SM Energy Co
Form 10-Q
August 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 June 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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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 (Do not check if a smaller reporting company)	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 July 25, 2018, the registrant had 112,137,582 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)

	June 30, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$615,906	$313,943
Accounts receivable	178,682	160,154
Derivative assets	146,329	64,266
Prepaid expenses and other	14,293	10,752
Total current assets	955,210	549,115
Property and equipment (successful efforts method):		
Proved oil and gas properties	6,372,956	6,139,379
Accumulated depletion, depreciation, and amortization	(3,041,653)	(3,171,575)
Unproved oil and gas properties	1,917,883	2,047,203
Wells in progress	361,238	321,347
Oil and gas properties held for sale, net	5,040	111,700
Other property and equipment, net of accumulated depreciation of $53,483 and $49,985, respectively	102,986	106,738
Total property and equipment, net	5,718,450	5,554,792
Noncurrent assets:		
Derivative assets	31,151	40,362
Other noncurrent assets	31,674	32,507
Total noncurrent assets	62,825	72,869
Total assets	$6,736,485	$6,176,776
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$446,318	$386,630
Current portion of Senior Notes, net of unamortized deferred financing costs (note 5)	342,301	—
Derivative liabilities	259,338	172,582
Total current liabilities	1,047,957	559,212
Noncurrent liabilities:		
Revolving credit facility	—	—
Noncurrent portion of Senior Notes, net of unamortized deferred financing costs	2,429,994	2,769,663
Senior Convertible Notes, net of unamortized discount and deferred financing costs	143,430	139,107
Asset retirement obligations	87,279	103,026
Asset retirement obligations associated with oil and gas properties held for sale	—	11,369
Deferred income taxes	177,709	79,989
Derivative liabilities	67,583	71,402
Other noncurrent liabilities	45,906	48,400
Total noncurrent liabilities	2,951,901	3,222,956
Commitments and contingencies (note 6)		
Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 111,846,998 and 111,687,016 shares, respectively	1,118	1,117

Additional paid-in capital	1,754,169	1,741,623
Retained earnings [1]	997,641	665,657
Accumulated other comprehensive loss [1]	(16,301)	(13,789)
Total stockholders' equity	2,736,627	2,394,608
Total liabilities and stockholders' equity	$6,736,485	$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 June 30,		For the Six Months Ended June 30,	
	2018	2017 (as adjusted)	2018	2017 (as adjusted)
Operating revenues and other income:				
Oil, gas, and NGL production revenue	$402,558	$284,939	$785,444	$618,137
Net gain (loss) on divestiture activity	39,501	(167,133)	424,870	(129,670)
Other operating revenues	1,857	2,915	3,197	4,992
Total operating revenues and other income	443,916	120,721	1,213,511	493,459
Operating expenses:				
Oil, gas, and NGL production expense	117,400	124,376	238,279	262,422
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	151,765	153,232	282,238	291,044
Exploration	14,056	12,983	27,783	24,800
Abandonment and impairment of unproved properties	11,935	157	17,560	157
General and administrative	28,920	28,237	56,602	57,054
Net derivative (gain) loss	63,749	(55,189)	71,278	(169,963)
Other operating expenses, net	(57)	4,251	4,555	9,110
Total operating expenses	387,768	268,047	698,295	474,624
Income (loss) from operations	56,148	(147,326)	515,216	18,835
Interest expense	(41,654)	(44,595)	(84,739)	(91,548)
Loss on extinguishment of debt	—	—	—	(35)
Other non-operating income, net	1,802	953	2,211	720
Income (loss) before income taxes	16,296	(190,968)	432,688	(72,028)
Income tax (expense) benefit	901	71,061	(98,090)	26,555
Net income (loss)	$17,197	$(119,907)	$334,598	$(45,473)
Basic weighted-average common shares outstanding	111,701	111,277	111,698	111,274
Diluted weighted-average common shares outstanding	113,630	111,277	113,267	111,274
Basic net income (loss) per common share	$0.15	$(1.08)	$3.00	$(0.41)
Diluted net income (loss) per common share	$0.15	$(1.08)	$2.95	$(0.41)
Dividends per common share	$—	$—	$0.05	$0.05

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

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Net income (loss)	$17,197	$(119,907)	$334,598	$(45,473)
Other comprehensive income (loss), net of tax:				
Pension liability adjustment	198	124	458	(443)
Total other comprehensive income (loss), net of tax	198	124	458	(443)
Total comprehensive income (loss)	$17,395	$(119,783)	$335,056	$(45,916)

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)
(in thousands)

	For the Six Months Ended June 30,	
	2018	2017 (as adjusted)
Cash flows from operating activities:		
Net income (loss)	$334,598	$(45,473)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Net (gain) loss on divestiture activity	(424,870)	129,670
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	282,238	291,044
Abandonment and impairment of unproved properties	17,560	157
Stock-based compensation expense	10,676	9,813
Net derivative (gain) loss	71,278	(169,963)
Derivative settlement gain (loss)	(61,193)	16,310
Amortization of debt discount and deferred financing costs	7,750	8,679
Loss on extinguishment of debt	—	35
Deferred income taxes	97,505	(30,790)
Other, net	(2,302)	4,464
Net change in working capital	(21,722)	28,182
Net cash provided by operating activities	311,518	242,128
Cash flows from investing activities:		
Net proceeds from the sale of oil and gas properties	742,215	766,247
Capital expenditures	(723,319)	(366,743)
Acquisition of proved and unproved oil and gas properties	(24,615)	(88,140)
Net cash provided by (used in) investing activities	(5,719)	311,364
Cash flows from financing activities:		
Proceeds from credit facility	—	406,000
Repayment of credit facility	—	(406,000)
Cash paid to repurchase Senior Notes	—	(2,344)
Cash paid for extinguishment of debt	—	(13)
Net proceeds from sale of common stock	1,881	1,738
Dividends paid	(5,584)	(5,563)
Other, net	(133)	(161)
Net cash used in financing activities	(3,836)	(6,343)
Net change in cash, cash equivalents, and restricted cash [1]	301,963	547,149
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]	$615,906	$559,521

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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 Six Months Ended June 30,	
	2018	2017 (as adjusted)
Operating activities:		
Cash paid for interest, net of capitalized interest	$(77,803)	$(83,493)
Net cash (paid) refunded for income taxes	$207	$(8,220)
Investing activities:		
Changes in capital expenditure accruals and other	$62,167	$44,770
Supplemental non-cash investing activities:		
Carrying value of properties exchanged	$—	$279,750
Supplemental non-cash financing activities:		
Non-cash loss on extinguishment of debt, net	$—	$22

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

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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 June 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 Immaterial Errors

The accompanying unaudited condensed consolidated financial statements for the three months ended June 30, 2018, include non-cash adjustments that relate to the prior quarter. For the three months ended June 30, 2018, the net gain (loss) on divestiture activity line item on the accompanying unaudited condensed consolidated statements of operations ("accompanying statements of operations") includes $17.7 million of loss (approximately $13.7 million, net of tax) that should have been included in the estimated non-cash write down to fair value less selling costs recorded as of March 31, 2018, for the Divide County, North Dakota assets held for sale. Additionally, for the three months ended June 30, 2018, the depletion, depreciation, amortization, and asset retirement obligation liability accretion expense line item on the accompanying statements of operations includes $6.7 million of additional expense (approximately $5.2 million, net of tax) that should have been recognized during the first quarter of 2018. Aggregated, these non-cash adjustments resulted in reported net income for the three months ended March 31, 2018, to be overstated by approximately $18.9 million (net of tax) with the corrections being recorded during the three months ended June 30, 2018, resulting in net income for the three months ended June 30, 2018, to be understated by approximately $18.9 million (net of tax). These non-cash adjustments are not deemed material with respect to the first or second quarters of 2018, or the anticipated results for fiscal year 2018. Further, these non-cash adjustments do not have an impact on the unaudited condensed consolidated financial statements for the six months ended June 30, 2018.

Significant Accounting Policies

The significant accounting policies followed by the Company are set forth in Note 1 - Summary of Significant Accounting Policies to 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. 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 six months ended June 30, 2017, are summarized as follows:

	For the Six Months Ended June 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	$242,115	$242,128
Cash flows from investing activities:		
Other, net	$3,000	N/A
Net cash provided by (used in) investing activities	$314,364	$311,364
Cash flows from financing activities:		
Cash paid for extinguishment of debt	N/A	$(13)
Net cash used in financing activities	$(6,330)	$(6,343)
Net change in cash and cash equivalents	$550,149	N/A
Net change in cash, cash equivalents, and restricted cash	N/A	$547,149
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	$559,521	N/A
Cash, cash equivalents, and restricted cash at end of period	N/A	$559,521

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the accompanying balance sheets:

	As of June 30, 2018	As of December 31, 2017
	(in thousands)	
Cash and cash equivalents	$615,906	$313,943
Restricted cash	—	—
Total cash, cash equivalents, and restricted cash	$615,906	$313,943

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 six months ended June 30, 2017, are summarized as follows:

	For the Three Months Ended June 30, 2017		For the Six Months Ended June 30, 2017	
	As Reported	As Adjusted	As Reported	As Adjusted
	(in thousands)			
Operating expenses:				
Exploration	$13,072	$12,983	$25,050	$24,800
General and administrative	$28,460	$28,237	$57,684	$57,054
Total operating expenses	$268,359	$268,047	$475,504	$474,624
Income (loss) from operations	$(147,638)	$(147,326)	$17,955	$18,835
Other non-operating income, net	$1,265	$953	$1,600	$720

Effective January 1, 2018, the Company early adopted 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. Under ASU 2016-02, companies are permitted to make a policy election to not recognize lease assets or liabilities when the term of the lease is less than twelve months. For agreements that contain both lease and non-lease components, companies are also permitted to make a policy election to combine both the lease and non-lease components together and account for these arrangements as a single lease. 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. Further, the Company is also evaluating policies, controls, and processes that will be necessary to support the additional accounting and disclosure requirements. The Company is also in the process of designing and implementing a lease administration system that will support the on-going maintenance and accounting for leases after adoption. The Company will adopt ASU 2016-02 on January 1, 2019, and plans on 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 is currently evaluating ASU 2018-11 as part of its overall assessment of ASU 2016-02, and will adopt ASU 2018-11 at the same time it adopts ASU 2016-02.

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 June 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, the Company does not expect any additional 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 six months ended June 30, 2018, and 2017:

	Permian		South Texas & Gulf Coast		Rocky Mountain		Total	
	Three Months Ended June 30,		Three Months Ended June 30,		Three Months Ended June 30,		Three Months Ended June 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
	(in thousands)							
Oil, gas, and NGL production revenue:								
Oil production revenue	$227,636	$78,554	$19,346	$13,072	$19,168	$37,248	$266,150	$128,874
Gas production revenue	31,734	12,937	52,235	87,760	95	1,043	84,064	101,740
NGL production revenue	129	107	52,248	53,558	(33)	660	52,344	54,325
Total	$259,499	$91,598	$123,829	$154,390	$19,230	$38,951	$402,558	$284,939
Relative percentage	64 %	32 %	31 %	54 %	5 %	14 %	100 %	100 %

Note: Amounts may not calculate due to rounding.

	Permian		South Texas & Gulf Coast		Rocky Mountain		Total	
	Six Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
	(in thousands)							
Oil, gas, and NGL production revenue:								
Oil production revenue	$433,430	$160,053	$38,929	$51,936	$54,851	$84,509	$527,210	$296,498
Gas production revenue	56,611	24,246	104,968	175,961	1,594	2,714	163,173	202,921
NGL production revenue	253	254	94,018	116,915	790	1,549	95,061	118,718
Total	$490,294	$184,553	$237,915	$344,812	$57,235	$88,772	$785,444	$618,137
Relative percentage	63 %	30 %	30 %	56 %	7 %	14 %	100 %	100 %

Note: Amounts may not calculate due to rounding.

The Company recognizes oil, gas, and NGL production revenue at the point in time when 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 and is considered the customer. Proceeds received for unprocessed gas under these arrangements are reflected as gas production revenue above 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 June 30, 2018, and December 31, 2017, were $115.0 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 six months ended June 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 $410.1 million for the six months ended June 30, 2018.

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 $15.7 million for the six months ended June 30, 2018. Please refer to Note 1 - Summary of Significant Accounting Policies for a discussion of an immaterial non-cash adjustment related to the Divide County Divestiture that was recorded in the second quarter of 2018.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Loss before income taxes [1]	$(17,478)	$(153,442)	$(28,975)	$(486,161)

(1) 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 net divestiture proceeds received at closing of $747.4 million, and net divestiture proceeds of $744.1 million after final purchase price adjustments. The Company recorded an estimated net gain of $397.4 million for the six months ended June 30, 2017, and a final net gain of $396.8 million related to these divested assets for the year ended December 31, 2017. During the second quarter of 2017, the Company divested of assets located in Williams County, North Dakota, for net divestiture proceeds of $24.6 million.

Assets 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 June 30, 2018, there were $5.0 million of assets held for sale presented on the accompanying balance sheets.

During the second quarter of 2017, the Company reclassified its retained Divide County assets previously held for sale to assets held for use. A $359.6 million write-down was recorded on these assets in the first quarter of 2017 based on the estimated fair value less selling costs as of March 31, 2017. An additional $166.9 million write-down was recorded in the second quarter of 2017 based on market conditions that existed on the date the Company made its decision to retain these assets.

Acquisitions

During the second quarter of 2018, the Company acquired approximately 720 net acres of unproved properties in Martin County, Texas, for $24.6 million. Under authoritative accounting guidance, this transaction was considered an asset acquisition. Therefore, the properties were recorded based on the fair value of the total consideration transferred on the acquisition date and the transaction costs were capitalized as a component of the cost of the assets acquired. During the first half of 2017, the Company acquired approximately 3,400 net acres of primarily unproved properties in Howard and Martin Counties, Texas, in multiple transactions for a total of $72.3 million of cash consideration, which were accounted for as asset acquisitions. Also, during the first half of 2017, the Company completed several non-monetary acreage trades of primarily unproved properties in Howard and Martin Counties, Texas, resulting in the Company acquiring approximately 6,550 net acres in exchange for approximately 5,700 net acres, with $279.8 million of carrying value attributed to the properties surrendered by the Company in such trades. 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 six months ended June 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 six months ended June 30, 2018, and 2017, consisted of the following:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Current portion of income tax (expense) benefit:				
Federal	$—	$4,607	$—	$(2,832)
State	40	2,439	(585)	(1,403)
Deferred portion of income tax (expense) benefit	861	64,015	(97,505)	30,790
Income tax (expense) benefit	$901	$71,061	$(98,090)	$26,555
Effective tax rate	(5.5)%	37.2%	22.7%	36.9%

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 for the three or six months ended June 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. For the three months ended June 30, 2018, the decrease in the effective tax rate year-over-year also reflects the cumulative effects of property divestitures in higher marginal rate states in 2018. Cumulative effects of state tax rate changes are reflected in the period legislation is enacted. Excess tax benefits and deficiencies from share-based payment awards impact the Company’s effective tax rate between periods.

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. The Company is generally no longer subject to United States federal or state income tax examinations by tax authorities for years before 2013.

Note 5 - Long-Term Debt

Credit Agreement

The Company's Fifth Amended and Restated Credit Agreement, as amended, (the "Credit Agreement") provides for a maximum loan amount of $2.5 billion and has a maturity date of December 10, 2019. On April 24, 2018, as part of the regular, semi-annual borrowing base redetermination process, the borrowing base and aggregate lender commitments were increased to $1.4 billion and $1.0 billion, respectively. Upon completion of the Divide County Divestiture on May 30, 2018, the Company's borrowing base was reduced to $1.3 billion, while the aggregate lender commitments remained at $1.0 billion. Please refer to Note 3 - Divestitures, Assets Held for Sale, and Acquisitions for additional discussion on the sale of these assets. The next scheduled redetermination date is October 1, 2018.

The Company must comply with certain financial and non-financial covenants under the terms of the Credit Agreement and was in compliance with all such covenants as of June 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 as presented in Note 5 - Long-Term Debt in the 2017 Form 10-K. Eurodollar loans accrue interest at the London Interbank Offered Rate, plus the applicable margin from the utilization grid, and Alternate Base Rate and swingline loans accrue interest at the prime 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 interest expense in the accompanying statements of operations.

The following table presents the outstanding balance, total amount of letters of credit outstanding, and available borrowing capacity under the Credit Agreement as of July 25, 2018, June 30, 2018, and December 31, 2017:

	As of July 25, 2018	As of June 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

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(1) Unamortized deferred financing costs attributable to the credit facility are presented as a component of other noncurrent assets on the accompanying balance sheets and totaled $2.4 million and $3.1 million as of June 30, 2018, and December 31, 2017, respectively.

(2) Letters of credit outstanding reduce the amount available under the credit facility on a dollar-for-dollar basis.

Senior Notes

The Company's Senior Notes consist of 6.50% Senior Notes due 2021, 6.125% Senior Notes due 2022, 6.50% Senior Notes due 2023, 5.0% Senior Notes due 2024, 5.625% Senior Notes due 2025, and 6.75% Senior Notes due 2026 (collectively referred to as "Senior Notes"). On June 15, 2018, the Company called for redemption all of its 6.50% Senior Notes due 2021 ("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 to be redeemed ("2021 Senior Notes Redemption"). As a result of the 2021 Senior Notes Redemption, the 2021 Senior Notes, net of unamortized deferred financing costs, were classified as a current liability on the accompanying balance sheets as of June 30, 2018. On July 16, 2018, the Company completed the 2021 Senior Notes Redemption, which resulted in the payment of total consideration, including accrued interest, of $355.9 million. The Company will record a loss on extinguishment of debt of $9.8 million for the quarter ended September 30, 2018. This amount will include $7.5 million associated with the premium paid for the 2021 Senior Notes Redemption and $2.3 million related to the acceleration of unamortized deferred financing costs.

The current portion of Senior Notes, net of unamortized deferred financing costs and noncurrent portion of Senior Notes, net of unamortized deferred financing costs lines on the accompanying balance sheets as of June 30, 2018, and December 31, 2017, consisted of the following:

	As of June 30, 2018			As of December 31, 2017		
	Principal Amount	Unamortized Deferred Financing Costs	Senior Notes, Net of Unamortized Deferred Financing Costs	Principal Amount	Unamortized Deferred Financing Costs	Senior Notes, Net of Unamortized Deferred Financing Costs
	(in thousands)					
6.50% Senior Notes due 2021	$344,611	$ 2,310	$ 342,301	$344,611	$ 2,656	$ 341,955
6.125% Senior Notes due 2022	561,796	5,211	556,585	561,796	5,800	555,996
6.50% Senior Notes due 2023	394,985	3,342	391,643	394,985	3,707	391,278
5.0% Senior Notes due 2024	500,000	5,149	494,851	500,000	5,610	494,390
5.625% Senior Notes due 2025	500,000	6,261	493,739	500,000	6,714	493,286
6.75% Senior Notes due 2026	500,000	6,824	493,176	500,000	7,242	492,758
Total	$2,801,392	$ 29,097	$ 2,772,295	$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 June 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.

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 June 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 June 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 June 30, 2018, and 2017, respectively, and totaled $5.2 million and $4.9 million for the six months ended June 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. The Senior Convertible Notes, net of unamortized discount and deferred financing costs line on the accompanying balance sheets as of June 30, 2018, and December 31, 2017, consisted of the following:

	As of June 30, 2018	As of December 31, 2017
	(in thousands)	
Principal amount of Senior Convertible Notes	$172,500	$172,500
Unamortized debt discount	(26,319)	(30,183)
Unamortized deferred financing costs	(2,751)	(3,210)

Senior Convertible Notes, net of unamortized discount and deferred financing costs	$143,430	$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 June 30, 2018, and through the filing of this report.

Note 6 - Commitments and Contingencies

Commitments

As of June 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 31 MMBbl of oil, 737 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 June 30, 2018, would total approximately $360.6 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 six months of 2018 and subsequent to June 30, 2018. As of the filing of this report, the Company’s drilling rig and completion service contract commitments totaled $103.1 million; however, if the Company terminated these contracts immediately, it would incur penalties of $40.4 million.

Additionally, as of June 30, 2018, the Company had fixed price contracts with various third parties to purchase electricity through 2027 for a total of $30.8 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 six 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 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 June 30, 2018, 6.8 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. For PSUs that were granted in 2015, 2016, and 2017, the performance criteria is based on a combination of the Company’s annualized Total Shareholder Return (“TSR”) for the performance period and the relative performance of the Company’s TSR compared with the annualized TSR of certain peer companies for the performance period. Compensation expense for PSUs is recognized within general and administrative expense and exploration expense over the vesting periods of the respective awards.

Total compensation expense recorded for PSUs was $2.4 million and $1.7 million for the three months ended June 30, 2018, and 2017, respectively, and was $4.8 million and $4.2 million for the six months ended June 30, 2018, and 2017, respectively. As of June 30, 2018, there was $12.4 million of total unrecognized compensation expense related to non-vested PSU awards, which is being amortized through 2020. There were no material changes to the outstanding and non-vested PSUs during the six months ended June 30, 2018.

Subsequent to June 30, 2018, the Company granted 572,924 PSUs with a fair value of $14.0 million (“2018 PSU Grant”). The fair value of the 2018 PSU Grant was measured at the grant date using a stochastic Monte Carlo simulation using geometric Brownian motion. The number of shares of the Company’s common stock issued to settle the 2018 PSU Grant, after the completion of a three-year performance period, will range from zero to two times the number of PSUs granted on the award date, depending on the extent to which the Company has achieved certain performance criteria and to the extent the PSUs have vested. As outlined in the 2018 PSU Grant agreement, performance measurements affecting vesting are based on a combination of relative performance of the Company’s annualized TSR compared with the annualized TSR of certain peer companies over the three-year performance period, and relative performance of the Company’s debt adjusted per share cash flow growth (“DACFG”) compared with the DACFG of certain peer companies over the three-year performance period. In addition to these performance measures, the 2018 PSU Grant agreement also stipulates that if the Company’s annualized 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 peers. Compensation expense associated with the 2018 PSU Grant will be evaluated on a quarterly basis and may be adjusted depending on the likelihood of achieving certain performance goals. The 2018 PSU Grant generally vests on the third anniversary of the date of the grant. Also, subsequent to June 30, 2018, the Company settled PSUs that were granted in 2015, with no shares issued upon settlement because the grant settled at a zero multiplier.

Employee Restricted Stock Units

The Company grants restricted stock units (“RSUs”) to eligible employees 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. Total compensation expense recorded for employee RSUs was $2.3 million and $2.1 million for the three months ended June 30, 2018, and 2017, respectively, and was $5.0 million and $4.6 million for the six months ended June 30, 2018, and 2017, respectively. As of June 30, 2018, there was $12.8 million of total unrecognized compensation expense related to non-vested RSU awards, which is being amortized through 2020. There were no material changes to the outstanding and non-vested RSUs during the six months ended June 30, 2018.

Subsequent to June 30, 2018, the Company granted 534,770 RSUs with a fair value of $13.7 million. These RSUs generally vest one-third of the total grant on each of the next three anniversary dates of the grant. Also, subsequent to June 30, 2018, the Company settled 406,013 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 290,584 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.

Employee Stock Purchase Plan

Under the Company’s Employee Stock Purchase Plan (“ESPP”), eligible employees may purchase shares of the Company’s common stock through payroll deductions of up to 15 percent of eligible compensation, without accruing in excess of $25,000 in value from purchases for each calendar year. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on either the first or last day of the purchase period. The ESPP is intended to qualify under Section 423 of the Internal Revenue Code. There were 100,249 and 123,678 shares issued under the ESPP during the second quarters of 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 six months ended June 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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Service cost	$1,705	$1,269	$3,365	$3,319
Interest cost	637	617	1,310	1,344
Expected return on plan assets that reduces periodic pension benefit cost	(370)	(563)	(931)	(1,122)
Amortization of prior service cost	5	5	9	9
Amortization of net actuarial loss	340	253	664	649
Net periodic benefit cost	$2,317	$1,581	$4,417	$4,199

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 $6.1 million to the Qualified Pension Plan during the six months ended June 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 six months ended June 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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Anti-dilutive	—	44	—	59

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands, except per share data)			
Net income (loss)	$17,197	$(119,907)	$334,598	$(45,473)
Basic weighted-average common shares outstanding	111,701	111,277	111,698	111,274
Dilutive effect of non-vested RSUs and contingent PSUs	1,929	—	1,569	—
Dilutive effect of Senior Convertible Notes	—	—	—	—
Diluted weighted-average common shares outstanding	113,630	111,277	113,267	111,274
Basic net income (loss) per common share	$0.15	$(1.08)	$3.00	$(0.41)
Diluted net income (loss) per common share	$0.15	$(1.08)	$2.95	$(0.41)

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 June 30, 2018, all derivative counterparties were members of the Company's credit facility 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 June 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)
Third quarter 2018	1,769	$ 49.77
Fourth quarter 2018	1,894	$ 49.87
2019	1,940	$ 50.70
Total	5,603	

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MBbl)	(per Bbl)	(per Bbl)
Third quarter 2018	1,948	$ 50.00	$ 58.61
Fourth quarter 2018	2,222	$ 50.00	$ 58.44
2019	10,055	$ 50.59	$ 63.62
2020	366	$ 55.00	$ 67.01
Total	14,591		

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)
Third quarter 2018	3,018	$ (1.06)	—	$ —
Fourth quarter 2018	3,327	$ (1.08)	—	$ —
2019	11,217	$ (3.36)	—	$ —
2020	7,250	$ (1.13)	1,288	$ (7.97)
2021	—	$ —	1,460	$ (7.80)
2022	—	$ —	274	$ (7.67)
Total	24,812		3,022	

(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)
Third quarter 2018	28,218	$ 3.25	(7,480)	$ 4.23	20,738	$ 2.90
Fourth quarter 2018	28,204	$ 3.27	(7,210)	$ 4.27	20,994	$ 2.92
2019	41,394	$ 3.87	(24,415)	$ 4.34	16,979	$ 2.92
Total	97,816		(39,105)		58,711	

Gas Collars

Contract Period	IF HSC Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(BBtu)	(per MMBtu)	(per MMBtu)
2019	14,242	$ 2.50	$ 2.83
Total	14,242		

NGL Swaps

	OPIS Ethane Purity Mont Belvieu		OPIS Propane Mont Belvieu Non-TET		OPIS Normal Butane Mont Belvieu Non-TET		OPIS Isobutane Mont Belvieu Non-TET		OPIS Natural Gasoline Mont Belvieu Non-TET	
Contract Period	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price
	(MBbl)	(per Bbl)	(MBbl)	(per Bbl)	(MBbl)	(per Bbl)	(MBbl)	(per Bbl)	(MBbl)	(per Bbl)
Third quarter 2018	1,033	$ 10.99	610	$ 24.27	93	$ 35.70	70	$ 35.07	202	$ 51.13
Fourth quarter 2018	1,146	$ 11.18	671	$ 24.39	102	$ 35.70	76	$ 35.07	208	$ 50.99
2019	3,533	$ 12.31	1,503	$ 27.83	154	$ 35.64	117	$ 35.70	197	$ 50.93
2020	539	$ 11.13	—	$ —	—	$ —	—	$ —	—	$ —
Total	6,251		2,784		349		263		607	

Commodity Derivative Contracts Entered Into Subsequent to June 30, 2018

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

- NYMEX WTI costless collar contracts for 2020 for a total of 0.8 MMBbl of oil production with contract floor prices of $55.00 per Bbl and contract ceiling prices ranging from $64.50 per Bbl to $67.67 per Bbl;
- fixed price NYMEX WTI-ICE Brent basis swap contracts for 2020 for a total of 0.6 MMBbl of oil production at contract prices ranging from ($8.06) per Bbl to ($8.15) per Bbl;
- fixed price NYMEX WTI-ICE Brent basis swap contracts for 2021 for a total of 1.8 MMBbl of oil production at contract prices ranging from ($7.75) per Bbl to ($8.00) per Bbl;
- fixed price NYMEX WTI-ICE Brent basis swap contracts for 2022 for a total of 2.6 MMBbl of oil production at contract prices ranging from ($7.60) per Bbl to ($7.90) per Bbl; and
- fixed price OPIS Propane Mont Belvieu Non-TET swap contracts for 2019 for a total of 0.5 MMBbl of NGL production at contract prices ranging from $32.21 per Bbl to $32.26 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 $149.4 million and $139.4 million as of June 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 June 30, 2018	As of December 31, 2017
	(in thousands)	
Derivative assets:		
Current assets	$ 146,329	$ 64,266
Noncurrent assets	31,151	40,362
Total derivative assets	$ 177,480	$ 104,628
Derivative liabilities:		
Current liabilities	$ 259,338	$ 172,582
Noncurrent liabilities	67,583	71,402
Total derivative liabilities	$ 326,921	$ 243,984

Offsetting of Derivative Assets and Liabilities

As of June 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	
	June 30, 2018	December 31, 2017	June 30, 2018	December 31, 2017
	(in thousands)			
Gross amounts presented in the accompanying balance sheets	$ 177,480	$ 104,628	$ (326,921)	$ (243,984)
Amounts not offset in the accompanying balance sheets	(147,009)	(100,035)	147,009	100,035
Net amounts	$ 30,471	$ 4,593	$ (179,912)	$ (143,949)

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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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Derivative settlement (gain) loss:				
Oil contracts	$24,430	$2,754	$45,178	$11,838
Gas contracts	757	(21,751)	(5,653)	(39,257)
NGL contracts	11,478	2,694	21,668	11,109
Total derivative settlement (gain) loss	$36,665	$(16,303)	$61,193	$(16,310)
Net derivative (gain) loss:				
Oil contracts	$22,402	$(38,194)	$36,368	$(87,784)
Gas contracts	7,000	(6,038)	16,990	(50,506)
NGL contracts	34,347	(10,957)	17,920	(31,673)
Total net derivative (gain) loss	$63,749	$(55,189)	$71,278	$(169,963)

Credit Related Contingent Features

As of June 30, 2018, and through the filing of this report, all of the Company's derivative counterparties were members of the Company's credit facility lender group. Under the Credit Agreement and derivative contracts, the Company is required to secure mortgages on assets having a value equal to at least 90 percent of the total PV-9 of the Company's proved oil and gas properties evaluated in the most recent reserve report.

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 June 30, 2018:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives [(1)]	$—	$177,480	$ —
Liabilities:			
Derivatives [(1)]	$—	$326,921	$ —

[(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	$ —

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[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. The calculation of the discount rates is based on the best information available and the rates used ranged from 10 percent to 15 percent based on the reservoir-specific weightings of future estimated proved and unproved cash flows as of June 30, 2018, and December 31, 2017. The Company believes the discount rates are representative of current market conditions and considers estimates of future cash payments, reserve categories, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The prices for oil and gas are forecast based on NYMEX strip pricing, adjusted for basis differentials, for the first five years, after which a flat terminal price is used for each commodity stream. The prices for NGLs are forecast using OPIS pricing, for as long as the market is actively trading, after which a flat terminal price is used. Future operating costs are also adjusted as deemed appropriate for these estimates. There were no material impairments of proved properties during the three and six months ended June 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 six months ended June 30, 2018, the Company recorded $11.9 million and $17.6 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 or six months ended June 30, 2017.

Oil and gas properties held for sale. Proved and unproved oil and gas properties classified as held for sale, including the 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 income 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 June 30, 2018, or as of December 31, 2017. For the six months ended June 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 as well as in the 2017 Form 10-K for more information regarding the Company's oil and gas properties held for sale.
Long-Term Debt
The following table reflects the fair value of the Senior Notes and Senior Convertible Notes 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 June 30, 2018, or December 31, 2017, as they were recorded at carrying value, net of any unamortized discounts and deferred financing costs. On July 16, 2018, the 2021 Senior Notes were redeemed. Please refer to Note 5 - Long-Term Debt for additional discussion.

	As of June 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	$352,634	$344,611	$351,682
6.125% Senior Notes due 2022	$561,796	$573,847	$561,796	$571,627
6.50% Senior Notes due 2023	$394,985	$401,380	$394,985	$403,434
5.0% Senior Notes due 2024	$500,000	$468,750	$500,000	$483,440
5.625% Senior Notes due 2025	$500,000	$485,000	$500,000	$494,355
6.75% Senior Notes due 2026	$500,000	$502,350	$500,000	$516,350
1.50% Senior Convertible Notes due 2021	$172,500	$178,446	$172,500	$168,291

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

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

Overview of the Company

General Overview

We are an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in onshore North America. We currently have producing assets and significant acreage positions in the Midland Basin and Eagle Ford shale plays 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 achieving high full-cycle economic returns on our investments and maintaining a strong balance sheet.

Outlook for 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.

As previously announced, we completed three divestitures of non-core assets during the first half of 2018, which have generated total net proceeds of $741.6 million, subject to final purchase price adjustments. We have used these proceeds to support continued development of our core acreage positions in the Midland Basin and Eagle Ford shale, while maintaining an undrawn balance on our credit facility as of June 30, 2018. These proceeds also were used in part to call all of the $344.6 million aggregate principal amount outstanding on our 2021 Senior Notes, which we redeemed in full on July 16, 2018. 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.

We continue to see significant production growth and value within our Midland Basin assets as our operational execution in this program is yielding stronger than expected well results, which have been key to our continued increase in oil volumes produced. Our focus remains on developing our high-margin assets in the Midland Basin, which we believe will continue to provide us with the best opportunity for positive cash flow growth. 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 increasing basis differentials and support our ability to continue to generate positive cash flows from our Midland Basis assets during this period. Please refer to Note 10 - Derivative Financial Instruments 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, which reflects a slight increase of $40 million primarily to account for higher than expected working interests for projects in the Midland Basin. As a result of these higher working interests, we are also expecting a slight increase in full year net well completions for 2018. We expect to invest over 80 percent of our total capital program in drilling and completion activities. We plan to allocate the majority of our 2018 capital to our Midland Basin program, which generates the highest margins and returns in our portfolio. As a result of drilling and completion efficiencies in our Midland Basin program, we have been able to reduce the number of drilling rigs and completion crews that we are using in the area. Planned drilling and completion activity in the Eagle Ford shale continues to be partially funded by a third party as part of our previously announced drilling and completion carry agreement in a focused portion of our Eagle Ford North area. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on our 2018 capital program.

Financial Results

- We recorded net income of $17.2 million and $334.6 million, or $0.15 and $2.95 per diluted share, for the three and six months ended June 30, 2018, respectively, compared with net loss of $119.9 million and $45.5 million, or $1.08 and $0.41 per diluted share, for the three and six months ended June 30, 2017, respectively. Net income for the three and six months ended June 30, 2018, was driven largely by increased production revenue and net gain on divestiture activity of $39.5 million and $424.9 million, respectively, but was partially offset by net derivative losses of $63.7 million and $71.3 million for the three and six months ended June 30, 2018, respectively. Please refer to Comparison of Financial Results and Trends Between the Three Months and Six Months Ended June 30, 2018, and 2017 below for additional discussion regarding the components of net income (loss) for each period presented.
- We had net cash provided by operating activities of $171.4 million and $311.5 million for the three and six months ended June 30, 2018, respectively, compared with $107.1 million and $242.1 million for the same periods in 2017, respectively. The increases in net cash provided by operating activities for the three and six months ended June 30, 2018, were driven largely by increased production revenue. Please refer to Overview of Liquidity and Capital Resources below for additional discussion of our sources and uses of cash.
- Adjusted EBITDAX, a non-GAAP financial measure, for the three and six months ended June 30, 2018, was $225.0 million and $435.1 million, respectively, compared with $154.0 million and $326.0 million for the same periods in 2017, respectively. The increases in adjusted EBITDAX for the three and six months ended June 30, 2018, were driven largely by increased production revenue and lower operating costs. Please refer to Non-GAAP Financial Measures below for additional discussion, including our definition of adjusted EBITDAX and reconciliations of our net income (loss) and net cash provided by operating activities to adjusted EBITDAX.

Operational Activities

In our Midland Basin program, we began the second quarter of 2018 with nine operated drilling rigs and five completion crews. During the quarter, we released one rig and two completion crews. In July 2018, we released a second rig, bringing our total number of operated drilling rigs to seven. For the full year 2018, we anticipate that our Midland Basin program will average seven operated drilling rigs and four completion crews. During the second quarter of 2018, our operations continued to focus on delineating and developing the Lower Spraberry and Wolfcamp A and B shale intervals in our RockStar acreage in Howard and Martin Counties, Texas, as well as our Sweetie Peck acreage in Upton and Midland Counties, Texas. In addition, we completed the core build out of our water handling system during the second quarter of 2018, which is now operational and serving a significant portion of our water disposal needs on our RockStar acreage. We expect to allocate approximately 86 percent of our budgeted 2018 drilling and completion capital to our Midland Basin program.

During the second quarter of 2018, we expanded our core RockStar acreage position by acquiring approximately 720 contiguous net acres of unproved properties in Martin County, Texas, for cash consideration of $24.6 million. Further, we closed on the previously announced sale of our non-core third-party operated Halff East assets in the Midland Basin during the second quarter of 2018.

In our operated Eagle Ford shale program, we operated two drilling rigs and averaged one completion crew during the second quarter of 2018. For the full year 2018, we anticipate our Eagle Ford shale program will operate approximately one to two drilling rigs and one to 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 second quarter of 2018. We expect the remaining wells associated with this agreement to be drilled and completed in 2018, with minimal capital investment required on our part. We plan to allocate approximately 14 percent of our budgeted 2018 drilling and completion capital to our Eagle Ford shale program.

During the first quarter of 2018, we successfully closed on the sale of our previously announced PRB Divestiture for net divestiture proceeds of $490.8 million, subject to final purchase price adjustments. In addition, during the second quarter of 2018, we closed on our previously announced sale of our remaining Bakken/Three Forks assets in Divide County, North Dakota.

The table below provides a summary of changes in our drilled but not completed well count and current year drilling and completion activity in our operated programs during the three and six months ended June 30, 2018:

	Midland Basin		Eagle Ford Shale		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

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

(2) During the second quarter of 2018, we successfully closed on the sale of our remaining Bakken/Three Forks assets in Divide County, North Dakota. As a result, we will no longer have any drilling or completion activity in the Rocky Mountain region after the second quarter of 2018.

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 June 30, 2018, and 2017:

	Permian		South Texas & Gulf Coast		Rocky Mountain [(1)]		Total	
	Three Months Ended June 30,		Three Months Ended June 30,		Three Months Ended June 30,		Three Months Ended June 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
Production:								
Oil (MMBbl)	3.7	1.7	0.3	0.4	0.3	0.9	4.4	2.9
Gas (Bcf)	6.2	3.4	18.8	29.6	0.3	1.1	25.3	34.0
NGLs (MMBbl)	—	—	1.9	2.7	—	—	1.9	2.8
Equivalent (MMBOE)	4.8	2.3	5.4	8.0	0.4	1.1	10.5	11.3
Avg. daily equivalents (MBOE/d)	52.4	24.9	58.9	88.0	3.9	11.7	115.2	124.6
Relative percentage	46 %	20 %	51 %	71 %	3 %	9 %	100 %	100 %

Note: Amounts may not calculate due to rounding.

(1) During the first quarter of 2018, we closed the PRB Divestiture, and during the second quarter of 2018, we closed the Divide County Divestiture. As a result of these divestitures, we will no longer have production volumes from the Rocky Mountain region after the second quarter of 2018.

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

	Permian		South Texas & Gulf Coast		Rocky Mountain [1]		Total	
	Six Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
Production:								
Oil (MMBbl)	7.0	3.3	0.7	1.3	0.9	1.8	8.6	6.4
Gas (Bcf)	11.8	6.2	37.5	59.6	1.2	2.1	50.5	67.9
NGLs (MMBbl)	—	—	3.5	5.6	—	0.1	3.6	5.7
Equivalent (MMBOE)	9.0	4.4	10.5	16.8	1.1	2.3	20.6	23.4
Avg. daily equivalents (MBOE/d)	49.9	24.2	57.9	92.7	6.2	12.5	113.9	129.5
Relative percentage	44 %	19 %	51 %	71 %	5 %	10 %	100 %	100 %

Note: Amounts may not calculate due to rounding.

(1) During the first quarter of 2018, we closed the PRB Divestiture, and during the second quarter of 2018, we closed the Divide County Divestiture. As a result of these divestitures, we will no longer have production volumes from the Rocky Mountain region after the second quarter of 2018.

Production on an equivalent basis decreased eight percent and 12 percent for the three and six months ended June 30, 2018, respectively, compared with the same periods in 2017. Production declines were primarily a result of the divestiture of our outside-operated Eagle Ford shale assets, which occurred in the first quarter of 2017, and declining production from our retained assets in the South Texas & Gulf Coast and Rocky Mountain regions as a result of shifting capital from these assets to our Midland Basin program, which currently generates the highest returns in our portfolio. Production declines in the Eagle Ford and Rocky Mountain region were largely offset by the increased production from the development of our Midland Basin assets, which had production increases of 110 percent and 106 percent for the three and six months ended June 30, 2018, respectively, compared with the same periods in 2017. Please refer to A Three-Month and Six-Month Overview of Selected Production and Financial Information, Including Trends and Comparison of Financial Results and Trends Between the Three Months and Six Months Ended June 30, 2018, and 2017 below for additional discussion on production.

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 $460.2 million and $832.4 million for the three and six months ended June 30, 2018, respectively, and were incurred primarily in our Midland Basin and Eagle Ford shale programs.

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 second and first quarters of 2018, as well as the second quarter of 2017:

	For the Three Months Ended		
	June 30, 2018	March 31, 2018	June 30, 2017
Oil (per Bbl):			
Average NYMEX contract monthly price	$67.88	$62.87	$48.28
Realized price, before the effect of derivative settlements	$61.02	$61.25	$44.30
Effect of oil derivative settlements	$(5.60)	$(4.86)	$(0.94)
Gas:			
Average NYMEX monthly settle price (per MMBtu)	$2.80	$3.00	$3.18
Realized price, before the effect of derivative settlements (per Mcf)	$3.32	$3.14	$2.99
Effect of gas derivative settlements (per Mcf)	$(0.03)	$0.25	$0.64
NGLs (per Bbl):			
Average OPIS price (1)	$33.10	$30.87	$24.11
Realized price, before the effect of derivative settlements	$27.55	$25.53	$19.71
Effect of NGL derivative settlements	$(6.04)	$(6.09)	$(0.98)

(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, gas, 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 July 25, 2018, and June 30, 2018:

	As of July 25, 2018	As of June 30, 2018
NYMEX WTI oil (per Bbl)	$66.91	$69.58
NYMEX Henry Hub gas (per MMBtu)	$2.78	$2.91
OPIS NGLs (per Bbl)	$33.25	$33.30

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. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report and to Commodity Price Risk in

Overview of Liquidity and Capital Resources below for additional information regarding our oil, gas, and NGL derivatives.

Financial Results of Operations and Additional Comparative Data

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

	For the Three Months Ended			
	June 30, 2018	March 31, 2018	December 31, 2017	September 30, 2017
	(in millions)			
Production (MMBOE)	10.5	10.1	10.4	10.7
Oil, gas, and NGL production revenue	$402.6	$382.9	$ 341.2	$ 294.5
Oil, gas, and NGL production expense	$117.4	$120.9	$ 122.8	$ 122.7
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$151.8	$130.5	$ 131.4	$ 134.6
Exploration [(1)]	$14.1	$13.7	$ 15.8	$ 14.1
General and administrative [(1)]	$28.9	$27.7	$ 32.7	$ 27.6
Net income (loss)	$17.2	$317.4	$ (26.3)	$ (89.1)

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			
	June 30, 2018	March 31, 2018	December 31, 2017	September 30, 2017
Average net daily production equivalent (MBOE per day)	115.2	112.7	112.6	116.0
Lease operating expense (per BOE)	$4.66	$4.95	$5.10	$4.81
Transportation costs (per BOE)	$4.47	$4.63	$5.01	$5.24
Production taxes as a percent of oil, gas, and NGL production revenue	4.3 %	4.4 %	4.3 %	4.2 %
Ad valorem tax expense (per BOE)	$0.41	$0.67	$0.33	$0.29
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$14.48	$12.87	$12.69	$12.61
General and administrative (per BOE) [(1)]	$2.76	$2.73	$3.15	$2.58

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

	For the Three Months Ended June 30, 2018	2017	Amount Change Between Periods	Percent Change Between Periods	For the Six Months Ended June 30, 2018	2017	Amount Change Between Periods	Percent Change Between Periods
Net production volumes: (1)								
Oil (MMBbl)	4.4	2.9	1.5	50 %	8.6	6.4	2.2	34 %
Gas (Bcf)	25.3	34.0	(8.7)	(26)%	50.5	67.9	(17.4)	(26)%
NGLs (MMBbl)	1.9	2.8	(0.9)	(31)%	3.6	5.7	(2.1)	(37)%
Equivalent (MMBOE)	10.5	11.3	(0.9)	(8)%	20.6	23.4	(2.8)	(12)%
Average net daily production: (1)								
Oil (MBbl per day)	47.9	32.0	16.0	50 %	47.6	35.5	12.1	34 %
Gas (MMcf per day)	278.3	374.1	(95.8)	(26)%	279.3	375.3	(96.1)	(26)%
NGLs (MBbl per day)	20.9	30.3	(9.4)	(31)%	19.7	31.4	(11.6)	(37)%
Equivalent (MBOE per day)	115.2	124.6	(9.4)	(8)%	113.9	129.5	(15.5)	(12)%
Oil, gas, and NGL production revenue (in millions): (1)								
Oil production revenue	$266.2	$128.9	$137.3	107 %	$527.2	$296.5	$230.7	78 %
Gas production revenue	84.1	101.7	(17.6)	(17)%	163.2	202.9	(39.7)	(20)%
NGL production revenue	52.3	54.3	(2.0)	(4)%	95.1	118.7	(23.7)	(20)%
Total oil, gas, and NGL production revenue	$402.6	$284.9	$117.6	41 %	$785.4	$618.1	$167.3	27 %
Oil, gas, and NGL production expense (in millions): (1)								
Lease operating expense	$48.8	$46.6	$2.2	5 %	$99.0	$92.7	$6.3	7 %
Transportation costs	46.9	64.7	(17.8)	(28)%	93.8	135.8	(42.0)	(31)%
Production taxes	17.4	11.3	6.1	54 %	34.4	25.4	9.0	35 %
Ad valorem tax expense	4.3	1.8	2.5	139 %	11.1	8.5	2.6	31 %
Total oil, gas, and NGL production expense	$117.4	$124.4	$(7.0)	(6)%	$238.3	$262.4	$(24.1)	(9)%
Realized price (before the effect of derivative settlements):								
Oil (per Bbl)	$61.02	$44.30	$16.72	38 %	$61.14	$46.08	$15.06	33 %
Gas (per Mcf)	$3.32	$2.99	$0.33	11 %	$3.23	$2.99	$0.24	8 %
NGLs (per Bbl)	$27.55	$19.71	$7.84	40 %	$26.60	$20.92	$5.68	27 %
Per BOE	$38.40	$25.13	$13.27	53 %	$38.09	$26.38	$11.71	44 %
Per BOE data:								
Production costs:								
Lease operating expense	$4.66	$4.11	$0.55	13 %	$4.80	$3.96	$0.84	21 %
Transportation costs	$4.47	$5.71	$(1.24)	(22)%	$4.55	$5.79	$(1.24)	(21)%
Production taxes	$1.66	$1.00	$0.66	66 %	$1.67	$1.09	$0.58	53 %
Ad valorem tax expense	$0.41	$0.16	$0.25	156 %	$0.54	$0.36	$0.18	50 %
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$14.48	$13.52	$0.96	7 %	$13.69	$12.42	$1.27	10 %
General and administrative (2)	$2.76	$2.49	$0.27	11 %	$2.74	$2.43	$0.31	13 %
Derivative settlement gain (loss) (3)	$(3.49)	$1.44	$(4.93)	(342)%	$(2.97)	$0.70	$(3.67)	(524)%
Earnings per share information:								
Basic net income (loss) per common share	$0.15	$(1.08)	$1.23	114 %	$3.00	$(0.41)	$3.41	832 %

Diluted net income (loss) per common share	$0.15	$(1.08)	$1.23	114	%	$2.95	$(0.41)	$3.36	820	%
Basic weighted-average common shares outstanding (in thousands)	111,701	111,277	424	—	%	111,698	111,274	424	—	%
Diluted weighted-average common shares outstanding (in thousands)	113,630	111,277	2,353	2	%	113,267	111,274	1,993	2	%

(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 six months ended June 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 and six months ended June 30, 2018, decreased eight percent and 12 percent, respectively, compared with the same periods 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 PRB, Divide County, and Halff East divestitures in the first half of 2018, and declining production from our retained Eagle Ford shale assets as a result of shifting capital from this area to fund development of our Midland Basin assets. 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 to increase and the percentage of oil relative to our total product mix to also increase in 2018 compared with 2017. Please refer to Comparison of Financial Results and Trends Between the Three Months and Six Months Ended June 30, 2018, and 2017 below for additional discussion.

Changes in production volumes, revenues, and costs are directly influenced by the volatility of commodity prices for the products we produce, fluctuations in costs necessary to develop and operate our properties, our ability to increase efficiencies in operations, and changes in our overall asset portfolio. 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 six months ended June 30, 2018, increased 53 percent and 44 percent, respectively, compared with the same periods in 2017. For the three and six months ended June 30, 2018, we realized a loss of $3.49 and $2.97 per BOE, respectively, on the settlement of our derivative contracts, which was primarily driven by improving oil and NGL prices in 2018. For the three and six months ended June 30, 2017, we realized a gain of $1.44 and $0.70 per BOE, respectively, on the settlement of our derivative contracts.

Lease operating expense ("LOE") on a per BOE basis increased 13 percent and 21 percent, for the three and six months ended June 30, 2018, respectively, compared with the same periods in 2017. The increase in LOE on a per BOE basis was 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. We expect LOE on a per BOE basis to be higher in 2018 compared with 2017 as our product mix continues to shift toward more oil production, which typically has higher LOE per BOE. We expect to experience volatility in our LOE as a result of changes in industry activity and the effects this has on service provider costs, changes in total production, changes in our overall production mix, and timing of workover projects.

Transportation expense on a per BOE basis decreased 22 percent and 21 percent, for the three and six months ended June 30, 2018, respectively, compared with the same periods in 2017. As discussed in the Production Results section above, the decrease in transportation costs per BOE was primarily driven by production declines from our Eagle Ford shale assets, which have higher average transportation costs than our Midland Basin assets. Going forward, we expect total transportation expense 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 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 expense on these assets.

Production taxes on a per BOE basis increased 66 percent and 53 percent, for the three and six months ended June 30, 2018, respectively, compared with the same periods in 2017. This increase was primarily driven by a 53 percent and

44 percent increase in our realized price before the effect of derivative settlements for the three and six months ended June 30, 2018, respectively, compared with the same periods in 2017. There was also a slight increase in our overall production tax rate, which for the six months ended June 30, 2018, was 4.4 percent, 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 156 percent and 50 percent for the three and six months ended June 30, 2018, respectively, compared with the same periods in 2017 as a result of 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 seven percent and 10 percent, for the three and six months ended June 30, 2018, respectively, compared with the same periods in 2017. The increase for the three and six months ended June 30, 2018, is driven by the increase in production volumes from our Midland Basin assets, which have higher depletion rates than our Eagle Ford shale assets. Our DD&A rate fluctuates as a result of impairments, divestiture activity, 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 increased 11 percent and 13 percent for the three and six months ended June 30, 2018, respectively, compared with the same periods in 2017 due to the lower production volumes as a result of divestitures and declining production from our retained operated Eagle Ford shale assets. 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 flat compared with 2017 as full year 2018 production is expected to be in line with 2017.
Please refer to Comparison of Financial Results and Trends Between the Three Months and Six Months Ended June 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 Six Months Ended June 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 six months ended June 30, 2018, and 2017:

	Net Equivalent Production Increase (Decrease)		Production Revenue Increase (Decrease)		Production Expense Increase (Decrease)	
	Three Months Ended	Six Months Ended	Three Months Ended	Six Months Ended	Three Months Ended	Six Months Ended
	(MMBOE)		(in millions)		(in millions)	
Permian	2.5	4.7	$167.9	$305.7	$20.6	$41.6
South Texas & Gulf Coast	(2.6)	(6.3)	(30.6)	(106.9)	(17.5)	(52.4)
Rocky Mountain [(1)]	(0.7)	(1.2)	(19.7)	(31.5)	(10.1)	(13.4)
Total	(0.9)	(2.8)	$117.6	$167.3	$(7.0)	$(24.1)

Note: Amounts may not calculate due to rounding.
(1) During the first quarter of 2018, we closed the PRB Divestiture, and during the second quarter of 2018, we closed the Divide County Divestiture. As a result of these divestitures, we will no longer have production volumes from the Rocky Mountain region after the second quarter of 2018.

For the three months and six months ended June 30, 2018, compared with the same periods in 2017, we experienced an eight percent and a 12 percent decrease, respectively, in net equivalent production volumes primarily as a result of divestiture activity and declining production from our retained Eagle Ford shale assets as a result of shifting capital to our Midland Basin program. These declines were largely offset by increased production in our Permian region, which compared with the same periods in 2017, had production increases of 110 percent and 106 percent for the three and six months ended June 30, 2018, respectively. Increased production in the Permian region also drove oil production as a percentage of our overall product mix to increase from 27 percent for the six months ended June 30, 2017, to 42 percent for the six months ended June 30, 2018. Compared with the same periods in 2017, realized prices on a per BOE basis increased 53 percent and 44 percent for the three and six months ended June 30, 2018, respectively, resulting in an overall 41 percent and 27 percent increase in oil, gas, and NGL production revenues for the three and six months ended June 30, 2018, respectively. Production expense for the three and six months ended June 30, 2018, compared with the same periods in 2017, decreased six percent and nine percent, respectively, primarily as a result of the decreased production volumes discussed above.

Please refer to A Three-Month and Six-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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Net gain (loss) on divestiture activity	$39.5	$(167.1)	$424.9	$(129.7)

The $39.5 million net gain on divestiture activity recorded for the three months ended June 30, 2018, was primarily the result of a net gain recorded for the Halff East Divestiture partially offset by a loss recorded for the Divide County Divestiture. The $424.9 million net gain on divestiture activity recorded for the six months ended June 30, 2018, was primarily the result of an estimated net gain of $410.1 million recorded for the PRB Divestiture, which closed in the first quarter of 2018.

The net loss on divestiture activity recorded for the three months ended June 30, 2017, was a result of a $166.9 million write-down recorded on certain North Dakota assets that were reclassified from assets held for sale to assets held for use, based on market conditions that existed when we decided to retain these assets during 2017. There was also a $359.6 million write-down recorded on these assets in the first quarter of 2017 based on the estimated fair value less selling costs as of March 31, 2017. Partially offsetting these write-downs recorded during the six months ended June 30, 2017, was the $397.4 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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$151.8	$153.2	$282.2	$291.0

DD&A expense decreased one percent and three percent for the three and six months ended June 30, 2018, respectively, compared with the same periods in 2017, due to the decline in our production volumes and the impact of assets sold. Please refer to the section A Three-Month and Six-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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Exploration [1]	$14.1	$13.0	$27.8	$24.8

[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 increased eight percent and 12 percent for the three and six months ended June 30, 2018, respectively, compared with the same periods in 2017, due to increased expenditures for geological and geophysical activity on our Midland Basin assets. As we continue our focus on testing and delineating our Midland Basin acreage, we expect increased 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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Abandonment and impairment of unproved properties	$11.9	$0.2	$17.6	$0.2

Unproved property impairments recorded for the three and six months ended June 30, 2018, and 2017, related to lease expirations. We expect unproved property 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. Any amount of future impairment is difficult to predict, but based on updated commodity price assumptions as of July 25, 2018, we do not expect any material impairments in the third quarter of 2018 resulting from commodity price impacts. Abandonment and impairment of unproved properties expense will be recognized as additional lease expirations are identified.

General and administrative

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
General and administrative [(1)]	$28.9	$28.2	$56.6	$57.1

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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 six months ended June 30, 2018, compared with the same periods in 2017. We expect G&A expense in total to continue to remain flat for the full year 2018 compared with 2017. Please refer to the section A Three-Month and Six-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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Net derivative (gain) loss	$63.7	$(55.2)	$71.3	$(170.0)

We recognized a $63.7 million derivative loss for the three months ended June 30, 2018, due in part to a $59.3 million decrease in the fair value of contracts settling subsequent to June 30, 2018. Additionally, we recognized a $4.4 million loss on contracts that settled during the second quarter of 2018, which had a fair value of $32.2 million at March 31, 2018, and settled for a loss of $36.7 million. We recognized a $3.2 million loss on first quarter 2018 contract settlements and recorded a $4.4 million decrease to the fair value of remaining contracts as of March 31, 2018, resulting in a year-to-date net derivative loss of $71.3 million for the six months ended June 30, 2018.

We recognized a $55.2 million derivative gain for the three months ended June 30, 2017, due largely to a $51.1 million increase in the fair value of contracts settling subsequent to June 30, 2017. Additionally, we recognized a $4.1

million gain on contracts that settled during the second quarter of 2017, which had a fair value of $12.2 million at March 31, 2017, and settled for $16.3 million. We recognized a $20.5 million gain on first quarter 2017 contract settlements and recorded a $94.3 million increase in the fair value of remaining contracts as of March 31, 2017, resulting in a year-to-date net derivative gain of $170.0 million.

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

Interest expense

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Interest expense	$(41.7)	$(44.6)	$(84.7)	$(91.5)

The seven percent decrease in interest expense for both the three and six months ended June 30, 2018, compared with the same periods in 2017, was primarily driven by an increase in capitalized interest as a result of our higher level of development activity. 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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions, except tax rate)			
Income tax (expense) benefit	$0.9	$71.1	$(98.1)	$26.6
Effective tax rate	(5.5)%	37.2 %	22.7 %	36.9 %

The decrease in the effective tax rate for the three and six months ended June 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. For the three months ended June 30, 2018 and June 30, 2017, the effect of minor changes to permanent state items on changing year-to-date pretax income caused an additional rate decrease year-over-year. The rate also 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 six months ended June 30, 2018, we received $742.2 million of net proceeds from the sale of oil and gas properties. As of June 30, 2018, our cash balance totaled $615.9 million. As of June 30, 2018, the combination of our cash balance with our $999.8 million of available borrowing capacity under our Credit Agreement, resulted in $1.6 billion in liquidity.

Although we anticipate cash flows from operations and divestiture proceeds will be sufficient to fund our expected 2018 capital program and the 2021 Senior Notes Redemption, which was completed on July 16, 2018, 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 net increase in our borrowing base in the second quarter of 2018. Our borrowing base could be reduced as a result of lower commodity prices, divestitures of proved properties, or newly issued debt. 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

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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

Our Credit Agreement provides for a maximum loan amount of $2.5 billion and has a maturity date of December 10, 2019. On April 24, 2018, as part of the regular, semi-annual borrowing base redetermination process, our borrowing base and aggregate lender commitments were increased to $1.4 billion and $1.0 billion, respectively. The increase in the borrowing base was primarily driven by the increased value of our estimated proved reserves at December 31, 2017. Upon completion of the Divide County Divestiture on May 30, 2018, the borrowing base was reduced to $1.3 billion while the aggregate lender commitments remained at $1.0 billion. The next scheduled redetermination date is October 1, 2018.

We had no outstanding balance under our Credit Agreement as of June 30, 2018, or as of the filing of this report. No individual bank participating in our Credit Agreement represents more than 10 percent of the lender commitments under the Credit Agreement. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion as well as the presentation of the outstanding balance, total amount of letters of credit, and available borrowing capacity under our Credit Agreement as of July 25, 2018, June 30, 2018, and December 31, 2017.

We must comply with certain financial and non-financial covenants under the Credit Agreement, including covenants limiting dividend payments and requiring us to maintain certain financial ratios, as defined by the Credit Agreement. Certain financial covenants under the Credit Agreement require, as of the last day of each fiscal quarter, our (a) ratio of senior secured debt to 12-month trailing adjusted EBITDAX to be not more than 2.75 to 1.0; (b) adjusted current ratio to be not less than 1.0 to 1.0; and (c) ratio of 12-month trailing adjusted EBITDAX to interest expense to be not less than 2.0 to 1.0. We were in compliance with all financial and non-financial covenants under the Credit Agreement as of June 30, 2018, and through the filing of this report. Please refer to the caption Non-GAAP Financial Measures below for the calculation of adjusted EBITDAX and reconciliations of net income (loss) and net cash provided by operating activities to adjusted EBITDAX.

We had no credit facility activity during the six months ended June 30, 2018, due to our cash balance resulting primarily from proceeds received from divestiture activity. 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 facility.

Weighted-Average Interest Rates

Our weighted-average interest rates include 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 six months ended June 30, 2018, and 2017:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Weighted-average interest rate	6.4%	6.4%	6.5%	6.5%

Weighted-average borrowing rate 5.8% 5.8% 5.8% 5.8%

The weighted-average interest rate and weighted-average borrowing for the three and six months ended June 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. 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 six months ended June 30, 2018, we spent $747.9 million 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 assimilate acquisitions and 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 June 15, 2018, we announced that we would be calling for redemption all of our 2021 Senior Notes. On July 16, 2018, we completed the 2021 Senior Notes Redemption which resulted in the payment of total consideration, including accrued interest, of $355.9 million. As part of our strategy for 2018, we continue to focus on opportunities for improving our debt metrics. 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 Six Months Ended June 30, 2018, and 2017

The following tables present changes in cash flows between the six months ended June 30, 2018, and 2017, for our operating, investing, and financing activities. The six months ended June 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 Six Months Ended June 30,	
	2018	2017
	(in millions)	
Net cash provided by operating activities	$311.5	$242.1

Cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, including derivative cash settlements, increased $54.1 million for the six months ended June 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 Six Months Ended June 30,	
	2018	2017
	(in millions)	
Net cash provided by (used in) investing activities	$(5.7)	$311.4

The decrease in cash flows from investing activities for the six months ended June 30, 2018, compared with the same period in 2017 is largely due to an increase in capital expenditures of $356.6 million, partially offset by a $63.5 million decrease in acquisition expenditures. The overall increase is due to higher capital expenditures in our Midland Basin program as compared with the same period in 2017. Further, divestiture cash proceeds received in the first half of 2018 decreased $24.0 million, compared with the same period in 2017.

Financing activities

	For the Six Months Ended June 30,	
	2018	2017
	(in millions)	
Net cash used in financing activities	$(3.8)	$(6.3)

Cash used in financing activities is primarily the result of $5.6 million of dividends paid during the six months ended June 30, 2018, and 2017, respectively.

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 June 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 June 30, 2018, our outstanding fixed-rate debt totaled $3.0 billion. On July 16, 2018, we completed the 2021 Senior Notes Redemption, which reduced our outstanding fixed-rate debt total to $2.6 billion. Please refer to Note 5 - Long-Term Debt and Note 11 - Fair Value Measurements in Part I, Item 1 of this report for additional discussion of the 2021 Senior Notes Redemption and 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 six months ended June 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 $52.7 million, $16.3 million, and $9.5 million, respectively. If commodity prices had been 10 percent lower, our net derivative settlements for the six months ended June 30, 2018, would have offset the declines in oil, gas, and NGL production revenues by approximately $51.8 million.

We enter into commodity derivative contracts in order to reduce the impact of fluctuations in commodity prices. The fair value of our commodity derivative contracts are largely determined by estimates of the forward curves of the relevant price indices. As of June 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 $102.2 million, $20.5 million, and $24.4 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 six months ended June 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 Credit Agreement 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 senior secured debt to adjusted EBITDAX and a minimum permitted ratio of adjusted EBITDAX to interest, 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 June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Net income (loss) (GAAP)	$17,197	$(119,907)	$334,598	$(45,473)
Interest expense	41,654	44,595	84,739	91,548
Interest income [1]	(2,414)	(1,265)	(3,263)	(1,600)
Income tax expense (benefit)	(901)	(71,061)	98,090	(26,555)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	151,765	153,232	282,238	291,044
Exploration [2] [3]	12,867	11,988	25,278	22,397
Abandonment and impairment of unproved properties	11,935	157	17,560	157
Stock-based compensation expense	5,264	4,358	10,676	9,813
Net derivative (gain) loss	63,749	(55,189)	71,278	(169,963)
Derivative settlement gain (loss)	(36,665)	16,303	(61,193)	16,310
Net (gain) loss on divestiture activity	(39,501)	167,133	(424,870)	129,670
Loss on extinguishment of debt	—	—	—	35
Other, net	2	3,655	9	8,641
Adjusted EBITDAX (non-GAAP) [3]	224,952	153,999	435,140	326,024
Interest expense	(41,654)	(44,595)	(84,739)	(91,548)
Interest income [1]	2,414	1,265	3,263	1,600
Income tax (expense) benefit	901	71,061	(98,090)	26,555
Exploration [2] [3]	(12,867)	(11,988)	(25,278)	(22,397)
Amortization of debt discount and deferred financing costs	3,884	3,733	7,750	8,679
Deferred income taxes	(861)	(64,015)	97,505	(30,790)
Other, net [3]	223	(2,567)	(2,311)	(4,177)
Net change in working capital	(5,609)	256	(21,722)	28,182
Net cash provided by operating activities (GAAP) [3]	$171,383	$107,149	$311,518	$242,128

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(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 the Chief Executive Officer and the 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 second 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 June 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)
04/01/18 - 04/30/18	—	$ —	—	3,072,184
05/01/18 - 05/31/18	355	$ 26.64	—	3,072,184
06/01/18 - 06/30/18	—	$ —	—	3,072,184
Total:	355	$ 26.64	—	3,072,184

(1) All shares purchased by us in the second 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 covenants under the terms of our Credit Agreement that limit our annual dividend payments to no more than $50.0 million per year. We are also subject to certain covenants under the indentures governing our Senior Notes and Senior Convertible Notes that restrict certain payments, including dividends; however, the first $6.5 million of dividends paid each year are not restricted by these covenants. Based on our current performance, we do not anticipate that 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)
10.1*†	Performance Share Unit Award Agreement as of July 1, 2018
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

August 2, 2018 By: /s/ JAVAN D. OTTOSON

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

August 2, 2018 By: /s/ A. WADE PURSELL

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

August 2, 2018 By: /s/ MARK T. SOLOMON

Mark T. Solomon
Vice President - Controller and Assistant Secretary
(Principal Accounting Officer)