are supplemented by the notes to the unaudited condensed consolidated financial statements included in this report. These unaudited condensed consolidated financial statements should be read in conjunction with the 2018 Form 10-K.

Recently Issued Accounting Standards

In February 2016, the Financial Accounting Standards Board issued Accounting Standards Update ("ASU") No. 2016-02, Leases (Topic 842), followed by other related ASUs that provided targeted improvements and additional practical expedient options (collectively "ASU 2016-02" or "Topic 842"). The Company adopted ASU 2016-02 on January 1, 2019, using the modified retrospective method. The Company elected as part of its adoption to also use the optional transition methodology whereby previously reported periods continue to be reported in accordance with historical accounting guidance for leases that were in effect for those prior periods. Policy elections and practical expedients the Company has implemented in connection with the adoption of ASU 2016-02, include (a) excluding from the balance sheet leases with terms that are less than one year, (b) for agreements that contain both lease and non-lease components, combining these components together and accounting for them as a single lease, (c) the package of practical expedients, which among other requirements, allows the Company to avoid reassessing contracts that commenced prior to adoption that were properly evaluated under legacy GAAP, and (d) excluding land easements that existed or expired before adoption of ASU 2016-02. The scope of ASU 2016-02 does not apply to leases used in the exploration or use of minerals, oil, natural gas, or other similar non-regenerative resources.
Upon adoption on January 1, 2019, the Company recognized approximately $50.0 million in right-of-use ("ROU") assets and related lease liabilities for its operating leases. There was no cumulative effect to retained earnings upon the adoption of this guidance. Please refer to Note 12 - Leases for additional discussion.
Other than as disclosed in the 2018 Form 10-K, there are no ASUs that would have a material effect on the Company's consolidated financial statements and related disclosures that have been issued but not yet adopted by the Company as of March 31, 2019, and through the filing of this report.

Note 2 - Revenue from Contracts with Customers

The Company recognizes its share of revenue from the sale of produced oil, gas, and NGLs in its Permian and South Texas & Gulf Coast regions. As a result of divestiture activity in the first half of 2018, there has been no production revenue from the Rocky Mountain region after the second quarter of 2018. Oil, gas, and NGL production revenue presented within the accompanying unaudited condensed consolidated statements of operations (“accompanying statements of operations”) is reflective of the revenue generated from contracts with customers.

The table below presents oil, gas, and NGL production revenue by product type for each of the Company's operating regions for the three months ended March 31, 2019, and 2018:

	Permian		South Texas & Gulf Coast		Rocky Mountain		Total	
	Three Months Ended March 31,		Three Months Ended March 31,		Three Months Ended March 31,		Three Months Ended March 31,	
	2019	2018	2019	2018	2019	2018	2019	2018
	(in thousands)							
Oil production revenue	$225,247	$205,794	$13,814	$19,583	$—	$35,683	$239,061	$261,060
Gas production revenue	15,592	24,876	49,521	52,733	—	1,500	65,113	79,109
NGL production revenue	21	124	36,281	41,770	—	823	36,302	42,717
Total	$240,860	$230,794	$99,616	$114,086	$—	$38,006	$340,476	$382,886
Relative percentage	71 %	60 %	29 %	30 %	—%	10 %	100 %	100 %

Note: Amounts may not calculate due to rounding.

The Company recognizes oil, gas, and NGL production revenue at the point in time when custody and title ("control") of the product transfers to the customer, which differs depending on the contractual terms of each of the Company's arrangements. Transfer of control drives the presentation of transportation, gathering, processing, and other post-production expenses ("fees and other deductions") within the accompanying statements of operations. Fees and other deductions incurred prior to control transfer are recorded within the oil, gas, and NGL production expense line item on the accompanying statements of operations, while fees and other deductions incurred subsequent to control transfer are embedded in the price and effectively recorded as a reduction of oil, gas, and NGL production revenue. Please refer to Note 2 - Revenue from Contracts with Customers in the 2018 Form 10-K for more information regarding the types of contracts under which oil, gas, and NGL production revenue is generated.

Significant judgments made in applying the guidance in Accounting Standards Codification Topic 606, Revenue from Contracts with Customers relate to the point in time when control transfers to customers in gas processing arrangements with midstream processors. The Company does not believe that significant judgments are required with respect to the determination of the transaction price, including amounts that represent variable consideration, as volume and price carry a low level of estimation uncertainty given the precision of volumetric measurements and the use of index pricing with predictable differentials. Accordingly, the Company does not consider estimates of variable consideration to be constrained.

The Company's contractual performance obligations arise upon the production of hydrocarbons from wells in which the Company has an ownership interest. The performance obligations are considered satisfied upon control transferring to a customer at the wellhead, inlet, or tailgate of the midstream processor's processing facility, or other contractually specified delivery point. The time period between production and satisfaction of performance obligations is generally less than one day; thus, there are no material unsatisfied or partially unsatisfied performance obligations at the end of the reporting period.

Revenue is recorded in the month when contractual performance obligations are satisfied. However, settlement statements from the purchasers of hydrocarbons and the related cash consideration are received 30 to 90 days after production has occurred. As a result, the Company must estimate the amount of production delivered to the customer and the consideration that will ultimately be received for sale of the product. Estimated revenue due to the Company is recorded within the accounts receivable line item on the accompanying unaudited condensed consolidated balance sheets ("accompanying balance sheets") until payment is received. The accounts receivable balances from contracts with customers within the accompanying balance sheets as of March 31, 2019, and December 31, 2018, were $109.4 million and $107.2 million, respectively. To estimate accounts receivable from contracts with customers, the Company uses knowledge of its properties, historical performance, contractual arrangements, index pricing, quality and transportation differentials, and other factors as the basis for these estimates. Differences between estimates and actual amounts received for product sales are recorded in the month that payment is received from the purchaser.

Revenue recognized during the three months ended March 31, 2019, that related to performance obligations satisfied in prior reporting periods, was immaterial.

Note 3 - Divestitures, Assets Held for Sale, and Acquisitions

Divestitures

On March 26, 2018, the Company divested approximately 112,000 net acres of its Powder River Basin assets (the "PRB Divestiture") for total cash received at closing, net of costs (referred to throughout this report as "net divestiture proceeds"), of $490.8 million, and recorded an estimated net gain of $409.2 million for the three months ended March 31, 2018. After final purchase price adjustments, the Company received net divestiture proceeds of $492.2 million, and recorded a final net gain of $410.6 million related to these divested assets for the year ended December 31, 2018.

During the first quarter of 2018, the company entered into definitive agreements for the sale of its Divide County assets (the “Divide County Divestiture”) and its Halff East assets in the Midland Basin (the “Halff East Divestiture”). Certain of these assets were written down by $24.1 million during the first quarter of 2018 to reflect fair value less estimated costs to sell upon classification as held for sale. These divestitures were completed during the second quarter of 2018.

Acquisitions

During the first quarter of 2019, the Company completed several non-monetary acreage trades of undeveloped properties located in Howard, Martin, and Midland Counties, Texas, resulting in the exchange of approximately 2,000 net acres, with $65.8 million of carrying value attributed to the properties surrendered by the Company. These trades were recorded at carryover basis with no gain or loss recognized. No such trades occurred during the first quarter of 2018.

Note 4 - Income Taxes

The income tax (expense) benefit recorded for the three months ended March 31, 2019, and 2018, differs from the amounts that would be provided by applying the statutory United States federal income tax rate to income or loss before income taxes primarily due to the effect of state income taxes, excess tax benefits and deficiencies from share-based payment awards, limitations on the compensation of certain covered individuals, changes in valuation allowances, and accumulated impacts of other smaller permanent differences. The quarterly rate can also be affected by the proportional impacts of forecasted net income or loss as of each period end presented.

The provision for income taxes for the three months ended March 31, 2019, and 2018, consisted of the following:

	For the Three Months Ended March 31,	
	2019	2018
	(in thousands)	
Current portion of income tax (expense) benefit:		
Federal	$—	$—
State	(965)	(625)
Deferred portion of income tax (expense) benefit	47,003	(98,366)
Income tax (expense) benefit	$46,038	$(98,991)
Effective tax rate	20.6 %	23.8 %

The change in the Company’s effective tax rate for the periods presented in the table above generally reflects differences in its estimated highest marginal state tax rate due to changes in the composition of income or loss from Company activities, including divestitures, among multiple state tax jurisdictions. Future periods are not expected to reflect these differences as the Company’s current activities are occurring predominately in Texas. For years before 2015, the Company is generally no longer subject to United States federal or state income tax examinations by tax authorities.

Note 5 - Long-Term Debt

Credit Agreement

As of March 31, 2019, the Company’s Sixth Amended and Restated Credit Agreement (the “Credit Agreement”) provided for a senior secured revolving credit facility with a maximum loan amount of $2.5 billion, an initial borrowing base of $1.5 billion, and initial aggregate lender commitments totaling $1.0 billion, which were unchanged from December 31, 2018. On April 18, 2019, the Company entered into the First Amendment to the Credit Agreement (the “First Amendment”) with its lenders. Pursuant to the First Amendment, and as part of the regular, semi-annual borrowing base redetermination process, the borrowing base and aggregate lender commitments were increased to $1.6 billion and $1.2 billion, respectively. The borrowing base increase was primarily driven by the increased value of the Company’s estimated proved reserves at December 31, 2018. The next scheduled borrowing base redetermination date is October 1, 2019.

The Credit Agreement is scheduled to mature on September 28, 2023. The maturity date could, however, occur earlier on August 16, 2022, if the Company has not completed certain repurchase, redemption, or refinancing activities associated with its 6.125% Senior Notes due 2022 (“2022 Senior Notes”), as outlined in the Credit Agreement. Please refer to Note 5 - Long-Term Debt in the 2018 Form 10-K for additional detail on the terms of the Company’s Credit

Agreement.

The Company must comply with certain financial and non-financial covenants under the terms of the Credit Agreement and was in compliance with all such covenants as of March 31, 2019, and through the filing of this report.

Interest and commitment fees are accrued based on a borrowing base utilization grid set forth in the Credit Agreement as presented in Note 5 - Long-Term Debt in the Company's 2018 Form 10-K. At the Company's election, borrowings under the Credit Agreement may be in the form of Eurodollar, Alternate Base Rate ("ABR"), or Swingline loans. Eurodollar loans accrue interest at the London Interbank Offered Rate, plus the applicable margin from the utilization grid, and ABR and Swingline loans accrue interest at a market-based floating rate, plus the applicable margin from the utilization grid. Commitment fees are accrued on the unused portion of the aggregate lender commitment amount at rates from the utilization grid and are included in the interest expense line item on the accompanying statements of operations.

The following table presents the outstanding balance, total amount of letters of credit outstanding, and available borrowing capacity under the Credit Agreement as of April 25, 2019, March 31, 2019, and December 31, 2018:

	As of April 25, 2019	As of March 31, 2019	As of December 31, 2018
	(in thousands)		
Credit facility balance [1]	$40,000	$46,500	$—
Letters of credit [2]	—	—	200
Available borrowing capacity	1,160,000	953,500	999,800
Total aggregate lender commitment amount	$1,200,000	$1,000,000	$1,000,000

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(1) Unamortized deferred financing costs attributable to the credit facility are presented as a component of other noncurrent assets on the accompanying balance sheets and totaled $6.0 million and $6.4 million as of March 31, 2019, and December 31, 2018, respectively. These costs are being amortized over the term of the credit facility on a straight-line basis.

(2) Letters of credit outstanding reduce the amount available under the credit facility on a dollar-for-dollar basis. The letter of credit outstanding as of December 31, 2018, was released during the quarter ended March 31, 2019.

Senior Notes

As of March 31, 2019, the Company's Senior Notes consisted of 6.125% Senior Notes due 2022, 5.0% Senior Notes due 2024, 5.625% Senior Notes due 2025, 6.75% Senior Notes due 2026, and 6.625% Senior Notes due 2027 (collectively referred to as "Senior Notes"). The Senior Notes, net of unamortized deferred financing costs line item on the accompanying balance sheets as of March 31, 2019, and December 31, 2018, consisted of the following:

	As of March 31, 2019			As of December 31, 2018		
	Principal Amount	Unamortized Deferred Financing Costs	Principal Amount, Net of Unamortized Deferred Financing Costs	Principal Amount	Unamortized Deferred Financing Costs	Principal Amount, Net of Unamortized Deferred Financing Costs
	(in thousands)					
6.125% Senior Notes due 2022	$476,796	$ 3,671	$ 473,125	$476,796	$ 3,921	$ 472,875
5.0% Senior Notes due 2024	500,000	4,457	495,543	500,000	4,688	495,312
5.625% Senior Notes due 2025	500,000	5,582	494,418	500,000	5,808	494,192
6.75% Senior Notes due 2026	500,000	6,198	493,802	500,000	6,407	493,593
6.625% Senior Notes due 2027	500,000	7,300	492,700	500,000	7,533	492,467
Total	$2,476,796	$ 27,208	$ 2,449,588	$2,476,796	$ 28,357	$ 2,448,439

The Senior Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt and are senior in right of payment to any future subordinated debt. There are no subsidiary guarantors of the Senior Notes. The Company is subject to certain covenants under the indentures governing the Senior Notes and was in compliance with all such covenants as of March 31, 2019, and through the filing of this report. The Company may redeem some or all of its Senior Notes prior to their maturity at redemption prices based on a premium, plus accrued and unpaid interest as described in the indentures governing the Senior Notes.

Senior Convertible Notes

The Company’s Senior Convertible Notes consist of $172.5 million in aggregate principal amount of 1.50% Senior Convertible Notes due July 1, 2021 (the “Senior Convertible Notes”). The Senior Convertible Notes are unsecured senior obligations and rank equal in right of payment with all of the Company’s existing and any future unsecured senior debt and are senior in right of payment to any future subordinated debt. Please refer to Note 5 - Long-Term Debt in the 2018 Form 10-K for additional detail on the Company’s Senior Convertible Notes and associated capped call transactions.

The Senior Convertible Notes were not convertible at the option of holders as of March 31, 2019, or through the filing of this report. Notwithstanding the inability to convert, the if-converted value of the Senior Convertible Notes as of March 31, 2019, did not exceed the principal amount. The debt discount and debt-related issuance costs are amortized to the principal value of the Senior Convertible Notes as interest expense through the maturity date of July 1, 2021. Interest expense recognized on the Senior Convertible Notes related to the stated interest rate and amortization of the debt discount totaled $2.7 million and $2.6 million for the three months ended March 31, 2019, and 2018, respectively.

There have been no changes to the initial net carrying amount of the equity component of the Senior Convertible Notes recorded in additional paid-in capital on the accompanying balance sheets since issuance. The Senior Convertible Notes, net of unamortized discount and deferred financing costs line on the accompanying balance sheets as of March 31, 2019, and December 31, 2018, consisted of the following:

	As of March 31, 2019	As of December 31, 2018
	(in thousands)	
Principal amount of Senior Convertible Notes	$172,500	$172,500
Unamortized debt discount	(20,238)	(22,313)
Unamortized deferred financing costs	(2,063)	(2,293)
Senior Convertible Notes, net of unamortized discount and deferred financing costs	$150,199	$147,894

The Company is subject to certain covenants under the indenture governing the Senior Convertible Notes and was in compliance with all such covenants as of March 31, 2019, and through the filing of this report.

Capitalized Interest

Capitalized interest costs for the Company for the three months ended March 31, 2019, and 2018, were $4.9 million and $4.5 million, respectively. The amount of interest the Company capitalizes generally fluctuates based on its capital program and the timing and amount of costs associated with capital projects that are considered in progress.

Note 6 - Commitments and Contingencies

Commitments

Other than those items discussed below, there have been no changes in commitments through the filing of this report that differ materially from those disclosed in the 2018 Form 10-K. Please refer to Note 6 - Commitments and Contingencies in the 2018 Form 10-K for additional discussion of the Company’s commitments.

Delivery and Purchase Commitments. Subsequent to March 31, 2019, the Company executed an amendment to its existing sand sourcing agreement that created certain commitments and potential penalties which will vary based on the amount of actual sand the Company uses in well completions occurring in a particular area. This amended sand sourcing agreement expires on December 31, 2023. As of the filing of this report, potential penalties under this sand sourcing agreement range from zero to $10.0 million. The Company does not expect to incur penalties with regard to this agreement.

Drilling Rig and Completion Service Contracts. The Company entered into new and amended drilling rig and well completion service contracts during the first three months of 2019, and subsequent to March 31, 2019. As of the filing of this report, the Company’s drilling rig and completion service contract commitments totaled $105.3 million. If all of these contracts were terminated as of the filing of this report, the Company would avoid a portion of the contractual service commitments; however, the Company would be required to pay $50.0 million in early termination fees. Excluded from these amounts are variable commitments and penalties determined by the number of completion crews the Company has in operation in a particular area under a completion service arrangement. As of the filing of this report, potential penalties under this completion service arrangement, which expires on December 31, 2023, range from zero to a maximum of $15.7 million. The Company does not expect to incur penalties with regard to its drilling rig and completion service contracts.

Contingencies

The Company is subject to litigation and claims arising in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the anticipated results of any pending litigation and claims are not expected to have a material effect on the results of operations, the financial position, or the cash flows of the Company.

Note 7 - Compensation Plans

Performance Share Units

The Company grants performance share units ("PSUs") to eligible employees as part of its long-term equity incentive compensation program. The number of shares of the Company's common stock issued to settle PSUs ranges from zero to two times the number of PSUs awarded and is determined based on certain performance criteria over a three-year performance period. PSUs generally vest on the third anniversary of the date of the grant or upon other triggering events as set forth in the Company's Equity Incentive Compensation Plan ("Equity Plan").

PSUs are subject to a combination of market, performance, and service vesting criteria. Awards with a market criteria component are based on annualized Total Shareholder Return ("TSR") for the performance period and the relative performance of the Company's TSR compared with the annualized TSR of the Company's peer group for the performance period. Compensation expense for market-based PSUs is recognized on a straight-line basis within general and administrative expense and exploration expense over the vesting periods of the respective awards. Awards with a performance criteria component are based on relative debt adjusted per share cash flow growth ("DACFG") compared with DACFG, as calculated by the Company, of its peer group that is evaluated over the three-year performance period. Compensation expense for performance-based PSUs will be evaluated on a quarterly basis and may be adjusted as the number of units expected to vest increases or decreases.

Total compensation expense recorded for PSUs was $2.8 million and $2.4 million for the three months ended March 31, 2019, and 2018, respectively. As of March 31, 2019, there was $15.9 million of total unrecognized compensation expense related to non-vested PSU awards, which is being amortized through 2021. There have been no material changes to the outstanding and non-vested PSUs during the three months ended March 31, 2019.

Employee Restricted Stock Units

The Company grants restricted stock units ("RSUs") to eligible persons as part of its long-term equity incentive compensation program. Each RSU represents a right to receive one share of the Company's common stock upon settlement of the award at the end of the specified vesting period. Compensation expense for RSUs is recognized within general and administrative expense and exploration expense over the vesting periods of the respective awards. RSUs granted to employees generally vest one-third on each anniversary date of the grant over a three-year vesting period or upon other triggering events as set forth in the Company's Equity Plan.

Total compensation expense recorded for employee RSUs was $2.7 million for each of the three months ended March 31, 2019, and 2018. As of March 31, 2019, there was $16.4 million of total unrecognized compensation expense related to non-vested RSU awards, which is being amortized through 2021. There have been no material changes to the outstanding and non-vested RSUs during the three months ended March 31, 2019.

Note 8 - Pension Benefits

Pension Plans

The Company has a non-contributory defined benefit pension plan covering employees who meet age and service requirements and who began employment with the Company prior to January 1, 2016 (the "Qualified Pension Plan"). The Company also has a supplemental non-contributory pension plan covering certain management employees (the "Nonqualified Pension Plan" and together with the Qualified Pension Plan, the "Pension Plans"). The Company froze the Pension Plans to new participants, effective as of January 1, 2016. Employees participating in the Pension Plans prior to the plans being frozen will continue to earn benefits.

Components of Net Periodic Benefit Cost for the Pension Plans

	For the Three Months Ended March 31,	
	2019	2018
	(in thousands)	
Components of net periodic benefit cost:		
Service cost	$1,683	$1,660
Interest cost	656	673
Expected return on plan assets that reduces periodic pension benefit cost	(466)	(561)
Amortization of prior service cost	4	4
Amortization of net actuarial loss	332	324
Net periodic benefit cost	$2,209	$2,100

Prior service costs are amortized on a straight-line basis over the average remaining service period of active participants. Gains and losses in excess of 10 percent of the greater of the benefit obligation or the market-related value of assets are amortized over the average remaining service period of active participants. The service cost component of net periodic benefit cost for the Pension Plans is presented as an operating expense within the general and administrative and exploration expense line items on the accompanying statements of operations while the other components of net periodic benefit cost for the Pension Plans are presented as non-operating expenses within the other non-operating income (expense), net line item on the accompanying statements of operations.

Contributions

The Company contributed $4.3 million to the Qualified Pension Plan during the three months ended March 31, 2019.

Note 9 - Earnings Per Share

Basic net income or loss per common share is calculated by dividing net income or loss available to common stockholders by the basic weighted-average number of common shares outstanding for the respective period. Diluted net income or loss per common share is calculated by dividing net income or loss by the diluted weighted-average number of common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist primarily of non-vested RSUs, contingent PSUs, and shares into which the Senior Convertible Notes are convertible, which are measured using the treasury stock method. Shares of the Company’s common stock traded at an average closing price below the $40.50 conversion price for the three months ended March 31, 2019, and 2018, and therefore the Senior Convertible Notes had no dilutive impact. Please refer to Note 9 - Earnings Per Share in the 2018 Form 10-K for additional detail on these potentially dilutive securities. When the Company recognizes a loss from continuing operations, all potentially dilutive shares are anti-dilutive and are consequently excluded from the calculation of diluted net loss per common share. The following table details the weighted-average dilutive and anti-dilutive securities for the periods presented:

	For the Three Months Ended March 31,	
	2019	2018
	(in thousands)	
Dilutive	—	1,183
Anti-dilutive	781	—

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The following table sets forth the calculations of basic and diluted net income (loss) per common share:

	For the Three Months Ended March 31,	
	2019	2018
	(in thousands, except per share data)	
Net income (loss)	$(177,568)	$317,401
Basic weighted-average common shares outstanding	112,252	111,696
Dilutive effect of non-vested RSUs and contingent PSUs	—	1,183
Dilutive effect of Senior Convertible Notes	—	—
Diluted weighted-average common shares outstanding	112,252	112,879
Basic net income (loss) per common share	$(1.58)	$2.84
Diluted net income (loss) per common share	$(1.58)	$2.81

Note 10 - Derivative Financial Instruments

Summary of Oil, Gas, and NGL Derivative Contracts in Place

The Company has entered into various commodity derivative contracts to mitigate a portion of its exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows. As of March 31, 2019, all derivative counterparties were members of the Company's Credit Agreement lender group and all contracts were entered into for other-than-trading purposes. The Company's commodity derivative contracts consist of swap and collar arrangements for oil and gas production, and swap arrangements for NGL production. In a typical commodity swap agreement, if the agreed upon published third-party index price ("index price") is lower than the swap fixed price, the Company receives the difference between the index price and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, the Company pays the difference. For collar arrangements, the Company receives the difference between an agreed upon index and the floor price if the index price is below the floor price. The Company pays the difference between the agreed upon ceiling price and the index price if the index price is above the ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices.

The Company has also entered into fixed price oil basis swaps in order to mitigate exposure to adverse pricing differentials between certain industry benchmark prices and the actual physical pricing points where the Company's production volumes are sold. Currently, the Company has basis swap contracts with fixed price differentials between NYMEX WTI and WTI Midland for a portion of its Midland Basin production with sales contracts that settle at WTI Midland prices. The Company also has basis swaps with fixed price differentials between NYMEX WTI and Intercontinental Exchange Brent Crude ("ICE Brent") for a portion of its Midland Basin oil production with sales contracts that settle at ICE Brent prices.

As of March 31, 2019, the Company had commodity derivative contracts outstanding through the fourth quarter of 2022 as summarized in the tables below.

Oil Swaps

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price
	(MBbl)	(per Bbl)
Second quarter 2019	575	$ 55.52
Third quarter 2019	1,217	$ 61.41
Fourth quarter 2019	1,115	$ 59.97
2020	2,491	$ 65.68
Total	5,398	

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MBbl)	(per Bbl)	(per Bbl)
Second quarter 2019	3,034	$ 52.39	$ 64.32
Third quarter 2019	2,547	$ 49.50	$ 62.64
Fourth quarter 2019	3,168	$ 50.54	$ 62.49
2020	3,405	$ 55.00	$ 63.00
Total	12,154		

Oil Basis Swaps

Contract Period	WTI Midland-NYMEX WTI Volumes	Weighted-Average Contract Price [(1)]	NYMEX WTI-ICE Brent Volumes	Weighted-Average Contract Price [(2)]
	(MBbl)	(per Bbl)	(MBbl)	(per Bbl)
Second quarter 2019	2,571	$ (4.49)	—	$ —
Third quarter 2019	3,291	$ (2.86)	—	$ —
Fourth quarter 2019	3,338	$ (2.87)	—	$ —
2020	11,601	$ (1.03)	2,750	$ (8.03)
2021	3,707	$ 0.33	3,650	$ (7.86)
2022	—	$ —	3,650	$ (7.78)
Total	24,508		10,050	

(1) Represents the price differential between WTI Midland (Midland, Texas) and NYMEX WTI (Cushing, Oklahoma).

(2) Represents the price differential between NYMEX WTI (Cushing, Oklahoma) and ICE Brent (North Sea).

Gas Swaps

Contract Period	IF HSC Volumes	Weighted-Average Contract Price	WAHA Volumes	Weighted-Average Contract Price
	(BBtu)	(per MMBtu)	(BBtu)	(per MMBtu)
Second quarter 2019	11,177	$ 2.82	4,546	$ 0.70
Third quarter 2019	14,102	$ 2.84	4,340	$ 1.30
Fourth quarter 2019	14,433	$ 2.88	2,962	$ 1.75
2020	9,123	$ 2.98	2,060	$ 2.20
Total [(1)]	48,835		13,908	

(1) The Company has natural gas swaps in place that settle against Inside FERC Houston Ship Channel (“IF HSC”), Inside FERC West Texas (“IF WAHA”), and Platt’s Gas Daily West Texas (“GD WAHA”). As of March 31, 2019, total volumes for gas swaps are comprised of 78 percent IF HSC, 12 percent GD Waha, and 10 percent IF Waha.

Gas Collars

Contract Period	IF HSC Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(BBtu)	(per MMBtu)	(per MMBtu)
Second quarter 2019	4,358	$ 2.50	$ 2.83
Third quarter 2019	5,066	$ 2.50	$ 2.83
Fourth quarter 2019	4,818	$ 2.50	$ 2.83
Total	14,242		

NGL Swaps

	OPIS Ethane Purity Mont Belvieu		OPIS Propane Mont Belvieu Non-TET		OPIS Normal Butane Mont Belvieu Non-TET		OPIS Isobutane Mont Belvieu Non-TET		OPIS Natural Gasoline Mont Belvieu Non-TET	
Contract Period	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price
	(MBbl)	(per Bbl)	(MBbl)	(per Bbl)	(MBbl)	(per Bbl)	(MBbl)	(per Bbl)	(MBbl)	(per Bbl)
Second quarter 2019	877	$ 12.29	561	$ 31.32	38	$ 35.64	29	$ 35.70	49	$ 50.93
Third quarter 2019	907	$ 12.34	637	$ 31.29	39	$ 35.64	30	$ 35.70	50	$ 50.93
Fourth quarter 2019	896	$ 12.36	651	$ 31.64	39	$ 35.64	29	$ 35.70	50	$ 50.93
2020	711	$ 11.38	—	$ —	—	$ —	—	$ —	—	$ —
Total	3,391		1,849		116		88		149	

Commodity Derivative Contracts Entered Into Subsequent to March 31, 2019

Subsequent to March 31, 2019, the Company entered into various commodity derivative contracts, as summarized below:

- fixed price NYMEX WTI oil swap contracts through the second quarter of 2020 for a total of 1.6 MMBbl of oil production at a weighted-average contract price of $61.49 per Bbl;
- NYMEX WTI costless collar contracts through the third quarter of 2020 for a total of 1.7 MMBbl of oil production with a weighted-average contract floor price of $55.00 per Bbl and a weighted-average contract ceiling price of $65.07 per Bbl; and
- fixed price OPIS Propane Mont Belvieu Non-TET swap contracts through the fourth quarter of 2020 for a total of 0.6 MMBbl of propane production at a contract price of $28.10 per Bbl.

Derivative Assets and Liabilities Fair Value

The Company’s commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The Company does not designate its derivative commodity contracts as hedging instruments. The fair value of the commodity derivative contracts was a net liability of $13.8 million at March 31, 2019, and a net asset of $158.3 million at December 31, 2018.

The following table details the fair value of commodity derivative contracts recorded in the accompanying balance sheets, by category:

	As of March 31, 2019	As of December 31, 2018
	(in thousands)	
Derivative assets:		
Current assets	$ 67,567	$ 175,130
Noncurrent assets	27,202	58,499
Total derivative assets	$ 94,769	$ 233,629
Derivative liabilities:		
Current liabilities	$ 95,269	$ 62,853
Noncurrent liabilities	13,332	12,496
Total derivative liabilities	$ 108,601	$ 75,349

Offsetting of Derivative Assets and Liabilities

As of March 31, 2019, and December 31, 2018, all derivative instruments held by the Company were subject to master netting arrangements with various financial institutions. In general, the terms of the Company’s agreements provide for offsetting of amounts payable or receivable between it and the counterparty, at the election of both parties, for transactions that settle on the same date and in the same currency. The Company’s agreements also provide that in the event of an early termination, the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. The Company’s accounting policy is to not offset these positions in its accompanying balance sheets.

The following table provides a reconciliation between the gross assets and liabilities reflected on the accompanying balance sheets and the potential effects of master netting arrangements on the fair value of the Company's commodity derivative contracts:

	Derivative Assets		Derivative Liabilities	
	As of		As of	
	March 31, 2019	December 31, 2018	March 31, 2019	December 31, 2018
	(in thousands)			
Gross amounts presented in the accompanying balance sheets	$94,769	$ 233,629	$(108,601)	$ (75,349)
Amounts not offset in the accompanying balance sheets	(52,882)	(56,041)	52,882	56,041
Net amounts	$41,887	$ 177,588	$(55,719)	$ (19,308)

The following table summarizes the components of the net derivative loss line item presented in the accompanying statements of operations:

	For the Three Months Ended March 31,	
	2019	2018
	(in thousands)	
Derivative settlement (gain) loss:		
Oil contracts	$1,369	$20,748
Gas contracts	4,134	(6,410)
NGL contracts	(534)	10,190
Total derivative settlement loss	$4,969	$24,528
Net derivative (gain) loss:		
Oil contracts	$185,797	$13,966
Gas contracts	(6,113)	9,990
NGL contracts	(2,603)	(16,427)
Total net derivative loss	$177,081	$7,529

Credit Related Contingent Features

As of March 31, 2019, and through the filing of this report, all of the Company's derivative counterparties were members of the Company's Credit Agreement lender group. Under the Credit Agreement, the Company is required to provide mortgage liens on assets having a value equal to at least 85 percent of the total PV-9 of the Company's proved oil and gas properties evaluated in the most recent reserve report. Collateral securing indebtedness under the Credit Agreement also secures the Company's derivative agreement obligations.

Note 11 - Fair Value Measurements

The Company follows fair value measurement accounting guidance for all assets and liabilities measured at fair value. This guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Market or observable inputs are the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The fair value hierarchy for grouping these assets and liabilities is based on the significance level of the following inputs:

- Level 1 – quoted prices in active markets for identical assets or liabilities
- Level 2 – quoted prices in active markets for similar assets or liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable
- Level 3 – significant inputs to the valuation model are unobservable

The following table is a listing of the Company's assets and liabilities that are measured at fair value in the accompanying balance sheets and where they are classified within the fair value hierarchy as of March 31, 2019:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives [1]	$—	$94,769	$ —
Liabilities:			
Derivatives [1]	$—	$108,601	$ —

[1] This represents a financial asset or liability that is measured at fair value on a recurring basis.

The following table is a listing of the Company's assets and liabilities that are measured at fair value in the accompanying balance sheets and where they were classified within the fair value hierarchy as of December 31, 2018:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives [1]	$—	$233,629	$ —
Liabilities:			
Derivatives [1]	$—	$75,349	$ —

[1] This represents a financial asset or liability that is measured at fair value on a recurring basis.

Both financial and non-financial assets and liabilities are categorized within the above fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the above fair value hierarchy.

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, gas, and NGL commodity derivatives. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration forward commodity price curves, counterparties' credit ratings, the Company's credit rating, and the time value of money. These valuations are then compared to the respective counterparties' mark-to-market statements. The considered factors result in an estimated exit price that management believes provides a reasonable and consistent methodology for valuing derivative instruments. The commodity derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil, gas, and NGL commodity derivative markets are highly active.

Please refer to Note 10 - Derivative Financial Instruments and to Note 11 - Fair Value Measurements in the 2018 Form 10-K for more information regarding the Company's derivative instruments.

Proved and Unproved Oil and Gas Properties and Other Property and Equipment

Proved oil and gas properties. Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that associated carrying costs may not be recoverable. The Company uses Level 3 inputs and the income valuation technique to measure the fair value of proved properties through the application of discount rates and price forecasts representative of the current operating environment, as selected by the Company's management.

Unproved oil and gas properties. Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. To measure the fair value of unproved properties, the Company uses a market approach, which takes into account the following significant assumptions: remaining lease terms, future development plans, risk weighted potential resource recovery, estimated reserve values, and estimated acreage value based on price(s) received for similar, recent acreage transactions by the Company or other market participants. During the three months ended March 31, 2019, and 2018, the Company recorded $6.3 million and $5.6 million, respectively, in abandonment and impairment of unproved properties expense related to actual and anticipated lease expirations, as well as actual and anticipated losses on acreage due to title defects, changes in development plans, and other inherent acreage risks.

Properties held for sale. Properties classified as held for sale, including any corresponding asset retirement obligation liability, are valued using a market approach, based on an estimated net selling price, as evidenced by the most current bid prices received from third parties, if available. If an estimated selling price is not available, the Company utilizes the various valuation techniques discussed above. Any initial write-down and subsequent changes to the fair value less estimated cost to sell is included within the net gain on divestiture activity line item in the accompanying statements of operations.

There were $5.3 million of assets held for sale that were recorded at fair value less estimated costs to sell as of December 31, 2018. There were no assets held for sale as of March 31, 2019. For the three months ended March 31, 2018, write-downs to fair value less estimated costs to sell on assets held for sale totaled $24.1 million. Please refer to Note 3 - Divestitures, Assets Held for Sale, and Acquisitions above and in the 2018 Form 10-K for more information regarding the Company’s oil and gas properties held for sale.

Please refer to Note 1 – Summary of Significant Accounting Policies and Note 11 - Fair Value Measurements in the 2018 Form 10-K for more information regarding the Company’s approach in determining fair value of its properties.

Long-Term Debt

The following table reflects the fair value of the Company’s unsecured senior note obligations measured using Level 1 inputs based on quoted secondary market trading prices. These notes were not presented at fair value on the accompanying balance sheets as of March 31, 2019, or December 31, 2018, as they were recorded at carrying value, net of any unamortized discounts and deferred financing costs. Please refer to Note 5 - Long-Term Debt for additional discussion.

	As of March 31, 2019		As of December 31, 2018	
	Principal Amount	Fair Value	Principal Amount	Fair Value
	(in thousands)			
6.125% Senior Notes due 2022	$476,796	$477,988	$476,796	$452,336
5.0% Senior Notes due 2024	$500,000	$464,685	$500,000	$439,265
5.625% Senior Notes due 2025	$500,000	$464,820	$500,000	$436,460
6.75% Senior Notes due 2026	$500,000	$481,875	$500,000	$448,305
6.625% Senior Notes due 2027	$500,000	$476,205	$500,000	$442,500
1.50% Senior Convertible Notes due 2021	$172,500	$163,013	$172,500	$158,614

Note 12 - Leases

Effective January 1, 2019, the Company adopted Topic 842, which requires lessees to recognize operating and finance leases with terms greater than 12 months on the balance sheet. The Company adopted this standard using the modified retrospective method and elected to use the optional transition methodology whereby reporting periods prior to adoption continue to be presented in accordance with legacy accounting guidance. As of March 31, 2019, the Company did not have any agreements in place that were classified as finance leases under Topic 842. Arrangements classified as operating leases are included on the accompanying balance sheets within the other noncurrent assets, other current liabilities, and other noncurrent liabilities line items. For any agreement that contains both lease and non-lease components, such as a service arrangement that also includes an identifiable ROU asset, the Company’s policy for all asset classes is to combine lease and non-lease components together and account for the arrangement as a single lease. Aside from the recognition of ROU assets and corresponding lease liabilities on the accompanying balance sheets, Topic 842 will not have a material impact on the timing or classification of costs incurred for those agreements considered to be leases.

As outlined in Topic 842, a ROU asset represents a lessee’s right to use an underlying asset for the lease term, while the associated lease liability represents the lessee’s obligations to make lease payments. At the commencement date, which is the date on which a lessor makes an underlying asset available for use by a lessee, a lease ROU asset and corresponding lease liability is recognized based on the present value of the future lease payments. The initial measurement of lease payments may also be adjusted for certain items, including options that are reasonably certain to be exercised, such as options to purchase the asset at the end of the lease term, or options to extend or early terminate the lease. Excluded from the initial measurement of a ROU asset and corresponding lease liability are certain variable lease payments, such as payments made that vary depending on actual usage or performance.

The Company evaluates a contractual arrangement at its inception to determine if it is a lease or contains an identifiable lease component as defined by Topic 842. When evaluating a contract to determine appropriate classification and recognition under Topic 842, significant judgment may be necessary to determine, among other criteria, if an embedded leasing arrangement exists, the length of the term, classification as either an operating or financing lease, which options are reasonably likely to be exercised, fair value of the underlying ROU asset or assets, upfront costs, and future lease payments that are included or excluded in the initial measurement of the ROU asset. Certain assumptions and judgments made by the Company when evaluating a contract that meets the definition of a lease under Topic 842 include:

- Discount Rate - Unless implicitly defined, the Company will determine the present value of future lease payments using an estimated incremental borrowing rate based on a yield curve analysis that factors in certain assumptions, including the term of the lease and credit rating of the Company at lease inception.
- Lease Term - The Company evaluates each contract containing a lease arrangement at inception to determine the length of the lease term when recognizing a ROU asset and corresponding lease liability. When determining the lease term, options available to extend or early terminate the arrangement are evaluated and included when it is reasonably certain an option will be exercised. Because of the Company's intent to maintain financial and operational flexibility, there are no available options to extend that the Company is reasonably certain it will exercise. Additionally, based on expectations for those agreements with early termination options, there are no leases in which early termination options are reasonably certain to be exercised.

Currently, the Company has operating leases for asset classes that include office space, office equipment, drilling rigs, well completion agreements, midstream agreements, vehicles, and equipment rentals used in field operations. For those operating leases included on the accompanying balance sheets, which only includes leases with terms greater than 12 months at commencement, remaining lease terms range from less than one year to approximately seven years. The weighted-average lease term remaining for these leases is 3.2 years. Certain leases also contain optional extension periods that allow for terms to be extended for up to an additional 10 years. An early termination option also exists for certain leases, some of which allow for the Company to terminate a lease within one year. Exercising an early termination option may also result in an early termination penalty depending on the terms of the underlying agreement.

Subsequent to initial measurement, costs associated with the Company's operating leases are either expensed or capitalized depending on how the underlying ROU asset is utilized and in accordance with GAAP requirements. For example, costs associated with drilling rigs and completion crews that are considered ROU assets are typically capitalized as part of the development of the Company's oil and gas properties. Please refer to Note 1 – Summary of Significant Accounting Policies in the Company's 2018 Form 10-K for additional information on its accounting policies for oil and gas development and producing activities. When calculating the Company's ROU asset and liability for a contractual arrangement that qualifies as an operating lease, the Company considers all of the necessary payments made or that are expected to be made upon commencement of the lease. Excluded from the initial measurement are certain variable lease payments, which for the Company's drilling rigs, completion crews, and midstream agreements, may be a significant component of the total lease costs.

For the three months ended March 31, 2019, total costs related to operating leases, including short-term leases, and variable lease payments made for leases with initial lease terms greater than 12 months, were $175.3 million. This total does not reflect amounts that may be reimbursed by other third-parties in the normal course of business, such as non-operating working interest owners. Components of the Company's total lease cost, whether capitalized or expensed, for the three months ended March 31, 2019, were as follows:

	For the Three Months Ended March 31, 2019
	(in thousands)
Operating lease cost	$ 8,979
Short-term lease cost [1]	134,917
Variable lease cost [2]	31,408
Total lease cost [3]	$ 175,304

[1] Costs associated with short-term lease agreements relate primarily to operational activities where underlying lease terms are less than one year. This amount is significant as it includes drilling and completion activities and field equipment rentals, most of which are contracted for 12 months or less. It is expected this amount will fluctuate

primarily with the number of drilling rigs and completion crews the Company is operating under short-term agreements.

(2) Variable lease payments include additional payments made that were not included in the initial measurement of the ROU asset and corresponding liability for lease agreements with terms longer than 12 months. Variable lease payments relate to the actual volumes transported under certain midstream agreements, actual usage associated with drilling rigs and completion crews, and variable utility costs associated with the Company’s leased office space. Fluctuations in variable lease payments are driven by actual volumes delivered and the number of drilling rigs and completion crews operating under long-term agreements.

(3) Lease costs are either expensed on the accompanying statements of operations or capitalized on the accompanying balance sheets depending on the nature and use of the underlying ROU asset.

Other information related to the Company’s leases for the three months ended March 31, 2019, was as follows:

	For the Three Months Ended March 31, 2019 (in thousands)
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows from operating leases	$ 9,134
Right-of-use assets obtained in exchange for new operating lease liabilities	$ 12,191

Maturities for the Company’s operating lease liabilities included on the accompanying balance sheets as of March 31, 2019, were as follows:

	As of March 31, 2019 (in thousands)
2019 (remaining after March 31, 2019)	$ 21,217
2020	16,384
2021	11,074
2022	5,123
2023	3,316
Thereafter	3,721
Total Lease payments	$ 60,835
Less: Imputed interest [(1)]	(6,339)
Total	$ 54,496

(1) The weighted-average discount rate used to determine the operating lease liability as of March 31, 2019 was 6.6 percent.

Amounts recorded on the Company’s accompanying balance sheets for operating leases as of March 31, 2019, were as follows:

	As of March 31, 2019 (in thousands)
Other noncurrent assets	$ 51,448
Other current liabilities	$ 23,523
Other noncurrent liabilities	$ 30,973

As of March 31, 2019, the Company had an additional long-term operating lease arrangement for a drilling rig that commenced service in April 2019 for approximately $7.8 million with a lease term of 14 months. This agreement is not reflected in the amounts above as the commencement date was subsequent to March 31, 2019.

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

The following discussion includes certain forward-looking statements. Please refer to Cautionary Information about Forward-Looking Statements at the end of this item for important information about these types of statements.

Overview of the Company

General Overview

We are an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in onshore North America, with operations currently focused in the state of Texas. Our strategic objective is to be a premier operator of top tier assets. We seek to maximize the value of our assets by applying industry leading technology and outstanding operational execution. Our portfolio is comprised of unconventional resource prospects with expanding prospective drilling opportunities, which we believe provides for long-term production and reserves growth. We are focused on generating strong full-cycle economic returns on our investments and maintaining a strong balance sheet.

Regional Overview

Our Permian region is comprised of approximately 80,000 net acres in the Midland Basin located in western Texas ("Midland Basin"). Operations in the Midland Basin are primarily focused on developing the Lower Spraberry and Wolfcamp A and B intervals on our RockStar acreage in Howard and Martin Counties, Texas, and Lower and Middle Spraberry and Wolfcamp A and B intervals on our Sweetie Peck acreage in Upton and Midland Counties, Texas. We are also actively evaluating and testing additional intervals within our RockStar position, including the Middle Spraberry, Wolfcamp D, and Dean formations.

Our South Texas & Gulf Coast region is primarily comprised of approximately 163,000 net acres located in Dimmit and Webb Counties, Texas ("South Texas"). Our current operations in South Texas are primarily focused on developing the Eagle Ford shale formation and testing additional intervals, including the Austin Chalk formation.

First Quarter 2019 Highlights and Outlook for the Remainder of 2019

We remain focused on maximizing the returns and increasing the value of our top tier investment opportunities across our Midland Basin and South Texas positions. We expect to do this through exploration, acquisitions, and further development optimization. These assets provide significant production growth potential and strong returns that we believe will increase internally generated cash flows, which will support our priorities of improving our credit metrics and maintaining strong financial flexibility.

Our capital program for 2019, excluding acquisitions, is expected to range from $1.00 billion to $1.07 billion. Our program is concentrated on developing our top tier assets in the Midland Basin and South Texas, with the majority of our 2019 capital expected to be allocated to our Midland Basin program. Planned drilling and completion activity in our South Texas program continues to be partially funded by a third-party as part of a joint development agreement, which was extended into 2019 to include 12 additional wells. We expect that all 12 of these wells will be completed in 2019. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on our 2019 capital program.

Financial and Operational Results. During the first quarter of 2019, we had the following financial and operational results:

- Average net daily production for the three months ended March 31, 2019, was 118.7 MBOE, compared with 112.7 MBOE for the same period in 2018. The increase in total production was driven by our Midland Basin assets, which had a 34 percent increase in production volumes in the first quarter of 2019 compared to the same period in 2018. Average net daily production for the first quarter of 2018 also included 8.5 MBOE from our Rocky Mountain region, which we divested of in the second quarter of 2018. Please refer to Three-Month Overview of Selected Production and Financial Information, Including Trends below for additional discussion on production.
- Net cash provided by operating activities was $118.5 million for the three months ended March 31, 2019, compared with $140.1 million for the same period in 2018. The decrease in net cash provided by operating activities for the three months ended March 31, 2019, was primarily the result of a 16 percent decrease in our realized price per BOE before the effects of derivative settlements, which led to an 11 percent decrease in oil, gas, and NGL production revenue. Partially offsetting the decrease was a realized settlement loss on derivatives of $5.0 million during the first quarter of 2019, compared to a realized settlement loss of $24.5 million during the same period in 2018. Please refer

to Overview of Liquidity and Capital Resources below for additional discussion of our sources and uses of cash.

- We recorded a net loss of $177.6 million, or $1.58 per diluted share, for the three months ended March 31, 2019, compared with net income of $317.4 million, or $2.81 per diluted share, for the same period in 2018. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2019, and 2018 below for additional discussion regarding the components of net income (loss) for each of the periods presented.

- Adjusted EBITDAX, a non-GAAP financial measure, for the three months ended March 31, 2019, was $186.5 million, compared with $210.2 million for the same period in 2018. The decrease in the first quarter of 2019 compared to the same period in 2018 was primarily the result of an 11 percent decrease in oil, gas, and NGL production revenue. Please refer to Non-GAAP Financial Measures below for additional discussion, including our definition of adjusted EBITDAX and reconciliations to net income (loss) and net cash provided by operating activities.

Operational Activities. In our Midland Basin program, we averaged five drilling rigs and three completion crews during the first quarter of 2019. We ended the first quarter of 2019 with five drilling rigs and four completion crews, and added a sixth drilling rig in April 2019. Drilling and completion activities within our RockStar and Sweetie Peck positions in the Midland Basin continue to focus primarily on delineating and developing the Lower Spraberry and Wolfcamp A and B shale intervals. For the full year 2019, we expect to average six drilling rigs and three completion crews in the Midland Basin, and expect to allocate approximately 80 percent of our drilling and completion capital to our Midland Basin program.

During the first quarter of 2019, we completed several non-monetary acreage trades of primarily undeveloped properties in the Midland Basin, resulting in the exchange of approximately 2,000 net acres, with $65.8 million of carrying value attributed to the properties we surrendered. Acreage trades continue to increase our working interest in existing drilling units and are yielding an increasingly contiguous acreage position that will allow for longer lateral completions. There was no gain or loss recognized in connection with these trades.

In our South Texas program, we averaged two drilling rigs and two completion crews during the first quarter of 2019. Drilling and completion activities in South Texas continue to focus on developing the Eagle Ford shale and testing additional intervals, including the Austin Chalk formation. Certain drilling and completion activities in the northern portion of our South Texas acreage position continue to be partially funded by a third-party as part of a joint development agreement. For the full year 2019, we anticipate averaging one to two drilling rigs and one completion crew in South Texas and expect to allocate approximately 20 percent of our drilling and completion capital to this program.

The table below provides a quarterly summary of changes in our drilled but not completed well count and current year drilling and completion activity in our operated programs for the three months ended March 31, 2019:

	Permian		South Texas & Gulf Coast		Total	
	Gross	Net	Gross	Net	Gross	Net
Wells drilled but not completed at December 31, 2018	61	55	29	23	90	78
Wells drilled	31	28	8	7	39	35
Wells completed	(30)	(27)	(2)	(2)	(32)	(29)
Other [(1)]	—	—	(1)	—	(1)	—
Wells drilled but not completed at March 31, 2019	62	56	34	28	96	84

(1) Includes adjustments related to normal business activities, including wells that were previously drilled but that we no longer intend to complete and working interest changes for existing drilled but not completed wells.

Costs Incurred in Oil and Gas Producing Activities. Costs incurred in oil and gas property acquisition, exploration, and development activities, whether capitalized or expensed, totaled $322.0 million for the three months ended March 31, 2019, and were incurred in our Midland Basin and South Texas programs.

Production Results. The table below presents our production by product type for each of our operating regions for the three months ended March 31, 2019, and 2018:

	Permian		South Texas & Gulf Coast		Rocky Mountain (1)		Total	
	Three Months Ended March 31,		Three Months Ended March 31,		Three Months Ended March 31,		Three Months Ended March 31,	
	2019	2018	2019	2018	2019	2018	2019	2018
Production:								
Oil (MMBbl)	4.5	3.3	0.3	0.4	—	0.6	4.8	4.3
Gas (Bcf)	6.9	5.6	17.0	18.7	—	0.9	23.9	25.2
NGLs (MMBbl)	—	—	1.9	1.6	—	—	1.9	1.7
Equivalent (MMBOE)	5.7	4.3	5.0	5.1	—	0.8	10.7	10.1
Avg. daily equivalents (MBOE/d)	63.3	47.3	55.5	56.9	—	8.5	118.7	112.7
Relative percentage	53 %	42 %	47 %	50 %	— %	8 %	100 %	100 %

Note: Amounts may not calculate due to rounding.

(1) We divested all remaining producing assets in the Rocky Mountain region in the first half of 2018. As a result, there have been no production volumes from this region after the second quarter of 2018.

For the three months ended March 31, 2019, production on an equivalent basis increased five percent compared with the same period in 2018. This increase in overall production volumes was driven by our Permian region, which had a 34 percent increase in production volumes for the three months ended March 31, 2019, compared with the same period in 2018. Increased production volumes from our Permian region were partially offset as a result of the divestiture of our remaining producing assets in the Rocky Mountain region in the first half of 2018.

Please refer to Three-Month Overview of Selected Production and Financial Information, Including Trends and Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2019, and 2018 below for additional discussion on production.

Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for our oil, gas, and NGL production, which can fluctuate dramatically. When we refer to realized oil, gas, and NGL prices below, the disclosed price represents the average price for the respective period, before the effects of derivative settlements, unless otherwise indicated. While quoted NYMEX oil and gas and OPIS NGL prices are generally used as a basis for comparison within our industry, the prices we receive are affected by quality, energy content, location, and transportation differentials for these products.

The following table summarizes commodity price data, as well as the effects of derivative settlements, for the first quarter of 2019 as well as the fourth and first quarters of 2018:

	For the Three Months Ended		
	March 31, 2019	December 31, 2018	March 31, 2018
Oil (per Bbl):			
Average NYMEX contract monthly price	$54.90	$ 58.81	$ 62.87
Realized price, before the effect of derivative settlements	$49.47	$ 49.29	$ 61.25
Effect of oil derivative settlements	$(0.28)	$ (1.35)	$ (4.86)
Gas:			
Average NYMEX monthly settle price (per MMBtu)	$3.15	$ 3.64	$ 3.00
Realized price, before the effect of derivative settlements (per Mcf)	$2.73	$ 3.71	$ 3.14
Effect of gas derivative settlements (per Mcf)	$(0.18)	$ (0.70)	$ 0.25
NGLs (per Bbl):			
Average OPIS price [1]	$26.28	$ 29.91	$ 30.87
Realized price, before the effect of derivative settlements	$19.39	$ 24.01	$ 25.53
Effect of NGL derivative settlements	$0.28	$ (4.65)	$ (6.09)

(1) Average OPIS prices per barrel of NGL, historical or strip, are based on a product mix of 37% Ethane, 32% Propane, 6% Isobutane, 11% Normal Butane, and 14% Natural Gasoline for all periods presented. This product mix represents the industry standard composite barrel and does not necessarily represent our product mix for NGL production. Realized prices reflect our actual product mix.

We expect future prices for oil and NGLs to continue to be volatile. In addition to supply and demand fundamentals, as a global commodity, the price of oil is affected by real or perceived geopolitical risks in various regions of the world as well as the relative strength of the United States dollar compared to other currencies. We expect oil prices to remain volatile due to uncertainty in global supply and demand. We expect NGL prices to continue to benefit from increased demand from export and petrochemical markets, but these benefits could be partially or completely offset by increased drilling activity in areas containing liquid-rich gas capable of yielding additional NGL volumes.

We expect gas prices to remain near current levels in the near term due to the abundance of supply relative to demand. Demand from increased liquefied natural gas (“LNG”) exports and gas exports to Mexico are expected to help alleviate oversupply.

The following table summarizes 12-month strip prices for NYMEX WTI oil, NYMEX Henry Hub gas, and OPIS NGLs (same product mix as discussed under the table above) as of April 25, 2019, and March 31, 2019:

	As of April 25, 2019	As of March 31, 2019
NYMEX WTI oil (per Bbl)	$64.37	$60.21
NYMEX Henry Hub gas (per MMBtu)	$2.70	$2.85
OPIS NGLs (per Bbl)	$27.46	$25.81

We use financial derivative instruments as part of our financial risk management program. We have a financial risk management policy governing our use of derivatives. The amount of our production covered by derivative instruments is driven by the amount of debt on our balance sheet, the magnitude of capital commitments and long-term obligations we have in place, and our ability to enter into favorable derivative commodity contracts. With our current derivative contracts, we believe we have partially reduced our exposure to volatility in commodity prices and location differentials in the near term. Our use of costless collars for a portion of our derivatives allows us to participate in some of the upward movements in oil and gas prices while also setting a price floor for a portion of our oil and gas production.

Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report and to Commodity Price Risk in Overview of Liquidity and Capital Resources below for additional information regarding our oil, gas, and NGL derivatives.

Financial Results of Operations and Additional Comparative Data

The tables below provide information regarding selected production and financial information for the three months ended March 31, 2019, and the immediately preceding three quarters. A detailed discussion follows.

	For the Three Months Ended			
	March 31, 2019	December 31, 2018	September 30, 2018	June 30, 2018
	(in millions)			
Production (MMBOE)	10.7	11.3	12.0	10.5
Oil, gas, and NGL production revenue	$340.5	$ 392.5	$458.4	$402.6
Oil, gas, and NGL production expense	$121.3	$ 121.5	$127.6	$117.4
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$177.7	$ 182.0	$201.1	$151.8
Exploration	$11.3	$ 14.3	$13.1	$14.1
General and administrative	$32.1	$ 30.4	$29.5	$28.9
Net income (loss)	$(177.6)	$ 309.7	$(135.9)	$17.2

Note: Amounts may not calculate due to rounding.

Selected Performance Metrics

	For the Three Months Ended			
	March 31, 2019	December 31, 2018	September 30, 2018	June 30, 2018
Average net daily production equivalent (MBOE per day)	118.7	122.8	130.2	115.2
Lease operating expense (per BOE)	$5.20	$4.98	$4.41	$4.66
Transportation costs (per BOE)	$4.08	$4.19	$4.20	$4.47
Production taxes as a percent of oil, gas, and NGL production revenue	4.1 %	3.4 %	4.1 %	4.3 %
Ad valorem tax expense (per BOE)	$0.76	$0.39	$0.45	$0.41
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$16.63	$16.10	$16.78	$14.48
General and administrative (per BOE)	$3.00	$2.69	$2.46	$2.76

Note: Amounts may not calculate due to rounding.

Three-Month Overview of Selected Production and Financial Information, Including Trends

	For the Three Months Ended March 31, 2019	2018	Amount Change Between Periods	Percent Change Between Periods
Net production volumes: [1]				
Oil (MMBbl)	4.8	4.3	0.6	13 %
Gas (Bcf)	23.9	25.2	(1.3)	(5)%
NGLs (MMBbl)	1.9	1.7	0.2	12 %
Equivalent (MMBOE)	10.7	10.1	0.6	5 %
Average net daily production: [1]				
Oil (MBbl per day)	53.7	47.4	6.3	13 %
Gas (MMcf per day)	265.5	280.2	(14.8)	(5)%
NGLs (MBbl per day)	20.8	18.6	2.2	12 %
Equivalent (MBOE per day)	118.7	112.7	6.0	5 %
Oil, gas, and NGL production revenue (in millions): [1]				
Oil production revenue	$239.1	$261.1	$(22.0)	(8)%
Gas production revenue	65.1	79.1	(14.0)	(18)%
NGL production revenue	36.3	42.7	(6.4)	(15)%
Total oil, gas, and NGL production revenue	$340.5	$382.9	$(42.4)	(11)%
Oil, gas, and NGL production expense (in millions): [1]				
Lease operating expense	$55.6	$50.2	$5.4	11 %
Transportation costs	43.6	46.9	(3.3)	(7)%
Production taxes	14.0	17.0	(3.0)	(18)%
Ad valorem tax expense	8.1	6.8	1.3	20 %
Total oil, gas, and NGL production expense	$121.3	$120.9	$0.4	— %
Realized price (before the effect of derivative settlements):				
Oil (per Bbl)	$49.47	$61.25	$(11.78)	(19)%
Gas (per Mcf)	$2.73	$3.14	$(0.41)	(13)%
NGLs (per Bbl)	$19.39	$25.53	$(6.14)	(24)%
Per BOE	$31.86	$37.76	$(5.90)	(16)%
Per BOE data:				
Production costs:				
Lease operating expense	$5.20	$4.95	$0.25	5 %
Transportation costs	$4.08	$4.63	$(0.55)	(12)%
Production taxes	$1.31	$1.68	$(0.37)	(22)%
Ad valorem tax expense	$0.76	$0.67	$0.09	13 %
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$16.63	$12.87	$3.76	29 %
General and administrative	$3.00	$2.73	$0.27	10 %
Derivative settlement loss [2]	$(0.47)	$(2.42)	$1.95	81 %
Earnings per share information:				
Basic weighted-average common shares outstanding (in thousands)	112,252	111,696	556	— %
Diluted weighted-average common shares outstanding (in thousands)	112,252	112,879	(627)	(1)%
Basic net income (loss) per common share	$(1.58)	$2.84	$(4.42)	(156)%
Diluted net income (loss) per common share	$(1.58)	$2.81	$(4.39)	(156)%

[1] Amount and percentage changes may not calculate due to rounding.

[2] Derivative settlements for the three months ended March 31, 2019, and 2018, are included within the net derivative loss line item in the accompanying statements of operations.

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Average net equivalent daily production for the three months ended March 31, 2019, increased five percent compared with the same period in 2018, which was driven by a 34 percent increase in production from our Midland Basin assets. Increased production volumes from the Midland Basin were partially offset by the divestiture of our remaining producing assets in the Rocky Mountain region in the first half of 2018. For the full year 2019, we expect total production, as well as oil production as a percentage of our total product mix, to increase slightly compared with 2018, primarily as a result of actual and anticipated production increases in our Midland Basin program. Currently, we expect production volumes from South Texas to remain flat year over year.

We present certain information on a per BOE basis in order to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis and discussion.

Our realized price before the effects of derivative settlements on a per BOE basis decreased 16 percent for the three months ended March 31, 2019, compared with the same period in 2018. The decrease in realized price before derivative settlements was primarily driven by decreased commodity pricing for oil, gas, and NGLs. Additionally, certain third-party midstream force majeure events negatively impacted the price we received for our Midland Basin gas production. We expect the impacts associated with these force majeure events, as well as tight take away capacity, to continue to affect our realized price for Midland Basin gas production in the near term. For the three months ended March 31, 2019, and 2018, we realized losses of $0.47 per BOE and $2.42 per BOE, respectively, on the settlement of our derivative contracts.

For the three months ended March 31, 2019, lease operating expense (“LOE”) on a per BOE basis increased five percent compared with the same period in 2018. This increase was primarily driven by the increased percentage of oil in our total product mix, which has higher lifting costs per BOE. For the full year, we expect LOE on a per BOE basis to be slightly higher in 2019 compared with 2018 as our product mix continues to shift towards more oil production. We anticipate volatility in LOE on a per BOE basis as a result of changes in total production, changes in our overall production mix, timing of workover projects, and changes in industry activity and the effects this has on service provider costs.

Transportation costs on a per BOE basis decreased 12 percent for the three months ended March 31, 2019, compared with the same period in 2018. The decrease in transportation costs per BOE was driven primarily by an increased percentage of production from our Midland Basin assets, as these assets are subject to minimal transportation costs. We expect total transportation costs to fluctuate in line with changes in production from our South Texas program as these assets incur the majority of our transportation costs. On a per BOE basis, we expect transportation costs to decrease in 2019, compared with 2018, as production from our Midland Basin assets becomes a larger portion of our total production.

Production taxes on a per BOE basis decreased 22 percent for the three months ended March 31, 2019, compared with the same period in 2018. This decrease was primarily driven by a 16 percent decrease in our realized price on a per BOE basis before the effects of derivative settlements, compared with the same period in 2018. Our overall production tax rate for the three months ended March 31, 2019, and 2018 was 4.1 percent and 4.4 percent, respectively. The decrease in our production tax rate was primarily the result of divesting our producing assets in the Rocky Mountain region, which were subject to higher rates than our remaining properties in Texas. We generally expect production tax expense to trend with oil, gas, and NGL production revenue on an absolute and per BOE basis. Product mix, the location of production, and incentives to encourage oil and gas development can also impact the amount of production tax we recognize.

Ad valorem tax expense on a per BOE basis increased 13 percent for the three months ended March 31, 2019, compared with the same period in 2018, as a result of changes in our asset and production base and increases in the value attributed to our reserves volumes. We expect an increase in ad valorem tax expense on an absolute basis in 2019, compared with 2018. On a per BOE basis, we expect 2019 ad valorem tax expense to increase compared to 2018, but this increase could be partially offset by expected increases in production volumes in 2019 compared with 2018.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion (“DD&A”) expense on a per BOE basis increased 29 percent for the three months ended March 31, 2019, compared with the same period in 2018. The increase was primarily driven by the increase in production volumes from our Midland Basin assets, which have higher depletion rates than our Eagle Ford shale assets in South Texas. Our DD&A rate fluctuates as a result of impairments, divestiture activity, carrying cost funding and sharing arrangements with third parties, changes in our production mix, and changes in our total estimated proved reserve volumes. In general, we expect DD&A expense on a per BOE basis in 2019 to increase compared with 2018 as production from the Midland Basin continues to increase as a percentage of our total production.

General and administrative ("G&A") expense on a per BOE basis increased 10 percent for the three months ended March 31, 2019, compared with the same period in 2018. This increase was primarily driven by a reduction in the amount of employee compensation that is being reclassified to exploration expense, and timing of certain non-recurring costs. For the full year 2019, we expect total G&A expense to remain consistent with 2018. On a per BOE basis, we expect G&A expense to be slightly lower compared with 2018 as total production in 2019 is expected to increase from 2018.

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2019, and 2018 below for additional discussion on operating expenses.
Please refer to Note 9 - Earnings Per Share in Part I, Item 1 of this report for discussion of our basic and diluted net income (loss) per common share calculations.
Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2019, and 2018
Net equivalent production, production revenue, and production expense
The following table presents the regional changes in our net equivalent production, production revenue, and production expense between the three months ended March 31, 2019, and 2018:

	Net Equivalent Production Increase (Decrease) (MBOE per day)	Production Revenue Increase (Decrease) (in millions)	Production Expense Increase (Decrease) (in millions)
Permian	16.0	$ 10.1	$ 15.6
South Texas & Gulf Coast	(1.4)	(14.5)	0.6
Rocky Mountain [(1)]	(8.5)	(38.0)	(15.8)
Total	6.0	$ (42.4)	$ 0.4

Note: Amounts may not calculate due to rounding.
(1) We divested our remaining producing assets in the Rocky Mountain region in the first half of 2018. As a result, there have been no production volumes from this region after the second quarter of 2018.
As previously discussed, production on a net equivalent basis increased five percent for the three months ended March 31, 2019, compared with the same period in 2018, as a result of increased Midland Basin production. Oil, gas, and NGL production revenues decreased 11 percent for the three months ended March 31, 2019, compared with the same period in 2018, primarily as result of weaker commodity pricing. Production expense for the three months ended March 31, 2019, compared with the same period in 2018, increased slightly which was primarily a result of increased lease operating and ad valorem tax expenses, offset by decreased transportation costs and production taxes. Further offsetting increases in production expense was the divestiture of our remaining Rocky Mountain region assets, which had the highest average lifting costs in our portfolio. Please refer to Three-Month Overview of Selected Production and Financial Information, Including Trends above for additional discussion, including trends on a per BOE basis.
Net gain on divestiture activity

	For the Three Months Ended March 31, 2019	2018
	(in millions)	
Net gain on divestiture activity	$0.1	$385.4

During the three months ended March 31, 2018, estimated net gains of $409.2 million were recorded for our PRB Divestiture, partially offset by a $24.1 million write down on certain assets held for sale. Please refer to Note 3 - Divestitures, Assets Held for Sale, and Acquisitions in Part I, Item 1 of this report for additional discussion.
Depletion, depreciation, amortization, and asset retirement obligation liability accretion

	For the Three Months Ended March 31, 2019	2018
	(in millions)	

Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$177.7	$130.5

DD&A expense increased 36 percent for the three months ended March 31, 2019, compared with the same period in 2018. The increase is directly related to the 34 percent increase in production volumes from our Midland Basin assets, which have higher depletion rates than our Eagle Ford shale assets in South Texas.

Exploration

	For the Three Months Ended March 31,	
	2019	2018
	(in millions)	
Geological and geophysical expenses	$0.4	$1.4
Overhead and other expenses	10.9	12.3
Total	$11.3	$13.7

Exploration expense decreased 17 percent for the three months ended March 31, 2019, compared with the same period in 2018. This decrease was primarily driven by a reduction in the amount of employee compensation being reclassified to exploration expense as more employee time is being allocated to development activities, which is classified as G&A expense. Additionally, spending on geological and geophysical activities decreased for the three months ended March 31, 2019, compared with the same period in 2018. In 2019, we expect total exploration expense to be slightly lower compared with 2018; however, our expectations could change significantly depending on actual geological and geophysical studies performed and the potential for exploratory dry hole expense.

Impairment of proved properties and Abandonment and impairment of unproved properties

	For the Three Months Ended March 31,	
	2019	2018
	(in millions)	
Abandonment and impairment of unproved properties	$ 6.3	$ 5.6

There were no proved property impairments for the three months ended March 31, 2019 or 2018. Unproved property abandonment and impairment expense recorded for the three months ended March 31, 2019, and 2018 related to actual and anticipated lease expirations, as well as actual and anticipated losses on acreage due to title defects, changes in development plans, and other inherent acreage risks. We expect proved property impairments to occur more frequently in periods of declining or depressed commodity prices, and that the frequency of unproved property abandonments and impairments will fluctuate with the timing of lease expirations or defects, unsuccessful exploration activities, and changing economics associated with decreases in commodity prices. Additionally, changes in drilling plans, downward engineering revisions, or unsuccessful exploration efforts may result in proved and unproved property impairments.

Future impairments of proved and unproved properties are difficult to predict; however, based on our commodity price assumptions as of April 25, 2019, we do not expect any material property impairments in the second quarter of 2019 resulting from commodity price impacts.

General and administrative

	For the Three Months Ended March 31,	
	2019	2018
	(in millions)	
General and administrative	$32.1	$27.7

G&A expense increased 16 percent for the three months ended March 31, 2019, compared with the same period in 2018. Please refer to the section Three-Month Overview of Selected Production and Financial Information, Including Trends above for further discussion of G&A expense in total and on a per BOE basis.

Net derivative loss

	For the Three Months Ended March 31,	
	2019	2018
	(in millions)	
Net derivative loss	$177.1	$7.5

We recognized a $177.1 million derivative loss for the three months ended March 31, 2019. This loss was primarily driven by a $172.1 million downward mark-to-market adjustment on derivative contracts settling subsequent to March 31, 2019, due to strengthening oil prices during the quarter. There was an additional loss of $5.0 million on derivative contracts that settled during the three months ended March 31, 2019.

We recognized a $7.5 million derivative loss for the three months ended March 31, 2018, largely due to a $24.5 million loss on contracts that settled during the three months ended March 31, 2018, partially offset by a $17.0 million increase in the fair value of contracts settling subsequent to March 31, 2018.

Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information.

Interest expense

	For the Three Months Ended March 31,	
	2019	2018
	(in millions)	
Interest expense	$38.0	$43.1

Interest expense decreased 12 percent for the three months ended March 31, 2019, compared with the same period in 2018. The decrease was driven primarily by the redemption of our 6.50% Senior Notes due 2021 in the third quarter of 2018, which reduced interest expense related to debt in the first quarter of 2019 by $5.6 million compared with the same period in 2018. As a result of our overall reduction in long-term debt, we expect interest expense related to our Senior Notes to be lower in 2019 compared with 2018; however, total interest expense can vary based on the timing and amount of any borrowings against our credit facility. Please refer to Note 5 - Long-Term Debt in Part I, Item I of this report and Overview of Liquidity and Capital Resources below for additional information.

Income tax (expense) benefit

	For the Three Months Ended March 31,	
	2019	2018
	(in millions, except tax rate)	
Income tax (expense) benefit	$46.0	$(99.0)
Effective tax rate	20.6 %	23.8 %

The decrease in the effective tax rate for the three months ended March 31, 2019, compared with the same period in 2018, was primarily due to the differing effects of permanent items on a pretax loss in 2019 compared with pretax income in 2018. Excess tax deficiencies from share-based payment awards, limits to certain covered individual’s compensation, and other permanent expense items reduced the 2019 tax benefit rate. These same items increased the 2018 tax expense rate. The reduction in rate also reflects a cumulative effect in 2018 for divestitures and a correlative change to the Company’s state apportionment rate. Please refer to Overview of Liquidity and Capital Resources below as well as Note 4 - Income Taxes in Part I, Item 1 of this report for additional discussion.

Overview of Liquidity and Capital Resources

Based on the current commodity price environment, we believe we have sufficient liquidity and capital resources to execute our business plan for the foreseeable future. We continue to manage the duration and level of our drilling and completion service commitments to maintain the flexibility to adjust our activity and capital expenditures.

Sources of Cash

We currently expect our 2019 capital program to be funded by cash flows from operations, cash on hand as of December 31, 2018, and borrowings under our credit facility. During the three months ended March 31, 2019, we generated $118.5 million of cash flows from operating activities. As of March 31, 2019, the available borrowing capacity under our Credit Agreement provided $953.5 million in liquidity.

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Although we expect cash flows from these sources to be sufficient to fund our expected 2019 capital program, we may also elect to raise funds through debt or equity financings or from other sources. Further, we may enter into additional carrying cost funding and sharing arrangements with third parties for particular exploration and/or development programs. Our borrowing base could be reduced as a result of lower commodity prices, divestitures of proved properties, or the issuance of debt securities. If we raise additional funds through the issuance of equity or convertible debt securities, the percentage ownership of our current stockholders could be diluted, and these newly-issued securities may have rights, preferences, or privileges senior to those of existing stockholders. Any future downgrades in our credit ratings could make it more difficult or expensive for us to borrow additional funds. All of our sources of liquidity can be affected by the general condition of the broader economy and by fluctuations in commodity prices, operating costs, and volumes produced, all of which affect us and our industry.

We have no control over the market prices for oil, gas, or NGLs, although we may be able to influence the amount of our realized revenues from our oil, gas, and NGL sales through the use of derivative contracts as part of our commodity price risk management program. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information about our oil, gas, and NGL derivative contracts currently in place and the timing of settlement of those contracts.

The enactment of the Tax Cuts and Jobs Act (the “2017 Tax Act”) reduced our highest marginal corporate tax rate for 2018 and future years from 35 percent to 21 percent, however future deductibility of interest expense may be limited. In general, we believe the enactment of the 2017 Tax Act will have a positive impact on our future operating cash flows.

Credit Agreement

As of March 31, 2019, our Credit Agreement provided for a senior secured revolving credit facility with a maximum loan amount of $2.5 billion, an initial borrowing base of $1.5 billion, and initial aggregate lender commitments totaling $1.0 billion. The Credit Agreement is scheduled to mature on September 28, 2023. The maturity date could, however, occur earlier on August 16, 2022, if we have not completed certain repurchase, redemption, or refinancing activities associated with our 2022 Senior Notes, as outlined in the Credit Agreement. No individual bank participating in our Credit Agreement represents more than 10 percent of the lender commitments under the Credit Agreement. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion as well as the presentation of the outstanding balance, total amount of letters of credit, and available borrowing capacity under our Credit Agreement as of April 25, 2019, March 31, 2019, and December 31, 2018.

The borrowing base under the Credit Agreement is subject to regular, semi-annual redetermination, and considers the value of both our (a) proved oil and gas properties reflected in the most recent reserve report provided to our lenders under the Credit Agreement; and (b) commodity derivative contracts, each as determined by our lender group. On April 18, 2019, we entered into a First Amendment to the Credit Agreement with our lenders, and as part of the regular, semi-annual borrowing base redetermination process, the borrowing base and aggregate lender commitments were increased to $1.6 billion and $1.2 billion, respectively. The increase in the borrowing base was primarily driven by the increased value of our estimated proved reserves at December 31, 2018. The next scheduled borrowing base redetermination date is October 1, 2019.

Our daily weighted-average credit facility debt balance was approximately $12.1 million for the three months ended March 31, 2019, and we had an outstanding balance of $46.5 million, as of March 31, 2019. We did not have any credit facility debt activity in 2018. Cash flows provided by our operating activities, proceeds received from divestitures of properties, capital markets activities, and the amount of our capital expenditures all impact the amount we have borrowed under our credit facility.

We must comply with certain financial and non-financial covenants under the terms of the Credit Agreement, including covenants limiting dividend payments and requiring that we maintain certain financial ratios, as defined by the Credit Agreement. The financial covenants under the Credit Agreement require that our (a) total funded debt, as defined in the Credit Agreement, to adjusted EBITDAX ratio for the most recently ended four consecutive fiscal quarters (excluding the first three quarters which will use annualized adjusted EBITDAX), cannot be greater than 4.25 to 1.00 beginning with the quarter ended December 31, 2018 through and including the fiscal quarter ending December 31, 2019, and for each quarter ending thereafter, the ratio cannot be greater than 4.00 to 1.00; and (b) adjusted current ratio cannot be less than 1.0 to 1.0 as of the last day of any fiscal quarter. We were in compliance with all financial and non-financial covenants as of March 31, 2019, and through the filing of this report. Please refer to the caption Non-GAAP Financial Measures below for the calculation of adjusted EBITDAX and reconciliations of net income (loss) and net cash provided by operating activities to adjusted EBITDAX.

Weighted-Average Interest and Weighted-Average Borrowing Rates

Our weighted-average interest rate includes paid and accrued interest, fees on the unused portion of the aggregate commitment amount under the Credit Agreement, letter of credit fees, the non-cash amortization of deferred financing costs, and the non-cash amortization of the discount related to the Senior Convertible Notes. Our weighted-average borrowing rate includes paid and accrued interest only.

The following table presents our weighted-average interest rates and our weighted-average borrowing rates for the three months ended March 31, 2019, and 2018:

	For the Three Months Ended March 31,	
	2019	2018
Weighted-average interest rate	6.5%	6.5%
Weighted-average borrowing rate	5.8%	5.9%

Our weighted-average interest rates and weighted average borrowing rates for the three months ended March 31, 2019, and 2018, have been impacted by the timing of long-term debt issuances and redemptions, the average balance on our revolving credit facility under the Credit Agreement, and the fees paid on the unused portion of our aggregate commitment. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion.

Uses of Cash

We use cash for the acquisition, exploration, and development of oil and gas properties and for the payment of operating and general and administrative costs, income taxes, dividends, and debt obligations, including interest. Expenditures for the acquisition, exploration, and development of oil and gas properties are the primary use of our capital resources. During the three months ended March 31, 2019, we spent $249.3 million on capital expenditures. This amount differs from the costs incurred amount, which is accrual-based and includes asset retirement obligations, geological and geophysical expenses, and exploration overhead amounts.

The amount and allocation of our future capital expenditures will depend upon a number of factors, including the number and size of acquisitions, our cash flows from operating, investing, and financing activities, and our ability to execute our drilling program. In addition, the impact of oil, gas, and NGL prices on investment opportunities, the availability of capital, and the timing and results of our exploration and development activities may lead to changes in funding requirements for future development. We periodically review our capital expenditure budget to assess changes in current and projected cash flows, acquisition and divestiture activities, debt requirements, and other factors.

We may from time to time repurchase certain amounts of our outstanding debt securities for cash and/or through exchanges for other securities. Such repurchases or exchanges may be made in open market transactions, privately negotiated transactions, or otherwise. Any such repurchases or exchanges will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, compliance with securities laws, and other factors. The amounts involved in any such transaction may be material. Repurchases or exchanges are reviewed as part of the allocation of our capital. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion. As part of our strategy for 2019, we will continue to focus on improving our debt metrics and potentially reducing outstanding debt.

As of the filing of this report, we could repurchase up to 3,072,184 shares of our common stock under our stock repurchase program, subject to the approval of our Board of Directors. Shares may be repurchased from time to time in the open market, or in privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our Credit Agreement, the indentures governing our Senior Notes, the indenture governing our Senior Convertible Notes, compliance with securities laws, and the terms and provisions of our stock repurchase program. Our Board of Directors periodically reviews this program as part of the allocation of our capital. During the three months ended March 31, 2019, we did not repurchase any shares of our common stock, and we currently do not plan to repurchase any outstanding shares of our common stock during the remainder of 2019.

Analysis of Cash Flow Changes Between the Three Months Ended March 31, 2019, and 2018

The following tables present changes in cash flows between the three months ended March 31, 2019, and 2018, for our operating, investing, and financing activities. The analysis following each table should be read in conjunction with our accompanying condensed consolidated statements of cash flows in Part I, Item 1 of this report.

Operating activities

	For the Three Months Ended March 31,		Amount Change Between Periods	Percent Change Between Periods
	2019	2018		
	(in millions)			
Net cash provided by operating activities	$118.5	$140.1	$ (21.6)	(15)%

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Cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, including derivative cash settlements, decreased $5.8 million for the three months ended March 31, 2019, compared with the same period in 2018, primarily as a result of weaker commodity pricing. Cash paid for LOE and ad valorem taxes increased $8.1 million for the three months ended March 31, 2019, compared with the same period in 2018. Net cash provided by operating activities is also affected by working capital changes and the timing of cash receipts and disbursements.

Investing activities

	For the Three Months Ended March 31, 2019	2018	Amount Change Between Periods	Percent Change Between Periods
	(in millions)			
Net cash provided by (used in) investing activities	$(242.9)	$189.3	$(432.2)	(228)%

The decrease in cash provided by (used in) investing activities for the three months ended March 31, 2019, compared with the same period in 2018, is largely due to a decrease in divestiture cash proceeds of $484.7 million partially offset by a decrease in capital expenditures of $52.2 million.

Financing activities

	For the Three Months Ended March 31, 2019	2018	Amount Change Between Periods	Percent Change Between Periods
	(in millions)			
Net cash provided by financing activities	$46.5	$ —	$ 46.5	100 %

Financing activities for the three months ended March 31, 2019, consisted of borrowings and repayments on our credit facility. We had no credit facility activity during the first quarter of 2018.

Interest Rate Risk

We are exposed to market risk due to the floating interest rate associated with any outstanding balance on our revolving credit facility. As of March 31, 2019, we had a $46.5 million balance on our credit facility. Our Credit Agreement allows us to fix the interest rate for all or a portion of the principal balance of our revolving credit facility for a period up to six months. To the extent that the interest rate is fixed, interest rate changes will affect the credit facility's fair market value but will not impact results of operations or cash flows. Conversely, for the portion of the credit facility that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. Changes in interest rates do not impact the amount of interest we pay on our fixed-rate Senior Notes or fixed-rate Senior Convertible Notes but can impact their fair market values. As of March 31, 2019, our outstanding principal amount of fixed-rate debt totaled $2.6 billion. Please refer to Note 11 - Fair Value Measurements in Part I, Item 1 of this report for additional discussion on the fair values of our Senior Notes and Senior Convertible Notes.

Commodity Price Risk

The prices we receive for our oil, gas, and NGL production directly impact our revenue, overall profitability, access to capital, and future rate of growth. Oil, gas, and NGL prices are subject to wide fluctuations in response to changes in supply and demand and other factors. The markets for oil, gas, and NGLs have been volatile, especially over the last several years, and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Based on our production for the three months ended March 31, 2019, a 10 percent decrease in our average realized oil, gas, and NGL prices, before the effects of derivative settlements, would have reduced our oil, gas, and NGL production revenues by approximately $23.9 million, $6.5 million, and $3.6 million, respectively. If commodity prices had been 10 percent lower, our net derivative settlements for the three months ended March 31, 2019, would have offset the declines in oil, gas, and NGL production revenue by approximately $19.9 million.

We enter into commodity derivative contracts in order to reduce the risk of fluctuations in commodity prices. The fair value of our commodity derivative contracts is largely determined by estimates of the forward curves of the relevant price indices. As of March 31, 2019, a 10 percent increase or decrease in the forward curves associated with our oil, gas, and NGL commodity derivative instruments would have changed our net liability positions by approximately $91.8 million, $17.5 million, and $10.0 million, respectively.

Off-Balance Sheet Arrangements

As part of our ongoing business, we have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities ("SPEs"), which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes.

We evaluate our transactions to determine if any variable interest entities exist. If we determine that we are the primary beneficiary of a variable interest entity, that entity is consolidated into our consolidated financial statements. We have not been involved in any unconsolidated SPE transactions during the three months ended March 31, 2019, or through the filing of this report.

Critical Accounting Policies and Estimates

Please refer to the corresponding section in Part II, Item 7 and to Note 1 - Summary of Significant Accounting Policies included in Part II, Item 8 of our 2018 Form 10-K for discussion of our accounting policies and estimates.

New Accounting Pronouncements

Please refer to Note 1 - Summary of Significant Accounting Policies under Part I, Item 1 of this report for new accounting pronouncements.

Non-GAAP Financial Measures

Adjusted EBITDAX represents net income (loss) before interest expense, interest income, income taxes, depletion, depreciation, amortization and asset retirement obligation liability accretion expense, exploration expense, property abandonment and impairment expense, non-cash stock-based compensation expense, derivative gains and losses net of settlements, gains and losses on divestitures, and certain other items. Adjusted EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items that are generally non-recurring in nature or whose timing and/or amount cannot be reasonably estimated. Adjusted EBITDAX is a non-GAAP measure that we present because we believe it provides useful additional information to investors and analysts, as a performance measure, for analysis of our ability to internally generate funds for exploration, development, acquisitions, and to service debt. We are also subject to financial covenants under our Credit Agreement based on adjusted EBITDAX ratios as further described in the Credit Agreement section in Overview of Liquidity and Capital Resources above. In addition, adjusted EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. Adjusted EBITDAX should not be considered in isolation or as a substitute for net income (loss), income (loss) from operations, net cash provided by operating activities, or other profitability or liquidity measures prepared under GAAP. Because adjusted EBITDAX excludes some, but not all items that affect net income (loss) and may vary among companies, the adjusted EBITDAX amounts presented may not be comparable to similar metrics of other companies. Our credit facility provides a material source of liquidity for us. Under the terms of our Credit Agreement, if we failed to comply with the covenants that establish a maximum permitted ratio of total funded debt, as defined in the Credit Agreement, to adjusted EBITDAX, we would be in default, an event that would prevent us from borrowing under our credit facility and would therefore materially limit our sources of liquidity. In addition, if we are in default under our credit facility and are unable to obtain a waiver of that default from our lenders, lenders under that facility and under the indentures governing our outstanding Senior Notes and Senior Convertible Notes would be entitled to exercise all of their remedies for default.

The following table provides reconciliations of our net income (loss) (GAAP) and net cash provided by operating activities (GAAP) to adjusted EBITDAX (non-GAAP) for the periods presented:

	For the Three Months Ended March 31,	
	2019	2018
	(in thousands)	
Net income (loss) (GAAP)	$(177,568)	$317,401
Interest expense	37,980	43,085
Income tax expense (benefit)	(46,038)	98,991
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	177,746	130,473
Exploration [(1)]	10,143	12,411
Abandonment and impairment of unproved properties	6,338	5,625
Stock-based compensation expense	5,838	5,412
Net derivative loss	177,081	7,529
Derivative settlement loss	(4,969)	(24,528)
Net gain on divestiture activity	(61)	(385,369)
Other, net	4	(842)
Adjusted EBITDAX (non-GAAP)	186,494	210,188
Interest expense	(37,980)	(43,085)
Income tax (expense) benefit	46,038	(98,991)
Exploration [(1)]	(10,143)	(12,411)
Amortization of debt discount and deferred financing costs	3,789	3,866
Deferred income taxes	(47,003)	98,366
Other, net	(2,534)	(1,685)
Net change in working capital	(20,159)	(16,113)

Net cash provided by operating activities (GAAP)	$118,502	$140,135

(1) Stock-based compensation expense is a component of exploration expense and general and administrative expense on the accompanying statements of operations. Therefore, the exploration line items shown in the reconciliation above will vary from the amount shown on the accompanying statements of operations for the component of stock-based compensation expense recorded to exploration expense.

Cautionary Information about Forward-Looking Statements

This Report on Form 10-Q ("Form 10-Q") contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical facts, included in this report that address activities, events, or developments with respect to our financial condition, results of operations, or economic performance that we expect, believe, or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words "anticipate," "assume," "believe," "budget," "estimate," "expect," "forecast," "intend," "pending," "plan," "project," "target," "will," and similar expressions are intended t forward-looking statements. Forward-looking statements appear throughout this report, and include statements about such matters as:

- the amount and nature of future capital expenditures and the availability of liquidity and capital resources to fund capital expenditures;
- any changes to the borrowing base or aggregate lender commitments under our Credit Agreement;
- our outlook on future oil, gas, and NGL prices, well costs, service costs, and general and administrative costs;
- the drilling of wells and other exploration and development activities and plans by us, our joint development partners, and/or other third-party operators, as well as possible or expected acquisitions or divestitures;
- the possible divestiture or farm-down of, or joint venture relating to, certain properties;
- proved reserve estimates and the estimates of both future net revenues and the present value of future net revenues associated with those reserve estimates;
- future oil, gas, and NGL production estimates;
- cash flows, anticipated liquidity, interest and related debt service expenses, changes in the Company's effective tax rate, and the future repayment of debt;
- business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations or to defer capital investment, plans with respect to future dividend payments, and our outlook on our future financial condition or results of operations; and
- other similar matters, such as those discussed in the Management's Discussion and Analysis of Financial Condition and Results of Operations section in Part I, Item 2 of this report.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. These statements are subject to a number of known and unknown risks and uncertainties, which may cause our actual results and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. Some of these risks are described in the Risk Factors section in Part I, Item 1A of our 2018 Form 10-K, and include without limitation such factors as:

- domestic and foreign supply of oil, natural gas, and NGLs;
- the volatility of oil, gas, and NGL prices, and the effect it may have on our profitability, financial condition, cash flows, access to capital, and ability to grow production volumes and/or proved reserves;
- weakness in economic conditions, consumer demand, and uncertainty in financial markets;
- our ability to replace reserves in order to sustain production;
- our ability to raise the substantial amount of capital required to develop and/or replace our reserves;
- our ability to compete against competitors that have greater financial, technical, and human resources;
- our ability to attract and retain key personnel;
- the imprecise estimations of our actual quantities and present value of proved oil, gas, and NGL reserves, and that development of our proved undeveloped reserves may take longer and may require greater capital expenditures than we anticipate;
- the uncertainty in evaluating recoverable reserves and estimating expected benefits or liabilities;
- the possibility that exploration and development drilling may not result in commercially producible reserves;
- our limited control over activities on outside-operated properties;
-

our reliance on the skill, expertise and availability of third-party service providers and equipment for our operated activities;

- the possibility that title to properties in which we claim an interest may be defective;

- our planned drilling in existing or emerging resource plays using some of the latest available horizontal drilling and completion techniques is subject to drilling and completion risks and may not meet our expectations for reserves or production;
- the uncertainties associated with acquisitions, divestitures, joint ventures, farm-downs, farm-outs and similar transactions with respect to certain assets, including our success in integrating new assets, and whether such transactions will be consummated or completed in the form or timing and for the value that we anticipate;
- the uncertainties associated with enhanced recovery methods;
- our commodity derivative contracts expose us to counterparty credit risk and may result in financial losses or may limit the prices we receive for oil, gas, and NGL sales;
- the inability of one or more of our service providers, customers, or contractual counterparties to meet their obligations;
- our ability to deliver required quantities of oil, gas, NGL, or water to contractual counterparties;
- price declines or unsuccessful exploration efforts resulting in write-downs of our asset carrying values;
- the impact that depressed oil, gas, or NGL prices could have on our borrowing capacity under our Credit Agreement;
- the possibility our amount of debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt;
- the possibility that covenants in our Credit Agreement or the indentures governing the Senior Notes and Senior Convertible Notes may limit our discretion in the operation of our business, prohibit us from engaging in beneficial transactions or lead to the accelerated payment of our debt;
- the possibility of security threats, including terrorist attacks and cybersecurity attacks and breaches, against, or otherwise impacting, our facilities and systems;
- operating and environmental risks and hazards that could result in substantial losses;
- the impact of extreme weather conditions, laws and regulations, and lease stipulations on our ability to conduct drilling activities;
- our ability to acquire adequate supplies of water and dispose of or recycle water we use at a reasonable cost in accordance with environmental and other applicable rules;
- complex laws and regulations, including environmental regulations, that result in substantial costs, delays, and other risks;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities;
- our ability to sell and/or receive market prices for our oil, gas, and NGLs;
- new technologies may cause our current exploration and drilling methods to become obsolete; and
- litigation, environmental matters, the potential impact of legislation and government regulations, and the use of management estimates regarding such matters.

We caution you that forward-looking statements are not guarantees of future performance and actual results or performance may be materially different from those expressed or implied in the forward-looking statements. The forward-looking statements in this report speak as of the filing of this report. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is provided under the captions Commodity Price Risk and Interest Rate Risk in Item 2 above, as well as under the section entitled Summary of Oil, Gas, and NGL Derivative Contracts in Place under Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report and is incorporated herein by reference. Please also refer to the information under Commodity Price Risk and Interest Rate Risk in Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II, Item 7 of our 2018 Form 10-K.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that are designed to reasonably ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and to reasonably ensure that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) ("Disclosure Controls") will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our Disclosure Controls are effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There have been no changes during the first quarter of 2019 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

From time to time, we may be involved in litigation relating to claims arising out of our business and operations in the normal course of business. As of the filing of this report, no legal proceedings are pending against us that we believe individually or collectively are expected to have a materially adverse effect upon our financial condition, results of operations or cash flows.

ITEM 1A. RISK FACTORS

There have been no material changes to the risk factors as previously disclosed in our 2018 Form 10-K.

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

The following table provides information about purchases made by us and any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the quarter ended March 31, 2019, of shares of our common stock, which is the sole class of equity securities registered by us pursuant to Section 12 of the Exchange Act:

PURCHASES OF EQUITY SECURITIES BY ISSUER AND AFFILIATED PURCHASERS

Period	Total Number of Shares Purchased (1)	Weighted Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet Be Purchased Under the Program (2)
01/01/2019 - 01/31/2019	542	$ 19.85	—	3,072,184
02/01/2019 - 02/28/2019	28	$ 19.81	—	3,072,184
03/01/2019 - 03/31/2019	420	$ 15.07	—	3,072,184
Total:	990	$ 17.82	—	3,072,184

(1) All shares purchased by us in the first quarter of 2019 were to offset tax withholding obligations that occurred upon the delivery of outstanding shares underlying RSUs issued under the terms of award agreements granted under the Equity Incentive Compensation Plan.

(2) In July 2006, our Board of Directors approved an increase in the number of shares that may be repurchased under the original August 1998 authorization to 6,000,000 as of the effective date of the resolution. Accordingly, as of the filing of this report, subject to the approval of our Board of Directors, we may repurchase up to 3,072,184 shares of common stock on a prospective basis. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our Credit Agreement, the indentures governing our Senior Notes and Senior Convertible Notes, and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flows, or borrowings under our Credit Agreement. The stock repurchase program may be suspended or discontinued at any time.

Our payment of cash dividends to our stockholders is subject to certain covenants under the terms of our Credit Agreement, Senior Notes, and Senior Convertible Notes. Based on our current performance, we do not anticipate that any of these covenants will limit our payment of dividends at our current rate for the foreseeable future if any dividends are declared by our Board of Directors.

ITEM 6. EXHIBITS

The following exhibits are filed or furnished with or incorporated by reference into this report:

Exhibit Number	Description
3.1	Restated Certificate of Incorporation of SM Energy Company, as amended through June 1, 2010 (filed as Exhibit 3.1 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, and incorporated herein by reference)
3.2	Amended and Restated By-Laws of SM Energy Company, effective as of February 21, 2017 (filed as Exhibit 3.2 to the registrant’s Annual Report on Form 10-K for the year ended December 31, 2016, and incorporated herein by reference)
10.1	First Amendment to Sixth Amended and Restated Credit Agreement, dated April 18, 2019 among SM Energy Company, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant’s Current Report on Form 8-K filed on April 18, 2019, and incorporated herein by reference)
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002
32.1**	Certification pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document

* Filed with this report.

** Furnished with this report.

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 hereunto duly authorized.

SM ENERGY COMPANY

May 2, 2019 By: /s/ JAVAN D. OTTOSON

Javan D. Ottoson
President and Chief Executive Officer
(Principal Executive Officer)

May 2, 2019 By: /s/ A. WADE PURSELL

A. Wade Pursell
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

May 2, 2019 By: /s/ PATRICK A. LYTLE

Patrick A. Lytle
Controller and Assistant Secretary
(Principal Accounting Officer)