CIMAREX ENERGY CO
Form 10-Q
August 07, 2018
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
ý 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 No. 001-31446
CIMAREX ENERGY CO.
(Exact name of registrant as specified in its charter)

Delaware	45-0466694
(State of other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1700 Lincoln Street, Suite 3700, Denver, Colorado	80203
(Address of principal executive offices)	(Zip Code)

(303) 295-3995
(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 ý 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 ý No o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ý	Accelerated filer o	Non-accelerated filer o	Smaller reporting company o
		(Do not check if a smaller reporting company)	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 ý

The number of shares of Cimarex Energy Co. common stock outstanding as of July 31, 2018 was 95,356,074.

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GLOSSARY

Bbls—Barrels
Bcf—Billion cubic feet
BOE—Barrels of oil equivalent
Gross Wells—The total wells in which a working interest is owned.
MBbls—Thousand barrels
MBOE—Thousand barrels of oil equivalent
Mcf—Thousand cubic feet
MMBtu—Million British thermal units
MMcf—Million cubic feet
Net Wells—The sum of the fractional working interest owned in gross wells expressed in whole numbers and fractions of whole numbers.
NGL or NGLs—Natural gas liquids
Energy equivalent is determined using the ratio of one barrel of crude oil, condensate, or NGL to six Mcf of natural gas

CAUTIONARY INFORMATION ABOUT FORWARD-LOOKING STATEMENTS

Throughout this Form 10-Q, we make statements that may be deemed “forward-looking” statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended. These forward-looking statements include, among others, statements concerning our outlook with regard to timing and amount of future production of oil and gas, price realizations, amounts, nature and timing of capital expenditures for exploration and development, plans for funding operations and capital expenditures, drilling of wells, operating costs and other expenses, marketing of oil, gas, and NGLs and other statements of expectations, beliefs, future plans and strategies, anticipated events or trends, and similar expressions concerning matters that are not historical facts. The forward-looking statements in this report are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in or implied by the statements.

These risks and uncertainties include, but are not limited to, fluctuations in the price we receive for our oil and gas production, full cost ceiling test impairments to the carrying values of our oil and gas properties, reductions in the quantity of oil and gas sold due to decreased industry-wide demand and/or curtailments in production from specific properties or areas due to mechanical, transportation, marketing, weather or other problems, operating and capital expenditures that are either significantly higher or lower than anticipated because the actual cost of identified projects varied from original estimates and/or from the number of exploration and development opportunities being greater or fewer than currently anticipated, increased financing costs due to a significant increase in interest rates, availability of financing, and the effectiveness of our internal control over financial reporting and our ability to remediate a material weakness in our internal control over financial reporting. In addition, exploration and development opportunities that we pursue may not result in economic, productive oil and gas properties. There are also numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and the timing of development expenditures. These and other risks and uncertainties affecting us are discussed in greater detail in this report and in our other filings with the Securities and Exchange Commission.

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PART I
ITEM 1. - Financial Statements
CIMAREX ENERGY CO.
Condensed Consolidated Balance Sheets
(in thousands, except share and per share information)
(Unaudited)

	June 30, 2018	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$410,823	$ 400,534
Accounts receivable, net of allowance:		
Trade	128,984	100,356
Oil and gas sales	304,255	344,552
Gas gathering, processing, and marketing	11,416	15,266
Oil and gas well equipment and supplies	53,375	49,722
Derivative instruments	72,943	15,151
Prepaid expenses	7,419	8,518
Other current assets	927	1,536
Total current assets	990,142	935,635
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	18,112,548	17,513,460
Unproved properties and properties under development, not being amortized	532,715	476,903
	18,645,263	17,990,363
Less—accumulated depreciation, depletion, amortization, and impairment	(15,000,443)	(14,748,833)
Net oil and gas properties	3,644,820	3,241,530
Fixed assets, net of accumulated depreciation of $312,927 and $290,114, respectively	238,964	210,922
Goodwill	620,232	620,232
Derivative instruments	2,330	2,086
Other assets	34,905	32,234
	$5,531,393	$ 5,042,639
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable:		
Trade	$74,596	$ 68,883
Gas gathering, processing, and marketing	20,643	29,503
Accrued liabilities:		
Exploration and development	146,886	115,762
Taxes other than income	24,392	23,687
Other	199,093	212,400
Derivative instruments	90,480	42,066
Revenue payable	180,869	187,273
Total current liabilities	736,959	679,574
Long-term debt:		
Principal	1,500,000	1,500,000
Less—unamortized debt issuance costs and discount	(12,261)	(13,080)
Long-term debt, net	1,487,739	1,486,920
Deferred income taxes	201,350	101,618
Asset retirement obligation	159,568	158,421

Derivative instruments	11,511	4,268
Other liabilities	47,768	43,560
Total liabilities	2,644,895	2,474,361
Commitments and contingencies (Note 10)		
Stockholders’ equity:		
Preferred stock, $0.01 par value, 15,000,000 shares authorized, no shares issued	—	—
Common stock, $0.01 par value, 200,000,000 shares authorized, 95,392,547 and 95,437,434 shares issued, respectively	954	954
Additional paid-in capital	2,770,532	2,764,384
Retained earnings (accumulated deficit)	112,811	(199,259)
Accumulated other comprehensive income	2,201	2,199
Total stockholders’ equity	2,886,498	2,568,278
	$5,531,393	$5,042,639

See accompanying Notes to Condensed Consolidated Financial Statements.

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CIMAREX ENERGY CO.
Condensed Consolidated Statements of Operations and Comprehensive Income
(in thousands, except per share information)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenues:				
Oil sales	$342,184	$232,453	$693,907	$456,519
Gas and NGL sales	202,202	213,360	405,920	425,731
Gas gathering and other	11,810	10,735	23,262	21,360
Gas marketing	78	(96)	319	18
	556,274	456,452	1,123,408	903,628
Costs and expenses:				
Depreciation, depletion, and amortization	143,388	107,884	276,247	203,700
Asset retirement obligation	2,053	960	3,113	2,580
Production	79,215	62,578	150,486	124,999
Transportation, processing, and other operating	51,933	58,624	97,098	113,647
Gas gathering and other	9,467	8,647	19,290	17,074
Taxes other than income	27,930	17,477	58,118	38,790
General and administrative	19,739	19,762	43,060	37,796
Stock compensation	3,095	6,293	9,825	12,581
Loss (gain) on derivative instruments, net	21,699	(22,509)	17,540	(66,370)
Other operating expense, net	5,252	266	5,455	882
	363,771	259,982	680,232	485,679
Operating income	192,503	196,470	443,176	417,949
Other (income) and expense:				
Interest expense	16,895	20,095	33,678	41,147
Capitalized interest	(4,850)	(5,442)	(9,660)	(12,083)
Loss on early extinguishment of debt	—	28,169	—	28,169
Other, net	(2,605)	(2,231)	(7,172)	(4,441)
Income before income tax	183,063	155,879	426,330	365,157
Income tax expense	42,066	58,617	99,015	136,923
Net income	$140,997	$97,262	$327,315	$228,234
Earnings per share to common stockholders:				
Basic	$1.48	$1.02	$3.44	$2.40
Diluted	$1.48	$1.02	$3.44	$2.40
Dividends declared per share	$0.16	$0.08	$0.32	$0.16
Comprehensive income:				
Net income	$140,997	$97,262	$327,315	$228,234
Other comprehensive income:				
Change in fair value of investments, net of tax of $57, $128, $1, and $359, respectively	192	224	2	626
Total comprehensive income	$141,189	$97,486	$327,317	$228,860

See accompanying Notes to Condensed Consolidated Financial Statements.

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CIMAREX ENERGY CO.
Condensed Consolidated Statements of Cash Flows
(in thousands)
(Unaudited)

	Six Months Ended June 30, 2018	2017
Cash flows from operating activities:		
Net income	$327,315	$228,234
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, and amortization	276,247	203,700
Asset retirement obligation	3,113	2,580
Deferred income taxes	99,732	136,929
Stock compensation	9,825	12,581
Loss (gain) on derivative instruments, net	17,540	(66,370)
Settlements on derivative instruments	(19,919)	(5,717)
Loss on early extinguishment of debt	—	28,169
Changes in non-current assets and liabilities	713	1,076
Other, net	2,179	3,445
Changes in operating assets and liabilities:		
Accounts receivable	15,012	(61,145)
Other current assets	1,886	(11,104)
Accounts payable and other current liabilities	(29,304)	32,422
Net cash provided by operating activities	704,339	504,800
Cash flows from investing activities:		
Oil and gas capital expenditures	(650,807)	(582,172)
Other capital expenditures	(56,112)	(18,209)
Sales of oil and gas assets	34,842	9,163
Sales of other assets	525	394
Net cash used by investing activities	(671,552)	(590,824)
Cash flows from financing activities:		
Borrowings of long-term debt	—	748,110
Repayments of long-term debt	—	(750,000)
Call premium, financing, and underwriting fees	—	(29,035)
Dividends paid	(22,801)	(15,153)
Employee withholding taxes paid upon the net settlement of equity-classified stock awards	(946)	(1,215)
Proceeds from exercise of stock options	1,249	36
Net cash used by financing activities	(22,498)	(47,257)
Net change in cash and cash equivalents	10,289	(133,281)
Cash and cash equivalents at beginning of period	400,534	652,876
Cash and cash equivalents at end of period	$410,823	$519,595

See accompanying Notes to Condensed Consolidated Financial Statements.
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CIMAREX ENERGY CO.
Condensed Consolidated Statement of Stockholders’ Equity
(in thousands)
(Unaudited)

	Common Stock		Additional Paid-in	Retained Earnings (Accumulated	Accumulated Other Comprehensive	Total Stockholders’
	Shares	Amount	Capital	Deficit)	Income	Equity
Balance, December 31, 2017	95,437	$ 954	$2,764,384	$(199,259)	$ 2,199	$2,568,278
Dividends paid on stock awards subsequently forfeited	—	—	29	17	—	46
Dividends	—	—	—	(15,262)	—	(15,262)
Dividends in excess of retained earnings	—	—	(15,250)	—	—	(15,250)
Net income	—	—	—	327,315	—	327,315
Unrealized change in fair value of investments, net of tax	—	—	—	—	2	2
Issuance of restricted stock awards	29	—	—	—	—	—
Common stock reacquired and retired	(8)	—	(946)	—	—	(946)
Restricted stock forfeited and retired	(82)	—	—	—	—	—
Exercise of stock options	17	—	1,249	—	—	1,249
Stock-based compensation	—	—	21,066	—	—	21,066
Balance, June 30, 2018	95,393	$ 954	$2,770,532	$ 112,811	$ 2,201	$2,886,498

See accompanying Notes to Condensed Consolidated Financial Statements.
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CIMAREX ENERGY CO.
Notes to Condensed Consolidated Financial Statements
June 30, 2018
(Unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited financial statements have been prepared by Cimarex Energy Co. (“Cimarex,” “we,” or “us”) pursuant to rules and regulations of the Securities and Exchange Commission (“SEC”). Accordingly, certain disclosures required by accounting principles generally accepted in the United States and normally included in Annual Reports on Form 10-K have been omitted. Although management believes that our disclosures in these interim financial statements are adequate, they should be read in conjunction with the financial statements, summary of significant accounting policies, and footnotes included in our Annual Report on Form 10-K for the year ended December 31, 2017.

In the opinion of management, the accompanying financial statements reflect all adjustments necessary to fairly present our financial position, results of operations, and cash flows for the periods and as of the dates shown. Certain amounts in the prior year financial statements have been reclassified to conform to the 2018 financial statement presentation.

Use of Estimates

Areas of significance requiring the use of management’s judgments include the estimation of proved oil and gas reserves used in calculating depletion, the estimation of future net revenues used in computing ceiling test limitations, the estimation of future abandonment obligations used in recording asset retirement obligations, and the assessment of goodwill. Estimates and judgments also are required in determining allowances for doubtful accounts, impairments of unproved properties and other assets, valuation of deferred tax assets, fair value measurements, and contingencies.

Oil and Gas Well Equipment and Supplies

Our oil and gas well equipment and supplies are valued at the lower of cost and net realizable value, where net realizable value is estimated selling prices in the ordinary course of business, less reasonably predictable costs of disposal and transportation. Declines in the price of oil and gas well equipment and supplies in future periods could cause us to recognize impairments on these assets. An impairment would not affect cash flow from operating activities, but would adversely affect our net income and stockholders’ equity.

Oil and Gas Properties

We use the full cost method of accounting for our oil and gas operations. All costs associated with property acquisition, exploration, and development activities are capitalized. Under the full cost method of accounting, we are required to perform a quarterly ceiling test calculation to test our oil and gas properties for possible impairment. If the net capitalized cost of our oil and gas properties, as adjusted for income taxes, exceeds the ceiling limitation, the excess is charged to expense. The ceiling limitation is equal to the sum of: (i) the present value discounted at 10% of estimated future net revenues from proved reserves, (ii) the cost of properties not being amortized, and (iii) the lower of cost or estimated fair value of unproven properties included in the costs being amortized, as adjusted for income taxes. We currently do not have any unproven properties that are being amortized. Estimated future net revenues are determined based on trailing twelve-month average commodity prices and estimated proved reserve quantities, operating costs, and capital expenditures. The calculated ceiling limitation is not intended to be indicative of the fair market value of our proved reserves or future results.

We did not recognize a ceiling test impairment during the six months ended June 30, 2018 and 2017 because the net capitalized cost of our oil and gas properties, as adjusted for income taxes, did not exceed the ceiling limitation. If pricing conditions deteriorate, including the further widening of local market basis differentials, or if there is a negative impact on one or more of the other components of the calculation, we may incur full cost ceiling test impairments in future quarters. Impairment charges do not affect cash flow from operating activities, but do adversely affect our net income and various components of our balance sheet. Any impairment of oil and gas properties is not reversible at a later date.

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June 30, 2018
(Unaudited)

Revenue Recognition
Oil, Gas, and NGL Sales
Effective January 1, 2018, we adopted the provisions of Accounting Standards Codification 606, Revenue from Contracts with Customers ("ASC 606"), utilizing the modified retrospective approach, which we applied to contracts that were not completed as of that date. Because we utilized the modified retrospective approach, there was no impact to prior periods' reported amounts. Application of ASC 606 has no impact on our net income or cash flows from operations; however, certain costs classified as Transportation, processing, and other operating expenses in the statement of operations under prior accounting standards are now reflected as deductions from revenue under ASC 606. The following tables present the impact on our Oil sales, Gas sales, and NGL sales and on our Transportation, processing, and other operating costs from the application of ASC 606 in the current reporting period:

	Three Months Ended June 30,			
	2018			2017
(in thousands)	Pre-ASC 606 Adoption	Impact of ASC 606	Post-ASC 606 Adoption	As Reported
Oil sales	$342,184	$—	$342,184	$232,453
Gas sales	84,727	(3,940)	80,787	132,474
NGL sales	125,126	(3,711)	121,415	80,886
Total oil, gas, and NGL sales	$552,037	$(7,651)	$544,386	$445,813
Transportation, processing, and other operating costs	$59,584	$(7,651)	$51,933	$58,624

	Six Months Ended June 30,			
	2018			2017
(in thousands)	Pre-ASC 606 Adoption	Impact of ASC 606	Post-ASC 606 Adoption	As Reported
Oil sales	$693,907	$—	$693,907	$456,519
Gas sales	197,404	(6,896)	190,508	264,419
NGL sales	230,739	(15,327)	215,412	161,312
Total oil, gas, and NGL sales	$1,122,050	$(22,223)	$1,099,827	$882,250
Transportation, processing, and other operating costs	$119,321	$(22,223)	$97,098	$113,647

Revenue is recognized from the sales of oil, gas, and NGLs when the customer obtains control of the product, when we have no further obligations to perform related to the sale, and when collectability is probable. All of our sales of oil, gas, and NGLs are made under contracts with customers, which typically include variable consideration based on monthly pricing tied to local indices and monthly volumes delivered. The nature of our contracts with customers does not require us to constrain that variable consideration or to estimate the amount of transaction price attributable to future performance obligations for accounting purposes. As of June 30, 2018, we had open contracts with customers with terms of one month to multiple years, as well as "evergreen" contracts that renew on a periodic basis if not canceled by us or the customer. Performance obligations under our contracts with customers are typically satisfied at a point-in-time through monthly delivery of oil, gas, and/or NGLs. Our contracts with customers typically require payment within one month of delivery.

Our gas and NGLs are sold under a limited number of contract structure types common in our industry. Under these contracts the gas and its components, including NGLs, may be sold to a single purchaser or the residue gas and NGLs may be sold to separate purchasers. Regardless of the contract structure type, the terms of these contracts compensate us for the value of the residue gas and NGLs at current market prices for each product, and are disaggregated in the tables above on that basis. Our oil typically is sold at specific delivery points under contract terms that also are common in our industry.

Gas Gathering

When we transport and/or process third-party gas associated with our equity gas, we recognize revenue for the fees charged to third-parties for such services.

Gas Marketing

When we market and sell gas for working interest owners, we act as agent under short-term sales and supply agreements and may earn a fee for such services. Revenues from such services are recognized as gas is delivered.

Gas Imbalances

Revenue from the sale of gas is recorded on the basis of gas actually sold by us. If our aggregate sales volumes for a well are greater (or less) than our proportionate share of production from the well, a liability (or receivable) is established to the extent there are insufficient proved reserves available to make-up the overproduced (or underproduced) imbalance. Imbalances have not been significant in the periods presented.

Recently Issued Accounting Standards

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-02, Leases (Topic 842). The key provision of this ASU is that a lessee must recognize on its balance sheet: (i) liabilities to make lease payments and (ii) right-of-use assets. The ASU permits lessees to make a policy election to not recognize lease assets and liabilities for leases with terms of less than 12 months. Under current generally accepted accounting principles, a determination of whether a lease is a capital or operating lease is made at lease inception and no assets or liabilities are recognized for operating leases. Under this ASU, the determination to be made at the inception of a contract is whether the contract is, or contains, a lease. Leases convey the right to control the use of an identified asset in exchange for consideration. Only the lease components of a contract must be accounted for in accordance with this ASU. Non-lease components, such as activities that transfer a good or service to the customer, shall be accounted for under other applicable Topics. An entity may make a policy election to not separate lease and non-lease components and account for the non-lease components together with the lease components as a single lease component. This ASU retains a distinction between finance and operating leases concerning the recognition and presentation of the expense and payments related to leases in the statements of operations and comprehensive income and cash flows, however, both types of leases require the recognition of assets and liabilities on the balance sheet. This ASU is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years, with early adoption permitted. We are evaluating the potential impact of adopting this guidance, but believe the primary effect will be to record assets and liabilities for contracts currently accounted for as operating leases. We do not intend to adopt the standard early.

In January 2018, the FASB issued ASU 2018-01, Leases (Topic 842) Land Easement Practical Expedient for Transition to Topic 842. This ASU provides an optional transition practical expedient to not evaluate under Topic 842 (discussed above) existing or expired land easements that were not previously accounted for as leases under the current leases guidance in Topic 840. An entity that elects this practical expedient should evaluate new or modified land easements under Topic 842 beginning at the date that the entity adopts Topic 842. Under the full cost method of accounting, we capitalize to oil and gas properties all property acquisition, exploration, and development costs, which include the costs of land easements. We plan to elect this practical expedient and continue to apply our current accounting policy to account for land easements that existed before our adoption of Topic 842 and will evaluate new or modified land easements under Topic 842 upon our adoption of Topic 842. We are evaluating the potential impact of adopting this guidance and do not intend to adopt the standard early.

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June 30, 2018
(Unaudited)

2. LONG-TERM DEBT

Long-term debt at June 30, 2018 and December 31, 2017 consisted of the following:

	June 30, 2018			December 31, 2017		
(in thousands)	Principal	Unamortized Debt Issuance Costs and Discount (1)	Long-term Debt, net	Principal	Unamortized Debt Issuance Costs and Discount (1)	Long-term Debt, net
4.375% Senior Notes	$750,000	$ (4,906)	$745,094	$750,000	$ (5,383)	$744,617
3.90% Senior Notes	750,000	(7,355)	742,645	750,000	(7,697)	742,303
Total long-term debt	$1,500,000	$ (12,261)	$1,487,739	$1,500,000	$ (13,080)	$1,486,920

(1) At June 30, 2018, the unamortized debt issuance costs and discount related to the 3.90% notes were $5.7 million and $1.7 million, respectively. At December 31, 2017, the unamortized debt issuance costs and discount related to the 3.90% notes were $5.9 million and $1.8 million, respectively. The 4.375% notes were issued at par.

Bank Debt

We have a senior unsecured revolving credit facility (“Credit Facility”) that matures October 16, 2020. The Credit Facility has aggregate commitments of $1.0 billion, with an option for us to increase the aggregate commitments to $1.25 billion at any time. There is no borrowing base subject to the discretion of the lenders based on the value of our proved reserves under the Credit Facility. As of June 30, 2018, we had no bank borrowings outstanding under the Credit Facility, but did have letters of credit of $2.5 million outstanding, leaving an unused borrowing availability of $997.5 million.

At our option, borrowings under the Credit Facility may bear interest at either (a) LIBOR plus 1.125 – 2.0% based on the credit rating for our senior unsecured long-term debt, or (b) a base rate (as defined in the credit agreement) plus 0.125 – 1.0%, based on the credit rating for our senior unsecured long-term debt. Unused borrowings are subject to a commitment fee of 0.125 – 0.35%, based on the credit rating for our senior unsecured long-term debt.

The Credit Facility contains representations, warranties, covenants, and events of default that are customary for investment grade, senior unsecured bank credit agreements, including a financial covenant for the maintenance of a defined total debt-to-capital ratio of no greater than 65%. As of June 30, 2018, we were in compliance with all of the financial covenants.

At June 30, 2018 and December 31, 2017, we had $2.7 million and $3.4 million, respectively, of unamortized debt issuance costs associated with our Credit Facility, which were recorded as assets and included in Other assets on our Condensed Consolidated Balance Sheets. These costs are being amortized to interest expense ratably over the life of the Credit Facility.

Senior Notes

In April 2017, we issued $750 million aggregate principal amount of 3.90% senior unsecured notes at 99.748% of par to yield 3.93% per annum. These notes are due May 15, 2027 and interest is payable semiannually on May 15 and November 15. The effective interest rate on these notes, including the amortization of debt issuance costs and discount, is 4.01%.

In June 2014, we issued $750 million aggregate principal amount of 4.375% senior unsecured notes at par. These notes are due June 1, 2024 and interest is payable semiannually on June 1 and December 1. The effective interest rate on these notes, including the amortization of debt issuance costs, is 4.50%.

Our senior unsecured notes are governed by indentures containing certain covenants, events of default, and other restrictive provisions with which we were in compliance as of June 30, 2018.

3. DERIVATIVE INSTRUMENTS

We periodically use derivative instruments to mitigate volatility in commodity prices. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future cash flow from favorable price changes. Depending on changes in oil and gas futures markets and management's view of underlying supply and demand trends, we may increase or decrease our derivative positions from current levels.

As of June 30, 2018, we have entered into oil and gas collars and oil basis swaps. Under our collars, we receive the difference between the published index price and a floor price if the index price is below the floor price or we pay the difference between the 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 the ceiling prices. By using a collar, we have fixed the minimum and maximum prices we can receive on the underlying production. Our basis swaps are settled based on the difference between a published index price minus a fixed differential and the applicable local index price under which the underlying production is sold. By using a basis swap, we have fixed the differential between the published index price and certain of our physical pricing points. For our Permian oil production, the basis swaps fix the price differential between the WTI NYMEX (Cushing Oklahoma) price and the WTI Midland price. For our Permian and Mid-Continent gas production, the contract prices in our collars are consistent with the index prices used to sell our production. The following tables summarize our outstanding derivative contracts as of June 30, 2018 (subsequent to June 30, 2018 through August 6, 2018, we have not entered into any additional derivative contracts):

Oil Collars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2018:					
WTI (1)					
Volume (Bbls)	—	—	3,220,000	2,668,000	5,888,000
Weighted Avg Price - Floor	$ —	$ —	$ 49.80	$ 51.03	$ 50.36
Weighted Avg Price - Ceiling	$ —	$ —	$ 60.49	$ 61.74	$ 61.06
2019:					
WTI (1)					
Volume (Bbls)	2,070,000	2,093,000	1,472,000	736,000	6,371,000
Weighted Avg Price - Floor	$ 51.83	$ 51.83	$ 53.50	$ 57.00	$ 52.81
Weighted Avg Price - Ceiling	$ 63.77	$ 63.77	$ 67.13	$ 68.04	$ 65.04

(1) The index price for these collars is West Texas Intermediate ("WTI") as quoted on the New York Mercantile Exchange ("NYMEX").

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Gas Collars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2018:					
PEPL (1)					
Volume (MMBtu)	—	—	11,960,000	9,200,000	21,160,000
Weighted Avg Price - Floor	$ —	$ —	$ 2.19	$ 2.12	$ 2.16
Weighted Avg Price - Ceiling	$ —	$ —	$ 2.48	$ 2.42	$ 2.45
Perm EP (2)					
Volume (MMBtu)	—	—	9,200,000	7,360,000	16,560,000
Weighted Avg Price - Floor	$ —	$ —	$ 1.92	$ 1.81	$ 1.87
Weighted Avg Price - Ceiling	$ —	$ —	$ 2.14	$ 2.03	$ 2.09
Waha (3)					
Volume (MMBtu)	—	—	920,000	920,000	1,840,000
Weighted Avg Price - Floor	$ —	$ —	$ 1.35	$ 1.35	$ 1.35
Weighted Avg Price - Ceiling	$ —	$ —	$ 1.56	$ 1.56	$ 1.56
2019:					
PEPL (1)					
Volume (MMBtu)	8,100,000	8,190,000	5,520,000	2,760,000	24,570,000
Weighted Avg Price - Floor	$ 2.08	$ 2.08	$ 1.92	$ 1.90	$ 2.02
Weighted Avg Price - Ceiling	$ 2.39	$ 2.39	$ 2.26	$ 2.33	$ 2.36
Perm EP (2)					
Volume (MMBtu)	6,300,000	6,370,000	4,600,000	1,840,000	19,110,000
Weighted Avg Price - Floor	$ 1.73	$ 1.73	$ 1.50	$ 1.35	$ 1.64
Weighted Avg Price - Ceiling	$ 1.95	$ 1.95	$ 1.74	$ 1.55	$ 1.86
Waha (3)					
Volume (MMBtu)	900,000	910,000	920,000	920,000	3,650,000
Weighted Avg Price - Floor	$ 1.35	$ 1.35	$ 1.35	$ 1.35	$ 1.35
Weighted Avg Price - Ceiling	$ 1.56	$ 1.56	$ 1.56	$ 1.56	$ 1.56

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(1) The index price for these collars is Panhandle Eastern Pipe Line, Tex/OK Mid-Continent Index (“PEPL”) as quoted in Platt’s Inside FERC.

(2) The index price for these collars is El Paso Natural Gas Company, Permian Basin Index (“Perm EP”) as quoted in Platt’s Inside FERC.

(3) The index price for these collars is Waha West Texas Natural Gas Index (“Waha”) as quoted in Platt’s Inside FERC.

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Oil Basis Swaps	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2018:					
WTI Midland (1)					
Volume (Bbls)	—	—	2,484,000	2,024,000	4,508,000
Weighted Avg Differential (2)	$ —	$ —	$ (3.89)	$ (4.56)	$ (4.19)
2019:					
WTI Midland (1)					
Volume (Bbls)	1,710,000	1,729,000	1,288,000	552,000	5,279,000
Weighted Avg Differential (2)	$ (5.17)	$ (5.17)	$ (6.84)	$ (10.73)	$ (6.16)

(1) The index price we pay under these basis swaps is WTI Midland as quoted by Argus Americas Crude.
(2) The index price we receive under these basis swaps is WTI as quoted on the NYMEX less the weighted average differential shown in the table.

Derivative Gains and Losses

Net gains and losses on our derivative instruments are a function of fluctuations in the underlying commodity index prices as compared to the contracted prices and the monthly cash settlements (if any) of the instruments. We have elected not to designate our derivatives as hedging instruments for accounting purposes and, therefore, we do not apply hedge accounting treatment to our derivative instruments. Consequently, changes in the fair value of our derivative instruments and cash settlements on the instruments are included as a component of operating costs and expenses as either a net gain or loss on derivative instruments. Cash settlements of our contracts are included in cash flows from operating activities in our statements of cash flows. The following table presents the components of Loss (gain) on derivative instruments, net for the periods indicated.

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2018	2017	2018	2017
Change in fair value of derivative instruments, net:				
Gas contracts	$ 14,566	$ (5,748)	$ 2,777	$ (27,939)
Oil contracts	(397)	(16,418)	(5,156)	(44,148)
	14,169	(22,166)	(2,379)	(72,087)
Cash (receipts) payments on derivative instruments, net:				
Gas contracts	(9,918)	(1,308)	(15,037)	1,136
Oil contracts	17,448	965	34,956	4,581
	7,530	(343)	19,919	5,717
Loss (gain) on derivative instruments, net	$ 21,699	$ (22,509)	$ 17,540	$ (66,370)

Derivative Fair Value

Our derivative contracts are carried at their fair value on our balance sheet using Level 2 inputs and are subject to master netting arrangements, which allow us to offset recognized asset and liability fair value amounts on contracts with the same counterparty. Our accounting policy is to not offset asset and liability positions in our balance sheets.

The following tables present the amounts and classifications of our derivative assets and liabilities as of June 30, 2018 and December 31, 2017, as well as the potential effect of netting arrangements on our recognized derivative asset and liability amounts.

		June 30, 2018	
(in thousands)	Balance Sheet Location	Asset	Liability
Oil contracts	Current assets — Derivative instruments	$57,768	$—
Gas contracts	Current assets — Derivative instruments	15,175	—
Oil contracts	Non-current assets — Derivative instruments	1,106	—
Gas contracts	Non-current assets — Derivative instruments	1,224	—
Oil contracts	Current liabilities — Derivative instruments	—	88,814
Gas contracts	Current liabilities — Derivative instruments	—	1,666
Oil contracts	Non-current liabilities — Derivative instruments	—	11,237
Gas contracts	Non-current liabilities — Derivative instruments	—	274
Total gross amounts presented in the balance sheet		75,273	101,991
Less: gross amounts not offset in the balance sheet		(68,377)	(68,377)
Net amount		$6,896	$33,614

		December 31, 2017	
(in thousands)	Balance Sheet Location	Asset	Liability
Gas contracts	Current assets — Derivative instruments	$15,151	$—
Gas contracts	Non-current assets — Derivative instruments	2,086	—
Oil contracts	Current liabilities — Derivative instruments	—	42,066
Oil contracts	Non-current liabilities — Derivative instruments	—	4,268
Total gross amounts presented in the balance sheet		17,237	46,334
Less: gross amounts not offset in the balance sheet		(17,237)	(17,237)
Net amount		$—	$29,097

We are exposed to financial risks associated with our derivative contracts from non-performance by our counterparties. We mitigate our exposure to any single counterparty by contracting with a number of financial institutions, each of which have a high credit rating and is a member of our bank credit facility. Our member banks do not require us to post collateral for our derivative liability positions. Because some of the member banks have discontinued derivative activities, in the future we may enter into derivative instruments with counterparties outside our bank group to obtain competitive terms and to spread counterparty risk.

4. FAIR VALUE MEASUREMENTS

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The FASB has established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs are the highest priority and consist of unadjusted quoted prices in active markets for identical assets and liabilities. Level 2 are inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. Level 3 are unobservable inputs for an asset or liability.

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The following table provides fair value measurement information for certain assets and liabilities as of June 30, 2018 and December 31, 2017:

(in thousands)	June 30, 2018 Book Value	June 30, 2018 Fair Value	December 31, 2017 Book Value	December 31, 2017 Fair Value
Financial Assets (Liabilities):				
4.375% Notes due 2024	$(750,000)	$(758,228)	$(750,000)	$(797,010)
3.90% Notes due 2027	$(750,000)	$(721,763)	$(750,000)	$(767,813)
Derivative instruments — assets	$75,273	$75,273	$17,237	$17,237
Derivative instruments — liabilities	$(101,991)	$(101,991)	$(46,334)	$(46,334)

Assessing the significance of a particular input to the fair value measurement requires judgment, including the consideration of factors specific to the asset or liability. The fair value (Level 1) of our fixed rate notes was based on their last traded value before period end. The fair value of our derivative instruments (Level 2) was estimated using option pricing models. These models use certain variables including forward price and volatility curves and the strike prices for the instruments. The fair value estimates are adjusted relative to non-performance risk as appropriate. See Note 3 for further information on the fair value of our derivative instruments.

Other Financial Instruments

The carrying amounts of our cash, cash equivalents, accounts receivable, accounts payable, and accrued liabilities approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities. Included in “Accrued liabilities — Other” at June 30, 2018 were accrued operating expenses of approximately $59.6 million. Included in “Accrued liabilities — Other” at December 31, 2017 were: (i) accrued operating expenses of approximately $61.3 million and (ii) accrued general and administrative, primarily payroll-related, costs of approximately $54.6 million.

Most of our accounts receivable balances are uncollateralized and result from transactions with other companies in the oil and gas industry. Concentration of customers may impact our overall credit risk because our customers may be similarly affected by changes in economic or other conditions within the industry.

We conduct credit analyses prior to making any sales to new customers or increasing credit for existing customers and may require parent company guarantees, letters of credit, or prepayments when deemed necessary.

We routinely assess the recoverability of all material accounts receivable to determine their collectability. We accrue a reserve to the allowance for doubtful accounts when it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated. At June 30, 2018 and December 31, 2017, the allowance for doubtful accounts was $2.7 million and $2.2 million, respectively.

5. CAPITAL STOCK

Authorized capital stock consists of 200 million shares of common stock and 15 million shares of preferred stock. At June 30, 2018, there were 95.4 million shares of common stock and no shares of preferred stock outstanding.

Dividends

In May 2018, our Board of Directors declared a cash dividend of $0.16 per share. The dividend is payable on or before August 31, 2018 to stockholders of record on August 15, 2018. Dividends declared are recorded as a reduction of retained earnings to the extent retained earnings are available at the close of the period prior to the date of the declared dividend. Dividends in excess of retained earnings are recorded as a reduction of additional paid-in capital. The $15.3 million dividend declared during the first quarter 2018 was recorded as a reduction of additional paid-in capital, while the $15.3 million dividend declared during the second quarter 2018 was recorded as a reduction of retained earnings. Nonforfeitable dividends paid on stock awards that

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subsequently forfeit are reclassified out of retained earnings or additional paid-in capital, as applicable, to compensation expense in the period in which the forfeitures occur. Future dividend payments will depend on our level of earnings, financial requirements, and other factors considered relevant by our Board of Directors.

6. STOCK-BASED COMPENSATION

We have recognized stock-based compensation cost as shown below for the periods indicated.

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2018	2017	2018	2017
Restricted stock awards:				
Performance stock awards	$3,809	$6,438	$10,538	$12,840
Service-based stock awards	4,247	4,208	9,319	9,132
	8,056	10,646	19,857	21,972
Stock option awards	637	579	1,254	1,245
Total stock compensation cost	8,693	11,225	21,111	23,217
Less amounts capitalized to oil and gas properties	(5,598)	(4,932)	(11,286)	(10,636)
Stock compensation expense	$3,095	$6,293	$9,825	$12,581

Periodic stock compensation expense will fluctuate based on the grant-date fair value of awards, the number of awards, the requisite service period of the awards, employee forfeitures, and the timing of the awards. The decrease in total stock compensation cost in the 2018 periods as compared to the 2017 periods is primarily due to performance stock award forfeitures during the three months ended June 30, 2018. Our accounting policy is to account for forfeitures in compensation cost when they occur.

7. ASSET RETIREMENT OBLIGATIONS

We recognize the present value of the fair value of liabilities for retirement obligations associated with tangible long-lived assets in the period in which there is a legal obligation associated with the retirement of such assets and the amount can be reasonably estimated. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. This liability includes costs related to the plugging and abandonment of wells, the removal of facilities and equipment, and site restorations. Subsequent to initial measurement, the asset retirement liability is accreted each period. If there is a change in the estimated cost or timing of retirement, a revision is recorded to both the asset retirement obligation and the asset retirement capitalized cost. Capitalized costs are included as a component of the depreciation and depletion calculations.

The following table reflects the components of the change in the carrying amount of the asset retirement obligation for the six months ended June 30, 2018:

(in thousands)	Six Months Ended June 30, 2018
Asset retirement obligation at January 1, 2018	$169,469
Liabilities incurred	3,921
Liability settlements and disposals	(10,103)
Accretion expense	3,712
Revisions of estimated liabilities	999
Asset retirement obligation at June 30, 2018	167,998
Less current obligation	(8,430)
Long-term asset retirement obligation	$159,568

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8. EARNINGS PER SHARE

The calculations of basic and diluted net earnings per common share under the two-class method are presented below for the periods indicated:

	Three Months Ended June 30,					
	2018			2017		
(in thousands, except per share information)	Income (Numerator)	Shares (Denominator)	Per-Share Amount	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Net income	$140,997			$97,262		
Less: net income attributable to participating securities	(1,892)			(1,643)		
Basic earnings per share						
Income available to common stockholders	139,105	93,728	$ 1.48	95,619	93,402	$ 1.02
Effects of dilutive securities						
Options (1)	—	31		1	33	
Diluted earnings per share						
Income available to common stockholders and assumed conversions	$139,105	93,759	$ 1.48	$95,620	93,435	$ 1.02

	Six Months Ended June 30,					
	2018			2017		
(in thousands, except per share information)	Income (Numerator)	Shares (Denominator)	Per-Share Amount	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Net income	$327,315			$228,234		
Less: net income attributable to participating securities	(4,546)			(3,898)		
Basic earnings per share						
Income available to common stockholders	322,769	93,713	$ 3.44	224,336	93,396	$ 2.40
Effects of dilutive securities						
Options (1)	1	35		1	35	
Diluted earnings per share						
Income available to common stockholders and assumed conversions	$322,770	93,748	$ 3.44	$224,337	93,431	$ 2.40

(1) Inclusion of certain shares would have an anti-dilutive effect; therefore, 292.1 thousand and 295.6 thousand shares were excluded from the calculations for the three and six months ended June 30, 2018 and 300.5 thousand and 255.0 thousand shares were excluded from the calculations for the three and six months ended June 30, 2017.

9. INCOME TAXES

The components of our provision for income taxes are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2018	2017	2018	2017
Current tax benefit	$(717)	$—	$(717)	$(6)
Deferred tax expense	42,783	58,617	99,732	136,929
	$42,066	$58,617	$99,015	$136,923
Combined federal and state effective income tax rate	23.0 %	37.6 %	23.2 %	37.5 %

At December 31, 2017, we had a U.S. net tax operating loss carryforward of approximately $1,377.7 million, which will expire in tax years 2031 through 2037. We believe that the carryforward will be utilized before it expires. We also had an alternative minimum tax credit carryforward of approximately $3.0 million and other credits of $0.9 million.

At June 30, 2018, we had no unrecognized tax benefits that would impact our effective tax rate and have made no provisions for interest or penalties related to uncertain tax positions. The tax years 2014 through 2016 remain open to examination by the Internal Revenue Service of the United States. We file tax returns with various state taxing authorities, which remain open to examination for tax years 2013 through 2016.

Our combined federal and state effective income tax rates differ from the U.S. federal statutory rate of 21% in 2018 and 35% in 2017 primarily due to state income taxes and non-deductible expenses.

As a result of the enactment of H.R.1, known as the Tax Cuts and Jobs Act, on December 22, 2017, we remeasured our deferred tax assets and liabilities as of December 31, 2017 to reflect the reduction in the U.S. income tax rate from 35% to 21% for years after 2017. We believe the accounting for the effects of H.R.1 recognized in the December 31, 2017 financial statements is materially complete. However, evolving analyses and interpretations of the law may cause a change to the amounts presented. Any such changes that may arise will be recognized in the period determined, but no later than December 31, 2018. As a result of H.R.1, we expect our effective tax rate in future periods will be lower than in periods prior to enactment.

10. COMMITMENTS AND CONTINGENCIES

Commitments

At June 30, 2018, we had estimated commitments of approximately: (i) $154.4 million to finish drilling, completing, or performing other work on wells and various other infrastructure projects in progress and (ii) $14.4 million to finish gathering system construction in progress.

At June 30, 2018, we had firm sales contracts to deliver approximately 330.7 Bcf of gas over the next 6.6 years. If we do not deliver this gas, our estimated financial commitment, calculated using the July 2018 index price, would be approximately $659.9 million. The value of this commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no financial commitment will be due based on our current proved reserves and production levels from which we can fulfill these volumetric obligations.

In connection with gas gathering and processing agreements, we have volume commitments over the next 9.5 years. If we do not deliver the committed gas or NGLs, as the case may be, the estimated maximum amount that would be payable under these commitments, calculated as of June 30, 2018, would be approximately $351.0 million. However, we believe no financial commitment will be due based on our current proved reserves and production levels from which we can fulfill these volumetric obligations.

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We have minimum volume delivery commitments associated with agreements to reimburse connection costs to various pipelines. If we do not deliver this gas, the estimated maximum amount that would be payable under these commitments, calculated as of June 30, 2018, would be approximately $7.4 million. Of this total, we have accrued a liability of $2.5 million representing the estimated amount we will have to pay due to insufficient forecasted volumes at particular connection points.

At June 30, 2018, we have various firm transportation agreements for gas pipeline capacity with end dates ranging from 2018 - 2025 under which we will have to pay an estimated $26.6 million over the remaining terms of the agreements. These agreements were entered into to support our residue gas marketing efforts, and we believe we have sufficient reserves that will utilize this firm transportation.

At June 30, 2018, we have various future commitments under operating lease arrangements for commercial real estate, consisting primarily of office space, and compressor equipment. The commitments under the commercial real estate operating leases, which have lease terms expiring within the next 8.2 years, total approximately $80.9 million. The commitments under the compressor equipment operating leases, which have lease terms expiring within the next 2 - 24 months, total approximately $9.3 million.

All of the noted commitments were routine and made in the ordinary course of our business.

Litigation

We have various litigation matters related to the ordinary course of our business. We assess the probability of estimable amounts related to these matters in accordance with guidance established by the FASB and adjust our accruals accordingly. Though some of the related claims may be significant, we believe the resolution of them, individually or in the aggregate, would not have a material adverse effect on our financial condition or results of operations after consideration of current accruals.

11. SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2018	2017	2018	2017
Cash paid during the period for:				
Interest expense (net of capitalized amounts of $9,233, $11,659, $9,389, and $11,962, respectively)	$22,954	$28,115	$23,343	$28,772
Income taxes	$—	$1	$—	$3
Cash received for income tax refunds	$717	$—	$718	$21

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

OVERVIEW

Cimarex is an independent oil and gas exploration and production company. Our operations are entirely located in the United States, mainly in Oklahoma, Texas, and New Mexico. Currently our operations are focused in two main areas: the Permian Basin and the Mid-Continent. Our Permian Basin region encompasses west Texas and southeast New Mexico. Our Mid-Continent region consists of Oklahoma and the Texas Panhandle.

Our principal business objective is to profitably grow proved reserves and production for the long-term benefit of our stockholders through a balanced and abundant drilling inventory while seeking to minimize our impact on the communities in which we operate for the long-term. Our strategy centers on maximizing cash flow from producing properties and profitably reinvesting that cash flow in exploration and development activities. We consider property acquisitions, dispositions, and occasional mergers to enhance our competitive position.

We believe that detailed technical analysis, operational focus, and a disciplined capital investment process mitigate risk and position us to continue to achieve profitable increases in proved reserves and production. Our drilling inventory and limited long-term commitments provide the flexibility to respond quickly to industry volatility.

Our investments are generally funded with cash flow provided by operating activities together with cash on hand, bank borrowings, sales of non-strategic assets, and occasional public financing based on our monitoring of capital markets and our balance sheet. Conservative use of leverage has long been a part of our financial strategy. We believe that maintaining a strong balance sheet mitigates financial risk and enables us to withstand unpredictable fluctuations in commodity prices.

Market Conditions

The oil and gas industry is cyclical and commodity prices can fluctuate significantly. We expect this volatility to persist. Commodity prices are affected by many factors outside of our control, including changes in market supply and demand, inventory storage levels, weather conditions, and other factors.

During the first six months of 2018 as compared to the first six months of 2017, market prices for oil have improved, while market prices for gas have declined. For the first six months of 2018, average NYMEX oil and gas prices were $65.37 per barrel and $2.90 per Mcf, respectively, representing an increase of 30% and a decrease of 11%, respectively, from the average NYMEX oil and gas prices for the first six months of 2017. However, local market prices for oil and gas can be impacted by pipeline capacity constraints limiting takeaway and increasing basis differentials. Gas production growth and pipeline constraints in the Permian Basin and Mid-Continent region and oil production growth and pipeline constraints in the Permian Basin have resulted in higher basis differentials and, therefore, lower realized prices. The average realized price per barrel for our Permian oil production was less than the WTI Cushing index by $8.05, $3.12, and $4.14 in the three months ended June 30, 2018, March 31, 2018, and June 30, 2017, respectively. The average realized price per Mcf for our Permian gas production was less than the Henry Hub index by $1.31, $0.78, and $0.42 in the three months ended June 30, 2018, March 31, 2018, and June 30, 2017, respectively. The average realized price per Mcf for our Mid-Continent gas production was less than the Henry Hub index by $1.03, $0.70, and $0.34 in the three months ended June 30, 2018, March 31, 2018, and June 30, 2017, respectively. If pipeline constraints remain, higher differentials will persist or potentially worsen. Our revenue, profitability, and future growth are highly dependent on the prices we receive for our oil and gas production. See RESULTS OF OPERATIONS Revenues below for further information regarding our realized commodity prices.

See "Risk Factors" in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2017, for a discussion of risk factors that affect our business, financial condition, and results of operations. Also see CAUTIONARY INFORMATION ABOUT FORWARD-LOOKING STATEMENTS in this report for important information about these types of statements.

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Summary of Operating and Financial Results for the Six Months Ended June 30, 2018 Compared to the Six Months Ended June 30, 2017:

- Total production volumes increased 13% to 208.8 MBOE per day.
- Oil volumes increased 15% to 63.4 MBbls per day.
- Gas volumes increased 7% to 537.1 MMcf per day.
- NGL volumes increased 21% to 55.8 MBbls per day.
- Total production revenue increased 25% to $1.1 billion.
- Cash flow provided by operating activities increased 40% to $704.3 million.
- Exploration and development expenditures increased 15% to $688.9 million.
- Net income was $327.3 million, or $3.44 per diluted share, for the first six months of 2018, as compared to net income of $228.2 million, or $2.40 per diluted share, for the first six months of 2017.

RESULTS OF OPERATIONS

Three and Six Months Ended June 30, 2018 vs. Three and Six Months Ended June 30, 2017

Effective January 1, 2018, we adopted the provisions of Accounting Standards Codification 606, Revenue from Contracts with Customers (“ASC 606”), utilizing the modified retrospective approach, which we applied to contracts that were not completed as of that date. Because we utilized the modified retrospective approach, there was no impact to prior periods’ reported amounts. Application of ASC 606 has no impact on our net income or cash flows from operations; however, certain costs classified as Transportation, processing, and other operating expenses in the statement of operations under prior accounting standards are now reflected as deductions from revenue under ASC 606. The following tables present the impact on our Oil sales, Gas sales, and NGL sales and on our Transportation, processing, and other operating costs from the application of ASC 606 in the current reporting period:

	Three Months Ended June 30,			
	2018			2017
(in thousands)	Pre-ASC 606 Adoption	Impact of ASC 606	Post-ASC 606 Adoption	As Reported
Oil sales	$342,184	$—	$342,184	$232,453
Gas sales	84,727	(3,940)	80,787	132,474
NGL sales	125,126	(3,711)	121,415	80,886
Total oil, gas, and NGL sales	$552,037	$(7,651)	$544,386	$445,813
Transportation, processing, and other operating costs	$59,584	$(7,651)	$51,933	$58,624

	Six Months Ended June 30,			
	2018			2017
(in thousands)	Pre-ASC 606 Adoption	Impact of ASC 606	Post-ASC 606 Adoption	As Reported
Oil sales	$693,907	$—	$693,907	$456,519
Gas sales	197,404	(6,896)	190,508	264,419
NGL sales	230,739	(15,327)	215,412	161,312
Total oil, gas, and NGL sales	$1,122,050	$(22,223)	$1,099,827	$882,250
Transportation, processing, and other operating costs	$119,321	$(22,223)	$97,098	$113,647

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Revenues

Almost all of our revenues are derived from sales of our oil, gas, and NGL production. Increases or decreases in our revenues, profitability, and future production growth are highly dependent on the commodity prices we receive. Prices are market driven and we expect that future prices will continue to fluctuate due to supply and demand factors, seasonality, geopolitical, and economic factors. See QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for more information regarding the sensitivity of our revenues to price fluctuations.

Production volumes were higher for all products during the three and six months ended June 30, 2018 as compared to the three and six months ended June 30, 2017. Realized oil and NGL prices also were higher, while realized gas prices were lower. Our revenue increased 22%, or $98.6 million, during the three months ended June 30, 2018 as compared to the three months ended June 30, 2017 and increased 25%, or $217.6 million, during the six months ended June 30, 2018 as compared to the six months ended June 30, 2017. The following tables show our production revenue for the periods indicated as well as the change in revenue due to changes in volumes and prices.

	Three Months Ended June 30,		Variance Between 2018 / 2017		Price/Volume Variance		
Production Revenue (in thousands)	2018	2017			Price	Volume	Total
Oil sales	$342,184	$232,453	$109,731	47%	$94,533	$15,198	$109,731
Gas sales	80,787	132,474	(51,687)	(39)%	(57,440)	5,753	(51,687)
NGL sales	121,415	80,886	40,529	50%	22,060	18,469	40,529
	$544,386	$445,813	$98,573	22%	$59,153	$39,420	$98,573

	Six Months Ended June 30,		Variance Between 2018 / 2017		Price/Volume Variance		
Production Revenue (in thousands)	2018	2017			Price	Volume	Total
Oil sales	$693,907	$456,519	$237,388	52%	$167,943	$69,445	$237,388
Gas sales	190,508	264,419	(73,911)	(28)%	(92,358)	18,447	(73,911)
NGL sales	215,412	161,312	54,100	34%	20,809	33,291	54,100
	$1,099,827	$882,250	$217,577	25%	$96,394	$121,183	$217,577

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The table below presents our production volumes by region.

Production Volumes	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Oil (Bbls per day)				
Permian Basin	48,797	45,828	49,318	43,446
Mid-Continent	12,473	11,893	13,841	11,475
Other	381	150	263	121
	61,651	57,871	63,422	55,042
Gas (MMcf per day)				
Permian Basin	240.5	219.8	239.2	210.4
Mid-Continent	297.0	295.4	296.2	290.2
Other	2.0	1.5	1.7	1.4
	539.5	516.7	537.1	502.0
NGL (Bbls per day)				
Permian Basin	32,865	24,996	28,817	23,319
Mid-Continent	26,894	23,693	26,927	22,926
Other	98	42	66	36
	59,857	48,731	55,810	46,281
Total (BOE per day)				
Permian Basin	121,744	107,456	118,002	101,829
Mid-Continent	88,864	84,827	90,142	82,774
Other	816	437	608	395
	211,424	192,720	208,752	184,998

Our total production increased 10%, or 18,704 BOE per day, during the three months ended June 30, 2018, as compared to the three months ended June 30, 2017 and increased 13%, or 23,754 BOE per day, during the six months ended June 30, 2018, as compared to the six months ended June 30, 2017. This increase was the result of our ongoing drilling and completion activity throughout 2017 and into 2018. See LIQUIDITY AND CAPITAL RESOURCES Capital Expenditures for information on our capital expenditures.

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The table below presents our production volumes by commodity, our average realized commodity prices, and certain major U.S. index prices. The sale of our Permian Basin oil production is typically tied to the WTI Midland benchmark price and the sale of our Mid-Continent oil production is typically tied to the WTI Cushing benchmark price. During all periods presented, approximately 79% of our oil production was in the Permian Basin. Our realized prices do not include settlements of commodity derivative contracts.

	Three Months Ended June 30, 2018		2017	Change Between 2018 / 2017	Six Months Ended June 30, 2018		2017	Change Between 2018 / 2017
Oil								
Total volume — MBbls	5,610		5,266	7%	11,479		9,963	15%
Total volume — MBbls per day	61.7		57.9	7%	63.4		55.0	15%
Percentage of total production	29 %		30 %		30 %		30 %	
Average realized price — per barrel	$60.99		$44.14	38%	$60.45		$45.82	32%
Average WTI Midland price — per barrel	$62.76		$47.44	32%	$63.01		$50.00	26%
Average WTI Cushing price — per barrel	$67.88		$48.29	41%	$65.37		$50.10	30%
Gas								
Total volume — MMcf	49,094		47,021	4%	97,219		90,871	7%
Total volume — MMcf per day	539.5		516.7	4%	537.1		502.0	7%
Percentage of total production	43 %		45 %		43 %		45 %	
Average realized price — per Mcf	$1.65	(1)	$2.82	(41)%	$1.96	(1)	$2.91	(33)%
Average Henry Hub price — per Mcf	$2.80		$3.19	(12)%	$2.90		$3.25	(11)%
NGL								
Total volume — MBbls	5,447		4,434	23%	10,102		8,377	21%
Total volume — MBbls per day	59.9		48.7	23%	55.8		46.3	21%
Percentage of total production	28 %		25 %		27 %		25 %	
Average realized price — per barrel	$22.29	(2)	$18.24	22%	$21.32	(2)	$19.26	11%
Total								
Total production — MBOE	19,240		17,538	10%	37,784		33,485	13%
Total production — MBOE per day	211.4		192.7	10%	208.8		185.0	13%
Average realized price — per BOE	$28.30	(3)	$25.42	11%	$29.11	(3)	$26.35	10%

(1)

ASC 606 reduced the average realized gas price by $0.08 per Mcf and $0.07 per Mcf for the three and six months ended June 30, 2018, respectively.

(2) ASC 606 reduced the average realized NGL price by $0.68 per barrel and $1.52 per barrel for the three and six months ended June 30, 2018, respectively.

(3) ASC 606 reduced the average realized total price by $0.39 per BOE and $0.59 per BOE for the three and six months ended June 30, 2018, respectively.

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Other revenues

We transport, process, and market some third-party gas that is associated with our equity gas. We market and sell gas for other working interest owners under short-term agreements and may earn a fee for such services. The table below reflects income from third-party gas gathering and processing and our net marketing margin for marketing third-party gas.

Gas Gathering and Marketing Revenues (in thousands)	Three Months Ended June 30, 2018	2017	Variance Between 2018 / 2017	Six Months Ended June 30, 2018	2017	Variance Between 2018 / 2017
Gas gathering and other	$11,810	$10,735	$ 1,075	$23,262	$21,360	$ 1,902
Gas marketing	$78	$(96)	$ 174	$319	$18	$ 301

Fluctuations in revenues from gas gathering and gas marketing activities are a function of increases and decreases in volumes, commodity prices, and gathering rate charges.

Operating Costs and Expenses

Costs associated with producing oil and gas are substantial. Among other factors, some of these costs vary with commodity prices, some trend with the volume of production, others are a function of the number of wells we own, and some depend on the prices charged by service companies.

Total operating costs and expenses for the three months ended June 30, 2018 were higher by 40%, or $103.8 million, compared to the three months ended June 30, 2017. The primary reasons for the increase are: (i) the $44.2 million decrease in net gains on derivative instruments to an overall net loss, (ii) the $35.5 million increase in depreciation, depletion, and amortization, (iii) the $16.6 million increase in production expense, and (iv) the $10.5 million increase in taxes other than income, partially offset by the $6.7 million decrease in transportation, processing, and other operating expense.

Operating Costs and Expenses (in thousands, except per BOE)	Three Months Ended June 30, 2018	2017	Variance Between 2018 / 2017	Per BOE 2018	2017
Depreciation, depletion, and amortization	$143,388	$107,884	$35,504	$7.45	$6.15
Asset retirement obligation	2,053	960	1,093	$0.11	$0.05
Production	79,215	62,578	16,637	$4.12	$3.57
Transportation, processing, and other operating	51,933	58,624	(6,691)	$2.70	$3.34
Gas gathering and other	9,467	8,647	820	$0.49	$0.49
Taxes other than income	27,930	17,477	10,453	$1.45	$1.00
General and administrative	19,739	19,762	(23)	$1.03	$1.13
Stock compensation	3,095	6,293	(3,198)	$0.16	$0.36
Loss (gain) on derivative instruments, net	21,699	(22,509)	44,208	N/A	N/A
Other operating expense, net	5,252	266	4,986	N/A	N/A
	$363,771	$259,982	$103,789		

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Total operating costs and expenses for the six months ended June 30, 2018 were higher by 40%, or $194.6 million, compared to the six months ended June 30, 2017. The primary reasons for the increase are: (i) the $83.9 million decrease in net gains on derivative instruments to an overall net loss, (ii) the $72.5 million increase in depreciation, depletion, and amortization, (iii) the $25.5 million increase in production expense, and (iv) the $19.3 million increase in taxes other than income, partially offset by the $16.5 million decrease in transportation, processing, and other operating expense.

	Six Months Ended June 30,		Variance Between	Per BOE	
Operating Costs and Expenses (in thousands, except per BOE)	2018	2017	2018 / 2017	2018	2017
Depreciation, depletion, and amortization	$276,247	$203,700	$72,547	$7.31	$6.08
Asset retirement obligation	3,113	2,580	533	$0.08	$0.08
Production	150,486	124,999	25,487	$3.98	$3.73
Transportation, processing, and other operating	97,098	113,647	(16,549)	$2.57	$3.39
Gas gathering and other	19,290	17,074	2,216	$0.51	$0.51
Taxes other than income	58,118	38,790	19,328	$1.54	$1.16
General and administrative	43,060	37,796	5,264	$1.14	$1.13
Stock compensation	9,825	12,581	(2,756)	$0.26	$0.38
Loss (gain) on derivative instruments, net	17,540	(66,370)	83,910	N/A	N/A
Other operating expense, net	5,455	882	4,573	N/A	N/A
	$680,232	$485,679	$194,553		

Depreciation, Depletion, and Amortization

Depletion of our producing properties is computed using the units-of-production method. The economic life of each producing well depends upon the estimated proved reserves for that well, which in turn depend upon the assumed realized sales price for future production. Therefore, fluctuations in oil and gas prices will impact the level of proved reserves used in the calculation. Higher prices generally have the effect of increasing reserves, which reduces depletion expense. Conversely, lower prices generally have the effect of decreasing reserves, which increases depletion expense. The cost of replacing production also impacts our depletion expense. In addition, changes in estimates of reserve quantities, estimates of operating and future development costs, reclassifications of properties from unproved to proved, and impairments of oil and gas properties will also impact depletion expense. While the increase in oil prices has more than offset the decrease in gas prices during 2018 as compared to 2017, thus increasing our reserves, the increase in production combined with our ongoing exploration and development capital expenditures throughout 2017 and into 2018, have resulted in an overall increase in depletion expense.

Fixed assets consist primarily of gathering and plant facilities, vehicles, airplanes, office furniture, and computer equipment and software. These items are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets, which range from 3 to 30 years. Depreciation, depletion, and amortization ("DD&A") consisted of the following for the periods indicated:

	Three Months Ended June 30,		Variance Between 2018 /	Per BOE	
DD&A Expense (in thousands, except per BOE)	2018	2017	2017	2018	2017
Depletion	$131,220	$95,735	$35,485	$6.82	$5.46
Depreciation	12,168	12,149	19	0.63	0.69
	$143,388	$107,884	$35,504	$7.45	$6.15

	Six Months Ended June 30,		Variance Between	Per BOE	
DD&A Expense (in thousands, except per BOE)	2018	2017	2018 / 2017	2018	2017

Depletion	$251,610	$180,746	$70,864	$6.66	$5.40
Depreciation	24,637	22,954	1,683	0.65	0.68
	$276,247	$203,700	$72,547	$7.31	$6.08

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Production

Production expense generally consists of costs for labor, equipment, maintenance, saltwater disposal, compression, power, treating, and miscellaneous other costs (lease operating expense). Production expense also includes well workover activity necessary to maintain production from existing wells. Production expense consisted of lease operating expense and workover expense as follows:

Production Expense (in thousands, except per BOE)	Three Months Ended June 30, 2018	2017	Variance Between 2018 / 2017	Per BOE 2018	2017
Lease operating expense	$62,355	$55,812	$6,543	$3.24	$3.18
Workover expense	16,860	6,766	10,094	0.88	0.39
	$79,215	$62,578	$16,637	$4.12	$3.57

Production Expense (in thousands, except per BOE)	Six Months Ended June 30, 2018	2017	Variance Between 2018 / 2017	Per BOE 2018	2017
Lease operating expense	$122,831	$101,347	$21,484	$3.25	$3.03
Workover expense	27,655	23,652	4,003	0.73	0.70
	$150,486	$124,999	$25,487	$3.98	$3.73

Lease operating expense in the second quarter 2018 increased 12%, or $6.5 million, compared to the second quarter of 2017. Lease operating expense for the six months ended June 30, 2018 increased 21%, or $21.5 million, compared to the six months ended June 30, 2017. The increases have primarily stemmed from the addition of new wells as a result of our ongoing exploration and development activities. Additional wells and increased production have increased the following costs between the two quarters: (i) equipment rental, primarily flowback equipment and compressors, (ii) saltwater disposal, due to increased water volumes, (iii) environmental compliance, primarily emissions-related, and (iv) labor. The preceding costs also increased between the two six-month periods, as did the following costs: (i) tank battery and processing equipment and maintenance, (ii) electricity, and (iii) chemicals and treating, due to increased water volumes and chemical treating.

Workover expense in the second quarter 2018 increased 149%, or $10.1 million, compared to the second quarter of 2017. Workover expense for the six months ended June 30, 2018 increased 17%, or $4.0 million, compared to the six months ended June 30, 2017. We had a larger quantity of workover projects during the six months ended June 30, 2018 as compared to the six months ended June 30, 2017. Additionally, during the second quarter 2018, we had several artificial lift conversions underway, which increased workover expense. We received insurance proceeds of $4.0 million in the first quarter 2018 and $4.9 million in the second quarter 2017 related to remediation and repairs incurred as a result of a 2015 flooding event. These insurance proceeds decreased workover expense in the periods received, thus resulting in the following increases in workover expense when comparing periods: (i) a $4.9 million increase in the second quarter 2018 as compared to the second quarter 2017 and (ii) a $0.9 million increase during the six months ended June 30, 2018 as compared to the six months ended June 30, 2017. Generally, workover costs will fluctuate based on the amount of maintenance and remedial activity required during the period.

Transportation, Processing, and Other Operating

Transportation, processing, and other operating costs principally consist of expenditures to prepare and transport production from the wellhead, including gathering, fuel, compression, and processing costs. Costs vary by region and will fluctuate with increases or decreases in production volumes, contractual fees, and changes in fuel and compression costs.

Transportation, processing, and other operating costs in the second quarter 2018 were 11%, or $6.7 million, lower than the costs in the second quarter 2017. Transportation, processing, and other operating costs in the six months ended June 30, 2018 were 15%, or $16.5 million, lower than the costs in the six months ended June 30, 2017. These decreases were primarily due to our adoption of ASC 606 effective January 1, 2018, whereby certain transportation and processing costs are now reclassified out of transportation, processing, and other operating costs and are treated as a deduction from revenue. The adoption of ASC 606 reduced Transportation, processing, and other operating costs by $7.7 million in the second quarter 2018 and by $22.2 million in the six months ended June 30, 2018. These reductions were partially offset by increased costs due to increased production volumes. See Note 1 to the Condensed Consolidated Financial Statements for additional information regarding the adoption of ASC 606.

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Gas Gathering and Other

Gas gathering and other includes costs associated with operating our gas gathering and processing infrastructure, including product costs and operating and maintenance expenses. Gas gathering and other in the three months ended June 30, 2018 was 9%, or $0.8 million, higher than gas gathering and other in the three months ended June 30, 2017. Gas gathering and other in the six months ended June 30, 2018 was 13%, or $2.2 million, higher than gas gathering and other in the six months ended June 30, 2017. The increases were primarily due to overall increases in operating costs partially offset by lower product costs associated with processing third-party production due to lower commodity prices and volumes.

Taxes Other than Income

Taxes other than income consist of production (or severance) taxes, ad valorem taxes, and other taxes. State and local taxing authorities assess these taxes, with production taxes being based on the volume or value of production and ad valorem taxes being based on the value of properties. Production taxes make up the majority of this expense for us, with revenue-based production taxes being the largest component of these taxes. Taxes other than income increased $10.5 million, or 60%, in the second quarter of 2018 as compared to the second quarter of 2017. Taxes other than income increased $19.3 million, or 50%, in the six months ended June 30, 2018 as compared to the six months ended June 30, 2017. The increases are due to the increases in revenue seen between the comparable periods. All periods included credits for tax refunds related to high-cost gas wells in the State of Texas, however, the refunds in the three and six months ended June 30, 2018 were $3.6 million and $4.6 million, respectively, lower than the refunds in the three and six months ended June 30, 2017. Taxes other than income was 5.1% and 3.9% of production revenues for the three months ended June 30, 2018 and 2017, respectively, and was 5.3% and 4.4% of production revenues for the six months ended June 30, 2018 and 2017, respectively.

General and Administrative

General and administrative ("G&A") expense consists primarily of salaries and related benefits, office rent, legal and consulting fees, systems costs, and other administrative costs incurred that are not directly associated with exploration, development, or production activities. Our G&A expense is reported net of amounts reimbursed to us by working interest owners of the oil and gas properties we operate and net of amounts capitalized pursuant to the full cost method of accounting. The amount of expense capitalized varies and depends on whether the cost incurred can be directly identified with acquisition, exploration, and development activities. The percentage of gross G&A capitalized ranged from 46% to 50% during the periods presented in the table below, which shows our G&A costs.

General and Administrative Expense (in thousands)	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Variance Between 2018 / 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017	Variance Between 2018 / 2017
Gross G&A	$39,276	$38,541	$ 735	$80,124	$72,631	$7,493
Less amounts capitalized to oil and gas properties	(19,537)	(18,779)	(758)	(37,064)	(34,835)	(2,229)
G&A expense	$19,739	$19,762	$ (23)	$43,060	$37,796	$5,264

G&A expense for the six months ended June 30, 2018 was 14%, or $5.3 million, higher than G&A expense for the six months ended June 30, 2017. This increase was primarily due to increased employee headcount and increased salaries and wages, other compensation, consisting of incentive bonuses and vacation pay, benefits, primarily consisting of profit sharing, and consulting expense.

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Stock Compensation

Stock compensation expense consists of non-cash charges resulting from the amortization of the cost of restricted stock and stock option awards, net of amounts capitalized to oil and gas properties. We have recognized stock-based compensation cost as follows:

Stock Compensation Expense (in thousands)	Three Months Ended June 30, 2018	2017	Variance Between 2018 / 2017	Six Months Ended June 30, 2018	2017	Variance Between 2018 / 2017
Restricted stock awards:						
Performance stock awards	$3,809	$6,438	$(2,629)	$10,538	$12,840	$(2,302)
Service-based stock awards	4,247	4,208	39	9,319	9,132	187
	8,056	10,646	(2,590)	19,857	21,972	(2,115)
Stock option awards	637	579	58	1,254	1,245	9
Total stock compensation cost	8,693	11,225	(2,532)	21,111	23,217	(2,106)
Less amounts capitalized to oil and gas properties	(5,598)	(4,932)	(666)	(11,286)	(10,636)	(650)
Stock compensation expense	$3,095	$6,293	$(3,198)	$9,825	$12,581	$(2,756)

Periodic stock compensation expense will fluctuate based on the grant-date fair value of awards, the number of awards, the requisite service period of the awards, employee forfeitures, and the timing of the awards. The decrease in total stock compensation cost in the 2018 periods as compared to the 2017 periods is primarily due to performance stock award forfeitures during the three months ended June 30, 2018. Our accounting policy is to account for forfeitures in compensation cost when they occur.

Loss (Gain) on Derivative Instruments, Net

The following table presents the components of Loss (gain) on derivative instruments, net for the periods indicated. See Note 3 to the Condensed Consolidated Financial Statements for additional information regarding our derivative instruments.

Loss (Gain) on Derivative Instruments, Net (in thousands)	Three Months Ended June 30, 2018	2017	Variance Between 2018 / 2017	Six Months Ended June 30, 2018	2017	Variance Between 2018 / 2017
Change in fair value of derivative instruments, net:						
Gas contracts	$14,566	$(5,748)	$20,314	$2,777	$(27,939)	$30,716
Oil contracts	(397)	(16,418)	16,021	(5,156)	(44,148)	38,992
	14,169	(22,166)	36,335	(2,379)	(72,087)	69,708
Cash (receipts) payments on derivative instruments, net:						
Gas contracts	(9,918)	(1,308)	(8,610)	(15,037)	1,136	(16,173)
Oil contracts	17,448	965	16,483	34,956	4,581	30,375
	7,530	(343)	7,873	19,919	5,717	14,202
Loss (gain) on derivative instruments, net	$21,699	$(22,509)	$44,208	$17,540	$(66,370)	$83,910

Other Operating Expense, Net

Other operating expense, net is comprised primarily of litigation settlements and allowance for doubtful accounts adjustments.

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Other Income and Expense

Other Income and Expense (in thousands)	Three Months Ended June 30, 2018	2017	Variance Between 2018 / 2017	Six Months Ended June 30, 2018	2017	Variance Between 2018 / 2017
Interest expense	$16,895	$20,095	$(3,200)	$33,678	$41,147	$(7,469)
Capitalized interest	(4,850)	(5,442)	592	(9,660)	(12,083)	2,423
Loss on early extinguishment of debt	—	28,169	(28,169)	—	28,169	(28,169)
Other, net	(2,605)	(2,231)	(374)	(7,172)	(4,441)	(2,731)
	$9,440	$40,591	$(31,151)	$16,846	$52,792	$(35,946)

The majority of our interest expense relates to interest on our senior unsecured notes. Also included in interest expense is the amortization of debt issuance costs and discount. See LIQUIDITY AND CAPITAL RESOURCES Long-term Debt below for further information regarding our debt. The decrease in interest expense in the 2018 periods as compared to the 2017 periods is primarily due to the completion of a tender offer and redemption of $750 million 5.875% senior unsecured notes and the issuance of $750 million 3.90% senior unsecured notes, both of which occurred during the second quarter of 2017. The $28.2 million loss on early extinguishment of debt incurred during the three and six months ended June 30, 2017 was also associated with the debt tender offer and redemption. The loss was composed primarily of tender and redemption premiums of $22.6 million and the write-off of $5.3 million of unamortized debt issuance costs. The original maturity date of the 5.875% notes was May 1, 2022.

We capitalize interest on non-producing leasehold costs, the in-progress costs of drilling and completing wells, and constructing assets. Capitalized interest will fluctuate based on the rates applicable to borrowings outstanding during the period and the amount of costs subject to interest capitalization. The amount of costs subject to interest capitalization was lower in the 2018 periods as compared to the 2017 periods, thus reducing our capitalized interest. Also contributing to lower capitalized interest in the 2018 periods was a lower average interest rate on borrowings outstanding due to the replacement of our 5.875% notes with 3.90% notes in the second quarter of 2017.

Components of Other, net consist of miscellaneous income and expense items that vary from period to period, including interest income, gain or loss related to the sale or value of oil and gas well equipment and supplies, gain or loss on miscellaneous asset sales, and income and expense associated with other non-operating activities.

Income Tax Expense (Benefit)

The components of our provision for income taxes are as follows:

Income Tax Expense (Benefit) (in thousands)	Three Months Ended June 30, 2018	2017	Variance Between 2018 / 2017	Six Months Ended June 30, 2018	2017	Variance Between 2018 / 2017
Current tax benefit	$(717)	$—	$(717)	$(717)	$(6)	$(711)
Deferred tax expense	42,783	58,617	(15,834)	99,732	136,929	(37,197)
	$42,066	$58,617	$(16,551)	$99,015	$136,923	$(37,908)
Combined federal and state effective income tax rate	23.0 %	37.6 %		23.2 %	37.5 %	

Our combined federal and state effective income tax rates differ from the U.S. federal statutory rate of 21% in 2018 and 35% in 2017 primarily due to state income taxes and non-deductible expenses. See Note 9 to the Condensed Consolidated Financial Statements for additional information regarding our income taxes.

LIQUIDITY AND CAPITAL RESOURCES

Overview

We strive to maintain an adequate liquidity level to address volatility and risk. Sources of liquidity include our cash flow from operations, cash on hand, available borrowing capacity under our revolving credit facility, proceeds from sales of non-core assets, and occasional public financings based on our monitoring of capital markets and our balance sheet.

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Our liquidity is highly dependent on prices we receive for the oil, gas, and NGLs we produce. Prices we receive are determined by prevailing market conditions and greatly influence our revenue, cash flow, profitability, access to capital, and future rate of growth. See RESULTS OF OPERATIONS Revenues above for further information regarding the impact realized prices have had on our earnings.

We deal with volatility in commodity prices primarily by maintaining flexibility in our capital investment program. We have a balanced and abundant drilling inventory and limited long-term commitments, which enables us to respond quickly to industry volatility. Based on current economic conditions, our 2018 exploration and development ("E&D") expenditures are projected to range from $1.6 billion to $1.7 billion. Investments in midstream and other assets are projected to range from $80 million to $90 million for the year. See Capital Expenditures below for information regarding our E&D activities for the three and six months ended June 30, 2018 and 2017.

We periodically use derivative instruments to mitigate volatility in commodity prices. At June 30, 2018, we had derivative contracts covering a portion of our 2018 and 2019 production. Depending on changes in oil and gas futures markets and management's view of underlying supply and demand trends, we may increase or decrease our derivative positions from current levels. See Note 3 to the Condensed Consolidated Financial Statements for information regarding our derivative instruments.

We believe our conservative use of leverage, strong balance sheet, and hedging activities will mitigate our exposure to lower prices. Cash and cash equivalents at June 30, 2018 were $410.8 million. At June 30, 2018, our long-term debt consisted of $1.5 billion of senior unsecured notes, with $750 million 4.375% notes due in 2024 and $750 million 3.90% notes due in 2027. At June 30, 2018, we had no borrowings and $2.5 million in letters of credit outstanding under our credit facility, leaving an unused borrowing availability of $997.5 million. See Long-term Debt below for more information regarding our debt.

Our debt to total capitalization ratio at June 30, 2018 was 34%, down from 37% at December 31, 2017. This ratio is calculated by dividing the principal amount of long-term debt by the sum of (i) the principal amount of long-term debt and (ii) total stockholders' equity, with all numbers coming directly from the Condensed Consolidated Balance Sheet. Management uses this ratio as one indicator of our financial condition and believes professional research analysts and rating agencies use this ratio for this purpose and to compare our financial condition to other companies' financial conditions. Additionally, our credit facility includes a financial covenant for the maintenance of a defined total debt-to-capital ratio of no greater than 65%.

We expect our operating cash flow and other capital resources to be adequate to meet our needs for planned capital expenditures, working capital, debt service, and dividends declared for the next twelve months.

Analysis of Cash Flow Changes

The following table presents the totals of the major cash flow classification categories from our Condensed Consolidated Statements of Cash Flows for the periods indicated.

	Six Months Ended June 30,	
(in thousands)	2018	2017
Net cash provided by operating activities	$704,339	$504,800
Net cash used by investing activities	$(671,552)	$(590,824)
Net cash used by financing activities	$(22,498)	$(47,257)

Net cash provided by operating activities for the six months ended June 30, 2018 was $704.3 million, up $199.5 million, or 40%, from $504.8 million for the six months ended June 30, 2017. The $199.5 million increase resulted primarily from the increase in production revenue, which increased due to increased production volumes and realized oil and NGL prices. Also contributing to the increase was a decreased investment in working capital. These increases were partially offset by a net increase in operating costs and expenses and increased cash outflows for settlements of derivative instruments. See RESULTS OF OPERATIONS above for more information regarding the changes in revenue and operating expenses.

Net cash used by investing activities for the six months ended June 30, 2018 and 2017 was $671.6 million and $590.8 million, respectively. The majority of our cash flows used by investing activities are for E&D expenditures, which totaled $650.8 million and $582.2 million for the six months ended June 30, 2018 and 2017, respectively. The remaining investing cash outflows are primarily for midstream asset expenditures. Proceeds from the sales of non-core assets slightly offset capital expenditure cash outflows in both periods.

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Net cash used by financing activities for the six months ended June 30, 2018 and 2017 was $22.5 million and $47.3 million, respectively. During the six months ended June 30, 2017, we extinguished our $750 million principal amount 5.875% senior notes, paying $22.6 million in tender and redemption premiums and $0.2 million in other costs and issued $750 million principal amount 3.90% senior notes at 99.748% of par for proceeds of $748.1 million, paying $6.2 million in underwriting, financing, and other costs. Additionally, net cash used by financing activities during both periods included: (i) the payment of dividends, (ii) the payment of income tax withholdings made on behalf of our employees upon the net settlement of employee stock awards, and (iii) the receipt of proceeds from exercises of stock options. During the six months ended June 30, 2018, we paid one $0.08 per share dividend and one $0.16 per share dividend, totaling $22.8 million and during the six months ended June 30, 2017, we paid two $0.08 per share dividends totaling $15.2 million.

Capital Expenditures

The following table presents capitalized expenditures for oil and gas acquisition, exploration, and development activities, net of proceeds from property sales.

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2018	2017	2018	2017
Acquisitions:				
Proved	$—	$255	$62	$260
Unproved	77	792	2,236	3,825
	77	1,047	2,298	4,085
Exploration and development:				
Land and seismic	10,327	33,302	20,424	110,487
Exploration and development	365,097	262,575	668,469	491,042
	375,424	295,877	688,893	601,529
Property sales:				
Proved	(4,577)	(1,957)	(29,541)	(1,892)
Unproved	(441)	(2,305)	(5,301)	(7,271)
	(5,018)	(4,262)	(34,842)	(9,163)
	$370,483	$292,662	$656,349	$596,451

Amounts in the table above are presented on an accrual basis. The Condensed Consolidated Statements of Cash Flows reflect activities on a cash basis, when payments are made and proceeds received.

Our 2018 E&D capital investment is projected to range from $1.6 billion to $1.7 billion, with the majority expected to be invested in the Permian Basin.

As has been our historical practice, we regularly review our capital expenditures throughout the year and will adjust our investments based on increases or decreases in commodity prices, service costs, and drilling success. We have the flexibility to adjust our capital expenditures based upon market conditions.

We intend to continue to fund our 2018 capital investment program with cash flow from our operating activities and cash on hand. Sales of non-core assets and borrowings under our credit facility may also be used to supplement funding of capital expenditures. The timing of capital expenditures and the receipt of cash flows do not necessarily match, which may cause us to borrow and repay funds under our credit facility from time-to-time. See Long-term Debt—Bank Debt below for further information regarding our credit facility.

On May 23, 2018, we entered into a Purchase and Sale Agreement with Callon Petroleum Operating Company (“Callon”) pursuant to which we agreed to sell, and Callon agreed to purchase, oil and gas properties principally located in Ward County, Texas for $570 million in cash. This sale is part of our continuous portfolio optimization and high-grading of our investment opportunities. The Purchase and Sale Agreement contains representations, warranties, covenants, conditions to closing, purchase price adjustments, and other terms customary in transactions of this type. We expect to complete this transaction on August 31, 2018.

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The following table reflects wells completed by region during the periods indicated.

	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
Gross wells				
Permian Basin	32	11	49	36
Mid-Continent	57	40	94	85
	89	51	143	121
Net wells				
Permian Basin	13	10	22	26
Mid-Continent	10	8	16	18
	23	18	38	44

As of June 30, 2018, we had 29 gross (11 net) wells in the process of being drilled: 14 gross (9 net) in the Permian Basin and 15 gross (2 net) in the Mid-Continent region. As of June 30, 2018, there were 141 gross (57 net) wells waiting on completion: 45 gross (32 net) in the Permian Basin and 96 gross (25 net) in the Mid-Continent region. As of June 30, 2018, we had 12 operated rigs running: nine in the Permian Basin and three in the Mid-Continent region.

We have made, and will continue to make, expenditures to comply with environmental and safety regulations and requirements. These costs are considered a normal recurring cost of our ongoing operations. While we expect current pending legislation or regulations to increase the cost of business, we do not anticipate that we will be required to expend amounts that will have a material adverse effect on our financial position or operations, nor are we aware of any pending regulatory changes that would have a material impact, based on current laws and regulations. However, compliance with new legislation or regulations could increase our costs or adversely affect demand for oil or gas and result in a material adverse effect on our financial position or operations. See our Form 10-K for the year ended December 31, 2017, Item 1A Risk Factors, for a description of risks related to current and potential future environmental and safety regulations and requirements that could adversely affect our operations and financial condition.

Long-term Debt

Long-term debt at June 30, 2018 and December 31, 2017 consisted of the following:

(in thousands)	June 30, 2018 Principal	Unamortized Debt Issuance Costs and Discount (1)	Long-term Debt, net	December 31, 2017 Principal	Unamortized Debt Issuance Costs and Discount (1)	Long-term Debt, net
4.375% Senior Notes	$750,000	$ (4,906)	$745,094	$750,000	$ (5,383)	$744,617
3.90% Senior Notes	750,000	(7,355)	742,645	750,000	(7,697)	742,303
Total long-term debt	$1,500,000	$ (12,261)	$1,487,739	$1,500,000	$ (13,080)	$1,486,920

(1) At June 30, 2018, the unamortized debt issuance costs and discount related to the 3.90% notes were $5.7 million and $1.7 million, respectively. At December 31, 2017, the unamortized debt issuance costs and discount related to the 3.90% notes were $5.9 million and $1.8 million, respectively. The 4.375% notes were issued at par.

Bank Debt

We have a senior unsecured revolving credit facility (“Credit Facility”) that matures October 16, 2020. The Credit Facility has aggregate commitments of $1.0 billion, with an option for us to increase the aggregate commitments to $1.25 billion at any time. There is no borrowing base subject to the discretion of the lenders based on the value of our proved reserves under the Credit Facility. As of June 30, 2018, we had no bank borrowings outstanding under the

Credit Facility, but did have letters of credit of $2.5 million outstanding, leaving an unused borrowing availability of $997.5 million.

At our option, borrowings under the Credit Facility may bear interest at either (a) LIBOR plus 1.125 – 2.0% based on the credit rating for our senior unsecured long-term debt, or (b) a base rate (as defined in the credit agreement) plus 0.125 – 1.0%,

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based on the credit rating for our senior unsecured long-term debt. Unused borrowings are subject to a commitment fee of 0.125 – 0.35%, based on the credit rating for our senior unsecured long-term debt.

The Credit Facility contains representations, warranties, covenants, and events of default that are customary for investment grade, senior unsecured bank credit agreements, including a financial covenant for the maintenance of a defined total debt-to-capital ratio of no greater than 65%. As of June 30, 2018, we were in compliance with all of the financial and non-financial covenants.

At June 30, 2018 and December 31, 2017, we had $2.7 million and $3.4 million, respectively, of unamortized debt issuance costs associated with our Credit Facility, which were recorded as assets and included in Other assets on our Condensed Consolidated Balance Sheets. These costs are being amortized to interest expense ratably over the life of the Credit Facility.

Senior Notes

In April 2017, we issued $750 million aggregate principal amount of 3.90% senior unsecured notes at 99.748% of par to yield 3.93% per annum. These notes are due May 15, 2027 and interest is payable semiannually on May 15 and November 15. The effective interest rate on these notes, including the amortization of debt issuance costs and discount, is 4.01%.

In June 2014, we issued $750 million aggregate principal amount of 4.375% senior unsecured notes at par. These notes are due June 1, 2024 and interest is payable semiannually on June 1 and December 1. The effective interest rate on these notes, including the amortization of debt issuance costs, is 4.50%.

Our senior unsecured notes are governed by indentures containing certain covenants, events of default, and other restrictive provisions with which we were in compliance as of June 30, 2018.

Working Capital Analysis

Our working capital fluctuates primarily as a result of our realized commodity prices, increases or decreases in our production volumes, changes in receivables and payables related to our operating and E&D activities, changes in our oil and gas well equipment and supplies, and changes in the fair value of our derivative instruments.

At June 30, 2018, we had working capital of $253.2 million, a decrease of $2.9 million or 1% compared to working capital of $256.1 million at December 31, 2017.

Working capital decreases consisted primarily of the following:

- Accrued liabilities related to our E&D expenditures increased by $31.1 million.
- Operations-related accounts receivable decreased by $15.5 million.

Working capital increases consisted primarily of the following:

- Operations-related accounts payable and accrued liabilities decreased by $22.2 million.
- Cash and cash equivalents increased by $10.3 million.
- Current derivative instrument net liability decreased by $9.4 million.
- Oil and gas well equipment and supplies increased by $3.7 million.

Accounts receivable are a major component of our working capital and include amounts due from a diverse group of companies comprised of major energy companies, pipeline companies, local distribution companies, and other end-users. Historically, losses associated with uncollectible receivables have not been significant. The fair value of derivative instruments fluctuates based on changes in the underlying price indices as compared to the contracted prices.

Dividends

A quarterly cash dividend has been paid to stockholders every quarter since the first quarter of 2006. In May 2018, a $0.16 per share dividend was declared, which is payable on or before August 31, 2018 to stockholders of record on August 15, 2018. Future dividend payments will depend on our level of earnings, financial requirements, and other factors considered relevant by our Board of Directors. See Note 5 to the Condensed Consolidated Financial Statements for further information regarding dividends.

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Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of June 30, 2018, our material off-balance sheet arrangements consisted of operating lease agreements, which are included in the contractual obligations table below.

Contractual Obligations and Material Commitments

At June 30, 2018, we had the following contractual obligations and material commitments:

	Payments Due by Period				
Contractual obligations (in thousands)	Total	1 Year or Less	2-3 Years	4-5 Years	More than 5 Years
Long-term debt—principal (1)	$1,500,000	$—	$—	$—	$1,500,000
Long-term debt—interest (1)	460,044	60,844	124,125	124,125	150,950
Operating leases (2)	90,206	15,372	25,399	22,512	26,923
Unconditional purchase obligations (3)	80,863	31,176	35,585	6,900	7,202
Derivative liabilities	101,991	90,480	11,511	—	—
Asset retirement obligation (4)	167,998	8,430	— (4)	— (4)	— (4)
Other long-term liabilities (5)	39,567	2,034	3,540	5,138	28,855
	$2,440,669	$208,336	$200,160	$158,675	$1,713,930

(1) The interest payments presented above include the accrued interest payable on our long-term debt as of June 30, 2018 as well as future payments calculated using the long-term debt's fixed rates, stated maturity dates, and principal amounts outstanding as of June 30, 2018. See Note 2 to the Condensed Consolidated Financial Statements for additional information regarding our debt.

(2) Operating leases include various lease commitments for commercial real estate, which consists primarily of office space, and compressor equipment.

(3) Of the total Unconditional purchase obligations, $43.9 million represents obligations for the purchase of sand for well completions and $26.6 million represents obligations for firm transportation agreements for gas pipeline capacity.

(4) We have excluded the presentation of the timing of the cash flows associated with our long-term asset retirement obligations because we cannot make a reasonably reliable estimate of the future period of cash settlement. The long-term asset retirement obligation is included in the total asset retirement obligation presented.

(5) Other long-term liabilities include contractual obligations associated with our employee supplemental savings plan, gas balancing liabilities, and other miscellaneous liabilities. All of these liabilities are accrued on our Condensed Consolidated Balance Sheet. The current portion associated with these long-term liabilities is also presented in the table above in the "1 Year or Less" column.

The following discusses various commercial commitments that we have made that may include potential future cash payments if we fail to meet various performance obligations. These are not reflected in the table above.

At June 30, 2018, we had estimated commitments of approximately: (i) $154.4 million to finish drilling, completing, or performing other work on wells and various other infrastructure projects in progress and (ii) $14.4 million to finish gathering system construction in progress.

At June 30, 2018, we had firm sales contracts to deliver approximately 330.7 Bcf of gas over the next 6.6 years. If we do not deliver this gas, our estimated financial commitment, calculated using the July 2018 index price, would be approximately $659.9 million. The value of this commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no financial commitment will be due based on our current proved reserves and production levels from which we can fulfill these volumetric obligations.

In connection with gas gathering and processing agreements, we have volume commitments over the next 9.5 years. If we do not deliver the committed gas or NGLs, as the case may be, the estimated maximum amount that would be payable under these commitments, calculated as of June 30, 2018, would be approximately $351.0 million. However, we believe no financial commitment will be due based on our current proved reserves and production levels from which we can fulfill these volumetric obligations.

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We have minimum volume delivery commitments associated with agreements to reimburse connection costs to various pipelines. If we do not deliver this gas, the estimated maximum amount that would be payable under these commitments, calculated as of June 30, 2018, would be approximately $7.4 million. Of this total, we have accrued a liability of $2.5 million representing the estimated amount we will have to pay due to insufficient forecasted volumes at particular connection points.

All of the noted commitments were routine and made in the ordinary course of our business.

Taking into account current commodity prices and anticipated levels of production, we believe that our net cash flow generated from operations and our other capital resources will be adequate to meet future obligations.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We consider accounting policies and estimates related to oil and gas reserves, full cost accounting, and income taxes to be critical accounting policies and estimates. These are summarized in “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2017.

Recent Accounting Developments

See Note 1 to the Condensed Consolidated Financial Statements in this report for a discussion of recently issued accounting pronouncements and their anticipated effect on our financial statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk including the risk of loss arising from adverse changes in commodity prices and interest rates.

Price Fluctuations

Our major market risk is pricing applicable to our oil, gas, and NGL production. The prices we receive for our production are based on prevailing market conditions and are influenced by many factors that are beyond our control. Pricing for oil, gas, and NGL production has been volatile and unpredictable. For the three months ended June 30, 2018, our total production revenue was comprised of 63% oil sales, 15% gas sales, and 22% NGL sales. For the six months ended June 30, 2018, our total production revenue was comprised of 63% oil sales, 17% gas sales, and 20% NGL sales. The following table shows how hypothetical changes in the realized prices we receive for our commodity sales may have impacted revenue for the periods indicated.

	Change in Realized Price	Impact on Revenue Three Months Ended June 30, 2018	Six Months Ended June 30, 2018
		(in thousands)	
Oil	± $1.00 per barrel	± $5,610	± $11,479
Gas	± $0.10 per Mcf	± $4,909	± $9,722
NGL	± $1.00 per barrel	± $5,447	± $10,102
		± $15,966	± $31,303

We periodically enter into financial derivative contracts to hedge a portion of our price risk associated with our future oil and gas production. At June 30, 2018, we had oil and gas derivatives covering a portion of our 2018 and 2019 production, which were recorded as current and non-current assets and liabilities. At June 30, 2018, our oil and gas derivatives had a gross asset fair value of $75.3 million and a gross liability fair value of $102.0 million. See Note 3 to the Condensed Consolidated Financial Statements for additional information regarding our derivative instruments.

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While these contracts limit the downside risk of adverse price movements, they may also limit future cash flow from favorable price movements. The following table shows how hypothetical changes in the forward prices used to calculate the fair value of our derivatives may have impacted the fair value as of June 30, 2018.

Change in Forward Price		Impact on Fair Value June 30, 2018 (in thousands)
Oil	-$1.00	$ 9,870
Oil	+$1.00	$ (10,056)
Gas	-$0.10	$ 6,714
Gas	+$0.10	$ (6,728)

Interest Rate Risk

At June 30, 2018, our long-term debt consisted of $750 million of 4.375% senior unsecured notes that will mature on June 1, 2024 and $750 million of 3.90% senior unsecured notes that will mature on May 15, 2027. Because all of our outstanding long-term debt is at a fixed rate, we consider our interest rate exposure to be minimal. See Note 2 to the Condensed Consolidated Financial Statements for additional information regarding our debt.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Cimarex's management, under the supervision and with the participation of the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), have evaluated the effectiveness of Cimarex's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of June 30, 2018. Based on that evaluation, the CEO and CFO concluded that the disclosure controls and procedures are effective in providing reasonable assurance that information required to be disclosed in reports filed or submitted under the Exchange Act is recorded, processed, summarized, and reported within the time periods required by the U.S. Securities and Exchange Commission's rules and forms and that such information is accumulated and communicated to management, including the CEO and CFO, to allow timely decisions regarding required disclosures.

Changes in Internal Control over Financial Reporting

There was no change in our internal control over financial reporting that occurred during the fiscal quarter ended June 30, 2018 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II

ITEM 1. LEGAL PROCEEDINGS

The information set forth under the heading "Litigation" in Note 10 to the Condensed Consolidated Financial Statements is incorporated by reference in response to this item.

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the risks discussed in our Annual Report on Form 10-K for the year ended December 31, 2017. There have been no material changes in our risk factors from those described in the Annual Report on Form 10-K for the year ended December 31, 2017. The risks described in the Annual Report on Form 10-K for the year ended December 31, 2017 are not the only risks facing us. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition, or future results.

ITEM 6. EXHIBITS

10.1	Purchase and Sale Agreement dated May 23, 2018 between Cimarex Energy Co., Prize Energy Resources, Inc., and Magnum Hunter Production, Inc. (collectively, as "Seller") and Callon Petroleum Operating Company as Buyer (filed as Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on May 24, 2018 and incorporated herein by reference).
31.1	Certification of Thomas E. Jorden, Chief Executive Officer of Cimarex Energy Co., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of G. Mark Burford, Chief Financial Officer of Cimarex Energy Co., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Thomas E. Jorden, Chief Executive Officer of Cimarex Energy Co., pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350.
32.2	Certification of G. Mark Burford, Chief Financial Officer of Cimarex Energy Co., pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

August 7, 2018

CIMAREX ENERGY CO.

/s/ G. Mark Burford
G. Mark Burford
Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Timothy A. Ficker
Timothy A. Ficker
Vice President, Controller, and Chief Accounting Officer
(Principal Accounting Officer)