SM Energy Co
Form 10-Q
November 02, 2018

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

For the quarterly period ended September 30, 2018

OR

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

For the transition period from ___________ to ___________

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

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

(303) 861-8140
(Registrant's telephone number, including area code)
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o
Indicate by check mark whether the registrant has submitted electronically, every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes þ No o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised

financial accounting standards provided pursuant to
Section 13(a) of the Exchange Act. o

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

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, 2018, the registrant had 112,142,751 shares of common stock, $0.01 par value, outstanding.

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

	September 30, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 176,806	$ 313,943
Accounts receivable	179,347	160,154
Derivative assets	81,163	64,266
Prepaid expenses and other	15,826	10,752
Total current assets	453,142	549,115
Property and equipment (successful efforts method):		
Proved oil and gas properties	6,686,922	6,139,379
Accumulated depletion, depreciation, and amortization	(3,240,124)	(3,171,575)
Unproved oil and gas properties	1,892,557	2,047,203
Wells in progress	328,808	321,347
Properties held for sale, net	5,040	111,700
Other property and equipment, net of accumulated depreciation of $56,067 and $49,985, respectively	102,984	106,738
Total property and equipment, net	5,776,187	5,554,792
Noncurrent assets:		
Derivative assets	8,853	40,362
Other noncurrent assets	35,539	32,507
Total noncurrent assets	44,392	72,869
Total assets	$ 6,273,721	$ 6,176,776
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 429,698	$ 386,630
Derivative liabilities	304,159	172,582
Total current liabilities	733,857	559,212
Noncurrent liabilities:		
Revolving credit facility	—	—
Senior Notes, net of unamortized deferred financing costs	2,447,290	2,769,663
Senior Convertible Notes, net of unamortized discount and deferred financing costs	145,662	139,107
Asset retirement obligations	88,149	103,026
Asset retirement obligations associated with oil and gas properties held for sale	—	11,369
Deferred income taxes	140,949	79,989
Derivative liabilities	72,605	71,402
Other noncurrent liabilities	45,810	48,400
Total noncurrent liabilities	2,940,465	3,222,956
Commitments and contingencies (note 6)		
Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 112,137,582 and 111,687,016 shares, respectively	1,121	1,117
Additional paid-in capital	1,758,205	1,741,623

Retained earnings [1]	856,111	665,657
Accumulated other comprehensive loss [1]	(16,038)	(13,789)
Total stockholders' equity	2,599,399	2,394,608
Total liabilities and stockholders' equity	$ 6,273,721	$ 6,176,776

[1] The Company reclassified $3.0 million of tax effects stranded in accumulated other comprehensive loss to retained earnings as of January 1, 2018. Please refer to Note 1 - Summary of Significant Accounting Policies for further detail.
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,	
	2018	2017 (as adjusted)	2018	2017 (as adjusted)
Operating revenues and other income:				
Oil, gas, and NGL production revenue	$458,382	$294,459	$1,243,826	$912,596
Net gain (loss) on divestiture activity	786	(1,895)	425,656	(131,565)
Other operating revenues	201	2,815	3,398	7,807
Total operating revenues and other income	459,369	295,379	1,672,880	788,838
Operating expenses:				
Oil, gas, and NGL production expense	127,638	122,651	365,917	385,073
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	201,105	134,599	483,343	425,643
Exploration	13,061	14,119	40,844	38,919
Abandonment and impairment of unproved properties	9,055	—	26,615	157
General and administrative	29,464	27,564	86,066	84,618
Net derivative (gain) loss	178,026	80,599	249,304	(89,364)
Other operating expenses, net	9,664	999	14,219	10,109
Total operating expenses	568,013	380,531	1,266,308	855,155
Income (loss) from operations	(108,644)	(85,152)	406,572	(66,317)
Interest expense	(38,111)	(44,091)	(122,850)	(135,639)
Loss on extinguishment of debt	(26,722)	—	(26,722)	(35)
Other non-operating income, net	806	861	3,017	1,581
Income (loss) before income taxes	(172,671)	(128,382)	260,017	(200,410)
Income tax (expense) benefit	36,748	39,270	(61,342)	65,825
Net income (loss)	$(135,923)	$(89,112)	$198,675	$(134,585)
Basic weighted-average common shares outstanding	112,107	111,575	111,836	111,366
Diluted weighted-average common shares outstanding	112,107	111,575	113,600	111,366
Basic net income (loss) per common share	$(1.21)	$(0.80)	$1.78	$(1.21)
Diluted net income (loss) per common share	$(1.21)	$(0.80)	$1.75	$(1.21)
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.

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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,	
	2018	2017	2018	2017
Net income (loss)	$(135,923)	$(89,112)	$198,675	$(134,585)
Other comprehensive income (loss), net of tax:				
Pension liability adjustment	263	(208)	721	(651)
Total other comprehensive income (loss), net of tax	263	(208)	721	(651)
Total comprehensive income (loss)	$(135,660)	$(89,320)	$199,396	$(135,236)

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, 2018	2017 (as adjusted)
Cash flows from operating activities:		
Net income (loss)	$198,675	$(134,585)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Net (gain) loss on divestiture activity	(425,656)	131,565
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	483,343	425,643
Abandonment and impairment of unproved properties	26,615	157
Stock-based compensation expense	17,680	16,160
Net derivative (gain) loss	249,304	(89,364)
Derivative settlement gain (loss)	(101,911)	29,402
Amortization of debt discount and deferred financing costs	11,542	12,478
Loss on extinguishment of debt	26,722	35
Deferred income taxes	60,672	(67,458)
Other, net	(2,084)	6,424
Net change in working capital	(3,725)	40,153
Net cash provided by operating activities	541,177	370,610
Cash flows from investing activities:		
Net proceeds from the sale of oil and gas properties	743,199	778,365
Capital expenditures	(1,032,588)	(624,969)
Acquisition of proved and unproved oil and gas properties	(24,571)	(87,389)
Net cash provided by (used in) investing activities	(313,960)	66,007
Cash flows from financing activities:		
Proceeds from credit facility	—	406,000
Repayment of credit facility	—	(406,000)
Debt issuance costs related to credit facility	(4,771)	—
Net proceeds from Senior Notes	492,079	—
Cash paid to repurchase Senior Notes, including premium	(844,984)	(2,357)
Net proceeds from sale of common stock	1,881	1,738
Dividends paid	(5,584)	(5,563)
Other, net	(2,975)	(1,392)
Net cash used in financing activities	(364,354)	(7,574)
Net change in cash, cash equivalents, and restricted cash [(1)]	(137,137)	429,043
Cash, cash equivalents, and restricted cash at beginning of period [(1)]	313,943	12,372
Cash, cash equivalents, and restricted cash at end of period [(1)]	$176,806	$441,415

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(1) Refer to Note 1 - Summary of Significant Accounting Policies for a reconciliation of cash, cash equivalents, and restricted cash reported to the amounts reported within the accompanying unaudited condensed consolidated balance sheets ("accompanying balance sheets").

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

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SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED) (Continued)
(in thousands)
Supplemental schedule of additional cash flow information and non-cash activities:

	For the Nine Months Ended September 30,	
	2018	2017 (as adjusted)
Operating activities:		
Cash paid for interest, net of capitalized interest	$(124,435)	$(124,443)
Net cash paid for income taxes	$(9,085)	$(2,800)
Investing activities:		
Changes in capital expenditure accruals and other	$19,811	$2,788
Supplemental non-cash investing activities:		
Carrying value of properties exchanged	$95,121	$283,651
Supplemental non-cash financing activities:		
Non-cash loss on extinguishment of debt, net	$6,334	$22
Dividends declared, but not paid	$5,607	$5,581

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

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

Note 1 - Summary of Significant Accounting Policies

Description of Operations

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

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements include the accounts of SM Energy 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 SM Energy's Annual Report on Form 10-K for the year ended December 31, 2017 (the "2017 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, 2018, and through the filing of this report. Certain prior period amounts have been reclassified to conform to the current presentation on the accompanying unaudited condensed consolidated financial statements.

Correction of an Immaterial Error

The accompanying unaudited condensed consolidated financial statements for the three and nine months ended September 30, 2018, include a non-cash adjustment that relates to prior years. For the three and nine months ended September 30, 2018, the depletion, depreciation, amortization, and asset retirement obligation liability accretion expense line item on the accompanying unaudited condensed consolidated statements of operations ("accompanying statements of operations") includes $11.8 million of additional expense that should have been recognized in prior years. This non-cash adjustment, net of tax, resulted in reported net income for the nine months ended September 30, 2018, to be understated by $9.0 million, and reported net loss for the three months ended September 30, 2018, to be overstated by $9.0 million. This non-cash adjustment is not deemed material with respect to any prior period reported, the third quarter of 2018, or the anticipated results for fiscal year 2018.

Significant Accounting Policies

The significant accounting policies followed by the Company are set forth in Note 1 - Summary of Significant Accounting Policies in the 2017 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 2017 Form 10-K.

Recently Issued Accounting Standards

Effective December 31, 2017, the Company early adopted, on a retrospective basis, Financial Accounting Standards Board ("FASB") Accounting Standards Update ("ASU") No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments ("ASU 2016-15") and FASB ASU No. 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash ("ASU 2016-18"). ASU 2016-15 is intended to reduce diversity in practice in how certain transactions are classified in the statement of cash flows and ASU 2016-18 is intended to clarify guidance on the classification and presentation of restricted cash and restricted cash equivalents in the statement of cash flows. The Company did not have restricted cash reported within the accompanying balance sheets as of September 30, 2018, or December 31, 2017. Please refer to Note 1 - Summary of Significant Accounting Policies in the 2017 Form 10-K for more information.

The accompanying unaudited condensed consolidated statements of cash flows ("accompanying statements of cash flows") line items that were adjusted as a result of the adoption of ASU 2016-15 and ASU 2016-18 for the nine months ended September 30, 2017, are summarized as follows:

	For the Nine Months Ended September 30, 2017	
	As Reported	As Adjusted
	(in thousands)	
Cash flows from operating activities:		
Non-cash (gain) loss on extinguishment of debt, net	$22	N/A
Loss on extinguishment of debt	N/A	$35
Net cash provided by operating activities	$370,597	$370,610
Cash flows from investing activities:		
Acquisition deposit held in escrow	$3,000	N/A
Net cash provided by (used in) investing activities	$69,007	$66,007
Cash flows from financing activities:		
Cash paid for extinguishment of debt [1]	N/A	$(13)
Net cash used in financing activities	$(7,561)	$(7,574)
Net change in cash and cash equivalents	$432,043	N/A
Net change in cash, cash equivalents, and restricted cash	N/A	$429,043
Cash and cash equivalents at beginning of period	$9,372	N/A
Cash, cash equivalents, and restricted cash at beginning of period	N/A	$12,372
Cash and cash equivalents at end of period	$441,415	N/A
Cash, cash equivalents, and restricted cash at end of period	N/A	$441,415

(1) Included as a component within the cash paid to repurchase Senior Notes, including premium line item on the accompanying statements of cash flows.

Effective January 1, 2018, the Company adopted FASB ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606) and all related ASUs ("ASU 2014-09"). Under the new guidance, revenue is recognized when a customer obtains control of promised goods or services in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. The Company adopted ASU 2014-09 using the modified retrospective transition method, which was applied to all active contracts as of the effective date. The adoption of ASU 2014-09 did not result in a change to current or prior period results nor did it result in a material change to the Company's business processes, systems, or controls. However, upon adopting ASU 2014-09, the Company expanded its disclosures to comply with the expanded disclosure requirements of ASU 2014-09. Please refer to Note 2 - Revenue from Contracts with Customers for additional discussion.

Effective January 1, 2018, the Company adopted FASB ASU No. 2017-07, Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost ("ASU 2017-07"). ASU 2017-07 requires presentation of service cost in the same line item(s) as other compensation costs arising from services rendered by employees during the period and presentation of the remaining components of net benefit cost in a separate line item, outside of operating items, which the Company adopted with retrospective application. In addition, only the service component of the net benefit cost is eligible for capitalization, which the Company adopted with prospective application. Please refer to Note 1 - Summary of Significant Accounting Policies in the 2017 Form 10-K for more information.

The accompanying statements of operations line items that were adjusted as a result of the adoption of ASU 2017-07 for the three and nine months ended September 30, 2017, are summarized as follows:

	For the Three Months Ended September 30, 2017		For the Nine Months Ended September 30, 2017	
	As Reported	As Adjusted	As Reported	As Adjusted
	(in thousands)			
Operating expenses:				
Exploration	$14,243	$14,119	$39,293	$38,919
General and administrative	$27,880	$27,564	$85,564	$84,618
Total operating expenses	$380,971	$380,531	$856,475	$855,155
Income (loss) from operations	$(85,592)	$(85,152)	$(67,637)	$(66,317)
Other non-operating income, net	$1,301	$861	$2,901	$1,581

Effective January 1, 2018, the Company early adopted FASB ASU No. 2018-02, Income Statement-Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income (“ASU 2018-02”) by applying the changes in the period of adoption. ASU 2018-02 permits entities to reclassify tax effects stranded in accumulated other comprehensive income (loss) to retained earnings as a result of the enactment into law on December 22, 2017, of H.R.1, formally the Tax Cuts and Jobs Act (the “2017 Tax Act”). As a result of adopting ASU 2018-02, the Company reclassified $3.0 million of tax effects stranded in accumulated other comprehensive loss to retained earnings as of January 1, 2018. The Company’s policy for releasing income tax effects within accumulated other comprehensive loss is an incremental, unit-of-account approach.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) (“ASU 2016-02”), which requires recognition of right-of-use assets and lease payment liabilities on the balance sheet by lessees for virtually all leases currently classified as operating leases. 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. The Company has established a cross-functional project team and is leveraging external consultants to evaluate the impacts of ASU 2016-02, which includes an analysis of non-cancelable leases, drilling rig contracts, certain midstream agreements, and other existing arrangements that may contain a lease component. The Company has substantially completed the process of reviewing and determining the contracts to which the new guidance applies. Further, the Company is also evaluating policies, internal controls, and processes that will be necessary to support the additional accounting and disclosure requirements. The Company will continue to monitor guidance issued by the FASB to clarify ASU 2016-02 and certain industry implementation issues. The Company is in the final stages of implementing a lease administration system that will support the on-going maintenance and accounting for leases after adoption. Policy elections allowed under ASU 2016-02 that the Company anticipates making as part of its adoption include (a) not recognizing lease assets or liabilities when lease terms are less than twelve months, and (b) for agreements that contain both lease and non-lease components, combining these components together and accounting for them as a single lease. Other policy elections allowed for under ASU 2016-02 are still being evaluated. The Company will adopt ASU 2016-02 on January 1, 2019, using the modified retrospective approach. Adoption of this guidance is expected to result in an increase in right-of-use assets and related liabilities on the Company’s consolidated balance sheets; however, the full impact to the Company’s financial statements and related disclosures is still being evaluated.

In January 2018, the FASB issued ASU No. 2018-01, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842 (“ASU 2018-01”), which provides an optional transitional practical expedient that allows entities to exclude from evaluation land easements that existed or expired before adoption of ASU 2016-02. Companies that elect this practical expedient will need to evaluate new or modified land easements after adopting ASU 2016-02. If this practical expedient is not elected, companies will need to evaluate all existing or expired land easements as part of the overall adoption of ASU 2016-02. The Company expects to elect to use this practical expedient as outlined in ASU 2018-01 and will adopt ASU 2018-01 at the same time it adopts ASU 2016-02.

In July 2018, the FASB issued ASU No. 2018-11, Leases (Topic 842): Targeted Improvements (“ASU 2018-11”). ASU 2018-11 provides an additional transition method for adopting ASU 2016-02, as well as provides lessors with a practical expedient when applying ASU 2016-02 to certain leases. The Company anticipates making a policy election in connection with adopting ASU 2018-11, which will eliminate the need for adjusting prior period comparable financial statements prepared under current lease accounting guidance. The Company will adopt ASU 2018-11 at the same time it adopts ASU 2016-02.

In August 2018, the FASB issued ASU No. 2018-14, Compensation-Retirement Benefits-Defined Benefit Plans-General (Subtopic 715-20): Disclosure Framework-Changes to the Disclosure Requirements for Defined Benefit Plans (“ASU 2018-14”). ASU 2018-14 provides updated disclosure requirements related to retirement benefits and defined pension plans with the purpose of improving the effectiveness of disclosures with regard to such topics. The guidance is to be applied using a retrospective method and is effective for fiscal years ending after December 15, 2020, with early adoption permitted. The Company expects to early adopt ASU

2018-14 on December 31, 2018. The Company is evaluating the impact of this guidance on its consolidated financial statements, but does not expect the impact to be material.

In August 2018, the FASB issued ASU No. 2018-15, Intangibles-Goodwill and Other-Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract ("ASU 2018-15"). ASU 2018-15 aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The Company expects to adopt ASU 2018-15 on January 1, 2020, with prospective application. The Company is evaluating the impact of ASU 2018-15 on its consolidated financial statements.

Other than as disclosed above or in the 2017 Form 10-K, there are no other ASUs applicable to the Company that would have a material effect on the Company's consolidated financial statements and related disclosures that have been issued but not yet adopted by the Company as of September 30, 2018, and through the filing of this report.

Note 2 - Revenue from Contracts with Customers

The Company recognizes its share of revenue from the sale of produced oil, gas, and NGLs in its Permian, South Texas & Gulf Coast, and Rocky Mountain regions. During the first quarter of 2018, the Company entered into two definitive agreements to sell all of its producing properties in its Rocky Mountain region. One transaction closed in the first quarter of 2018, and the second transaction closed in the second quarter of 2018. As a result of these divestitures, there has been no production revenue from the Rocky Mountain region after the second quarter of 2018. Please refer to Note 3 - Divestitures, Assets Held for Sale, and Acquisitions for additional detail. Oil, gas, and NGL production revenue presented within the accompanying statements of operations is reflective of the revenue generated from contracts with customers.

The tables below present the disaggregation of 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, 2018, and 2017:

	Permian		South Texas & Gulf Coast		Rocky Mountain		Total	
	Three Months Ended September 30,		Three Months Ended September 30,		Three Months Ended September 30,		Three Months Ended September 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
	(in thousands)							
Oil, gas, and NGL production revenue:								
Oil production revenue	$270,086	$107,248	$17,436	$13,726	$—	$33,229	$287,522	$154,203
Gas production revenue	40,364	16,034	56,446	69,069	—	1,162	96,810	86,265
NGL production revenue	563	151	73,487	53,023	—	817	74,050	53,991
Total	$311,013	$123,433	$147,369	$135,818	$—	$35,208	$458,382	$294,459
Relative percentage	68 %	42 %	32 %	46 %	—%	12 %	100 %	100 %

Note: Amounts may not calculate due to rounding.

	Permian		South Texas & Gulf Coast		Rocky Mountain		Total	
	Nine Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
	(in thousands)							
Oil, gas, and NGL production revenue:								
	$703,516	$267,301	$56,365	$65,662	$54,851	$117,738	$814,732	$450,701

Oil production revenue								
Gas production revenue	96,974	40,280	161,414	245,030	1,595	3,846	259,983	289,156
NGL production revenue	816	405	167,505	169,938	790	2,396	169,111	172,739
Total	$801,306	$307,986	$385,284	$480,630	$57,236	$123,980	$1,243,826	$912,596
Relative percentage	64 %	34 %	31 %	53 %	5 %	13 %	100 %	100 %

Note: Amounts may not calculate due to rounding.

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The Company recognizes oil, gas, and NGL production revenue at the point in time when control of the product transfers to the customer, which differs depending on the contractual terms of each of the Company's arrangements. Transfer of control drives the presentation of transportation, gathering, processing, and other post-production expenses ("fees and other deductions") within the accompanying statements of operations. Fees and other deductions incurred prior to control transfer are recorded within the oil, gas, and NGL production expense line item on the accompanying statements of operations, while fees and other deductions incurred subsequent to control transfer are recorded as a reduction of oil, gas, and NGL production revenue. The Company has four general categories under which oil, gas, and NGL production revenue is generated. Each of the Company's operating regions generate production revenue from a combination of some or all of the four different contract types summarized below:

1) The Company sells oil production at or near the wellhead and receives an agreed-upon index price from the purchaser, net of basis, quality, and transportation differentials. Under this arrangement, control transfers at or near the wellhead.
2) The Company sells unprocessed gas to a midstream processor at the wellhead or inlet of the midstream processing facility. The midstream processor gathers and processes the raw gas stream and remits proceeds to the Company from the ultimate sale of the processed NGLs and residue gas to third parties. In such arrangements, the midstream processor obtains control of the product at the wellhead or inlet of the facility and is considered the customer. Proceeds received for unprocessed gas under these arrangements are reflected as gas production revenue and are recorded net of transportation and processing fees incurred by the midstream processor after control has transferred.
3) The Company has certain processing arrangements that include the delivery of unprocessed gas to the inlet of a midstream processor's facility for processing. Upon completion of processing, the midstream processor purchases the NGLs and redelivers residue gas back to the Company in-kind. For the NGLs extracted during processing, the midstream processor remits payment to the Company based on the proceeds it generates from selling the NGLs to other third parties. For the residue gas taken in-kind, the Company has separate sales contracts where control transfers at points downstream of the processing facility. Given the structure of these arrangements and where control transfers, the Company separately recognizes gathering, transportation, and processing fees incurred prior to control transfer. These fees are recorded within the oil, gas, and NGL production expense line item on the accompanying statements of operations.
4) The Company has certain midstream processing arrangements where unprocessed gas is delivered to the inlet of the midstream processor's facility for processing. Upon completion of processing, the midstream processor purchases the processed NGLs and residue gas and remits the proceeds to the Company from the sale of the products to third-party customers. In these arrangements, control transfers at the tailgate of the midstream processing facility for both products. Given the structure of these arrangements and where control transfers, the Company separately recognizes gathering, transportation, and processing fees incurred prior to control transfer. These fees are recorded within the oil, gas, and NGL production expense line item on the accompanying statements of operations.

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

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

Revenue is recorded in the month when contractual performance obligations are satisfied. However, settlement statements from the purchasers of hydrocarbons and the related cash consideration are generally 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 accounts receivable 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, 2018, and December 31, 2017, were $120.3 million and $96.6 million, respectively. To estimate accounts receivable from contracts with customers, the Company uses knowledge of its properties, historical performance, contractual arrangements, 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 for the three and nine months ended September 30, 2018, that related to performance obligations satisfied in prior reporting periods was immaterial.

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

Divestitures

On March 26, 2018, the Company divested approximately 112,000 net acres of its Powder River Basin assets (the “PRB Divestiture”) for total cash received at closing, net of costs (referred to throughout this report as “net divestiture proceeds”), of $490.8 million, subject to final purchase price adjustments, and recorded an estimated net gain of $410.6 million for the nine months ended September 30, 2018. These assets were recorded as properties held for sale as of December 31, 2017.

During the second quarter of 2018, the Company completed the divestitures of its remaining assets in the Williston Basin 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 received at closing 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. A portion of these assets were recorded as properties held for sale as of December 31, 2017.

The following table presents income (loss) before income taxes from the Divide County, North Dakota assets sold for the three and nine months ended September 30, 2018, and 2017. The Divide County Divestiture was considered a disposal of a significant asset group.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)			
Income (loss) before income taxes [1]	$—	$7,593	$(28,975)	$(478,572)

[1] Income (loss) before income taxes reflects oil, gas, and NGL production revenue, less oil, gas, and NGL production expense, depletion, depreciation, amortization, and asset retirement obligation liability accretion expense, impairment expense, and net loss on divestiture activity.

On March 10, 2017, the Company closed the divestiture of its outside-operated Eagle Ford shale assets, including its ownership interest in related midstream assets, for final net divestiture proceeds of $744.1 million. The Company recorded a final net gain of $396.8 million related to these divested assets for the year ended December 31, 2017. Additionally, during the first nine months of 2017, the Company divested certain non-core properties in its Rocky Mountain and Permian regions for net divestiture proceeds of $31.0 million.

Properties Held for Sale

Assets are classified as held for sale when the Company commits to a plan to sell the assets and it is probable the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to identify and expense any excess of carrying value over fair value less estimated costs to sell. When assets no longer meet the criteria of assets held for sale, they are measured at the lower of the carrying value of the assets before being classified as held for sale, adjusted for any depletion, depreciation, and amortization expense that would have been recognized, or the fair value at the date they are reclassified to assets held for use. Any gain or loss recognized on assets held for sale or on assets held for sale that are subsequently reclassified to assets held for use is reflected in the net gain (loss) on divestiture activity line item on the accompanying statements of operations. As of September 30, 2018, and December 31, 2017, there were $5.0 million and $111.7 million, respectively, of assets held for sale presented on the accompanying balance sheets. The balance as of December 31, 2017, consisted primarily of approximately 112,000 net acres in the Powder River Basin, and is presented net of accumulated depletion, depreciation, and amortization expense. As discussed above, the Company sold these assets in the first quarter of 2018.

During the nine months ended September 30, 2017, the Company recorded a $526.5 million write-down on its Divide County, North Dakota, assets previously held for sale. As discussed above, the Company sold these assets in the

second quarter of 2018.
Acquisitions
During the third quarter of 2018, the Company completed two non-monetary acreage trades of primarily unproved properties located in Howard and Martin Counties, Texas, resulting in the Company receiving 2,658 net acres in exchange for 2,654 net acres, with $95.1 million of carrying value attributed to the properties surrendered by the Company. These trades were recorded at carryover basis with no gain or loss recognized. During the second quarter of 2018, the Company acquired 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.

During the nine months ended September 30, 2017, the Company acquired 3,400 net acres of primarily unproved properties in Howard and Martin Counties, Texas, in multiple transactions for a total of $72.2 million of cash consideration. Each of these transactions was accounted for as an asset acquisition. Also, during the nine months ended September 30, 2017, the Company completed several non-monetary acreage trades of primarily unproved properties in Howard and Martin Counties, Texas, resulting in the Company receiving 7,425 net acres in exchange for 6,725 net acres, with $283.7 million of carrying value attributed to the properties surrendered by the Company. These trades were recorded at carryover basis with no gain or loss recognized.

Note 4 - Income Taxes

The income tax (expense) benefit recorded for the three and nine months ended September 30, 2018, and 2017, differs from the amounts that would be provided by applying the statutory United States federal income tax rate to income or loss before income taxes primarily due to the effect of state income taxes, excess tax benefits and deficiencies from share-based payment awards, changes in valuation allowances, and accumulated impacts of other smaller permanent differences. The quarterly rate can also be affected by the proportional impacts of forecasted net income or loss as of each period end presented.

The provision for income taxes for the three and nine months ended September 30, 2018, and 2017, consisted of the following:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)			
Current portion of income tax (expense) benefit:				
Federal	$—	$2,832	$—	$—
State	(85)	(230)	(670)	(1,633)
Deferred portion of income tax (expense) benefit	36,833	36,668	(60,672)	67,458
Income tax (expense) benefit	$36,748	$39,270	$(61,342)	$65,825
Effective tax rate	21.3 %	30.6 %	23.6 %	32.8 %

The enactment of the 2017 Tax Act on December 22, 2017, reduced the Company’s federal tax rate for 2018 and future years from 35 percent to 21 percent. Although the Company believes it has properly analyzed the tax accounting impacts of the 2017 Tax Act, it will continue to monitor provisions with discrete rate impacts, such as the limitation on executive compensation for subsequent events and guidance within the one-year measurement period. There are no new estimates or finalized income tax items associated with the 2017 Tax Act included in income tax (expense) benefit for the three and nine months ended September 30, 2018.

On a year-to-date basis, a change in the Company’s effective tax rate between reporting periods will generally reflect differences in its estimated highest marginal state tax rate due to changes in the composition of income or loss from Company activities, including divestitures, among multiple state tax jurisdictions. Excess tax benefits and deficiencies from share-based payment awards impact the Company’s effective tax rate between periods. Cumulative effects of state tax rate changes are reflected in the period legislation is enacted.

In 2017, the Company re-evaluated various factors affecting deferred tax assets related to net operating losses and tax credits and determined utilization would be appropriate. The change in the current portion of income tax (expense) benefit between periods reflects the effect of this determination.

Subsequent to the quarter ended September 30, 2018, the Company received its anticipated $5.9 million cash refund for a net operating loss carryback claim. During the third quarter of 2018, the Internal Revenue Service finalized its examination of the net operating loss claims back to tax years 2003 through 2005 with no changes to claimed amounts. The Company is generally no longer subject to United States federal or state income tax examinations by tax authorities for years before 2015.

Note 5 - Long-Term Debt
Credit Agreement
On September 28, 2018, the Company and its lenders entered into the Sixth Amended and Restated Credit Agreement (the “Credit Agreement”). The Credit Agreement, which replaced the Company’s Fifth Amended and Restated Credit Agreement, provides for a senior secured revolving credit facility with a maximum loan amount of $2.5 billion, an initial borrowing base of $1.5 billion, and initial aggregate lender commitments totaling $1.0 billion. The borrowing base is subject to regular, semi-annual redetermination, and considers the value of both the Company’s (a) proved oil and gas properties reflected in the Company’s most recent reserve report; and (b) commodity derivative contracts, each as determined by the Company’s lender group. The next scheduled redetermination date is April 1, 2019.
The Credit Agreement is scheduled to mature on the earlier of September 28, 2023, (the “Scheduled Maturity Date”), and August 16, 2022, to the extent that, on or before such date, the Company’s outstanding 6.125% Senior Notes due 2022 (the “2022 Senior Notes”) are not repurchased, redeemed, or refinanced to have a maturity date at least 91 days after the Scheduled Maturity Date unless, on August 16, 2022, both (i) the aggregate outstanding principal amount of the 2022 Senior Notes is not more than $100.0 million and (ii) after giving pro forma effect to the repayment in full at maturity of the 2022 Senior Notes then outstanding, the aggregate amount of unrestricted cash and certain types of unrestricted investments held by the Company and its Consolidated Restricted Subsidiaries plus the amount of unused availability under the Credit Agreement is at least $300.0 million.
The Company must comply with certain financial and non-financial covenants under the terms of the Credit Agreement, including covenants limiting dividend payments and requiring the Company to maintain certain financial ratios, as defined by the Credit Agreement. The financial covenants under the Credit Agreement require that the Company’s (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 ending December 31, 2018, through and including the fiscal quarter ending December 31, 2019, and for each quarter ending thereafter, the ratio cannot be greater than 4.00 to 1.00; and (b) adjusted current ratio cannot be less than 1.0 to 1.0 as of the last day of any fiscal quarter. The Company was in compliance with all financial and non-financial covenants as of September 30, 2018, and through the filing of this report.
Interest and commitment fees are accrued based on a borrowing base utilization grid set forth in the Credit Agreement. Eurodollar loans accrue interest at the London Interbank Offered Rate, plus the applicable margin from the utilization grid, and Alternate Base Rate (“ABR”) 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 borrowing base utilization grid under the Credit Agreement is as follows:

Borrowing Base Utilization Percentage	<25%	≥25% <50%	≥50% <75%	≥75% <90%	≥90%
Eurodollar Loans	1.500%	1.750%	2.000%	2.250%	2.500%
ABR Loans or Swingline Loans	0.500%	0.750%	1.000%	1.250%	1.500%
Commitment Fee Rate	0.375%	0.375%	0.500%	0.500%	0.500%

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, 2018, and September 30, 2018, and under the Fifth Amended and Restated Credit Agreement as of December 31, 2017:

	As of October 24, 2018	As of September 30, 2018	As of December 31, 2017
	(in thousands)		
Credit facility balance (1)	$—	$—	$—
Letters of credit (2)	200	200	200
Available borrowing capacity	999,800	999,800	924,800
Total aggregate lender commitment amount	$1,000,000	$1,000,000	$925,000

(1) Unamortized deferred financing costs attributable to the credit facility are presented as a component of other noncurrent assets on the accompanying balance sheets and totaled $6.7 million and $3.1 million as of September 30, 2018, and December 31, 2017, 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.

Senior Notes

During the third quarter of 2018, the Company redeemed its 6.50% Senior Notes due 2021 ("2021 Senior Notes"), repurchased or redeemed all of its 6.50% Senior Notes due 2023 ("2023 Senior Notes"), repurchased a portion of its 6.125% Senior Notes due 2022 ("2022 Senior Notes"), and issued its 6.625% Senior Notes due 2027 ("2027 Senior Notes"). As of September 30, 2018, the Company's Senior Notes consisted of 6.125% Senior Notes due 2022, 5.0% Senior Notes due 2024, 5.625% Senior Notes due 2025, 6.75% Senior Notes due 2026, and 6.625% Senior Notes due 2027 (collectively referred to as "Senior Notes"). Please refer to the discussion below for additional information. The Senior Notes, net of unamortized deferred financing costs line item on the accompanying balance sheets as of September 30, 2018, and December 31, 2017, consisted of the following:

	As of September 30, 2018			As of December 31, 2017		
	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)					
6.50% Senior Notes due 2021	$—	$ —	$ —	$344,611	$ 2,656	$ 341,955
6.125% Senior Notes due 2022	476,796	4,171	472,625	561,796	5,800	555,996
6.50% Senior Notes due 2023	—	—	—	394,985	3,707	391,278
5.0% Senior Notes due 2024	500,000	4,919	495,081	500,000	5,610	494,390
5.625% Senior Notes due 2025	500,000	6,035	493,965	500,000	6,714	493,286
6.75% Senior Notes due 2026	500,000	6,615	493,385	500,000	7,242	492,758
6.625% Senior Notes due 2027	500,000	7,766	492,234	—	—	—
Total	$2,476,796	$ 29,506	$ 2,447,290	$2,801,392	$ 31,729	$ 2,769,663

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, 2018, 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.

2021 Senior Notes. On June 15, 2018, the Company called for redemption all of the $344.6 million principal outstanding on its 2021 Senior Notes at a redemption price of 102.167% of the principal amount, plus accrued and unpaid interest on the principal amount of the 2021 Senior Notes redeemed ("2021 Senior Notes Redemption"). On July 16, 2018, the Company completed the 2021 Senior Notes Redemption, which resulted in the payment of total cash consideration, including accrued interest, of $355.9 million. The Company recorded a loss on extinguishment of debt of $9.8 million for the quarter ended September 30, 2018. This amount included $7.5 million associated with the premium paid for the 2021 Senior Notes Redemption and $2.3 million of accelerated unamortized deferred financing costs.

Tender Offer and Redemption of the 2023 Senior Notes and 2022 Senior Notes. During the third quarter of 2018, the Company used the proceeds from the issuance of its 2027 Senior Notes, as discussed below, and cash on hand to retire $395.0 million of its 2023 Senior Notes and $85.0 million of its 2022 Senior Notes through a cash tender offer (the "Tender Offer") and subsequent redemption of the remaining 2023 Senior Notes not repurchased as part of the Tender Offer ("2023 Senior Notes Redemption"). Total consideration paid, including accrued interest, for the retirement of the 2023 Senior Notes and the 2022 Senior Notes was $497.8 million. As a result of the Tender Offer and the 2023 Senior Notes Redemption, the Company recorded a loss on extinguishment of debt of $16.9 million for the quarter ended September 30, 2018. This amount included $12.9 million of premiums paid for the Tender Offer and 2023 Senior Notes Redemption and $4.0 million of accelerated unamortized deferred financing costs.

2027 Senior Notes. On August 20, 2018, the Company issued $500.0 million in aggregate principal amount of 6.625% Senior Notes due 2027. The 2027 Senior Notes were issued at par and mature on January 15, 2027. The Company received 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 net proceeds were used to fund the Tender Offer and 2023 Senior Notes Redemption discussed above.

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 2017 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, 2018, 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, 2018, 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 $2.6 million and $2.5 million for the three months ended September 30, 2018, and 2017, respectively, and totaled $7.8 million and $7.4 million for the nine months ended September 30, 2018, and 2017, 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, 2018, and December 31, 2017, consisted of the following:

	As of September 30, 2018	As of December 31, 2017
	(in thousands)	
Principal amount of Senior Convertible Notes	$172,500	$172,500
Unamortized debt discount	(24,316)	(30,183)
Unamortized deferred financing costs	(2,522)	(3,210)
Senior Convertible Notes, net of unamortized discount and deferred financing costs	$145,662	$139,107

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, 2018, and through the filing of this report.

Note 6 - Commitments and Contingencies

Commitments

As of September 30, 2018, the Company had total gathering, processing, transportation throughput, and purchase commitments with various third parties that require delivery of a minimum quantity of 30 MMBbl of oil, 691 Bcf of gas, and 22 MMBbl of produced water through 2027 and a minimum purchase quantity of 7 MMBbl of water by 2022. If the Company fails to deliver or purchase any product, as applicable, the aggregate undiscounted future deficiency payments as of September 30, 2018, would total approximately $342.2 million. This amount does not include any costs that may be incurred for certain contracts where the Company cannot predict with accuracy the amount and timing of any payments that may be incurred for not meeting certain minimum commitments, as such payments are dependent upon the price of oil in effect at the time of settlement. Under certain of the Company's commitment agreements, if the Company is unable to deliver the minimum quantity from its production, it may deliver production acquired from third parties. As of the filing of this report, the Company does not expect to incur any material shortfalls with regard to these commitments.

The Company entered into new and amended drilling rig and completion service contracts during the first nine months of 2018, and subsequent to September 30, 2018. As of the filing of this report, the Company's drilling rig and completion service contract commitments totaled $93.0 million. If all of these contracts were terminated as of the filing of this report, the Company would avoid a portion of the contractual service commitments; however, would be required to pay $42.7 million in early termination fees.

Additionally, as of September 30, 2018, the Company had fixed price contracts with various third parties to purchase electricity through 2027 for total consideration of $29.9 million. As of the filing of this report, the Company expects to meet these purchase commitments.

There were no other material changes in commitments during the first nine months of 2018. Please refer to Note 6 - Commitments and Contingencies in the 2017 Form 10-K for additional discussion of the Company's commitments.

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, 2018, 5.7 million shares of common stock were available for grant under the Company's Equity Incentive Compensation 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 performance criteria over a three-year performance period. PSUs generally vest on the third anniversary of the date of the grant.

PSUs, which the Company has determined to be equity awards, are subject to a combination of market, performance, and service vesting criteria. For awards with market criteria or portions of awards with market criteria, which include annualized Total Shareholder Return ("TSR") for the performance period and the relative performance of the Company's TSR compared with the annualized TSR of the Company's peer group for the performance period, the fair value is measured at the grant date using a stochastic Monte Carlo simulation using geometric Brownian motion.

Compensation expense for market-based PSUs is recognized on a straight-line basis within general and administrative expense and exploration expense over the vesting periods of the respective awards.

For awards that include performance criteria, the grant-date fair value is equal to the Company's stock price on the grant date. Compensation expense for performance-based PSUs will be evaluated on a quarterly basis and may be adjusted as the number of units expected to vest increases or decreases. Currently, the Company uses debt adjusted per share cash flow growth ("DACFG") compared with the DACFG, as calculated by the Company, of its peer group as the performance criteria that is evaluated over the three-year performance period for PSUs.

Total compensation expense recorded for PSUs was $3.0 million and $2.6 million for the three months ended September 30, 2018, and 2017, respectively, and was $7.7 million and $6.8 million for the nine months ended September 30, 2018, and 2017, respectively. As of September 30, 2018, there was $22.9 million of total unrecognized compensation expense related to non-vested PSU awards, which is being amortized through 2021.

A summary of the status and activity of non-vested PSUs for the nine months ended September 30, 2018, is presented in the following table:

	PSUs [(1)]	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	1,533,491	$ 22.97
Granted	572,924	$ 24.45
Vested	(233,102)	$ 44.25
Forfeited	(97,122)	$ 22.89
Non-vested at end of quarter	1,776,191	$ 20.66

(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, 2018, the Company granted 572,924 PSUs to eligible employees with a fair value of $14.0 million ("2018 PSU Grant"). As outlined in the award agreement for the 2018 PSU Grant, performance measurements affecting vesting are based on a combination of relative performance of the Company's annualized TSR compared with the annualized TSR of the Company's peer group over the three-year performance period, and relative performance of the Company's DACFG compared with its peer group DACFG over the three-year performance period. In addition to these performance measures, the award agreement for the 2018 PSU Grant also stipulates that if the Company's absolute TSR is negative over the three-year performance period, the maximum number of shares of common stock that can be issued to settle outstanding PSUs is capped at one times the number of PSUs granted on the award date, regardless of the Company's TSR and DACFG performance relative to its peer group.

During the nine months ended September 30, 2018, PSUs that were granted in 2015 did not satisfy the minimum performance requirements. This resulted in a multiplier of zero times and therefore no shares were issued upon settlement.

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.

Total compensation expense recorded for employee RSUs was $3.0 million and $2.9 million for the three months ended September 30, 2018, and 2017, respectively, and was $8.0 million and $7.5 million for the nine months ended September 30, 2018, and 2017, respectively. As of September 30, 2018, there was $24.1 million of total unrecognized compensation expense related to non-vested RSU awards, which is being amortized through 2021.

A summary of the status and activity of non-vested RSUs granted to employees for the nine months ended September 30, 2018, is presented in the following table:

	RSUs	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	1,244,262	$ 20.25
Granted	583,552	$ 25.77
Vested	(407,529)	$ 24.30
Forfeited	(112,141)	$ 17.93
Non-vested at end of quarter	1,308,144	$ 21.46

During the nine months ended September 30, 2018, the Company granted 583,552 RSUs to eligible employees with a fair value of $15.0 million. During the nine months ended September 30, 2018, the Company settled 407,529 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 plan document and award agreements. As a result, the Company issued 291,745 net shares of common stock upon settlement of the awards.

Director Shares

During the second quarter of 2018, the Company issued 58,572 shares of its common stock to its non-employee directors under the Company’s Equity Incentive Compensation Plan, which fully vest on December 31, 2018. During the second quarter of 2017, the Company issued 71,573 shares of its common stock to its non-employee directors and 8,794 RSUs to a non-employee director. The Company did not issue any director shares during the third quarters of 2018, or 2017.

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. The Company issued 100,249 and 123,678 shares under the ESPP during the nine months ended September 30, 2018, and 2017, respectively. Total proceeds to the Company for the issuance of these shares was $1.9 million and $1.7 million for the nine months ended September 30, 2018, and 2017, 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 (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”). Effective as of January 1, 2016, the Company froze the Pension Plans to new participants, and employees eligible to participate in the Pension Plans prior to them being frozen will continue to earn benefits.

Components of Net Periodic Benefit Cost for the Pension Plans

The following table presents the components of the net periodic benefit cost for the Pension Plans:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)			
Service cost	$1,683	$1,660	$5,048	$4,979
Interest cost	657	673	1,967	2,017
Expected return on plan assets that reduces periodic pension benefit cost	(466)	(561)	(1,397)	(1,683)
Amortization of prior service cost	4	4	13	13
Amortization of net actuarial loss	331	324	995	973
Net periodic benefit cost	$2,209	$2,100	$6,626	$6,299

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. As a result of the adoption of ASU 2017-07, 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, net line item on the accompanying statements of operations. Please refer to Note 1 - Summary of Significant Accounting Policies for further detail.

Contributions

The Company contributed $8.1 million to the Qualified Pension Plan during the nine months ended September 30, 2018.

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 adjusted net income or loss by the diluted weighted-average number of common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist primarily of non-vested RSUs, contingent PSUs, and shares into which the Senior Convertible Notes are convertible, which are measured using the treasury stock method. Shares of the Company's common stock traded at an average closing price below the $40.50 conversion price for the three and nine months ended September 30, 2018, and 2017, and therefore the Senior Convertible Notes had no dilutive impact. Please refer to Note 1 - Summary of Significant Accounting Policies in the 2017 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 presents the weighted-average anti-dilutive securities for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)			
Anti-dilutive	2,433	—	—	78

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,	
	2018	2017	2018	2017
	(in thousands, except per share data)			
Net income (loss)	$(135,923)	$(89,112)	$198,675	$(134,585)
Basic weighted-average common shares outstanding	112,107	111,575	111,836	111,366
Dilutive effect of non-vested RSUs and contingent PSUs	—	—	1,764	—
Dilutive effect of Senior Convertible Notes	—	—	—	—
Diluted weighted-average common shares outstanding	112,107	111,575	113,600	111,366
Basic net income (loss) per common share	$(1.21)	$(0.80)	$1.78	$(1.21)
Diluted net income (loss) per common share	$(1.21)	$(0.80)	$1.75	$(1.21)

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, 2018, all derivative counterparties were members of the Company's Credit Agreement lender group and all contracts were entered into for other-than-trading purposes. The Company's commodity derivative contracts consist of swap and collar arrangements for oil and gas production, and swap arrangements for NGL production. In a typical commodity swap agreement, if the agreed upon published third-party index price ("index price") is lower than the swap fixed price, the Company receives the difference between the index price and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, the Company pays the difference. For collar arrangements, the Company receives the difference between an agreed upon index and the floor price if the index price is below the floor price. The

Company pays the difference between the agreed upon ceiling price and the index price if the index price is above the ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices.

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

As of September 30, 2018, the Company had commodity derivative contracts outstanding as summarized in the tables below:

Oil Swaps

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price
	(MBbl)	(per Bbl)
Fourth quarter 2018	1,894	$ 49.87
2019	3,733	$ 59.80
2020	2,491	$ 65.68
Total	8,118	

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MBbl)	(per Bbl)	(per Bbl)
Fourth quarter 2018	2,222	$ 50.00	$ 58.44
2019	10,055	$ 50.59	$ 63.62
2020	1,165	$ 55.00	$ 66.47
Total	13,442		

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 2018	3,327	$ (1.08)	—	$ —
2019	11,217	$ (3.36)	—	$ —
2020	10,960	$ (1.05)	1,840	$ (8.01)
2021	—	$ —	3,650	$ (7.86)
2022	—	$ —	3,650	$ (7.78)
Total	25,504		9,140	

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(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	Sold IF HSC Volumes	Weighted-Average Contract Price	Purchased IF HSC Volumes	Weighted-Average Contract Price	Net IF HSC Volumes	Weighted-Average Contract Price
	(BBtu)	(per MMBtu)	(BBtu)	(per MMBtu)	(BBtu)	(per MMBtu)
Fourth quarter 2018	28,204	$ 3.27	(7,210)	$ 4.27	20,994	$ 2.92
2019	50,021	$ 3.58	(24,415)	$ 4.34	25,606	$ 2.85
2020	2,942	$ 2.82	—	$ —	2,942	$ 2.82
Total	81,167		(31,625)		49,542	

Gas Collars

Contract Period	IF HSC Volumes	Weighted-Average Floor	Weighted-Average Ceiling

		Price	Price
	(BBtu)	(per MMBtu)	(per MMBtu)
2019	14,242	$ 2.50	$ 2.83

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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 2018	1,146	$ 11.18	671	$ 24.39	102	$ 35.70	76	$ 35.07	208	$ 50.99
2019	3,533	$ 12.31	1,980	$ 28.89	154	$ 35.64	117	$ 35.70	197	$ 50.93
2020	539	$ 11.13	—	$ —	—	$ —	—	$ —	—	$ —
Total	5,218		2,651		256		193		405	

Commodity Derivative Contracts Entered Into Subsequent to September 30, 2018

Subsequent to September 30, 2018, the Company entered into various commodity derivative contracts, as summarized below:

- fixed price NYMEX WTI-ICE Brent basis swap contracts for 2020 for a total of 0.9 MMBbl of oil production at contract prices ranging from ($8.05) per Bbl to ($8.10) per Bbl;
- IF HSC swap contracts for 2019 for a total of 15,769 BBtu of natural gas production at contract prices ranging from $2.80 per MMBtu to $3.42 per MMBtu;
- fixed price OPIS Propane Mont Belvieu Non-TET swap contract for the fourth quarter of 2018 for a total of 0.1 MMBbl of propane production at a contract price of $45.59 per Bbl; and
- fixed price OPIS Propane Mont Belvieu Non-TET swap contracts for 2019 for a total of 0.4 MMBbl of propane production at a contract price of $40.11 per Bbl.

Derivative Assets and Liabilities Fair Value

The Company's commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The fair value of the commodity derivative contracts was a net liability of $286.7 million and $139.4 million as of September 30, 2018, and December 31, 2017, respectively.

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

	As of September 30, 2018	As of December 31, 2017
	(in thousands)	
Derivative assets:		
Current assets	$ 81,163	$ 64,266
Noncurrent assets	8,853	40,362
Total derivative assets	$ 90,016	$ 104,628
Derivative liabilities:		
Current liabilities	$ 304,159	$ 172,582
Noncurrent liabilities	72,605	71,402
Total derivative liabilities	$ 376,764	$ 243,984

Offsetting of Derivative Assets and Liabilities

As of September 30, 2018, and December 31, 2017, 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, 2018	December 31, 2017	September 30, 2018	December 31, 2017
	(in thousands)			
Gross amounts presented in the accompanying balance sheets	$90,016	$ 104,628	$(376,764)	$ (243,984)
Amounts not offset in the accompanying balance sheets	(90,016)	(100,035)	90,016	100,035
Net amounts	$—	$ 4,593	$(286,748)	$ (143,949)

The following table summarizes 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,	
	2018	2017	2018	2017
	(in thousands)			
Derivative settlement (gain) loss:				
Oil contracts	$16,798	$2,472	$61,976	$14,310
Gas contracts	802	(24,088)	(4,851)	(63,345)
NGL contracts	23,118	8,524	44,786	19,633
Total derivative settlement (gain) loss	$40,718	$(13,092)	$101,911	$(29,402)
Net derivative (gain) loss:				
Oil contracts	$110,413	$45,874	$146,781	$(41,910)
Gas contracts	4,309	(6,068)	21,299	(56,574)
NGL contracts	63,304	40,793	81,224	9,120
Total net derivative (gain) loss	$178,026	$80,599	$249,304	$(89,364)

Credit Related Contingent Features

As of September 30, 2018, 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, 2018:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives [1]	$ —	$ 90,016	$ —
Liabilities:			
Derivatives [1]	$ —	$ 376,764	$ —

[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, 2017:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives [1]	$ —	$ 104,628	$ —
Liabilities:			
Derivatives [1]	$ —	$ 243,984	$ —

[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 2017 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 the carrying costs may not be recoverable. The Company uses Level 3 inputs and the income valuation technique, which converts future cash flows to a single present value amount, to measure the fair value of proved properties through an application of discount rates and price forecasts representative of the current operating environment, as selected by the Company's management. There were no material impairments of proved properties during the three and nine months ended September 30, 2018, or 2017.

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. Lease acquisition costs that are not individually significant are aggregated by prospect and the portion of such costs estimated to be nonproductive prior to lease expiration are amortized over the appropriate period. The estimate of what could be nonproductive is based on historical trends or other information, including current drilling plans and the Company's intent to renew leases. To measure the fair value of unproved properties, the Company uses a market approach, which takes into account the following significant assumptions: remaining lease terms, future development plans, risk-weighted potential resource recovery, estimated reserve values, and estimated acreage value based on price(s) received for similar, recent acreage transactions by the Company or other market participants. During the three and nine months ended September 30, 2018, the Company recorded $9.1 million and $26.6 million, respectively, in abandonment and impairment of unproved properties expense related to lease expirations. There were no material abandonments or impairments of unproved properties expenses for the three and nine months ended September 30, 2017.

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 (loss) on divestiture activity line item in the accompanying statements of operations.

There were no material assets held for sale that were recorded at fair value as of September 30, 2018. The Company had $111.7 million of assets classified as held for sale as of December 31, 2017; however, none of these properties were recorded at fair value as the carrying value of these assets was below their estimated fair value less selling costs. For the nine months ended September 30, 2017, the Company recorded a $526.5 million write-down on assets previously held for sale. Please refer to Note 3 - Divestitures, Assets Held for Sale, and Acquisitions above and in the 2017 Form 10-K for more information regarding the Company’s oil and gas properties held for sale.

Please refer to Note 11 - Fair Value Measurements in the 2017 Form 10-K for more information regarding the Company’s approach in determining fair value of its properties, including assets held for sale.

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, 2018, or December 31, 2017, 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, 2018		As of December 31, 2017	
	Principal Amount	Fair Value	Principal Amount	Fair Value
	(in thousands)			
6.50% Senior Notes due 2021	$—	$—	$344,611	$351,682
6.125% Senior Notes due 2022	$476,796	$491,076	$561,796	$571,627
6.50% Senior Notes due 2023	$—	$—	$394,985	$403,434
5.0% Senior Notes due 2024	$500,000	$491,000	$500,000	$483,440
5.625% Senior Notes due 2025	$500,000	$498,125	$500,000	$494,355
6.75% Senior Notes due 2026	$500,000	$522,150	$500,000	$516,350
6.625% Senior Notes due 2027	$500,000	$517,250	$—	$—
1.50% Senior Convertible Notes due 2021	$172,500	$191,044	$172,500	$168,291

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

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

Overview of the Company

General Overview

We are an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in onshore North America. We currently have producing assets and significant acreage positions in the Midland Basin and Eagle Ford shale in 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 provide 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.

Third Quarter 2018 Highlights and Outlook for the Remainder of 2018

Our priorities for 2018, as set at the beginning of the year, are to:

- continue generating high margin returns from top-tier projects that drive cash flow growth;
- core up our portfolio to focus on assets that generate the highest returns; and
- improve our credit metrics and maintain strong financial flexibility.

With respect to our priorities, we have substantially completed our multi-year portfolio transformation, and are now fully focused on developing and maximizing the value of our remaining core acreage positions in the Midland Basin and Eagle Ford shale. As part of our coring up strategy, we completed three divestitures of non-core assets in the first half of 2018, and used the proceeds, along with operating cash flows, to fund our Midland Basin and Eagle Ford shale capital programs, while maintaining an undrawn balance on our credit facility through September 30, 2018. Divestiture proceeds have also supported our ability to meaningfully reduce total long-term debt, as we retired our 2021 Senior Notes with cash on hand. Please refer to Note 3 - Divestitures, Assets Held for Sale, and Acquisitions and Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion.

Our capital program for 2018, excluding acquisitions, is expected to be approximately $1.31 billion. The majority of our 2018 capital has been allocated to our Midland Basin program. We anticipate that our Midland Basin program will average seven operated drilling rigs and four completion crews during 2018. Activity in our Eagle Ford shale program continues to be partially funded by a third party as part of our previously announced drilling and completion carry agreement. We anticipate our Eagle Ford shale program will average between one and two operated drilling rigs and one and two completion crews during 2018. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on our 2018 capital program.

Operational and Financial Results. During the third quarter of 2018, we had the following operational and financial results:

- Average net daily production for the three months ended September 30, 2018, was 130.2 MBOE, compared with 116.0 MBOE for the same period in 2017. The increase was primarily driven by our Permian region, which had a 100 percent increase in production volumes in the third quarter of 2018 compared to the same period in 2017. Please refer to A Three-Month and Nine-Month Overview of Selected Production and Financial Information, Including Trends below for additional discussion on production.
- Net cash provided by operating activities was $229.7 million for the three months ended September 30, 2018, compared with $128.5 million for the same period in 2017. The increase in net cash provided by operating activities for the three months ended September 30, 2018, was primarily the result of a 48 percent growth in higher margin oil production, which drove our 39 percent increase in pre-hedge realized price and 12 percent increase in net equivalent volumes produced. Partially offsetting the increase was a realized settlement loss on derivatives of $40.7 million during the third quarter of 2018, compared to a realized settlement gain of $13.1 million during the same period in 2017. Please refer to Overview of Liquidity and Capital Resources below for additional discussion of our sources and uses of cash.
- We recorded a net loss of $135.9 million, or $1.21 per diluted share, for the three months ended September 30, 2018, compared with a net loss of $89.1 million, or $0.80 per diluted share, for the same period in 2017. Our net loss for the

third quarter of 2018, was driven primarily by net derivative losses of $178.0 million and a loss on extinguishment of debt of $26.7 million. Please refer to Comparison of Financial Results and Trends Between the Three Months and Nine Months Ended September 30, 2018, and 2017 below for additional discussion regarding the components of net income (loss) for each of the periods presented.

- Adjusted EBITDAX, a non-GAAP financial measure, for the three months ended September 30, 2018, was $256.1 million, compared with $164.3 million for the same period in 2017. The increase in the third quarter of 2018 compared to the same period in 2017 was driven largely by increased production revenue, which was partially offset by increased losses on derivative settlements. Please refer to Non-GAAP Financial Measures below for additional discussion, including our definition of adjusted EBITDAX and reconciliations to our net income (loss) and net cash provided by operating activities.

Long-Term Debt. During the third quarter of 2018, we executed certain long-term debt transactions and agreements, which are summarized below:

- 2021 Senior Notes Redemption. On July 16, 2018, we redeemed all of the $344.6 million principal outstanding of our 2021 Senior Notes for total cash consideration, including the premium paid and accrued interest, of $355.9 million. Redemption of the 2021 Senior Notes resulted in a loss on extinguishment of debt of $9.8 million for the quarter ended September 30, 2018.
- 2027 Senior Notes Issuance. On August 20, 2018, we issued $500.0 million in aggregate principal amount of 6.625% Senior Notes due 2027. The 2027 Senior Notes were issued at par and mature on January 15, 2027. We received 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 net proceeds were used to fund the Tender Offer and 2023 Senior Notes Redemption discussed below.
- Tender Offer and Redemption of our 2023 Senior Notes and a Portion of our 2022 Senior Notes. Concurrently with our 2027 Senior Notes offering, as discussed above, we announced our Tender Offer for all of our 2023 Senior Notes and a portion of our 2022 Senior Notes, and our intention to redeem any remaining 2023 Senior Notes outstanding upon completion of the Tender Offer. Upon completing the Tender Offer and subsequent redemption, we retired all of the $395.0 million principal outstanding of our 2023 Senior Notes and $85.0 million principal outstanding of our 2022 Senior Notes. Consideration paid to complete these transactions totaled $497.8 million, including the premium paid and accrued interest. The Tender Offer and subsequent redemption of the remaining 2023 Senior Notes resulted in a loss on extinguishment of debt of $16.9 million for the quarter ended September 30, 2018.
- Credit Agreement. On September 28, 2018, we entered into the Credit Agreement with our lenders which provides for a senior secured revolving credit facility with a maximum loan amount of $2.5 billion, an initial borrowing base of $1.5 billion, and initial aggregate lender commitments totaling $1.0 billion. The Credit Agreement is scheduled to mature on September 28, 2023. The maturity date could, however, occur earlier on August 16, 2022, to the extent we have not completed certain repurchase, redemption, or refinancing activities associated with our 2022 Senior Notes as outlined in the Credit Agreement.

Please refer to Overview of Liquidity and Capital Resources below and Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion.

Operational Activities. In our Midland Basin program, we began the third quarter of 2018 with seven operated drilling rigs and three completion crews. During the quarter, we maintained three completion crews and released one drilling rig, bringing our total number of operated drilling rigs to six as of September 30, 2018. During the third quarter of 2018, operations on our RockStar acreage in Howard and Martin Counties, Texas, as well as on our Sweetie Peck acreage in Upton and Midland Counties, Texas, continued to focus on delineating and developing the Lower Spraberry and Wolfcamp A and B shale intervals. We expect to allocate approximately 86 percent of our expected 2018 drilling and completion capital to our Midland Basin program.

During the third quarter of 2018, we completed two non-monetary acreage trades where we acquired 2,658 net acres in exchange for 2,654 net acres in the Midland Basin. These trades increased our working interest in existing drilling units and also provide us the opportunity to drill longer lateral wells.

In our operated Eagle Ford shale program, we ended the third quarter of 2018 with one operated drilling rig and two completion crews. In October 2018, we released one of our two completion crews. Drilling and completion activities related to our previously announced drilling and completion carry agreement in a defined portion of our Eagle Ford North area continued throughout the third quarter of 2018. We expect the remaining wells associated with this agreement to be completed in the fourth quarter of 2018. We expect to allocate approximately 14 percent of our expected 2018 drilling and completion capital to our Eagle Ford shale program.

The table below provides a quarterly summary of changes in our drilled but not completed well count and current year drilling and completion activity in our operated programs for the nine months ended September 30, 2018:

	Permian		South Texas & Gulf Coast		Bakken/Three Forks [2]		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Wells drilled but not completed at December 31, 2017	49	41	33	30	18	15	100	86
Wells drilled	35	33	11	8	—	—	46	41
Wells completed	(22)	(17)	(5)	(5)	—	—	(27)	(22)
Other [1]	—	1	—	—	—	—	—	1
Wells drilled but not completed at March 31, 2018	62	58	39	33	18	15	119	106
Wells drilled	29	28	10	6	—	—	39	34
Wells completed	(41)	(38)	(16)	(9)	—	—	(57)	(47)
Wells sold [2]	—	—	—	—	(18)	(15)	(18)	(15)
Wells drilled but not completed at June 30, 2018	50	48	33	30	—	—	83	78
Wells drilled	35	34	8	5	—	—	43	39
Wells completed	(29)	(28)	(5)	(5)	—	—	(34)	(33)
Other [1]	—	1	—	—	—	—	—	1
Wells drilled but not completed at September 30, 2018	56	55	36	30	—	—	92	85

(1) Reflects net working interest changes resulting from normal business operations.

(2) We divested all remaining producing assets in the Rocky Mountain region in the first half of 2018. As a result, there has been no drilling or completion activity in the Rocky Mountain region after the second quarter of 2018.

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 $276.4 million and $1.1 billion for the three and nine months ended September 30, 2018, respectively, and were incurred primarily in our Midland Basin and Eagle Ford shale programs.

Production Results. The table below presents the disaggregation of our production by product type for each of our operating regions for the three months ended September 30, 2018, and 2017:

	Permian		South Texas & Gulf Coast		Rocky Mountain [1]		Total	
	Three Months Ended September 30,		Three Months Ended September 30,		Three Months Ended September 30,		Three Months Ended September 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
Production:								
Oil (MMBbl)	4.8	2.3	0.3	0.4	—	0.7	5.0	3.4
Gas (Bcf)	7.1	3.9	20.1	24.2	—	1.0	27.2	29.1
NGLs (MMBbl)	—	—	2.4	2.4	—	—	2.4	2.4
Equivalent (MMBOE)	6.0	3.0	6.0	6.7	—	1.0	12.0	10.7
Avg. daily equivalents (MBOE/d)	64.8	32.3	65.4	73.3	—	10.4	130.2	116.0
Relative percentage	50 %	28 %	50 %	63 %	— %	9 %	100 %	100 %

Note: Amounts may not calculate due to rounding.

(1)

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

For the three months ended September 30, 2018, production on an equivalent basis increased 12 percent compared with the same period in 2017. This increase in overall production volumes was driven by our Permian region, which had a 100 percent increase in production volumes for the three months ended September 30, 2018, compared with the same period in 2017. Increased production volumes from our Permian region were partially offset by the divestiture of our remaining producing assets in the Rocky Mountain region in the first half of 2018 and decreased production volumes from our Eagle Ford shale assets in our South Texas & Gulf Coast region as a result of reduced capital investment.

The table below presents the disaggregation of our production by product type for each of our operating regions for the nine months ended September 30, 2018, and 2017:

	Permian		South Texas & Gulf Coast		Rocky Mountain [1]		Total	
	Nine Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
Production:								
Oil (MMBbl)	11.8	5.6	1.0	1.6	0.9	2.6	13.7	9.8
Gas (Bcf)	18.9	10.1	57.6	83.8	1.2	3.1	77.7	97.0
NGLs (MMBbl)	—	—	5.9	8.0	—	0.1	6.0	8.1
Equivalent (MMBOE)	15.0	7.3	16.5	23.5	1.1	3.2	32.6	34.1
Avg. daily equivalents (MBOE/d)	54.9	26.9	60.4	86.2	4.1	11.8	119.4	124.9
Relative percentage	46 %	22 %	51 %	69 %	3 %	9 %	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.

Production on an equivalent basis decreased four percent for the nine months ended September 30, 2018, compared with the same period in 2017. Lower production was primarily a result of the divestiture of our outside-operated Eagle Ford shale assets, which occurred in the first quarter of 2017, declining production from our South Texas & Gulf Coast region as a result of reduced capital investment, and divestiture of our remaining producing assets in the Rocky Mountain region in the first half of 2018. Production declines in the South Texas & Gulf Coast and Rocky Mountain regions were largely offset by the Permian region, which had a 105 percent increase in volumes produced for the nine months ended September 30, 2018, compared with the same period in 2017.

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, 2018, and 2017 below for additional discussion on production.

Derivative Activity

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 derivatives is driven by the amount of debt on our balance sheet, the level of capital commitments and long-term obligations we have in place, and our ability to enter into favorable derivative commodity contracts. With our current derivative contracts, we believe we have partially reduced our exposure to volatility in commodity prices and price 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.

Currently, due to robust drilling activity across the Permian Basin, the industry expects takeaway capacity to remain tight through mid-to-late 2019 as announced pipeline infrastructure build-out is completed. We remain proactive in managing risks associated with price and basis differential volatility through the use of commodity derivative instruments, which we expect to help mitigate the expected effects of higher than average basis differentials and support our ability to continue to generate positive cash flows from our Midland Basin assets during this period.

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.

Oil, Gas, and NGL Prices

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

The following table summarizes commodity price data, as well as the effects of derivative settlements, for the third and second quarters of 2018, as well as the third quarter of 2017:

	For the Three Months Ended		
	September 30, 2018	June 30, 2018	September 30, 2017
Oil (per Bbl):			
Average NYMEX contract monthly price	$69.50	$67.88	$ 48.20
Realized price, before the effect of derivative settlements	$56.96	$61.02	$ 45.20
Effect of oil derivative settlements	$(3.32)	$(5.60)	$ (0.73)
Gas:			
Average NYMEX monthly settle price (per MMBtu)	$2.90	$2.80	$ 3.00
Realized price, before the effect of derivative settlements (per Mcf)	$3.56	$3.32	$ 2.96
Effect of gas derivative settlements (per Mcf)	$(0.03)	$(0.03)	$ 0.83
NGLs (per Bbl):			
Average OPIS price [1]	$37.97	$33.10	$ 27.55
Realized price, before the effect of derivative settlements	$30.77	$27.55	$ 22.40
Effect of NGL derivative settlements	$(9.61)	$(6.04)	$ (3.54)

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

We expect future prices for oil and NGLs to continue to be volatile. In addition to supply and demand fundamentals, as a global commodity, the price of oil is affected by real or perceived geopolitical risks in various regions of the world as well as the relative strength of the United States dollar compared to other currencies. Oil markets have strengthened due to recent inventory drawdowns, but we expect oil prices to remain volatile due to uncertainty in global supply and demand.

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 balance supply.

We expect NGL prices to continue to benefit from increased demand from export and petrochemical markets while being offset by increased drilling activity.

The following table summarizes 12-month strip prices for NYMEX WTI oil, NYMEX Henry Hub gas, and OPIS NGLs (same product mix as discussed under the table above) as of October 24, 2018, and September 30, 2018:

	As of October 24, 2018	As of September 30, 2018
NYMEX WTI oil (per Bbl)	$ 67.07	$ 72.28
NYMEX Henry Hub gas (per MMBtu)	$ 2.90	$ 2.85
OPIS NGLs (per Bbl)	$ 31.27	$ 38.94

Financial Results of Operations and Additional Comparative Data

The tables below provide information regarding selected production and financial information for the three months ended September 30, 2018, and the immediately preceding three quarters. A detailed discussion follows.

	For the Three Months Ended			
	September 30, 2018	June 30, 2018	March 31, 2018	December 31, 2017
	(in millions)			
Production (MMBOE)	12.0	10.5	10.1	10.4
Oil, gas, and NGL production revenue	$458.4	$402.6	$382.9	$ 341.2
Oil, gas, and NGL production expense	$127.6	$117.4	$120.9	$ 122.8
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$201.1	$151.8	$130.5	$ 131.4
Exploration (1)	$13.1	$14.1	$13.7	$ 15.8
General and administrative (1)	$29.5	$28.9	$27.7	$ 32.7
Net income (loss)	$(135.9)	$17.2	$317.4	$ (26.3)

Note: Amounts may not calculate due to rounding.

(1) Certain prior period amounts have been adjusted to conform to the current period presentation on the condensed consolidated financial statements. Please refer to Recently Issued Accounting Standards in Note 1 - Summary of Significant Accounting Policies in Part I, Item 1 of this report for additional discussion.

Selected Performance Metrics

	For the Three Months Ended			
	September 30, 2018	June 30, 2018	March 31, 2018	December 31, 2017
Average net daily production equivalent (MBOE per day)	130.2	115.2	112.7	112.6
Lease operating expense (per BOE)	$4.41	$4.66	$4.95	$5.10
Transportation costs (per BOE)	$4.20	$4.47	$4.63	$5.01
Production taxes as a percent of oil, gas, and NGL production revenue	4.1 %	4.3 %	4.4 %	4.3 %
Ad valorem tax expense (per BOE)	$0.45	$0.41	$0.67	$0.33
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$16.78	$14.48	$12.87	$12.69
General and administrative (per BOE) (1)	$2.46	$2.76	$2.73	$3.15

Note: Amounts may not calculate due to rounding.

(1) Certain prior period amounts have been adjusted to conform to the current period presentation on the condensed consolidated financial statements. Please refer to Recently Issued Accounting Standards in Note 1 - Summary of Significant Accounting Policies in Part I, Item 1 of this report for additional discussion.

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

	For the Three Months Ended September 30, 2018	2017	Amount Change Between Periods	Percent Change Between Periods	For the Nine Months Ended September 30, 2018	2017	Amount Change Between Periods	Percent Change Between Periods
Net production volumes: (1)								
Oil (MMBbl)	5.0	3.4	1.6	48 %	13.7	9.8	3.8	39 %
Gas (Bcf)	27.2	29.1	(1.9)	(7)%	77.7	97.0	(19.3)	(20)%
NGLs (MMBbl)	2.4	2.4	—	— %	6.0	8.1	(2.1)	(26)%
Equivalent (MMBOE)	12.0	10.7	1.3	12 %	32.6	34.1	(1.5)	(4)%
Average net daily production: (1)								
Oil (MBbl per day)	54.9	37.1	17.8	48 %	50.1	36.1	14.0	39 %
Gas (MMcf per day)	295.3	316.1	(20.8)	(7)%	284.7	355.4	(70.7)	(20)%
NGLs (MBbl per day)	26.2	26.2	—	— %	21.9	29.6	(7.7)	(26)%
Equivalent (MBOE per day)	130.2	116.0	14.2	12 %	119.4	124.9	(5.5)	(4)%
Oil, gas, and NGL production revenue (in millions): (1)								
Oil production revenue	$287.5	$154.2	$133.3	86 %	$814.7	$450.7	$364.0	81 %
Gas production revenue	96.8	86.3	10.6	12 %	260.0	289.2	(29.2)	(10)%
NGL production revenue	74.1	54.0	20.0	37 %	169.1	172.7	(3.6)	(2)%
Total oil, gas, and NGL production revenue	$458.4	$294.5	$163.9	56 %	$1,243.8	$912.6	$331.2	36 %
Oil, gas, and NGL production expense (in millions): (1)								
Lease operating expense	$52.8	$51.4	$1.5	3 %	$151.9	$144.1	$7.8	5 %
Transportation costs	50.4	55.9	(5.5)	(10)%	144.1	191.7	(47.6)	(25)%
Production taxes	19.0	12.4	6.6	54 %	53.4	37.8	15.6	41 %
Ad valorem tax expense	5.4	3.0	2.4	79 %	16.5	11.5	5.0	44 %
Total oil, gas, and NGL production expense	$127.6	$122.7	$5.0	4 %	$365.9	$385.1	$(19.2)	(5)%
Realized price (before the effect of derivative settlements):								
Oil (per Bbl)	$56.96	$45.20	$11.76	26 %	$59.60	$45.77	$13.83	30 %
Gas (per Mcf)	$3.56	$2.96	$0.60	20 %	$3.35	$2.98	$0.37	12 %
NGLs (per Bbl)	$30.77	$22.40	$8.37	37 %	$28.28	$21.36	$6.92	32 %
Per BOE	$38.26	$27.59	$10.67	39 %	$38.15	$26.76	$11.39	43 %
Per BOE data:								
Production costs:								
Lease operating expense	$4.41	$4.81	$(0.40)	(8)%	$4.66	$4.22	$0.44	10 %
Transportation costs	$4.20	$5.24	$(1.04)	(20)%	$4.42	$5.62	$(1.20)	(21)%
Production taxes	$1.58	$1.15	$0.43	37 %	$1.64	$1.11	$0.53	48 %
Ad valorem tax expense	$0.45	$0.29	$0.16	55 %	$0.51	$0.34	$0.17	50 %
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$16.78	$12.61	$4.17	33 %	$14.82	$12.48	$2.34	19 %
General and administrative (2)	$2.46	$2.58	$(0.12)	(5)%	$2.64	$2.48	$0.16	6 %
Derivative settlement gain (loss) (3)	$(3.40)	$1.23	$(4.63)	(376)%	$(3.13)	$0.86	$(3.99)	(464)%
Earnings per share information:								
Basic weighted-average common shares outstanding (in thousands)	112,107	111,575	532	— %	111,836	111,366	470	— %

Diluted weighted-average common shares outstanding (in thousands)	112,107	111,575	532	—	%	113,600	111,366	2,234	2 %
Basic net income (loss) per common share	$(1.21)	$(0.80)	$(0.41)	(51	)%	$1.78	$(1.21)	$2.99	247 %
Diluted net income (loss) per common share	$(1.21)	$(0.80)	$(0.41)	(51	)%	$1.75	$(1.21)	$2.96	245 %

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

(2) Prior periods have been adjusted to conform to the current period presentation on the condensed consolidated financial statements. Please refer to Recently Issued Accounting Standards in Note 1 - Summary of Significant Accounting Policies in Part I, Item 1 of this report for additional discussion.

(3) Derivative settlements for the three and nine months ended September 30, 2018, and 2017, are included within the net derivative (gain) loss line item in the accompanying statements of operations.

Average net equivalent daily production for the three months ended September 30, 2018, increased 12 percent compared with the same period in 2017. This increase was driven by our Permian region, which had a 100 percent increase in production volumes for the three months ended September 30, 2018, compared with the same period in 2017. Increased production volumes from our Permian region were partially offset by the divestiture of our remaining producing assets in the Rocky Mountain region in the first half of 2018 and decreased production volumes from our Eagle Ford shale assets as a result of reduced capital investment in these assets.

For the nine months ended September 30, 2018, average net equivalent daily production decreased four percent compared with the same period in 2017. This decrease was primarily due to the divestiture of our outside-operated Eagle Ford shale assets in the first quarter of 2017, the divestiture of our remaining producing assets in the Rocky Mountain region in the first half of 2018, and declining production due to reduced capital investment in our operated Eagle Ford shale assets. These decreases were largely offset by a 105 percent increase in production from our Midland Basin assets for the nine months ended September 30, 2018, compared with the same period in 2017. For the full year 2018, we expect total production to be in line with 2017, as actual and anticipated production increases in our Midland Basin program offset the production decreases resulting from our 2017 and 2018 divestiture activities and declines from our operated Eagle Ford shale program. On a retained asset basis, we expect production and the percentage of oil relative to our total product mix to increase in 2018 compared with 2017. Please refer to Comparison of Financial Results and Trends Between the Three Months and Nine Months Ended September 30, 2018, and 2017 below for additional discussion.

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

Our realized price before the effect of derivative settlements on a per BOE basis for the three and nine months ended September 30, 2018, increased 39 percent and 43 percent, respectively, compared with the same periods in 2017. For the three and nine months ended September 30, 2018, we realized losses of $3.40 and $3.13 per BOE, respectively, on the settlement of our derivative contracts, which was primarily driven by improving oil and NGL prices in 2018. Settlement losses due to strengthening commodity prices were partially offset by realized gains on our Midland Basin oil basis swaps that settled during the third quarter of 2018. For the three and nine months ended September 30, 2017, we realized gains of $1.23 and $0.86 per BOE, respectively, on the settlement of our derivative contracts.

For the three months ended September 30, 2018, lease operating expense (“LOE”) on a per BOE basis decreased eight percent compared with the same period in 2017. This decrease was primarily driven by the divestiture of our remaining producing assets in our Rocky Mountain region in the first half of 2018, as these assets had the highest lifting costs in our portfolio, as well as, decreases in LOE on a per BOE basis in the Permian region as a result of increased operating efficiencies.

For the nine months ended September 30, 2018, LOE on a per BOE basis increased 10 percent compared with the same period in 2017. This increase was primarily driven by the increase in oil production as a percentage of our total product mix, and production declines from our Eagle Ford shale assets, which have lower average lifting costs than our Permian region. We expect LOE on a per BOE basis to be higher in 2018 compared with 2017 as our product mix continues to shift towards more oil production, which typically has higher LOE per BOE. Going forward, we expect to 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 this may have on service provider costs.

Transportation costs on a per BOE basis decreased 20 percent and 21 percent, for the three and nine months ended September 30, 2018, respectively, compared with the same periods in 2017. The decrease in transportation costs per BOE continues to be driven by production declines from our Eagle Ford shale assets, which have higher average transportation costs, and production increases in our Permian region, which are subject to minimal transportation costs. We expect total transportation costs to fluctuate in line with changes in production from our operated Eagle Ford shale program as these assets incur the majority of our transportation costs. On a per BOE basis, we expect transportation costs to decrease in 2018, as compared with 2017, as production from our Midland Basin assets becomes a larger portion of our total production. The majority of our Midland Basin production is currently sold at the wellhead, and therefore, we incur minimal transportation costs on these assets.

Production taxes on a per BOE basis increased 37 percent and 48 percent, for the three and nine months ended September 30, 2018, respectively, compared with the same periods in 2017. These increases were primarily driven by a 39 percent and 43 percent increase in our realized price on a per BOE basis before the effect of derivative settlements for the three and nine months ended September 30, 2018, respectively, compared with the same periods in 2017. Our overall production tax rate increased to 4.3 percent for the nine months ended September 30, 2018, compared with 4.1 percent for the same period in 2017. This increase in our company-wide production tax rate is primarily a result of the increase in oil revenue as a percentage of total revenue and overall increase in realized oil prices. We generally expect production tax expense to trend with oil, gas, and NGL production revenue on an absolute and per BOE basis. Product mix, the location of production, and incentives to encourage oil and gas development can also impact the amount of production tax we recognize.

Ad valorem tax expense on a per BOE basis increased 55 percent and 50 percent for the three and nine months ended September 30, 2018, respectively, compared with the same periods in 2017, due to changes in our asset and production base and increased commodity price assumptions used in 2018 property tax valuations. As a result, we expect an increase in ad valorem tax expense for the full year 2018 as compared with 2017 in total and on a per BOE basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion ("DD&A") expense on a per BOE basis increased 33 percent and 19 percent, for the three and nine months ended September 30, 2018, respectively, compared with the same periods in 2017. These increases were driven primarily by the increase in production volumes from our Midland Basin assets, which have higher depletion rates than our Eagle Ford shale assets. DD&A on a per BOE basis for the three and nine months ended September 30, 2018, also increased as a result of an immaterial out of period adjustment recorded in third quarter of 2018, which related to prior years. Please refer to Correction of an Immaterial Error in Note 1 - Summary of Significant Accounting Policies in Part I, Item 1 of this report for additional discussion.

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 for the full year 2018 to increase compared with 2017 as production from our Midland Basin assets continues to increase as a percentage of our total production.

General and administrative ("G&A") expense on a per BOE basis decreased five percent and increased six percent for the three and nine months ended September 30, 2018, respectively, compared with the same periods in 2017. We expect total G&A expense for the full year 2018 to be relatively flat compared with 2017. We expect G&A expense on a per BOE basis in 2018 to also be relatively flat compared with 2017 as full year 2018 production is expected to be in line with 2017 production.

Please refer to Comparison of Financial Results and Trends Between the Three Months and Nine Months Ended September 30, 2018, and 2017 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, 2018, and 2017

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 and nine months ended September 30, 2018, and 2017:

	Net Equivalent Production Increase (Decrease)		Production Revenue Increase (Decrease)		Production Expense Increase (Decrease)	
	Three Months Ended	Nine Months Ended	Three Months Ended	Nine Months Ended	Three Months Ended	Nine Months Ended
	(MMBOE)		(in millions)		(in millions)	
Permian	3.0	7.6	$187.6	$493.3	$26.0	$67.6
South Texas & Gulf Coast	(0.7)	(7.0)	11.6	(95.3)	(5.1)	(57.5)
Rocky Mountain [1]	(1.0)	(2.1)	(35.2)	(66.7)	(15.9)	(29.3)
Total	1.3	(1.5)	$163.9	$331.2	$5.0	$(19.2)

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.

For the three months ended September 30, 2018, production on an equivalent basis increased 12 percent compared with the same period in 2017. This increase in overall production volumes was driven by our Permian region, which had a 100 percent increase in production volumes for the three months ended September 30, 2018, compared with the same period in 2017. Increased production volumes from our Permian region were partially offset by the divestiture of our remaining producing assets in the Rocky Mountain region in the first half of 2018 and decreased production volumes from our Eagle Ford shale assets as a result of reduced capital investment. Oil, gas, and NGL production revenue for the three months ended September 30, 2018, increased 56 percent compared with the same period in 2017, which resulted from realized prices before the effect of derivative settlements on a per BOE basis increasing 39 percent, oil production increasing 48 percent, and higher overall volumes produced in the third quarter of 2018 compared with the same period in 2017. Production expense increased slightly during the three months ended September 30, 2018, compared with the same period in 2017, as a result of increased overall production, as discussed above.

Production on an equivalent basis decreased four percent for nine months ended September 30, 2018, compared with the same period in 2017. Lower production was primarily a result of the divestiture of our outside-operated Eagle Ford shale assets, which occurred in the first quarter of 2017, declining production from our operated Eagle Ford shale assets as a result of reduced capital investment, and divestiture of our remaining producing assets in the Rocky Mountain region in the first half of 2018. Production declines in the Eagle Ford shale and Rocky Mountain region were largely offset by the Permian region, which had an increase in production volumes of 105 percent for the nine months ended September 30, 2018, compared with the same period in 2017. Increased production in the Permian region also drove oil production as a percentage of our overall product mix to increase from 29 percent for the nine months ended September 30, 2017, to 42 percent for the nine months ended September 30, 2018. Compared with the same period in 2017, realized prices on a per BOE basis increased 43 percent for the nine months ended September 30, 2018, resulting in an overall increase of 36 percent in oil, gas, and NGL production revenues for the nine months ended September 30, 2018. Production expense for the nine months ended September 30, 2018, compared with the same period in 2017, decreased five percent primarily as a result of the decreased production volumes, as discussed above.

Please refer to A Three-Month and Nine-Month Overview of Selected Production and Financial Information, Including Trends above for discussion of trends on a per BOE basis.

Net gain (loss) on divestiture activity

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Net gain (loss) on divestiture activity	$0.8	$(1.9)	$425.7	$(131.6)

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. The net loss on divestiture activity recorded for the nine months ended September 30, 2017, was the result of $526.5 million of write-downs recorded on certain retained North Dakota assets previously held for sale. Partially offsetting these write-downs recorded during the nine months ended September 30, 2017, was a $396.8 million net gain recorded on the sale of our outside-operated Eagle Ford shale assets. 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,	
	2018	2017	2018	2017
	(in millions)			
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$201.1	$134.6	$483.3	$425.6

DD&A expense increased 49 percent and 14 percent for the three and nine months ended September 30, 2018, respectively, compared with the same periods in 2017. These increases are directly related to the increase in oil production from the Permian region, which has higher depletion rates than our South Texas & Gulf Coast Region. Total oil production for the three and nine months ended September 30, 2018, increased 48 percent and 39 percent, respectively, compared with the same periods in 2017. Additionally, $11.8 million of DD&A expense was recorded in the third quarter of 2018 to correct an immaterial error related to prior years. 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 DD&A expense on a per BOE basis.

Exploration

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Exploration [1]	$13.1	$14.1	$40.8	$38.9

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(1) Prior periods have been adjusted to conform to the current period presentation on the condensed consolidated financial statements. Please refer to Recently Issued Accounting Standards in Note 1 - Summary of Significant Accounting Policies in Part I, Item 1 of this report for additional discussion.

Exploration expense decreased seven percent and increased five percent for the three and nine months ended September 30, 2018, respectively, compared with the same periods in 2017. As we continue our focus on testing and delineating our Midland Basin acreage, we expect to see a slight increase in exploration activity and related expenses for the full year 2018 compared with 2017. Exploration expense may vary depending upon allocated overhead and exploratory dry hole expense.

Abandonment and impairment of unproved properties

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Abandonment and impairment of unproved properties	$9.1	$ —	$26.6	$0.2

Unproved property abandonments and impairments recorded for the three and nine months ended September 30, 2018, related to actual and anticipated lease expirations. We expect unproved property abandonments and impairments to fluctuate with the timing of lease expirations, unsuccessful exploration activities, and changing economics associated with decreases in commodity prices. Additionally, changes in drilling plans, downward engineering revisions, or unsuccessful exploration efforts may result in 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, 2018, we do not expect any material property impairments in the fourth quarter of 2018 resulting from commodity price impacts.

General and administrative

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
General and administrative [1]	$29.5	$27.6	$86.1	$84.6

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(1) Prior periods have been adjusted to conform to the current period presentation on the condensed consolidated financial statements. Please refer to Recently Issued Accounting Standards in Note 1 - Summary of Significant

Accounting Policies in Part I, Item 1 of this report for additional discussion.
G&A expense was relatively flat for the three and nine months ended September 30, 2018, compared with the same periods in 2017. We expect G&A expense in total to continue to remain relatively flat for the full year 2018 compared with 2017. 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 on an absolute and per BOE basis.

Net derivative (gain) loss

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Net derivative (gain) loss	$178.0	$80.6	$249.3	$(89.4)

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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.

We recognized an $80.6 million derivative loss for the three months ended September 30, 2017, largely due to a $72.6 million decrease in the fair value of contracts settling subsequent to September 30, 2017. Additionally, we recognized an $8.0 million loss on contracts that settled during the third quarter of 2017, which had a fair value of $21.1 million at June 30, 2017, and settled for $13.1 million. We recognized a $24.6 million gain on contract settlements through the second quarter of 2017, and recorded a $145.4 million increase in the fair value of remaining contracts as of June 30, 2017, resulting in a year-to-date net derivative gain of $89.4 million.

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

Loss on extinguishment of debt

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
	(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.

Interest expense

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Interest expense	$(38.1)	$(44.1)	$(122.9)	$(135.6)

Interest expense decreased 14 percent and nine percent for the three and nine months ended September 30, 2018, respectively, compared with the same periods in 2017. The decrease in interest expense was driven in part by our decision to redeem our 2021 Senior Notes, which reduced interest expense related to debt in the third quarter of 2018 by $4.3 million compared with the same period in 2017. In addition to the overall reduction in debt, interest expense was also reduced as the amount of interest we capitalized increased given our higher levels of development activity in 2018 compared with the prior year. As a result of our overall reduction in long-term debt and increased development activities, we expect interest expense to be lower for the full year 2018 compared with 2017. 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,

	2018	2017	2018	2017
	(in millions, except tax rate)			
Income tax (expense) benefit	$36.7	$39.3	$(61.3)	$65.8
Effective tax rate	21.3 %	30.6 %	23.6 %	32.8 %

The decrease in the effective tax rate for the three and nine months ended September 30, 2018, compared with the same periods in 2017, was primarily due to the decrease in the federal tax rate caused by enactment of the 2017 Tax Act, which reduced the highest marginal corporate tax rate from 35 percent to 21 percent.

The discrete adjustment for the settlement of share-based payment awards recorded in the third quarter of 2018 was lower on an absolute basis and percentage impact basis than the discrete adjustment recorded in the third quarter of 2017, resulting in a decrease in the benefit tax rate for the three and nine months ended September 30, 2018, compared with the same periods in 2017. The tax expense rate increased for the nine months ended September 30, 2018, and decreased for the same period in 2017. The rate decreased year-over-year due to the cumulative effect of a change in the highest marginal state rate resulting from the Divide County Divestiture. Please refer to Overview of Liquidity and Capital Resources below as well as Note 4 - Income Taxes in Part I, Item 1 of this report for additional discussion.

Overview of Liquidity and Capital Resources

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

Sources of Cash

We currently expect our 2018 capital program to be funded by cash flows from operations and proceeds from the divestiture of properties. During the nine months ended September 30, 2018, we generated $541.2 million of cash flows from operating activities and we received $743.2 million of net proceeds from the sale of oil and gas properties. As of September 30, 2018, the combination of our cash balance of $176.8 million with our $999.8 million of available borrowing capacity under our Credit Agreement provided $1.2 billion in liquidity.

Although we anticipate cash flows from operations and divestiture proceeds will be sufficient to fund our expected 2018 capital program, we may also elect to borrow under our Credit Agreement and/or raise funds through debt or equity financings or from other sources. Further, we may enter into additional carrying cost funding and sharing arrangements with third parties for particular exploration and/or development programs. See Credit Agreement below for discussion of the initial borrowing base established under the Sixth Amended and Restated Credit Agreement we entered into with our lenders on September 28, 2018. Our borrowing base could be reduced as a result of lower commodity prices, divestitures of proved properties, or the issuance of debt securities. If we raise additional funds through the issuance of equity or convertible debt securities, the percentage ownership of our current stockholders could be diluted, and these newly-issued securities may have rights, preferences, or privileges senior to those of existing stockholders. Any future downgrades in our credit ratings could make it more difficult or expensive for us to borrow additional funds. All of our sources of liquidity can be affected by the general condition of the broader economy and by fluctuations in commodity prices, operating costs, and volumes produced, all of which affect us and our industry.

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

The enactment of the 2017 Tax Act reduced our highest marginal corporate tax rate for 2018 and future years from 35 percent to 21 percent. It also eliminated the domestic production activities deduction for all taxpayers, the alternative minimum tax (“AMT”) for corporate taxpayers, and may impact our ability to deduct interest expense in future years. However, it did not impact current tax deductions for intangible drilling costs, percentage depletion, or amortization of geological and geophysical expenses, and it will allow us the option to expense 100 percent of our equipment acquisition costs in future years. In general, we believe the enactment of the 2017 Tax Act will have a positive impact on our future operating cash flows.

Credit Agreement

On September 28, 2018, we entered into the Sixth Amended and Restated Credit Agreement with our lenders. The Credit Agreement, which replaced our Fifth Amended and Restated Credit Agreement, provides for a senior secured revolving credit facility with a maximum loan amount of $2.5 billion, an initial borrowing base of $1.5 billion, and initial aggregate lender commitments totaling $1.0 billion. The Credit Agreement is scheduled to mature on September 28, 2023. The maturity date could, however, occur earlier on August 16, 2022, if we have not completed certain repurchase, redemption, or refinancing activities associated with our 2022 Senior Notes, as outlined in the Credit Agreement.

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 redetermination date is April 1, 2019.

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 ending December 31, 2018 through and including the fiscal quarter ending December 31, 2019, and for each quarter ending thereafter, the ratio cannot be greater than 4.00 to 1.00; and (b) adjusted current ratio cannot be less than 1.0 to 1.0 as of the last day of any fiscal quarter. We were in compliance with all financial and non-financial covenants as of September 30, 2018, and through the filing of this report.

We had no outstanding balance under our Credit Agreement as of September 30, 2018, or as of the filing of this report, due to our cash balance resulting primarily from proceeds received from divestiture activity. Net cash flows provided by our operating activities, divestiture proceeds, capital markets activity, and the amount of our capital expenditures, including acquisitions, all impact the amount we borrow under our Credit Agreement. No individual bank participating in our Credit Agreement represents more than 10 percent of the lender commitments under the Credit Agreement. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion, including the presentation of the outstanding balance, total amount of letters of credit, and available borrowing capacity under our Credit Agreement as of October 24, 2018, September 30, 2018, and December 31, 2017.

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 rate and our weighted-average borrowing rate for the three and nine months ended September 30, 2018, and 2017:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
Weighted-average interest rate	6.4%	6.3%	6.4%	6.5%
Weighted-average borrowing rate	5.7%	5.7%	5.8%	5.8%

The weighted-average interest rate and weighted-average borrowing rate for the three and nine months ended September 30, 2018, remained consistent as compared with the same periods in 2017. We would expect our weighted-average interest and borrowing rates to fluctuate based on the timing and amount of Senior Notes redemptions, changes in our aggregate lender commitment amount on our credit facility, and the average balance on our credit facility. 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 acquisition, exploration, and development of oil and gas properties and for the payment of operating and general and administrative costs, income taxes, dividends, and debt obligations, including interest. Expenditures for the acquisition, exploration, and development of oil and gas properties are the primary use of our capital resources. During the nine months ended September 30, 2018, we spent $1.1 billion on capital expenditures and on acquiring unproved oil and gas properties. This amount differs from the costs incurred amount, which is accrual-based and includes asset retirement obligations, geological and geophysical expenses, and exploration overhead amounts.

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

We may from time to time repurchase certain amounts of our outstanding debt securities for cash and/or through exchanges for other securities. Such repurchases or exchanges may be made in open market transactions, privately negotiated transactions, or otherwise. Any such repurchases or exchanges will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, compliance with securities laws, and other factors. The amounts involved in any such transaction may be material. Repurchases or exchanges are reviewed as part of the allocation of our capital. On July 16, 2018, we completed the 2021 Senior Notes Redemption which resulted in the payment of total cash consideration, including accrued interest, of $355.9 million. On August 20, 2018, we 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 complete the Tender Offer and 2023 Senior Notes Redemption. As a result, we repurchased our 2023 Senior Notes and a portion of our 2022 Senior Notes during the third quarter of 2018, which resulted in the payment of total consideration, including accrued interest, of $497.8 million. 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. We currently do not plan to repurchase any outstanding shares of common stock during 2018.

Analysis of Cash Flow Changes Between the Nine Months Ended September 30, 2018, and 2017

The following tables present changes in cash flows between the nine months ended September 30, 2018, and 2017, for our operating, investing, and financing activities. The nine months ended September 30, 2017, have been adjusted to conform to the current period presentation. Please refer to Note 1 - Summary of Significant Accounting Policies in Part I, Item 1 of this report for additional discussion of adjustments made as a result of adopting new accounting standards. The analysis following each table should be read in conjunction with our accompanying statements of cash flows in Part I, Item 1 of this report.

Operating activities

	For the Nine Months Ended September 30,	
	2018	2017
	(in millions)	
Net cash provided by operating activities	$541.2	$370.6

Cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, including derivative cash settlements, increased $190.4 million for the nine months ended September 30, 2018, compared with the same period in 2017, primarily as a result of an increase in our realized price, after the effects of derivative settlements. Net cash provided by operating activities is affected by working capital changes and the timing of cash receipts and disbursements.

Investing activities

	For the Nine Months Ended September 30,	
	2018	2017
	(in millions)	
Net cash provided by (used in) investing activities	$(314.0)	$66.0

The increase in cash used in investing activities for the nine months ended September 30, 2018, compared with the same period in 2017, is largely due to an increase in capital expenditures of $407.6 million, primarily in our Midland Basin program, and a decrease in divestiture cash proceeds of $35.2 million. These increases are partially offset by a $62.8 million decrease in cash paid for acquisitions of proved and unproved properties.

Financing activities

	For the Nine Months Ended September 30,	
	2018	2017
	(in millions)	
Net cash used in financing activities	$(364.4)	$(7.6)

The increase in cash used in financing activities for the nine months ended September 30, 2018, is primarily the result of the redemption of $344.6 million principal outstanding on our 2021 Senior Notes, and the repurchase of $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. Cash used in financing activities during the nine months ended September 30, 2017, consisted primarily of dividend payments of $5.6 million. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion.

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, 2018, and through the filing of this report, we had a zero 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 of up to six months. 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, 2018, our outstanding principal amount of fixed-rate debt totaled $2.6 billion. Please refer to Note 11 - Fair Value Measurements in Part I, Item 1 of this report for additional discussion on the fair values of our Senior Notes and Senior Convertible Notes.

Commodity Price Risk

The prices we receive for our oil, gas, and NGL production directly impact our revenue, overall profitability, access to capital, and future rate of growth. Oil, gas, and NGL prices are subject to wide fluctuations in response to changes in supply and demand and other factors. The markets for oil, gas, and NGLs have been volatile, especially over the last several years, and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Based on our production for the nine months ended September 30, 2018, 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 $81.5 million, $26.0 million, and $16.9 million, respectively. If commodity prices had been 10 percent lower, our net derivative settlements for the nine months ended September 30, 2018, would have offset the declines in oil, gas, and NGL production revenue by approximately $86.1 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, 2018, a 10 percent increase or decrease in the forward curves associated with our oil, gas, and NGL commodity derivative instruments would have changed our net liability positions by approximately $133.7 million, $17.8 million, and $25.4 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, 2018, 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 2017 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, gains and losses on extinguishment of debt, 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 one-time in nature or whose timing and/or amount cannot be reasonably estimated. Adjusted EBITDAX is a non-GAAP measure that we present because we believe it provides useful additional information to investors and analysts, as a performance measure, for analysis of our ability to internally generate funds for exploration, development, acquisitions, and to service debt. We are also subject to financial covenants under our Credit Agreement based on adjusted EBITDAX ratios as further described in the Credit Agreement section in Overview of Liquidity and Capital Resources above. In addition, adjusted EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. Adjusted EBITDAX should not be considered in isolation or as a substitute for net income (loss), income (loss) from operations, net cash provided by operating activities, or other profitability or liquidity measures prepared under GAAP. Because adjusted EBITDAX excludes some, but not all, items that affect net income (loss) and may vary among companies, the adjusted EBITDAX amounts presented may not be comparable to similar metrics of other companies. Our credit facility provides a material source of liquidity for us. Under the terms of our Credit Agreement, if we failed to comply with the covenants that establish a maximum permitted ratio of total funded debt, as defined in the Credit Agreement, to adjusted EBITDAX, we would be in default, an event that would prevent us from borrowing under our credit facility and would therefore materially limit our sources of liquidity. In addition, if we are in default under our credit facility and are unable to obtain a waiver of that default from our lenders, lenders under that facility and under the indentures governing our outstanding Senior Notes and Senior Convertible Notes would be entitled to exercise all of their remedies for default.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)			
Net income (loss) (GAAP)	$(135,923)	$(89,112)	$198,675	$(134,585)
Interest expense	38,111	44,091	122,850	135,639
Interest income [(1)]	(1,332)	(1,301)	(4,595)	(2,901)
Income tax expense (benefit)	(36,748)	(39,270)	61,342	(65,825)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	201,105	134,599	483,343	425,643
Exploration [(2)] [(3)]	11,490	12,624	36,768	35,021
Abandonment and impairment of unproved properties	9,055	—	26,615	157
Stock-based compensation expense	7,004	6,347	17,680	16,160
Net derivative (gain) loss	178,026	80,599	249,304	(89,364)
Derivative settlement gain (loss)	(40,718)	13,092	(101,911)	29,402
Net (gain) loss on divestiture activity	(786)	1,895	(425,656)	131,565
Loss on extinguishment of debt	26,722	—	26,722	35
Other, net	67	785	76	9,426
Adjusted EBITDAX (non-GAAP) [(3)]	256,073	164,349	691,213	490,373
Interest expense	(38,111)	(44,091)	(122,850)	(135,639)
Interest income [(1)]	1,332	1,301	4,595	2,901
Income tax (expense) benefit	36,748	39,270	(61,342)	65,825
Exploration [(2)] [(3)]	(11,490)	(12,624)	(36,768)	(35,021)
Amortization of debt discount and deferred financing costs	3,792	3,799	11,542	12,478
Deferred income taxes	(36,833)	(36,668)	60,672	(67,458)
Other, net [(3)]	151	1,175	(2,160)	(3,002)
Net change in working capital	17,997	11,971	(3,725)	40,153
Net cash provided by operating activities (GAAP) [(3)]	$229,659	$128,482	$541,177	$370,610

(1) Interest income is included within the other non-operating income, net line item on the accompanying statements of operations in Part I, Item 1 of this report.

(2) 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.

(3) Certain prior period amounts have been adjusted to conform to the current period presentation on the condensed consolidated financial statements. Please refer to Note 1 - Summary of Significant Accounting Policies in Part I, Item 1 of this report for additional discussion.

Cautionary Information about Forward-Looking Statements

This report 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," "fore "intend," "pending," "plan," "project," "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;
- our outlook on future oil, gas, and NGL prices, well costs, and service costs;
- the drilling of wells and other exploration and development activities and plans, as well as possible or expected acquisitions or divestitures;
- 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, 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, and our outlook on our future financial condition or results of operations;
- the possible divestiture or farm-down of, or joint venture relating to, certain properties; 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 2017 Form 10-K, and include such factors as:

- 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 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;
- 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 and expertise of third-party service providers on our operated properties;
- 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 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 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, NGLs, or produced 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;
- operating and environmental risks and hazards that could result in substantial losses;
- the impact of extreme weather conditions 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 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;
- the possibility of security threats, including terrorist attacks and cybersecurity attacks and breaches, against, or otherwise impacting, our facilities and systems; and
- litigation, environmental matters, the potential impact of legislation and government regulations, and the use of management estimates regarding such matters.

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is provided under the captions Commodity Price Risk and Interest Rate Risk in Item 2 above, as well as under the section entitled Summary of Oil, Gas, and NGL Derivative Contracts in Place under Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report and is incorporated herein by reference. Please also refer to the information under Commodity Price Risk and Interest Rate Risk in Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II, Item 7 of our 2017 Form 10-K.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

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

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

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

Changes in Internal Control Over Financial Reporting

There have been no changes during the third quarter of 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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 2017 Form 10-K.

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

The following table provides information about purchases made by us and any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the quarter ended September 30, 2018, 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)
07/01/18 - 07/31/18	115,429	$ 25.69	—	3,072,184
08/01/18 - 08/31/18	—	$ —	—	3,072,184
09/01/18 - 09/30/18	—	$ —	—	3,072,184
Total:	115,429	$ 25.69	—	3,072,184

(1) All shares purchased by us in the third quarter of 2018 were to offset tax withholding obligations that occurred upon the delivery of outstanding shares underlying RSUs delivered under the terms of grants 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
2.1	Purchase and Sale Agreement, dated January 8, 2018, by and between SM Energy Company and Converse Energy Acquisitions, LLC (filed as Exhibit 2.1 to the registrant's Current Report on Form 8-K filed on January 11, 2018, and incorporated herein by reference)
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)
4.1†	SM Energy Company Equity Incentive Compensation Plan, amended and restated effective as of May 22, 2018 (filed as Annex A in the registrant's Definitive Proxy Statement on Schedule 14A, filed on April 12, 2018, and incorporated herein by reference)
4.2	Base Indenture, dated as of May 21, 2015, by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
4.3	Fourth Supplemental Indenture, dated as of August 20, 2018, by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on August 20, 2018, and incorporated herein by reference)
4.4	Supplemental Indenture, dated as of August 20, 2018, by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.3 to the registrant's Current Report on Form 8-K filed on August 20, 2018, and incorporated herein by reference)
10.1†	Performance Share Unit Award Agreement as of July 1, 2018 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, and incorporated herein by reference)
10.2	Sixth Amended and Restated Credit Agreement dated as of September 28, 2018, 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 October 4, 2018, and incorporated herein by reference)
12.1*	Computation of Ratio of Earnings to Fixed Charges
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002
32.1**	Certification pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document

* Filed with this report.

** Furnished with this report.

† 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 2, 2018
By: /s/ JAVAN D. OTTOSON
Javan D. Ottoson
President and Chief Executive Officer
(Principal Executive Officer)

November 2, 2018
By: /s/ A. WADE PURSELL
A. Wade Pursell
Executive Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)