UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2019

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ___________ to ___________

Commission File Number 001-31539

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)

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 by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically 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 ☑ No ☐

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	☑	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

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

As of October 24, 2019, the registrant had 112,857,163 shares of common stock outstanding.

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SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(in thousands, except share data)

	September 30, 2019	December 31, 2018
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10	$ 77,965
Accounts receivable	146,211	167,536
Derivative assets	143,142	175,130
Prepaid expenses and other	21,751	8,632
Total current assets	311,114	429,263
Property and equipment (successful efforts method):		
Proved oil and gas properties	8,143,381	7,278,362
Accumulated depletion, depreciation, and amortization	(3,953,181)	(3,417,953)
Unproved oil and gas properties	1,434,435	1,581,401
Wells in progress	325,230	295,529
Properties held for sale, net	—	5,280
Other property and equipment, net of accumulated depreciation of $64,971 and $57,102, respectively	79,278	88,546
Total property and equipment, net	6,029,143	5,831,165
Noncurrent assets:		
Derivative assets	38,571	58,499
Other noncurrent assets	74,255	33,935
Total noncurrent assets	112,826	92,434
Total assets	**$ 6,453,083**	**$ 6,352,862**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 431,440	$ 403,199
Derivative liabilities	37,798	62,853
Other current liabilities	21,804	—
Total current liabilities	491,042	466,052
Noncurrent liabilities:		
Revolving credit facility	129,000	—
Senior Notes, net of unamortized deferred financing costs	2,451,886	2,448,439
Senior Convertible Notes, net of unamortized discount and deferred financing costs	154,883	147,894
Asset retirement obligations	95,806	91,859
Deferred income taxes	217,469	223,278
Derivative liabilities	6,014	12,496
Other noncurrent liabilities	63,233	42,522
Total noncurrent liabilities	3,118,291	2,966,488
Commitments and contingencies (note 6)		
Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 112,857,163 and 112,241,966 shares, respectively	1,129	1,122
Additional paid-in capital	1,784,787	1,765,738
Retained earnings	1,069,642	1,165,842
Accumulated other comprehensive loss	(11,808)	(12,380)
Total stockholders' equity	2,843,750	2,920,322
Total liabilities and stockholders' equity	**$ 6,453,083**	**$ 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 September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
Operating revenues and other income:				
Oil, gas, and NGL production revenue	$ 389,419	$ 458,382	$ 1,136,749	$ 1,243,826
Net gain on divestiture activity	—	786	323	425,656
Other operating revenues	898	201	1,347	3,398
Total operating revenues and other income	390,317	459,369	1,138,419	1,672,880
Operating expenses:				
Oil, gas, and NGL production expense	129,042	127,638	373,397	365,917
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	211,125	201,105	595,201	483,343
Exploration	11,626	13,061	33,851	40,844
Abandonment and impairment of unproved properties	6,337	9,055	25,092	26,615
General and administrative	32,578	29,464	95,584	86,066
Net derivative (gain) loss	(100,889)	178,026	(3,463)	249,304
Other operating expenses, net	1,021	9,664	422	14,219
Total operating expenses	290,840	568,013	1,120,084	1,266,308
Income (loss) from operations	**99,477**	**(108,644)**	**18,335**	**406,572**
Interest expense	(40,584)	(38,111)	(118,191)	(122,850)
Loss on extinguishment of debt	—	(26,722)	—	(26,722)
Other non-operating income (expense), net	(548)	806	(1,427)	3,017
Income (loss) before income taxes	**58,345**	**(172,671)**	**(101,283)**	**260,017**
Income tax (expense) benefit	(16,111)	36,748	16,337	(61,342)
Net income (loss)	**$ 42,234**	**$ (135,923)**	**$ (84,946)**	**$ 198,675**
Basic weighted-average common shares outstanding	112,804	112,107	112,441	111,836
Diluted weighted-average common shares outstanding	113,334	112,107	112,441	113,600
Basic net income (loss) per common share	$ 0.37	$ (1.21)	$ (0.76)	$ 1.78
Diluted net income (loss) per common share	$ 0.37	$ (1.21)	$ (0.76)	$ 1.75
Dividends per common share	$ 0.05	$ 0.05	$ 0.10	$ 0.10

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 September 30,		For the Nine Months Ended September 30,	
	2019	**2018**	**2019**	**2018**
Net income (loss)	$ 42,234	$ (135,923)	$ (84,946)	$ 198,675
Other comprehensive income, net of tax:				
Pension liability adjustment	190	263	572	721
Total other comprehensive income, net of tax	190	263	572	721
Total comprehensive income (loss)	**$ 42,424**	**$ (135,660)**	**$ (84,374)**	**$ 199,396**

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 Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders' Equity
	Shares	Amount				
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**
Net income	—	—	—	50,388	—	50,388
Other comprehensive income	—	—	—	—	119	119
Issuance of common stock under Employee Stock Purchase Plan	184,079	2	1,957	—	—	1,959
Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings	290	—	(2)	—	—	(2)
Stock-based compensation expense	96,719	1	6,153	—	—	6,154
Other	—	—	(1)	1	—	—
Balances, June 30, 2019	**112,525,633**	**$ 1,125**	**$ 1,779,665**	**$ 1,033,051**	**$ (11,998)**	**$ 2,801,843**
Net income	—	—	—	42,234	—	42,234
Other comprehensive income	—	—	—	—	190	190
Cash dividends declared, $0.05 per share	—	—	—	(5,643)	—	(5,643)
Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings	331,530	4	(1,644)	—	—	(1,640)
Stock-based compensation expense	—	—	6,766	—	—	6,766
Balances, September 30, 2019	**112,857,163**	**$ 1,129**	**$ 1,784,787**	**$ 1,069,642**	**$ (11,808)**	**$ 2,843,750**

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) (Continued)
(in thousands, except share data and dividends per share)

	Common Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders' Equity
	Shares	Amount				
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**
Net income	—	—	—	17,197	—	17,197
Other comprehensive income	—	—	—	—	198	198
Issuance of common stock under Employee Stock Purchase Plan	100,249	1	1,880	—	—	1,881
Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings	1,161	—	(10)	—	—	(10)
Stock-based compensation expense	58,572	—	5,264	—	—	5,264
Balances, June 30, 2018	**111,846,998**	**$ 1,118**	**$ 1,754,169**	**$ 997,641**	**$ (16,301)**	**$ 2,736,627**
Net loss	—	—	—	(135,923)	—	(135,923)
Other comprehensive income	—	—	—	—	263	263
Cash dividends declared, $0.05 per share	—	—	—	(5,607)	—	(5,607)
Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings	290,584	3	(2,968)	—	—	(2,965)
Stock-based compensation expense	—	—	7,004	—	—	7,004
Balances, September 30, 2018	**112,137,582**	**$ 1,121**	**$ 1,758,205**	**$ 856,111**	**$ (16,038)**	**$ 2,599,399**

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 Nine Months Ended September 30, 2019	2018
Cash flows from operating activities:		
Net income (loss)	$ (84,946)	$ 198,675
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Net gain on divestiture activity	(323)	(425,656)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	595,201	483,343
Abandonment and impairment of unproved properties	25,092	26,615
Stock-based compensation expense	18,758	17,680
Net derivative (gain) loss	(3,463)	249,304
Derivative settlement gain (loss)	23,843	(101,911)
Amortization of debt discount and deferred financing costs	11,554	11,542
Loss on extinguishment of debt	—	26,722
Deferred income taxes	(13,620)	60,672
Other, net	(2,291)	(2,084)
Net change in working capital	11,781	(3,725)
Net cash provided by operating activities	**581,586**	**541,177**
Cash flows from investing activities:		
Net proceeds from the sale of oil and gas properties (1)	12,520	743,199
Capital expenditures	(788,642)	(1,032,588)
Acquisition of proved and unproved oil and gas properties	(2,581)	(24,571)
Net cash used in investing activities	**(778,703)**	**(313,960)**
Cash flows from financing activities:		
Proceeds from credit facility	1,124,500	—
Repayment of credit facility	(995,500)	—
Net proceeds from Senior Notes	—	492,079
Cash paid to repurchase Senior Notes, including premium	—	(844,984)
Net proceeds from sale of common stock	1,959	1,881
Dividends paid	(5,612)	(5,584)
Other, net	(2,684)	(7,746)
Net cash provided by (used in) financing activities	**122,663**	**(364,354)**
Net change in cash, cash equivalents, and restricted cash	(74,454)	(137,137)
Cash, cash equivalents, and restricted cash at beginning of period	77,965	313,943
Cash, cash equivalents, and restricted cash at end of period	**$ 3,511**	**$ 176,806**
Supplemental schedule of additional cash flow information and non-cash activities:		
Operating activities:		
Cash paid for interest, net of capitalized interest	$ (113,122)	$ (124,435)
Net cash paid for income taxes	$ (1,469)	$ (9,085)
Investing activities:		
Changes in capital expenditure accruals and other	$ 34,878	$ 19,811
Supplemental non-cash investing activities:		
Carrying value of properties exchanged	$ 70,808	$ 95,121
Supplemental non-cash financing activities:		
Non-cash loss on extinguishment of debt, net	$ —	$ 6,334
Reconciliation of cash, cash equivalents, and restricted cash:		
Cash and cash equivalents	$ 10	$ 176,806
Restricted cash (1)	3,501	—
Cash, cash equivalents, and restricted cash at end of period	**$ 3,511**	**$ 176,806**

(1) As of September 30, 2019, a portion of net proceeds from the sale of oil and gas properties was restricted for future property acquisitions. Restricted cash is included in the other noncurrent assets line item on the accompanying unaudited condensed consolidated balance sheets ("accompanying balance sheets").

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

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 September 30, 2019, and through the filing of this report.

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 lease accounting for previously reported periods continues to be reported in accordance with historical accounting guidance for leases 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 unaudited condensed consolidated financial statements and related disclosures that have been issued but not yet adopted by the Company as of September 30, 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 from its Midland Basin and South Texas assets. Following the divestiture of the Company’s remaining assets in the Rocky Mountain region during the first half of 2018, there has been no production revenue from this 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 tables below present oil, gas, and NGL production revenue by product type for each of the Company's operating regions for the three and nine months ended September 30, 2019, and 2018:

	Midland Basin		South Texas		Total	
	Three Months Ended September 30,		Three Months Ended September 30,		Three Months Ended September 30,	
	2019	2018	2019	2018	2019	2018
	(in thousands)					
Oil production revenue	$ 277,361	$ 270,086	$ 15,496	$ 17,436	$ 292,857	$ 287,522
Gas production revenue	17,780	40,364	46,267	56,446	64,047	96,810
NGL production revenue	124	563	32,391	73,487	32,515	74,050
Total	$ 295,265	$ 311,013	$ 94,154	$ 147,369	$ 389,419	$ 458,382
Relative percentage	76%	68%	24%	32%	100%	100%

Note: Amounts may not calculate due to rounding.

	Midland Basin		South Texas		Rocky Mountain		Total	
	Nine Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018	2019	2018	2019	2018
	(in thousands)							
Oil production revenue	$ 791,055	$ 703,516	$ 45,007	$ 56,365	$ —	$ 54,851	$ 836,062	$ 814,732
Gas production revenue	49,821	96,974	144,563	161,414	—	1,595	194,384	259,983
NGL production revenue	102	816	106,201	167,505	—	790	106,303	169,111
Total	$ 840,978	$ 801,306	$ 295,771	$ 385,284	$ —	$ 57,236	$ 1,136,749	$ 1,243,826
Relative percentage	74%	64%	26%	31%	—%	5%	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 purchaser, which may differ depending on the applicable contractual terms. 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 purchasers 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 generally predictable differentials. Accordingly, the Company does not consider estimates of variable consideration to be constrained.

The Company's 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 purchaser 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 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 balance sheets until payment is received. The accounts receivable balances from contracts with customers within the accompanying balance sheets as of September 30, 2019, and December 31, 2018, were $106.3 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 that related to performance obligations satisfied in prior reporting periods was immaterial for the three and nine months ended September 30, 2019, and 2018.

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

Divestitures

No material divestitures occurred during the first nine months of 2019, and there were no assets classified as held for sale as of September 30, 2019.

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, subject to final purchase price adjustments, and recorded an estimated net gain of $410.6 million for the nine months ended September 30, 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 second quarter of 2018, the Company completed the divestitures of its remaining Williston Basin assets located in Divide County, North Dakota (the “Divide County Divestiture”) and its Halff East assets in the Midland Basin (the “Halff East Divestiture”), for combined net divestiture proceeds of $250.8 million, subject to final purchase price adjustments, and recorded a combined estimated net gain of $15.4 million for the nine months ended September 30, 2018. After final purchase price adjustments, the Company received net divestiture proceeds of $252.2 million, and recorded a final net gain of $15.4 million related to these divested assets for the year ended December 31, 2018.

Acquisitions

During the first nine months 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 2,100 net acres, with $70.8 million of carrying value attributed to the properties transferred by the Company. These trades were recorded at carryover basis with no gain or loss recognized. During the third quarter of 2018, the Company completed two non-monetary acreage trades of primarily undeveloped properties located in Howard and Martin Counties, Texas, which resulted in the exchange of approximately 2,650 net acres, with $95.1 million of carrying value attributed to the properties transferred by the Company. These trades were recorded at carryover basis with no gain or loss recognized.

During the second quarter of 2018, the Company acquired approximately 720 net acres of unproved properties in Martin County, Texas, for $24.6 million. Under authoritative accounting guidance, this transaction was considered an asset acquisition. Therefore, the properties were recorded based on the fair value of the total consideration transferred on the acquisition date and the transaction costs were capitalized as a component of the cost of the assets acquired.

Note 4 - Income Taxes

Recorded income tax expense or benefit 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. These differences primarily relate to the effect of state income taxes, excess tax benefits and deficiencies from stock-based compensation awards, tax limitations on the compensation of certain covered individuals, changes in valuation allowances, and the cumulative impact of other smaller permanent differences. The quarterly rate can also be affected by the proportional impacts of forecasted net income or loss for each period presented, as reflected in the table below.

The provision for income taxes for the three and nine months ended September 30, 2019, and 2018, consisted of the following:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands)			
Current portion of income tax (expense) benefit:				
Federal	$ 3,826	$ —	$ 3,826	$ —
State	(320)	(85)	(1,109)	(670)
Deferred portion of income tax (expense) benefit	(19,617)	36,833	13,620	(60,672)
Income tax (expense) benefit	$ (16,111)	$ 36,748	$ 16,337	$ (61,342)
Effective tax rate	27.6%	21.3%	16.1%	23.6%

The change in the effective tax rate for the three months ended September 30, 2019, compared with the same period in 2018, was primarily due to the differing effects of permanent items on income before income taxes for the three months ended September 30, 2019, compared to their impact on the loss before income taxes for the same period in 2018.

The change in the effective tax rate for the nine months ended September 30, 2019, compared with the same period in 2018, was primarily due to the differing effects of permanent items on the loss before income taxes for the nine months ended September 30, 2019, compared to their impact on income before income taxes for the same period in 2018. Additionally, the year-to-date 2018 rate was also impacted by the estimated highest marginal state tax rates 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.

Subsequent to September 30, 2019, the Company filed its 2018 federal income tax return claiming a$7.7 million refund for a portion of its deferred AMT credit carryover. For all 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

On September 19, 2019, the Company and its lenders entered into the Second Amendment to the Sixth Amended and Restated Credit Agreement which permitted the Company to enter into swap agreements with respect to the price of electricity in order to minimize exposure to electrical price volatility. As of September 30, 2019, the Company's Sixth Amended and Restated Credit Agreement, as amended (the "Credit Agreement"), provided for a senior secured revolving credit facility with a maximum loan amount of $2.5 billion, a borrowing base of $1.6 billion, and aggregate lender commitments of$1.2 billion. Subsequent to September 30, 2019, the Company and its lenders completed the semi-annual borrowing base redetermination, which reaffirmed the Company's borrowing base and aggregate lender commitments at existing levels. The next scheduled borrowing base redetermination date is April 1, 2020.

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. 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 September 30, 2019, and through the filing of this report. 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.

Interest and commitment fees associated with the credit facility 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 October 24, 2019, September 30, 2019, and December 31, 2018:

	As of October 24, 2019	As of September 30, 2019	As of December 31, 2018
		(in thousands)	
Revolving credit facility [1]	$ 143,000	$ 129,000	$ —
Letters of credit [2]	—	—	200
Available borrowing capacity	1,057,000	1,071,000	999,800
Total aggregate lender commitment amount	$ 1,200,000	$ 1,200,000	$ 1,000,000

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(1) Unamortized deferred financing costs attributable to the credit facility are presented as a component of the other noncurrent assets line item on the accompanying balance sheets and totaled $6.3 million and $6.4 million as of September 30, 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 three months ended March 31, 2019.

Senior Notes

As of September 30, 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 ("2027 Senior Notes", and all senior notes collectively referred to as the "Senior Notes"). The Senior Notes, net of unamortized deferred financing costs line item on the accompanying balance sheets as of September 30, 2019, and December 31, 2018, consisted of the following:

	As of September 30, 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	$ 3,170	$ 473,626	$ 476,796	$ 3,921	$ 472,875
5.0% Senior Notes due 2024	500,000	3,996	496,004	500,000	4,688	495,312
5.625% Senior Notes due 2025	500,000	5,130	494,870	500,000	5,808	494,192
6.75% Senior Notes due 2026	500,000	5,780	494,220	500,000	6,407	493,593
6.625% Senior Notes due 2027	500,000	6,834	493,166	500,000	7,533	492,467
Total	$ 2,476,796	$ 24,910	$ 2,451,886	$ 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 September 30, 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.

On July 16, 2018, the Company redeemed its 6.50% Senior Notes due 2021 ("2021 Senior Notes") which resulted in the payment of total cash consideration, including accrued interest, of $355.9 million. On August 20, 2018, the Company issued $500.0 million in aggregate principal amount of 2027 Senior Notes, which resulted in the receipt of net proceeds of $492.1 million after deducting fees of $7.9 million, which are being amortized as deferred financing costs over the life of the 2027 Senior Notes. The proceeds received from the issuance of the 2027 Senior Notes were used to fund the cash tender offer and redemption of all of the Company's 6.50% Senior Notes due 2023 ("2023 Senior Notes") and a portion of its 2022 Senior Notes during the third quarter of 2018. The Company paid total consideration, including accrued interest, of $497.8 million to complete these transactions. As a result of the redemption of the 2021 Senior Notes, and the cash tender offer and redemption of all of the 2023 Senior Notes and a portion of the 2022 Senior Notes, the Company recorded a combined loss on extinguishment of debt of $26.7 million for the quarter ended September 30, 2018. This amount included combined premiums paid of $20.4 million and $6.3 million of accelerated unamortized deferred financing costs for the redemption. Please refer to *Note 5 - Long-Term Debt* in Part II, Item 8 of our 2018 Form 10-K for additional discussion.

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 September 30, 2019, or through the filing of this report. Notwithstanding the inability to convert, the if-converted value of the Senior Convertible Notes as of September 30, 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 $2.8 million and $2.6 million for the three months ended September 30, 2019, and 2018, respectively, and totaled $8.2 million and $7.8 million for the nine months ended September 30, 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 September 30, 2019, and December 31, 2018, consisted of the following:

	As of September 30, 2019	As of December 31, 2018
	(in thousands)	
Principal amount of Senior Convertible Notes	$ 172,500	$ 172,500
Unamortized debt discount	(16,012)	(22,313)
Unamortized deferred financing costs	(1,605)	(2,293)
Senior Convertible Notes, net of unamortized discount and deferred financing costs	$ 154,883	$ 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 September 30, 2019, and through the filing of this report.

Capitalized Interest

Capitalized interest costs for the three months ended September 30, 2019, and 2018, were $4.2 million and $5.2 million, respectively, and for the nine months ended September 30, 2019, and 2018, were $14.1 million and $15.7 million, respectively. The amount of interest the Company capitalizes generally fluctuates based on the amount borrowed, the Company's 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. During the second quarter of 2019, the Company executed an amendment to its existing sand sourcing agreement that created certain commitments and potential penalties that vary based on the amount of sand the Company uses in well completions occurring in a particular area. This amended sand sourcing agreement expires on December 31, 2023. As of September 30, 2019, potential penalties under this sand sourcing agreement range from zero to a maximum of $10.0 million. The Company does not expect to incur material 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 nine months ended September 30, 2019. As of September 30, 2019, the Company's drilling rig and completion service contract commitments totaled $57.1 million. If all of these contracts were terminated as of September 30, 2019, the Company would avoid a portion of the contractual service commitments; however, the Company would be required to pay $38.1 million in early termination fees. Excluded from these amounts are variable commitments and potential penalties determined by the number of completion crews the Company has in operation in a particular area under a completion service arrangement. As of September 30, 2019, potential penalties under this completion service arrangement, which expires on December 31, 2023, range from zero to a maximum of $14.3 million. The Company does not expect to incur material penalties with regard to its drilling rig and completion service contracts.

Electrical Power Purchase Contracts. During the second quarter of 2019, the Company entered into a fixed price contract for the purchase of electrical power that increased the purchase commitment under an existing agreement. As of September 30, 2019, the Company had a commitment to purchase electrical power through 2027 with a total remaining obligation of $55.1 million. As of the filing of this report, the Company expects to meet this commitment.

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

Equity Incentive Compensation Plan

As of September 30, 2019, 4.1 million shares of common stock were available for grant under the Company's Equity Incentive Compensation Plan ("Equity Plan").

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 settlement 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 Equity Plan.

For PSUs that were granted in 2016 and 2017, the settlement criteria included a combination of the Company's Total Shareholder Return ("TSR") on an absolute basis, and the Company's TSR relative to the TSR of certain peer companies over the associated three-year performance period. The fair value of the PSUs granted in 2016 and 2017 was measured on the applicable grant dates using a stochastic Monte Carlo simulation using geometric Brownian motion ("GBM Model"). As these awards depend entirely on market-based settlement criteria, the associated compensation expense is recognized on a straight-line basis within general and administrative expense and exploration expense over the vesting periods of the respective awards.

For PSUs granted in 2018 and 2019, the settlement criteria included a combination of the Company's TSR relative to the TSR of certain peer companies, and the Company's cash return on total capital invested ("CRTCI") relative to the CRTCI of certain peer companies over the associated three-year performance period. The fair value of the PSUs granted in 2018 and 2019 was measured on the applicable grant dates using the GBM Model, with the assumption that the associated CRTCI performance condition will be met at the target amount at the end of the respective performance periods. Compensation expense for PSUs granted in 2018 and 2019 is recognized within general and administrative expense and exploration expense over the vesting periods of the respective awards. As these awards depend on a combination of performance-based settlement criteria and market-based settlement criteria, compensation expense may be adjusted in future periods as the number of units expected to vest increases or decreases based on the Company's expected CRTCI performance relative to the applicable peer companies.

Total compensation expense recorded for PSUs was $2.9 million and $3.0 million for the three months ended September 30, 2019, and 2018, respectively, and was $8.6 million and $7.7 million for the nine months ended September 30, 2019, and 2018, respectively. As of September 30, 2019, there was $19.7 million of total unrecognized compensation expense related to non-vested PSU awards, which is being amortized through 2022.

A summary of the status and activity of non-vested PSUs for the nine months ended September 30, 2019, is presented in the following table:

	PSUs (1)	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	1,711,259	$ 20.68
Granted	793,125	$ 12.80
Vested	(346,021)	$ 26.31
Forfeited	(40,999)	$ 17.96
Non-vested at end of quarter	2,117,364	$ 16.86

(1) The number of awards assumes a multiplier of one. The final number of shares of common stock issued may vary depending on the three-year performance multiplier which ranges from zero to two.

During the nine months ended September 30, 2019, the Company issued 793,125 PSUs with a grant date fair value of $10.2 million. In addition to the settlement criteria described above, the 2019 Performance Share Unit Award Agreement also stipulates that if either the Company's absolute TSR, or absolute CRTCI, is negative over the three-year performance period, the maximum number of shares of common stock that can be issued to settle outstanding PSUs shall be capped at one times the number of PSUs granted on the award date, regardless of the Company's TSR and CRTCI performance relative to the peer group. During the nine months ended September 30, 2019, the Company settled PSUs that were granted in 2016, with no shares issued upon settlement because the grant settled at a zero multiplier.

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 Equity Plan.

Total compensation expense recorded for employee RSUs was $2.9 million and $3.0 million for the three months ended September 30, 2019, and 2018, respectively, and was $8.4 million and $8.0 million for the nine months ended September 30, 2019, and 2018, respectively. As of September 30, 2019, there was $21.4 million of total unrecognized compensation expense related to non-vested RSU awards, which is being amortized through 2022.

A summary of the status and activity of non-vested RSUs granted to employees for the nine months ended September 30, 2019, is presented in the following table:

	RSUs	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	1,243,163	$ 21.50
Granted	978,932	$ 12.36
Vested	(466,535)	$ 21.93
Forfeited	(111,188)	$ 19.94
Non-vested at end of quarter	1,644,372	$ 16.04

During the nine months ended September 30, 2019, the Company granted 978,932 RSUs with a grant date fair value of $12.1 million. Also, during the nine months ended September 30, 2019, the Company settled 466,535 RSUs that related to awards granted in previous years. The Company and the majority of grant participants mutually agreed to net share settle a portion of the awards to cover income and payroll tax withholdings, as provided for in the Equity Plan and award agreements. As a result, the Company issued 334,399 net shares of common stock upon settlement of the awards.

Director Shares

During the second quarters of 2019, and 2018, the Company issued 96,719 and 58,572 shares, respectively, of its common stock to its non-employee directors under the Equity Plan. Shares issued during the second quarter of 2019 will fully vest on December 31, 2019. Shares issued during the second quarter of 2018 fully vested on December 31, 2018. The Company did not issue any director shares during the third quarters of 2019, or 2018.

Employee Stock Purchase Plan

Under the Company’s Employee Stock Purchase Plan (“ESPP”), eligible employees may purchase shares of the Company’s common stock through payroll deductions of up to 15 percent of eligible compensation, without accruing in excess of $25,000 in value from purchases for each calendar year. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on either the first or last day of the purchase period. The ESPP is intended to qualify under Section 423 of the Internal Revenue Code. There were 184,079 and 100,249 shares issued under the ESPP during the nine months ended September 30, 2019, and 2018, respectively. Total proceeds to the Company for the issuance of these shares was $2.0 million and $1.9 million for the nine months ended September 30, 2019, and 2018, respectively. The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model.

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 September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands)			
Components of net periodic benefit cost:				
Service cost	$ 1,395	$ 1,683	$ 4,186	$ 5,048
Interest cost	699	657	2,094	1,967
Expected return on plan assets that reduces periodic pension benefit cost	(393)	(466)	(1,180)	(1,397)
Amortization of prior service cost	4	4	13	13
Amortization of net actuarial loss	239	331	718	995
Net periodic benefit cost	$ 1,944	$ 2,209	$ 5,831	$ 6,626

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

As of the filing of this report, the Company has contributed$7.2 million to the Qualified Pension Plan in 2019 and does not expect to make additional contributions for the remainder of 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 available to common stockholders 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 and nine months ended September 30, 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 anti-dilutive securities for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands)			
Anti-dilutive	—	2,433	707	—

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands, except per share data)			
Net income (loss)	$ 42,234	$ (135,923)	$ (84,946)	$ 198,675
Basic weighted-average common shares outstanding	112,804	112,107	112,441	111,836
Dilutive effect of non-vested RSUs and contingent PSUs	530	—	—	1,764
Diluted weighted-average common shares outstanding	113,334	112,107	112,441	113,600
Basic net income (loss) per common share	$ 0.37	$ (1.21)	$ (0.76)	$ 1.78
Diluted net income (loss) per common share	$ 0.37	$ (1.21)	$ (0.76)	$ 1.75

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 September 30, 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 price 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 September 30, 2019, the Company had commodity derivative contracts outstanding through thefourth quarter of 2022, as summarized in the tables below.

Oil Swaps

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price
	(MBbl)	(per Bbl)
Fourth quarter 2019	1,685	$ 61.38
2020	7,441	$ 59.64
Total	9,126	

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MBbl)	(per Bbl)	(per Bbl)
Fourth quarter 2019	3,168	$ 50.54	$ 62.49
2020	6,010	$ 55.00	$ 62.95
2021	329	$ 55.00	$ 56.70
Total	9,507		

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)
Fourth quarter 2019	3,338	$ (2.87)	—	$ —
2020	14,090	$ (0.73)	2,750	$ (8.03)
2021	3,708	$ 0.33	3,650	$ (7.86)
2022	—	$ —	3,650	$ (7.78)
Total	21,136		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)
Fourth quarter 2019	14,433	$ 2.88	2,962	$ 1.75
2020	11,773	$ 2.87	4,977	$ 1.70
Total [(1)]	26,206		7,939	

(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 September 30, 2019, WAHA volumes were comprised of56 percent IF WAHA and 44 percent GD WAHA.

Gas Collars

Contract Period	IF HSC Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(BBtu)	(per MMBtu)	(per MMBtu)
Fourth quarter 2019	4,818	$ 2.50	$ 2.83
Total	4,818		

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)
Fourth quarter 2019	896	$ 12.36	660	$ 31.60	39	$ 35.64	29	$ 35.70	50	$ 50.93
2020	711	$ 11.38	1,187	$ 23.58	—	$ —	—	$ —	—	$ —
Total	1,607		1,847		39		29		50	

Commodity Derivative Contracts Entered Into Subsequent to September 30, 2019

Subsequent to September 30, 2019, the Company entered into the following commodity derivative contracts:

- fixed price NYMEX WTI oil swap contracts for the third quarter of 2020 for a total of0.9 MMBbl of oil production at a weighted-average contract price of $51.61 per Bbl;
- fixed price IF HSC gas swap contracts for the second through fourth quarters of 2020 for a total of9,725 BBtu of gas production at a weighted-average contract price of $2.28 per MMBtu;
- fixed price IF WAHA gas swap contracts for 2020 and 2021 for a total of12,229 BBtu of gas production at a weighted-average contract price of$1.06 per MMBtu; and

- fixed price OPIS Propane Mont Belvieu Non-TET swap contracts for 2020 for a total of0.5 MMBbl of propane production at a weighted-average contract price of $19.27 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, with the exception of derivative instruments that meet the “normal purchase normal sale” exclusion. The Company does not designate its derivative commodity contracts as hedging instruments. The fair value of the commodity derivative contracts was a net asset of $137.9 million and $158.3 million as of September 30, 2019, and December 31, 2018, respectively.

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

	As of September 30, 2019	As of December 31, 2018
	(in thousands)	
Derivative assets:		
Current assets	$ 143,142	$ 175,130
Noncurrent assets	38,571	58,499
Total derivative assets	$ 181,713	$ 233,629
Derivative liabilities:		
Current liabilities	$ 37,798	$ 62,853
Noncurrent liabilities	6,014	12,496
Total derivative liabilities	$ 43,812	$ 75,349

Offsetting of Derivative Assets and Liabilities

As of September 30, 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	
	September 30, 2019	December 31, 2018	September 30, 2019	December 31, 2018
	(in thousands)			
Gross amounts presented in the accompanying balance sheets	$ 181,713	$ 233,629	$ (43,812)	$ (75,349)
Amounts not offset in the accompanying balance sheets	(43,812)	(56,041)	43,812	56,041
Net amounts	$ 137,901	$ 177,588	$ —	$ (19,308)

The following table summarizes the commodity components of the derivative settlement (gain) loss, as well as the components of the net derivative (gain) loss line item presented in the accompanying statements of operations:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands)			
Derivative settlement (gain) loss:				
Oil contracts	$ 2,246	$ 16,798	$ 14,304	$ 61,976
Gas contracts	(12,210)	802	(13,744)	(4,851)
NGL contracts	(14,758)	23,118	(24,403)	44,786
Total derivative settlement (gain) loss	$ (24,722)	$ 40,718	$ (23,843)	$ 101,911
Net derivative (gain) loss:				
Oil contracts	$ (83,984)	$ 110,413	$ 67,261	$ 146,781
Gas contracts	(4,228)	4,309	(36,337)	21,299
NGL contracts	(12,677)	63,304	(34,387)	81,224
Total net derivative (gain) loss	$ (100,889)	$ 178,026	$ (3,463)	$ 249,304

Credit Related Contingent Features

As of September 30, 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 September 30, 2019:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives [(1)]	$ —	$ 181,713	$ —
Liabilities:			
Derivatives [(1)]	$ —	$ 43,812	$ —

(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. The Company recorded abandonment and impairment of unproved properties expense of $6.3 million and $25.1 million during the three and nine months ended September 30, 2019, respectively, and $9.1 million and $26.6 million during three and nine months ended September 30, 2018, respectively. These expenses 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.

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 September 30, 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 September 30, 2019		As of December 31, 2018	
	Principal Amount	**Fair Value**	**Principal Amount**	**Fair Value**
	(in thousands)			
6.125% Senior Notes due 2022	$ 476,796	$ 459,321	$ 476,796	$ 452,336
5.0% Senior Notes due 2024	$ 500,000	$ 448,950	$ 500,000	$ 439,265
5.625% Senior Notes due 2025	$ 500,000	$ 431,335	$ 500,000	$ 436,460
6.75% Senior Notes due 2026	$ 500,000	$ 440,000	$ 500,000	$ 448,305
6.625% Senior Notes due 2027	$ 500,000	$ 432,500	$ 500,000	$ 442,500
1.50% Senior Convertible Notes due 2021	$ 172,500	$ 156,706	$ 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 September 30, 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 does 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 determines 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 material early termination options are reasonably certain to be exercised by the Company.

Currently, the Company has operating leases for asset classes that include office space, office equipment, drilling rigs, 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 approximately three 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 and nine months ended September 30, 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 $107.3 million and $422.4 million, respectively. These totals do 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 and nine months ended September 30, 2019, were as follows:

	For the Three Months Ended September 30, 2019	For the Nine Months Ended September 30, 2019
	(in thousands)	
Operating lease cost	$ 8,344	$ 28,802
Short-term lease cost [(1)]	72,874	309,876
Variable lease cost [(2)]	26,090	83,696
Total lease cost [(3)]	$ 107,308	$ 422,374

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(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 that 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 nine months ended September 30, 2019, was as follows:

	For the Nine Months Ended September 30, 2019
	(in thousands)
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows from operating leases	$ 9,029
Investing cash flows from operating leases	$ 20,256
Right-of-use assets obtained in exchange for new operating lease liabilities	$ 24,014

Maturities for the Company’s operating lease liabilities included on the accompanying balance sheets as of September 30, 2019, were as follows:

		As of September 30, 2019
		(in thousands)
2019 (remaining after September 30, 2019)	$	6,871
2020		20,427
2021		11,982
2022		5,712
2023		3,572
Thereafter		3,721
Total Lease payments	$	52,285
Less: Imputed interest [1]		(5,098)
Total	$	47,187

(1) The weighted-average discount rate used to determine the operating lease liability as of September 30, 2019 was 6.6 percent.

Amounts recorded on the accompanying balance sheets for operating leases as of September 30, 2019, were as follows:

		As of September 30, 2019
		(in thousands)
Other noncurrent assets	$	44,438
Other current liabilities	$	21,804
Other noncurrent liabilities	$	25,384

As of September 30, 2019, and through the filing of this report, the Company has no material lease arrangements which are scheduled to commence in the future.

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

The following discussion includes 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 formations and intervals within our RockStar position, including the Middle Spraberry, Wolfcamp D, and Dean.

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 focused on developing the Eagle Ford Shale Formation and testing additional intervals and formations, including the Austin Chalk Formation.

Third Quarter 2019 Highlights and Outlook for the Remainder of 2019

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

Our capital program for 2019, excluding acquisitions, is expected to range from $1.00 billion to $1.05 billion. Our program remains concentrated on developing our core assets in the Midland Basin and South Texas, with the majority of our 2019 capital allocated to our Midland Basin program. Drilling and completion activity on our South Texas acreage position was primarily funded by a third party as part of a joint development agreement. All wells subject to this agreement were completed as of September 30, 2019. Please refer to *Overview of Liquidity and Capital Resources* below for additional discussion on our 2019 capital program.

Financial and Operational Results. Average net daily production for the three months ended September 30, 2019, was 134.9 MBOE, compared with 130.2 MBOE for the same period in 2018. This increase was driven by an 11 percent increase in production volumes from our Midland Basin assets. Realized prices before the effects of derivative settlements for oil, gas, and NGLs decreased five percent, 39 percent, and 49 percent, respectively, for the three months ended September 30, 2019, compared with the same period in 2018. As a result of decreased commodity prices, oil, gas, and NGL production revenue decreased 15 percent to $389.4 million for the three months ended September 30, 2019 from $458.4 million for the same period in 2018. We recorded a net derivative gain of $100.9 million for the three months ended September 30, 2019, compared to a net derivative loss of $178.0 million recorded for the same period in 2018. Included within these derivative amounts is a gain of $24.7 million on derivative contracts that settled during the three months ended September 30, 2019, and a loss of $40.7 million for the same period in 2018. Together, these changes resulted in the following:

- net income of $42.2 million, or $0.37 per diluted share, for the three months ended September 30, 2019, compared to a net loss of $135.9 million, or $1.21 per diluted share, for the same period in 2018;

- net cash provided by operating activities of $203.2 million for the three months ended September 30, 2019, compared with $229.7 million for the same period in 2018; and

- adjusted EBITDAX, a non-GAAP financial measure, for the three months ended September 30, 2019, was $257.8 million, compared with $256.1 million for the same period in 2018. Please refer to the caption *Non-GAAP Financial Measures* below for our definition of adjusted EBITDAX and reconciliations of net income (loss) and net cash provided by operating activities to adjusted EBITDAX.

Please refer to *A Three Month and Nine Month Overview of Selected Production and Financial Information, Including Trends*, *Comparison of Financial Results and Trends Between the Three Months and Nine Months Ended September 30, 2019, and 2018*, and *Overview of Liquidity and Capital Resources*, below for additional discussion on production and production revenues.

Operational Activities. In our Midland Basin program, we operated six drilling rigs and three completion crews during the third quarter of 2019. Subsequent to September 30, 2019, we released one completion crew and we expect to operate two completion crews for the remainder of 2019. For the full year 2019, we expect to average six drilling rigs and three completion crews in the Midland Basin and to allocate approximately 80 percent of our drilling and completion capital to our Midland Basin program. 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 and Middle Spraberry and Wolfcamp A and B shale intervals.

In our South Texas program, we averaged one drilling rig and one completion crew during the third quarter of 2019. 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. Drilling and completion activities in South Texas continue to focus on developing the Eagle Ford Shale and testing additional intervals and formations, including the Austin Chalk Formation. Certain drilling and completion activities in the northern portion of our South Texas acreage position were primarily funded by a third party pursuant to our joint development agreement. All wells subject to this agreement were completed as of September 30, 2019.

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 and nine months ended September 30, 2019:

	Midland Basin		South Texas		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
Wells drilled	26	25	7	3	33	28
Wells completed	(36)	(32)	(11)	(11)	(47)	(43)
Wells drilled but not completed at June 30, 2019	52	49	30	20	82	69
Wells drilled	25	22	6	6	31	28
Wells completed	(21)	(19)	(17)	(6)	(38)	(25)
Other [(1)]	—	—	—	(1)	—	(1)
Wells drilled but not completed at September 30, 2019	56	52	19	19	75	71

(1) Includes adjustments related to normal business activities, including previously drilled wells 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 $270.9 million and $861.4 million for the three and nine months ended September 30, 2019, respectively, 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 areas of operation for the three months ended September 30, 2019, and 2018:

	Midland Basin		South Texas		Total	
	Three Months Ended September 30,		Three Months Ended September 30,		Three Months Ended September 30,	
	2019	2018	2019	2018	2019	2018
Production:						
Oil (MMBbl)	5.1	4.8	0.3	0.3	5.4	5.0
Gas (Bcf)	9.1	7.1	20.4	20.1	29.5	27.2
NGLs (MMBbl)	—	—	2.1	2.4	2.1	2.4
Equivalent (MMBOE)	6.6	6.0	5.8	6.0	12.4	12.0
Avg. daily equivalents (MBOE/d)	71.7	64.8	63.2	65.4	134.9	130.2
Relative percentage	53%	50%	47%	50%	100%	100%

Note: Amounts may not calculate due to rounding.

The table below presents our production by product type for each of our areas of operation for the nine months ended September 30, 2019, and 2018:

	Midland Basin		South Texas		Rocky Mountain [(1)]		Total	
	Nine Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018	2019	2018	2019	2018
Production:								
Oil (MMBbl)	14.8	11.8	0.9	1.0	—	0.9	15.7	13.7
Gas (Bcf)	24.4	18.9	57.3	57.6	—	1.2	81.7	77.7
NGLs (MMBbl)	—	—	6.2	5.9	—	—	6.2	6.0
Equivalent (MMBOE)	18.8	15.0	16.7	16.5	—	1.1	35.5	32.6
Avg. daily equivalents (MBOE/d)	69.0	54.9	61.1	60.4	—	4.1	130.1	119.4
Relative percentage	53%	46%	47%	51%	—%	3%	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.

Please refer to *A Three Month and Nine Month Overview of Selected Production and Financial Information, Including Trends* and *Comparison of Financial Results and Trends Between the Three Months and Nine Months Ended September 30, 2019, and 2018* below for 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 realized 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 third and second quarters of 2019 as well as the third quarter of 2018:

	For the Three Months Ended		
	September 30, 2019	June 30, 2019	September 30, 2018
Oil (per Bbl):			
Average NYMEX contract monthly price	$ 56.45	$ 59.81	$ 69.50
Realized price, before the effect of derivative settlements	$ 53.99	$ 56.04	$ 56.96
Effect of oil derivative settlements	$ (0.41)	$ (1.97)	$ (3.32)
Gas:			
Average NYMEX monthly settle price (per MMBtu)	$ 2.23	$ 2.64	$ 2.90
Realized price, before the effect of derivative settlements (per Mcf)	$ 2.17	$ 2.31	$ 3.56
Effect of gas derivative settlements (per Mcf)	$ 0.41	$ 0.20	$ (0.03)
NGLs (per Bbl):			
Average OPIS price [(1)]	$ 18.89	$ 22.23	$ 37.97
Realized price, before the effect of derivative settlements	$ 15.73	$ 16.42	$ 30.77
Effect of NGL derivative settlements	$ 7.14	$ 4.00	$ (9.61)

(1) Average OPIS price per barrel of NGL, historical or strip, assumes a composite barrel 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 remain 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. NGL prices have trended down as an abundance of NGL volumes from increased drilling in liquid-rich areas have over-supplied today's market. New demand from petrochemical markets and exports have helped to balance the NGL supply.

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.

Please refer to *A Three Month and Nine Month Overview of Selected Production and Financial Information, Including Trends* below for additional discussion on our realized prices for oil, gas, and NGLs.

The following table summarizes 12-month strip prices for NYMEX WTI oil, NYMEX Henry Hub gas, and OPIS NGLs (assuming the same composite NGL barrel product mix as discussed above) as of October 24, 2019, and September 30, 2019:

	As of October 24, 2019	As of September 30, 2019
NYMEX WTI oil (per Bbl)	$ 55.10	$ 52.66
NYMEX Henry Hub gas (per MMBtu)	$ 2.37	$ 2.41
OPIS NGLs (per Bbl)	$ 19.70	$ 18.89

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 commodity derivative 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 quarter ended September 30, 2019, and the immediately preceding three quarters. A detailed discussion follows.

	For the Three Months Ended			
	September 30, 2019	June 30, 2019	March 31, 2019	December 31, 2018
	(in millions)			
Production (MMBOE)	12.4	12.4	10.7	11.3
Oil, gas, and NGL production revenue	$ 389.4	$ 406.9	$ 340.5	$ 392.5
Oil, gas, and NGL production expense	$ 129.0	$ 123.1	$ 121.3	$ 121.5
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 211.1	$ 206.3	$ 177.7	$ 182.0
Exploration	$ 11.6	$ 10.9	$ 11.3	$ 14.3
General and administrative	$ 32.6	$ 30.9	$ 32.1	$ 30.4
Net income (loss)	$ 42.2	$ 50.4	$ (177.6)	$ 309.7

Selected Performance Metrics

	For the Three Months Ended			
	September 30, 2019	June 30, 2019	March 31, 2019	December 31, 2018
Average net daily production equivalent (MBOE per day)	134.9	136.5	118.7	122.8
Lease operating expense (per BOE)	$ 4.73	$ 4.16	$ 5.20	$ 4.98
Transportation costs (per BOE)	$ 4.00	$ 4.00	$ 4.08	$ 4.19
Production taxes as a percent of oil, gas, and NGL production revenue	4.1%	4.0%	4.1%	3.4%
Ad valorem tax expense (per BOE)	$ 0.39	$ 0.44	$ 0.76	$ 0.39
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$ 17.02	$ 16.61	$ 16.63	$ 16.10
General and administrative (per BOE)	$ 2.63	$ 2.49	$ 3.00	$ 2.69

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

	For the Three Months Ended September 30,		Amount Change Between Periods	Percent Change Between Periods	For the Nine Months Ended September 30,		Amount Change Between Periods	Percent Change Between Periods
	2019	2018			2019	2018		
Net production volumes: (1)								
Oil (MMBbl)	5.4	5.0	0.4	7 %	15.7	13.7	2.0	15 %
Gas (Bcf)	29.5	27.2	2.3	9 %	81.7	77.7	4.0	5 %
NGLs (MMBbl)	2.1	2.4	(0.3)	(14)%	6.2	6.0	0.2	4 %
Equivalent (MMBOE)	12.4	12.0	0.4	4 %	35.5	32.6	2.9	9 %
Average net daily production: (1)								
Oil (MBbl per day)	59.0	54.9	4.1	7 %	57.5	50.1	7.4	15 %
Gas (MMcf per day)	320.6	295.3	25.3	9 %	299.2	284.7	14.5	5 %
NGLs (MBbl per day)	22.5	26.2	(3.7)	(14)%	22.8	21.9	0.9	4 %
Equivalent (MBOE per day)	134.9	130.2	4.6	4 %	130.1	119.4	10.7	9 %
Oil, gas, and NGL production revenue (in millions): (1)								
Oil production revenue	$ 292.9	$ 287.5	$ 5.3	2 %	$ 836.1	$ 814.7	$ 21.3	3 %
Gas production revenue	64.0	96.8	(32.8)	(34)%	194.4	260.0	(65.6)	(25)%
NGL production revenue	32.5	74.1	(41.5)	(56)%	106.3	169.1	(62.8)	(37)%
Total oil, gas, and NGL production revenue	$ 389.4	$ 458.4	$ (69.0)	(15)%	$ 1,136.7	$ 1,243.8	$ (107.1)	(9)%
Oil, gas, and NGL production expense (in millions): (1)								
Lease operating expense	$ 58.7	$ 52.8	$ 5.8	11 %	$ 166.0	$ 151.9	$ 14.1	9 %
Transportation costs	49.6	50.4	(0.8)	(2)%	142.9	144.1	(1.2)	(1)%
Production taxes	16.0	19.0	(3.0)	(16)%	46.1	53.4	(7.3)	(14)%
Ad valorem tax expense	4.8	5.4	(0.7)	(12)%	18.4	16.5	1.9	11 %
Total oil, gas, and NGL production expense	$ 129.0	$ 127.6	$ 1.4	1 %	$ 373.4	$ 365.9	$ 7.5	2 %
Realized price (before the effect of derivative settlements):								
Oil (per Bbl)	$ 53.99	$ 56.96	$ (2.97)	(5)%	$ 53.31	$ 59.60	$ (6.29)	(11)%
Gas (per Mcf)	$ 2.17	$ 3.56	$ (1.39)	(39)%	$ 2.38	$ 3.35	$ (0.97)	(29)%
NGLs (per Bbl)	$ 15.73	$ 30.77	$ (15.04)	(49)%	$ 17.09	$ 28.28	$ (11.19)	(40)%
Per BOE	$ 31.39	$ 38.26	$ (6.87)	(18)%	$ 32.00	$ 38.15	$ (6.15)	(16)%
Per BOE data:								
Production costs:								
Lease operating expense	$ 4.73	$ 4.41	$ 0.32	7 %	$ 4.67	$ 4.66	$ 0.01	— %
Transportation costs	$ 4.00	$ 4.20	$ (0.20)	(5)%	$ 4.02	$ 4.42	$ (0.40)	(9)%
Production taxes	$ 1.29	$ 1.58	$ (0.29)	(18)%	$ 1.30	$ 1.64	$ (0.34)	(21)%
Ad valorem tax expense	$ 0.39	$ 0.45	$ (0.06)	(13)%	$ 0.52	$ 0.51	$ 0.01	2 %
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 17.02	$ 16.78	$ 0.24	1 %	$ 16.76	$ 14.82	$ 1.94	13 %
General and administrative	$ 2.63	$ 2.46	$ 0.17	7 %	$ 2.69	$ 2.64	$ 0.05	2 %
Derivative settlement gain (loss) (2)	$ 1.99	$ (3.40)	$ 5.39	159 %	$ 0.67	$ (3.13)	$ 3.80	121 %
Earnings per share information:								
Basic weighted-average common shares outstanding (in thousands)	112,804	112,107	697	1 %	112,441	111,836	605	1 %
Diluted weighted-average common shares outstanding (in thousands)	113,334	112,107	1,227	1 %	112,441	113,600	(1,159)	(1)%
Basic net income (loss) per common share	$ 0.37	$ (1.21)	$ 1.58	131 %	$ (0.76)	$ 1.78	$ (2.54)	(143)%
Diluted net income (loss) per common share	$ 0.37	$ (1.21)	$ 1.58	131 %	$ (0.76)	$ 1.75	$ (2.51)	(143)%

(1) Amount and percentage changes may not calculate due to rounding.

(2) Derivative settlements for the three and nine months ended September 30, 2019, and 2018, are included within the net derivative (gain) loss line item in the accompanying statements of operations.

Average net equivalent daily production for the three and nine months ended September 30, 2019, increased four percent and nine percent, respectively, compared with the same periods in 2018. These results were primarily driven by the performance of our Midland Basin assets, which had increases in production volumes of 11 percent and 26 percent for the three and nine months ended September 30, 2019, respectively, compared with the same periods in 2018. Production volumes from our South Texas assets decreased three percent and increased one percent for the three and nine months ended September 30, 2019, respectively. We divested our remaining producing assets in the Rocky Mountain region in the first half of 2018. On a retained asset basis, production volumes increased 13 percent for the nine months ended September 30, 2019, compared with the same period in 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 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.

Below is a discussion of certain financial results, some of which are presented on a per BOE basis. We present this information on a per BOE basis because we believe it is an effective way 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 effect of derivative settlements on a per BOE basis decreased 18 percent and 16 percent for the three and nine months ended September 30, 2019, respectively, compared with the same periods in 2018. These decreases were primarily driven by lower commodity prices for oil, gas, and NGLs. In addition to lower commodity prices, regional differentials in the Midland Basin caused by tight takeaway capacity further affected realized prices. In the first half of 2019, certain third-party midstream force majeure events negatively affected the price we received for our Midland Basin gas production. Regional differentials for gas in the Midland Basin are expected to continue to negatively affect our realized prices into 2020, when additional expected take-away capacity is anticipated to come on-line. For the three and nine months ended September 30, 2019, we recognized gains of $1.99 and $0.67 per BOE, respectively, on the settlement of our derivative contracts, compared to recognized losses of $3.40 and $3.13 per BOE, for the three and nine months ended September 30, 2018, respectively.

Lease operating expense (“LOE”) on a per BOE basis increased seven percent for the three months ended September 30, 2019, compared with the same period in 2018. This increase was primarily driven by increased LOE and workover expense on our South Texas assets. For the nine months ended September 30, 2019, LOE on a per BOE basis was flat compared with the same period in 2018. For the full year, we expect LOE on a per BOE basis to be flat in 2019 compared with 2018. We may experience 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 such changes could have on service provider costs.

Transportation costs on a per BOE basis decreased five percent and nine percent for the three and nine months ended September 30, 2019, respectively, compared with the same periods in 2018. These decreases were driven primarily by an increase in the percentage of production generated from our Midland Basin assets, as production from these assets is typically sold at or near the wellhead and incurs minimal transportation costs. We expect total transportation costs to fluctuate relative to changes in production from our South Texas assets, which 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 continues to become a larger portion of our total production.

Production taxes on a per BOE basis decreased 18 percent and 21 percent for the three and nine months ended September 30, 2019, respectively, compared with the same periods in 2018. These decreases were primarily driven by the 18 percent and 16 percent decreases in realized price on a per BOE basis before the effects of derivative settlements for the three and nine months ended September 30, 2019, respectively, compared with the same periods in 2018. Our overall production tax rate for each of the three and nine months ended September 30, 2019, was 4.1 percent compared to 4.1 percent and 4.3 percent for the three and nine months ended September 30, 2018, respectively. The decrease in our production tax rate for the nine months ended September 30, 2018 was primarily the result of divesting our producing assets in the Rocky Mountain region, which were subject to higher tax rates than our 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 decreased 13 percent for the three months ended September 30, 2019, compared to the same period in 2018. For the nine months ended September 30, 2019, ad valorem tax expense per BOE was relatively flat compared with the same period in 2018 as the expected increases on an absolute basis were consistent with higher production volumes. We expect our full-year 2019 ad valorem tax expense to remain consistent with 2018 on a per BOE basis, as increases on an absolute basis continue to trend in line with higher production volumes.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion (“DD&A”) expense on a per BOE basis increased one percent and 13 percent for the three and nine months ended September 30, 2019, respectively, compared with the same periods in 2018. These increases were driven by our focus on developing oil producing assets in the Midland Basin, which have higher depletion rates than our primarily gas and NGL producing 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 seven percent and two percent for the three and nine months ended September 30, 2019, respectively, compared with the same periods in 2018. These increases are primarily due to less employee compensation being reclassified to exploration expense as more employee time is being allocated to development activities. As we expect a continued high focus of capital allocation to the Midland Basin, we reorganized certain functions during the fourth quarter of 2019 to eliminate duplicative regional operation functions and reduce overhead costs, which we expect will result in reduced G&A expense in future years. As a result, we expect to incur total charges related to this reorganization ranging from $7.0 million to $8.5 million, including a range of $3.0 million to $5.0 million to be incurred in the fourth quarter of 2019. Therefore, we expect G&A expense for the full-year 2019 to increase compared with 2018.

Please refer to *Comparison of Financial Results and Trends Between the Three Months and Nine Months Ended September 30, 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 and Nine Months Ended September 30, 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 September 30, 2019, and 2018:

	Net Equivalent Production Increase (Decrease)	Production Revenue Decrease	Production Expense Increase (Decrease)
	(MBOE per day)	(in millions)	(in millions)
Midland Basin	6.9	$ (15.7)	$ 1.8
South Texas	(2.3)	(53.2)	(0.4)
Total	4.6	$ (69.0)	$ 1.4

Note: Amounts may not calculate due to rounding.

The following table presents the regional changes in our net equivalent production, production revenue, and production expense between the nine months ended September 30, 2019, and 2018:

	Net Equivalent Production Increase (Decrease)	Production Revenue Increase (Decrease)	Production Expense Increase (Decrease)
	(MBOE per day)	(in millions)	(in millions)
Midland Basin	14.1	$ 39.7	$ 24.3
South Texas	0.7	(89.5)	6.5
Rocky Mountain (1)	(4.1)	(57.2)	(23.3)
Total	10.7	$ (107.1)	$ 7.5

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 four percent and nine percent for the three and nine months ended September 30, 2019, respectively, compared with the same periods in 2018, as a result of increased production, primarily from our Midland Basin assets. Oil, gas, and NGL production revenues decreased 15 percent for the three months ended September 30, 2019, compared with the same period in 2018, primarily as a result of decreases in commodity prices. Oil, gas, and NGL production revenues decreased nine percent for the nine months ended September 30, 2019, compared with the same period in 2018, as a result of weaker commodity pricing and the divestiture in the first half of 2018 of our remaining producing assets in the Rocky Mountain region. On a retained asset basis, production volumes increased 13 percent for the nine months ended September 30, 2019, compared with the same period in 2018. Total production expense for the three and nine months ended September 30, 2019, compared with the same periods in 2018, was relatively flat as increased lease operating expense was offset by decreased production taxes and transportation costs. Production expense on a per BOE basis decreased two percent and six percent for the three and nine months ended September 30, 2019, respectively, compared with the same periods in 2018, primarily due to increased production volumes, decreased transportation costs on a per BOE basis, and decreased production taxes driven by lower oil, gas, and NGL production revenues. Please refer to *A Three Month and Nine 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 September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Net gain on divestiture activity	$ —	$ 0.8	$ 0.3	$ 425.7

The $425.7 million net gain on divestiture activity recorded for the nine months ended September 30, 2018, was primarily the result of an estimated net gain of $410.6 million recorded for the PRB Divestiture, which closed in the first quarter of 2018. 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 September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 211.1	$ 201.1	$ 595.2	$ 483.3

DD&A expense increased five percent and 23 percent for the three and nine months ended September 30, 2019, respectively, compared with the same periods in 2018. The increases directly relate to the 11 percent and 26 percent increases in production volumes from our Midland Basin assets for the three and nine months ended September 30, 2019, respectively, as these assets have higher depletion rates than our assets in South Texas.

Exploration

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Geological and geophysical expenses	$ 1.1	$ 0.6	$ 2.0	$ 4.5
Overhead and other expenses	10.5	12.5	31.9	36.3
Total exploration	$ 11.6	$ 13.1	$ 33.9	$ 40.8

Exploration expense decreased 11 percent and 17 percent for the three and nine months ended September 30, 2019, respectively, compared with the same periods in 2018. The decreases were primarily driven by a reduction in the amount of employee compensation reclassified to exploration expense as more employee time is being allocated to development activities, which is recognized as G&A expense. Additionally, spending on geological and geophysical activities decreased for the nine months ended September 30, 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 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 September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Abandonment and impairment of unproved properties	$ 6.3	$ 9.1	$ 25.1	$ 26.6

There were no proved property impairments for the three and nine months ended September 30, 2019 and 2018. Unproved property abandonment and impairment expense recorded for the three and nine months ended September 30, 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, and changing economics associated with decreases in commodity prices. Additionally, changes in drilling plans, unsuccessful exploration activities, and downward engineering revisions 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 October 24, 2019, we do not expect any material property impairments in the fourth quarter of 2019 resulting from commodity price impacts.

General and administrative

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
General and administrative	$ 32.6	$ 29.5	$ 95.6	$ 86.1

G&A expense increased 11 percent for each of the three and nine months ended September 30, 2019, compared with the same periods in 2018. Please refer to the section *A Three Month and Nine 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 (gain) loss

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Net derivative (gain) loss	$ (100.9)	$ 178.0	$ (3.5)	$ 249.3

We recognized a $177.1 million derivative loss in the first quarter of 2019, and derivative gains of $79.7 million and $100.9 million in the second and third quarters of 2019, respectively. The loss in the first quarter of 2019 was primarily driven by a $172.1 million downward mark-to-market adjustment due to strengthening oil prices during the first three months of the year. The derivative gains recognized in the second and third quarters were primarily driven by increases in the fair value of derivative contracts settling subsequent to June 30, 2019, and September 30, 2019, of $75.6 million and $76.2 million, respectively, as a result of weakening commodity prices during these periods. In addition, there was a $23.8 million gain on derivative contracts that settled during the nine months ended September 30, 2019.

We recognized a $178.0 million derivative loss for the three months ended September 30, 2018, due in part to a $186.0 million decrease in the fair value of contracts settling subsequent to September 30, 2018. Additionally, we recognized an $8.0 million gain on contracts that settled during the third quarter of 2018, which had a fair value of $48.7 million at June 30, 2018, and settled for a loss of $40.7 million. We recognized a $7.6 million loss on first and second quarter 2018 contract settlements and recorded a $63.7 million decrease to the fair value of remaining contracts as of June 30, 2018, resulting in a year-to-date net derivative loss of $249.3 million for the nine months ended September 30, 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 September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Interest expense	$ 40.6	$ 38.1	$ 118.2	$ 122.9

Interest expense increased six percent for the three months ended September 30, 2019, compared with the same period in 2018 as a result of increased interest expense associated with borrowings against our credit facility in 2019. Our credit facility remained undrawn throughout 2018.

Interest expense decreased four percent for the nine months ended September 30, 2019, compared with the same period in 2018. This decrease was driven primarily by the redemption of our 2021 Senior Notes in the third quarter of 2018, which reduced interest expense related to debt during the nine months ended September 30, 2019 by $12.1 million compared with the same period in 2018. This decrease was partially offset by increased interest expense associated with borrowings against our credit facility in 2019 whereas no borrowings were made against our credit facility in 2018. We expect interest expense related to our Senior Notes to remain relatively flat for the remainder of 2019 compared with 2018; however, total interest expense will vary based on the timing and amount of borrowings against our credit facility throughout the remainder of 2019.

Loss on extinguishment of debt

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Loss on extinguishment of debt	$ —	$ 26.7	$ —	$ 26.7

For the three and nine months ended September 30, 2018, we recorded a $26.7 million net loss on the early extinguishment of our 2021 Senior Notes, 2023 Senior Notes, and a portion of our 2022 Senior Notes, which included $20.4 million associated with the premiums paid upon redemption and repurchase, and $6.3 million related to the acceleration of unamortized deferred financing costs. Please refer to *Note 5 - Long-Term Debt* in Part I, Item 1 of this report for additional information.

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 September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions, except tax rate)			
Income tax (expense) benefit	$ (16.1)	$ 36.7	$ 16.3	$ (61.3)
Effective tax rate	27.6%	21.3%	16.1%	23.6%

The increase in the effective tax rate for the three months ended September 30, 2019, compared with the same period in 2018, was primarily due to the differing effects of permanent items on income before income taxes for the three months ended September 30, 2019, compared to their impact on the loss before income taxes for the same period in 2018.

The decrease in the effective tax rate for the nine months ended September 30, 2019, compared with the same period in 2018, was primarily due to the differing effects of permanent items on the loss before income taxes for the nine months ended September 30, 2019, compared to their impact on income before income taxes for the same period in 2018.

Discrete expenses related to excess tax deficiencies from stock-based compensation awards, limits to certain covered individual's compensation, and other permanent expense items reduced the tax benefit rate for the nine months ended September 30, 2019, and the three months ended September 30, 2018. These same items increased the tax expense rate for the three months ended September 30, 2019, and the nine months ended September 30, 2018. The reduction in the tax expense rate also reflects a cumulative effect in 2018 from divestitures, and the impact of a correlative change to our 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 in order to maintain flexibility with regard to our activity level and capital expenditures.

Sources of Cash

We currently expect our 2019 capital program to be funded by cash flows from operations, cash that was on hand as of December 31, 2018, and borrowings under our credit facility. During the nine months ended September 30, 2019, we generated

$581.6 million of cash flows from operating activities. As of September 30, 2019, the remaining available borrowing capacity under our Credit Agreement provided $1.1 billion in liquidity.

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 new debt or equity offerings or from other sources of financing. Further, we may enter into additional carrying cost funding and sharing arrangements with third parties for certain exploration or development programs. Our borrowing base could be reduced as a result of lower commodity prices, divestitures of properties with proved reserves, or the issuance of additional 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. 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 conditions of the broader economy, force majeure events, and 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, the enactment of the 2017 Tax Act has had a positive impact on operating cash flows, and we believe it will positively impact future operating cash flows.

Credit Agreement

Our Credit Agreement provides for a senior secured revolving credit facility with a maximum loan amount of $2.5 billion and 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. 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. The next scheduled borrowing base redetermination date is April 1, 2020.

Our daily weighted-average credit facility debt balance was approximately $170.9 million and $97.5 million for the three and nine months ended September 30, 2019. Our credit facility remained undrawn throughout 2018. Cash flows provided by our operating activities, proceeds received from divestitures of properties, capital markets activities, and our capital expenditures all impact the amount we borrow 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, as defined in the Credit Agreement, 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 September 30, 2019, and through the filing of this report. Please refer to the caption *Non-GAAP Financial Measures* below for our definition 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 and nine months ended September 30, 2019, and 2018:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
Weighted-average interest rate	6.3%	6.4%	6.4%	6.4%
Weighted-average borrowing rate	5.6%	5.7%	5.7%	5.8%

Our weighted-average interest rates and weighted average borrowing rates for the three and nine months ended September 30, 2019, and 2018, were 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 lender commitments. The rates disclosed in the above table do not reflect amounts associated with the repurchase of Senior Notes, such as the premium paid upon repurchase, or the acceleration of unamortized deferred financing costs expensed upon repurchase. 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 development, exploration, and acquisition 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 development, exploration, and acquisition of oil and gas properties are the primary use of our capital resources. During the nine months ended September 30, 2019, we spent $788.6 million on capital expenditures. This amount differs from the costs incurred amount of $861.4 million for the nine months ended September 30, 2019, as costs incurred is an accrual-based amount that also includes asset retirement obligations, geological and geophysical expenses, acquisitions of oil and gas properties, 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 development 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 or redeem all or portions of our outstanding debt securities for cash, through exchanges for other securities, or a combination of both. 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. During the third quarter of 2018, the Company redeemed its 2021 Senior Notes, repurchased or redeemed all of its 2023 Senior Notes, repurchased a portion of its 2022 Senior Notes, and issued its 2027 Senior Notes. We have not conducted similar debt transactions through September 30, 2019, or through the filing of this report. Please refer to *Note 5 - Long-Term Debt* in Part I, Item 1 of this report for additional discussion.

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 nine months ended September 30, 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 Nine Months Ended September 30, 2019, and 2018

The following tables present changes in cash flows between the nine months ended September 30, 2019, and 2018, for our operating, investing, and financing activities. The analysis following each table should be read in conjunction with our accompanying unaudited condensed consolidated statements of cash flows in Part I, Item 1 of this report.

Operating activities

	For the Nine Months Ended September 30,		Amount Change Between Periods
	2019	2018	
	(in millions)		
Net cash provided by operating activities	$ 581.6	$ 541.2	$ 40.4

Derivative cash settlements increased $125.9 million for the nine months ended September 30, 2019, compared with the same period in 2018. This increase was partially offset by decreased cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes of $80.7 million and increased cash paid for LOE and ad valorem taxes of $22.2 million for the nine months ended September 30, 2019, compared with the same period in 2018. Cash paid for interest decreased $11.3 million for the nine months ended September 30, 2019, compared with the same period in 2018, due to the redemption and repurchase of certain senior notes in the third quarter of 2018, partially offset by increased interest paid on the 2027 Senior Notes and interest paid on credit facility borrowings during the nine months ended September 30, 2019. 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 Nine Months Ended September 30,		Amount Change Between Periods
	2019	2018	
	(in millions)		
Net cash used in investing activities	$ (778.7)	$ (314.0)	$ (464.7)

The increase in cash used in investing activities for the nine months ended September 30, 2019, compared with the same period in 2018, is due to a decrease in proceeds from the sale of oil and gas properties of $730.7 million. This decrease is partially offset by a decrease in capital expenditures and a decrease in cash paid to acquire proved and unproved oil and gas properties of $243.9 million and $22.0 million, respectively.

Financing activities

	For the Nine Months Ended September 30,		Amount Change Between Periods
	2019	2018	
	(in millions)		
Net cash provided by (used in) financing activities	$ 122.7	$ (364.4)	$ 487.1

Net cash provided by (used in) financing activities increased $487.1 million for the nine months ended September 30, 2019, compared with the same period in 2018. During the nine months ended September 30, 2019, net borrowings under our credit facility increased $129.0 million. Our credit facility remained undrawn throughout 2018. During the nine months ended September 30, 2018, we redeemed $344.6 million principal outstanding on our 2021 Senior Notes, and repurchased $395.0 million principal outstanding of our 2023 Senior Notes and $85.0 million principal outstanding of our 2022 Senior Notes. As a result, premiums totaling $20.4 million were paid in connection with these redemptions and repurchases. Additionally, we issued our 2027 Senior Notes for net proceeds of $492.1 million. There were no such debt transactions during the nine months ended September 30, 2019.

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 September 30, 2019, we had a $129.0 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 September 30, 2019, our outstanding principal amount of fixed-rate debt totaled $2.6 billion and our floating-rate debt outstanding totaled $129.0 million. 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, 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 that are typically beyond our control. 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. Based on our production for the nine months ended September 30, 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 $83.6 million, $19.4 million, and $10.6 million, respectively. If commodity prices had been 10 percent lower, our net derivative settlements for the nine months ended September 30, 2019, would have offset the declines in oil, gas, and NGL production revenue by approximately $53.0 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 September 30, 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 derivative positions for these products by approximately $92.2 million, $8.1 million, and $5.1 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 nine months ended September 30, 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 believe 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 September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands)			
Net income (loss) (GAAP)	**$ 42,234**	**$ (135,923)**	**$ (84,946)**	**$ 198,675**
Interest expense	40,584	38,111	118,191	122,850
Income tax expense (benefit)	16,111	(36,748)	(16,337)	61,342
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	211,125	201,105	595,201	483,343
Exploration [(1)]	10,341	11,490	30,070	36,768
Abandonment and impairment of unproved properties	6,337	9,055	25,092	26,615
Stock-based compensation expense	6,766	7,004	18,758	17,680
Net derivative (gain) loss	(100,889)	178,026	(3,463)	249,304
Derivative settlement gain (loss)	24,722	(40,718)	23,843	(101,911)
Net gain on divestiture activity	—	(786)	(323)	(425,656)
Loss on extinguishment of debt	—	26,722	—	26,722
Other, net	434	(1,265)	1,129	(4,519)
Adjusted EBITDAX (non-GAAP)	**257,765**	**256,073**	**707,215**	**691,213**
Interest expense	(40,584)	(38,111)	(118,191)	(122,850)
Income tax (expense) benefit	(16,111)	36,748	16,337	(61,342)
Exploration [(1)]	(10,341)	(11,490)	(30,070)	(36,768)
Amortization of debt discount and deferred financing costs	3,921	3,792	11,554	11,542
Deferred income taxes	19,617	(36,833)	(13,620)	60,672
Other, net	(1,438)	1,483	(3,420)	2,435
Net change in working capital	(9,673)	17,997	11,781	(3,725)
Net cash provided by operating activities (GAAP)	**$ 203,156**	**$ 229,659**	**$ 581,586**	**$ 541,177**

(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 to identify 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 *Interest Rate Risk* and *Commodity Price 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 *Interest Rate Risk* and *Commodity Price 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, but 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 thethird 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 three months ended September 30, 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)
07/01/2019 - 07/31/2019	130,992	$ 12.52	—	3,072,184
08/01/2019 - 08/31/2019	—	$ —	—	3,072,184
09/01/2019 - 09/30/2019	—	$ —	—	3,072,184
Total:	130,992	$ 12.52	—	3,072,184

(1) All shares purchased by us in the third 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)
10.2†	Performance Share Unit Award Agreement as of July 1, 2019
10.3	Second Amendment to Sixth Amended and Restated Credit Agreement, dated September 19, 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 September 24, 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	Inline XBRL Instance Document - The instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH*	Inline XBRL Schema Document
101.CAL*	Inline XBRL Calculation Linkbase Document
101.LAB*	Inline XBRL Label Linkbase Document
101.PRE*	Inline XBRL Presentation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101.INS)

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*	Filed with this report.
**	Furnished with this report.
†	Exhibit constitutes a management contract or compensatory plan or agreement.

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
November 1, 2019	By:	/s/ JAVAN D. OTTOSON
		Javan D. Ottoson President and Chief Executive Officer (Principal Executive Officer)
November 1, 2019	By:	/s/ A. WADE PURSELL
		A. Wade Pursell Executive Vice President and Chief Financial Officer (Principal Financial Officer)
November 1, 2019	By:	/s/ PATRICK A. LYTLE
		Patrick A. Lytle Controller and Assistant Secretary (Principal Accounting Officer)

EXHIBIT 31.1

CERTIFICATION

I, Javan D. Ottoson, certify that:

1. I have reviewed this quarterly report on Form 10-Q of SM Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 1, 2019

/s/ JAVAN D. OTTOSON
Javan D. Ottoson
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, A. Wade Pursell, certify that:

1. I have reviewed this quarterly report on Form 10-Q of SM Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 1, 2019

/s/ A. WADE PURSELL
A. Wade Pursell
Executive Vice President and Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION

PURSUANT TO

18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of SM Energy Company (the "Company") for the quarterly period ended September 30, 2019, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Javan D. Ottoson, as President and Chief Executive Officer of the Company, and A. Wade Pursell, as Executive Vice President and Chief Financial Officer of the Company, each hereby certifies, pursuant to and solely for the purpose of 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to the best of his knowledge and belief, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ JAVAN D. OTTOSON

Javan D. Ottoson
President and Chief Executive Officer
November 1, 2019

/s/ A. WADE PURSELL

A. Wade Pursell
Executive Vice President and Chief Financial Officer
November 1, 2019