CIMAREX ENERGY CO
Form 10-Q
May 08, 2018
Table of Contents

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 March 31, 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 April 30, 2018 was 95,430,045.

Table of Contents

CIMAREX ENERGY CO.
Table of Contents

Table of Contents

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, the effectiveness of our internal control over financial reporting and our ability to remediate a material weakness in our internal control over financial reporting, 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, and availability of financing. 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.

Table of Contents

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

	March 31, 2018	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$463,810	$400,534
Accounts receivable, net of allowance:		
Trade	90,001	100,356
Oil and gas sales	313,462	344,552
Gas gathering, processing, and marketing	11,785	15,266
Oil and gas well equipment and supplies	54,223	49,722
Derivative instruments	36,157	15,151
Prepaid expenses	7,198	8,518
Other current assets	1,354	1,536
Total current assets	977,990	935,635
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	17,795,832	17,513,460
Unproved properties and properties under development, not being amortized	475,665	476,903
	18,271,497	17,990,363
Less—accumulated depreciation, depletion, amortization, and impairment	(14,869,223)	(14,748,833)
Net oil and gas properties	3,402,274	3,241,530
Fixed assets, net of accumulated depreciation of $301,407 and $290,114, respectively	216,873	210,922
Goodwill	620,232	620,232
Derivative instruments	9,441	2,086
Other assets	33,554	32,234
	$5,260,364	$5,042,639
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable:		
Trade	$76,350	$68,883
Gas gathering, processing, and marketing	24,067	29,503
Accrued liabilities:		
Exploration and development	103,559	115,762
Taxes other than income	24,171	23,687
Other	181,288	212,400
Derivative instruments	54,168	42,066
Revenue payable	194,695	187,273
Total current liabilities	658,298	679,574
Long-term debt:		
Principal	1,500,000	1,500,000
Less—unamortized debt issuance costs and discount	(12,670)	(13,080)
Long-term debt, net	1,487,330	1,486,920
Deferred income taxes	158,511	101,618
Asset retirement obligation	156,254	158,421

Derivative instruments	3,980	4,268
Other liabilities	44,398	43,560
Total liabilities	2,508,771	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, 95,433,321 and 95,437,434 shares issued, respectively	954	954
Additional paid-in capital	2,761,567	2,764,384
Retained earnings (accumulated deficit)	(12,937)	(199,259)
Accumulated other comprehensive income	2,009	2,199
Total stockholders' equity	2,751,593	2,568,278
	$5,260,364	$5,042,639

See accompanying Notes to Condensed Consolidated Financial Statements.

Table of Contents

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

	Three Months Ended March 31,	
	2018	2017
Revenues:		
Oil sales	$351,723	$224,066
Gas and NGL sales	203,718	212,371
Gas gathering and other	11,452	10,625
Gas marketing	241	114
	567,134	447,176
Costs and expenses:		
Depreciation, depletion, and amortization	132,859	95,816
Asset retirement obligation	1,060	1,620
Production	71,271	62,421
Transportation, processing, and other operating	45,165	55,023
Gas gathering and other	9,823	8,427
Taxes other than income	30,188	21,313
General and administrative	23,321	18,034
Stock compensation	6,730	6,288
Loss (gain) on derivative instruments, net	(4,159)	(43,861)
Other operating expense, net	203	616
	316,461	225,697
Operating income	250,673	221,479
Other (income) and expense:		
Interest expense	16,783	21,052
Capitalized interest	(4,810)	(6,641)
Other, net	(4,567)	(2,210)
Income before income tax	243,267	209,278
Income tax expense	56,949	78,306
Net income	$186,318	$130,972
Earnings per share to common stockholders:		
Basic	$1.96	$1.38
Diluted	$1.96	$1.38
Dividends declared per share	$0.16	$0.08
Comprehensive income:		
Net income	$186,318	$130,972
Other comprehensive income:		
Change in fair value of investments, net of tax of ($56) and $231, respectively	(190)	402
Total comprehensive income	$186,128	$131,374

See accompanying Notes to Condensed Consolidated Financial Statements.

5

Table of Contents

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

	Three Months Ended March 31,	
	2018	2017
Cash flows from operating activities:		
Net income	$186,318	$130,972
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, and amortization	132,859	95,816
Asset retirement obligation	1,060	1,620
Deferred income taxes	56,949	78,312
Stock compensation	6,730	6,288
Loss (gain) on derivative instruments, net	(4,159)	(43,861)
Settlements on derivative instruments	(12,389)	(6,060)
Changes in non-current assets and liabilities	(900)	1,019
Other, net	766	1,728
Changes in operating assets and liabilities:		
Accounts receivable	44,722	(44,662)
Other current assets	1,603	(2,965)
Accounts payable and other current liabilities	(30,466)	31,307
Net cash provided by operating activities	383,093	249,514
Cash flows from investing activities:		
Oil and gas capital expenditures	(323,455)	(311,841)
Other capital expenditures	(19,056)	(8,082)
Sales of oil and gas assets	29,824	4,901
Sales of other assets	432	45
Net cash used by investing activities	(312,255)	(314,977)
Cash flows from financing activities:		
Financing fees	—	(26)
Dividends paid	(7,602)	(7,577)
Employee withholding taxes paid upon the net settlement of equity-classified stock awards	(305)	(938)
Proceeds from exercise of stock options	345	36
Net cash used by financing activities	(7,562)	(8,505)
Net change in cash and cash equivalents	63,276	(73,968)
Cash and cash equivalents at beginning of period	400,534	652,876
Cash and cash equivalents at end of period	$463,810	$578,908

See accompanying Notes to Condensed Consolidated Financial Statements.

Table of Contents

CIMAREX ENERGY CO.
Condensed Consolidated Statement of Stockholders’ Equity
(in thousands)
(Unaudited)

	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income	Total Stockholders’ Equity
	Shares	Amount				
Balance, December 31, 2017	95,437	$ 954	$2,764,384	$(199,259)	$ 2,199	$2,568,278
Dividends paid on stock awards subsequently forfeited	—	—	3	4	—	7
Dividends in excess of retained earnings	—	—	(15,271)	—	—	(15,271)
Net income	—	—	—	186,318	—	186,318
Unrealized change in fair value of investments, net of tax	—	—	—	—	(190)	(190)
Issuance of restricted stock awards	2	—	—	—	—	—
Common stock reacquired and retired	(3)	—	(305)	—	—	(305)
Restricted stock forfeited and retired	(7)	—	—	—	—	—
Exercise of stock options	4	—	345	—	—	345
Stock-based compensation	—	—	12,411	—	—	12,411
Balance, March 31, 2018	95,433	$ 954	$2,761,567	$(12,937)	$ 2,009	$2,751,593

See accompanying Notes to Condensed Consolidated Financial Statements.
7

Table of Contents

CIMAREX ENERGY CO.
Notes to Condensed Consolidated Financial Statements
March 31, 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 three months ended March 31, 2018 and March 31, 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 decline, 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.

Table of Contents

CIMAREX ENERGY CO.
Notes to Condensed Consolidated Financial Statements
March 31, 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 March 31,			
	2018			2017
(in thousands)	Pre-ASC 606 Adoption	Impact of ASC 606	Post-ASC 606 Adoption	As Reported
Oil sales	$351,723	$—	$351,723	$224,066
Gas sales	112,677	(2,956)	109,721	131,945
NGL sales	105,613	(11,616)	93,997	80,426
Total oil, gas, and NGL sales	$570,013	$(14,572)	$555,441	$436,437

	Three Months Ended March 31,			
	2018			2017
(in thousands)	Pre-ASC 606 Adoption	Impact of ASC 606	Post-ASC 606 Adoption	As Reported
Transportation, processing, and other operating costs	$59,737	$(14,572)	$ 45,165	$ 55,023

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 reasonably assured. 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 March 31, 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. 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.

Table of Contents

Gas Marketing

When we market and sell gas for working interest owners, we act as agent under short-term sales and supply agreements and 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 in the process of 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 in the process of evaluating the potential impact of adopting this guidance and do not intend to adopt the standard early.

CIMAREX ENERGY CO.
Notes to Condensed Consolidated Financial Statements
March 31, 2018
(Unaudited)

2. LONG-TERM DEBT

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

	March 31, 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	$ (5,143)	$744,857	$750,000	$ (5,383)	$744,617
3.90% Senior Notes	750,000	(7,527)	742,473	750,000	(7,697)	742,303
Total long-term debt	$1,500,000	$ (12,670)	$1,487,330	$1,500,000	$ (13,080)	$1,486,920

(1) At March 31, 2018, the unamortized debt issuance costs and discount related to the 3.90% notes were $5.8 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 March 31, 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 March 31, 2018, we were in compliance with all of the financial covenants.

At March 31, 2018 and December 31, 2017, we had $3.0 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 March 31, 2018.

Table of Contents

CIMAREX ENERGY CO.
Notes to Condensed Consolidated Financial Statements
March 31, 2018
(Unaudited)

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 March 31, 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 March 31, 2018:

Oil Collars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2018:					
WTI (1)					
Volume (Bbls)	—	2,821,000	2,484,000	1,932,000	7,237,000
Weighted Avg Price - Floor	$ —	$ 47.97	$ 47.67	$ 48.76	$ 48.08
Weighted Avg Price - Ceiling	$ —	$ 58.35	$ 58.25	$ 59.33	$ 58.58
2019:					
WTI (1)					
Volume (Bbls)	1,350,000	1,365,000	736,000	—	3,451,000
Weighted Avg Price - Floor	$ 49.07	$ 49.07	$ 50.00	$ —	$ 49.27
Weighted Avg Price - Ceiling	$ 61.49	$ 61.49	$ 66.21	$ —	$ 62.50

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

Table of Contents

CIMAREX ENERGY CO.
Notes to Condensed Consolidated Financial Statements
March 31, 2018
(Unaudited)

Gas Collars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2018:					
PEPL (1)					
Volume (MMBtu)	—	11,830,000	9,200,000	6,440,000	27,470,000
Weighted Avg Price - Floor	$ —	$ 2.35	$ 2.28	$ 2.21	$ 2.29
Weighted Avg Price - Ceiling	$ —	$ 2.66	$ 2.52	$ 2.46	$ 2.57
Perm EP (2)					
Volume (MMBtu)	—	9,100,000	7,360,000	5,520,000	21,980,000
Weighted Avg Price - Floor	$ —	$ 2.15	$ 2.06	$ 1.97	$ 2.07
Weighted Avg Price - Ceiling	$ —	$ 2.43	$ 2.28	$ 2.19	$ 2.32
2019:					
PEPL (1)					
Volume (MMBtu)	5,400,000	5,460,000	2,760,000	—	13,620,000
Weighted Avg Price - Floor	$ 2.17	$ 2.17	$ 1.93	$ —	$ 2.12
Weighted Avg Price - Ceiling	$ 2.42	$ 2.42	$ 2.18	$ —	$ 2.37
Perm EP (2)					
Volume (MMBtu)	4,500,000	4,550,000	2,760,000	—	11,810,000
Weighted Avg Price - Floor	$ 1.88	$ 1.88	$ 1.60	$ —	$ 1.81
Weighted Avg Price - Ceiling	$ 2.12	$ 2.12	$ 1.87	$ —	$ 2.06

(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.

Oil Basis Swaps	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2018:					
WTI Midland (1)					
Volume (Bbls)	—	1,365,000	1,380,000	920,000	3,665,000
Weighted Avg Differential (2)	$—	$ (0.78)	$ (0.78)	$ (0.70)	$ (0.76)
2019:					
WTI Midland (1)					
Volume (Bbls)	630,000	637,000	184,000	—	1,451,000
Weighted Avg Differential (2)	$ (0.68)	$ (0.68)	$ (1.20)	$—	$ (0.74)

(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.

Table of Contents

CIMAREX ENERGY CO.
Notes to Condensed Consolidated Financial Statements
March 31, 2018
(Unaudited)

The following table summarizes our derivative contracts entered into subsequent to March 31, 2018 through May 7, 2018:

Oil Basis Swaps	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2018:					
WTI Midland (1)					
Volume (Bbls)	—	—	552,000	552,000	1,104,000
Weighted Avg Differential (2)	$—	$—	$(4.83)	$(4.83)	$(4.83)
2019:					
WTI Midland (1)					
Volume (Bbls)	540,000	546,000	552,000	—	1,638,000
Weighted Avg Differential (2)	$(4.83)	$(4.83)	$(4.83)	$—	$(4.83)

(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 March 31,	
(in thousands)	2018	2017
Change in fair value of derivative instruments, net:		
Gas contracts	$(11,789)	$(22,191)
Oil contracts	(4,759)	(27,730)
	(16,548)	(49,921)
Cash (receipts) payments on derivative instruments, net:		
Gas contracts	(5,119)	2,444
Oil contracts	17,508	3,616
	12,389	6,060
Loss (gain) on derivative instruments, net	$(4,159)	$(43,861)

Derivative Fair Value

Our derivative contracts are carried at their fair value on our balance sheet using Level 2 inputs and are subject to enforceable 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.

Table of Contents

CIMAREX ENERGY CO.
Notes to Condensed Consolidated Financial Statements
March 31, 2018
(Unaudited)

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

		March 31, 2018	
(in thousands)	Balance Sheet Location	Asset	Liability
Oil contracts	Current assets — Derivative instruments	$13,594	$—
Gas contracts	Current assets — Derivative instruments	22,563	—
Oil contracts	Non-current assets — Derivative instruments	2,055	—
Gas contracts	Non-current assets — Derivative instruments	7,386	—
Oil contracts	Current liabilities — Derivative instruments	—	53,244
Gas contracts	Current liabilities — Derivative instruments	—	924
Oil contracts	Non-current liabilities — Derivative instruments	—	3,980
Total gross amounts presented in the balance sheet		45,598	58,148
Less: gross amounts not offset in the balance sheet		(36,077)	(36,077)
Net amount		$9,521	$22,071

		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.

CIMAREX ENERGY CO.
Notes to Condensed Consolidated Financial Statements
March 31, 2018
(Unaudited)

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

	March 31, 2018		December 31, 2017	
(in thousands)	Book Value	Fair Value	Book Value	Fair Value
Financial Assets (Liabilities):				
4.375% Notes due 2024	$(750,000)	$(773,408)	$(750,000)	$(797,010)
3.90% Notes due 2027	$(750,000)	$(742,298)	$(750,000)	$(767,813)
Derivative instruments — assets	$45,598	$45,598	$17,237	$17,237
Derivative instruments — liabilities	$(58,148)	$(58,148)	$(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 March 31, 2018 were accrued operating expenses of approximately $61.5 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 March 31, 2018 and December 31, 2017, the allowance for doubtful accounts was $2.4 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 March 31, 2018, there were 95.4 million shares of common stock and no shares of preferred stock outstanding.

Dividends

In February 2018, our Board of Directors declared a cash dividend of $0.16 per share. The dividend is payable on or before June 1, 2018, to stockholders of record on May 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. Nonforfeitable dividends paid on stock awards that subsequently forfeit are reclassified out of retained earnings or additional paid-in capital, as applicable, to compensation

Table of Contents

CIMAREX ENERGY CO.
Notes to Condensed Consolidated Financial Statements
March 31, 2018
(Unaudited)

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.

(in thousands)	Three Months Ended March 31, 2018	2017
Restricted stock awards:		
Performance stock awards	$6,729	$6,402
Service-based stock awards	5,072	4,924
	11,801	11,326
Stock option awards	617	666
Total stock compensation cost	12,418	11,992
Less amounts capitalized to oil and gas properties	(5,688)	(5,704)
Stock compensation expense	$6,730	$6,288

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 increase in total stock compensation cost in 2018 as compared to 2017 is primarily due to awards granted either during or subsequent to the 2017 period, partially offset by awards vesting prior to or during the 2018 period.

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 three months ended March 31, 2018:

(in thousands)	Three Months Ended March 31, 2018
Asset retirement obligation at January 1, 2018	$169,469
Liabilities incurred	1,018
Liability settlements and disposals	(8,183)
Accretion expense	1,906
Revisions of estimated liabilities	431
Asset retirement obligation at March 31, 2018	164,641
Less current obligation	(8,387)

Long-term asset retirement obligation	$156,254

17

CIMAREX ENERGY CO.
Notes to Condensed Consolidated Financial Statements
March 31, 2018
(Unaudited)

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 March 31,					
	2018			2017		
(in thousands, except per share information)	Income (Numerator)	Shares (Denominator)	Per-Share Amount	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Net income	$186,318			$130,972		
Less: net income attributable to participating securities	(2,666)			(2,255)		
Basic earnings per share						
Income available to common stockholders	183,652	93,699	$ 1.96	128,717	93,389	$ 1.38
Effects of dilutive securities						
Options (1)		38			39	
Diluted earnings per share						
Income available to common stockholders and assumed conversions	$183,652	93,737	$ 1.96	$128,717	93,428	$ 1.38

(1) Inclusion of certain shares would have an anti-dilutive effect; therefore, 295.6 thousand and 161.8 thousand shares were excluded from the calculations for the three months ended March 31, 2018 and 2017, respectively.

9. INCOME TAXES

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

	Three Months Ended March 31,	
(in thousands)	2018	2017
Current tax benefit	$—	$(6)
Deferred tax expense	56,949	78,312
	$56,949	$78,306
Combined federal and state effective income tax rate	23.4 %	37.4 %

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 March 31, 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.

Table of Contents

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 March 31, 2018, we had estimated commitments of approximately: (i) $292.8 million to finish drilling, completing, or performing other work on wells and various other infrastructure projects in progress and (ii) $32.0 million to finish gathering system construction in progress.

At March 31, 2018, we had firm sales contracts to deliver approximately 238.4 Bcf of gas over the next 6.8 years. If we do not deliver this gas, our estimated financial commitment, calculated using the April 2018 index price, would be approximately $407.6 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 9.8 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 March 31, 2018, would be approximately $325.9 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.

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 March 31, 2018, would be approximately $8.9 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.

At March 31, 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 $34.2 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 March 31, 2018, we have various future commitments for office space and compressor equipment under operating lease arrangements. The commitments under the office space operating leases, which have lease terms expiring in the next 8.4 years, total approximately $83.6 million. The commitments under the compressor equipment operating leases, which have lease terms expiring in the next 2 - 27 months, total approximately $9.1 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.

Table of Contents

CIMAREX ENERGY CO.
Notes to Condensed Consolidated Financial Statements
March 31, 2018
(Unaudited)

11. SUPPLEMENTAL CASH FLOW INFORMATION

(in thousands)	Three Months Ended March 31, 2018	2017
Cash paid during the period for:		
Interest expense (net of capitalized amounts of $156 and $303, respectively)	$389	$657
Income taxes	$—	$2
Cash received for income tax refunds	$2	$21

Table of Contents

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 three months of 2018 as compared to the first three months of 2017, oil prices have improved, while gas prices have declined. For the first three months of 2018, average NYMEX oil and gas prices were $62.87 per barrel and $3.01 per Mcf, respectively, representing an increase of 23% and a decrease of 9%, respectively, from the average NYMEX oil and gas prices for the first three months of 2017. Further, local market prices for oil and gas can be impacted by pipeline capacity constraints limiting takeaway and increasing basis differentials. The Permian Basin and Mid-Continent region gas production growth has resulted in higher differentials and 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.

Summary of Operating and Financial Results for the Three Months Ended March 31, 2018 Compared to the Three Months Ended March 31, 2017:

- Total production volumes increased 16% to 206.1 MBOE per day.
- Oil volumes increased 25% to 65.2 MBbls per day.
- Gas volumes increased 10% to 534.7 MMcf per day.
- NGL volumes increased 18% to 51.7 MBbls per day.
- Total production revenue increased 27% to $555.4 million.
- Cash flow provided by operating activities increased 54% to $383.1 million.

Table of Contents

- Exploration and development expenditures increased 3% to $313.5 million.
- Net income was $186.3 million, or $1.96 per diluted share, for the first three months of 2018, as compared to net income of $131.0 million, or $1.38 per diluted share, for the first three months of 2017.

RESULTS OF OPERATIONS

Three Months Ended March 31, 2018 vs. Three Months Ended March 31, 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 March 31,			
	2018			2017
(in thousands)	Pre-ASC 606 Adoption	Impact of ASC 606	Post-ASC 606 Adoption	As Reported
Oil sales	$351,723	$—	$351,723	$224,066
Gas sales	112,677	(2,956)	109,721	131,945
NGL sales	105,613	(11,616)	93,997	80,426
Total oil, gas, and NGL sales	$570,013	$(14,572)	$555,441	$436,437

	Three Months Ended March 31,			
	2018			2017
(in thousands)	Pre-ASC 606 Adoption	Impact of ASC 606	Post-ASC 606 Adoption	As Reported
Transportation, processing, and other operating costs	$59,737	$(14,572)	$45,165	$55,023

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.

Table of Contents

Production volumes were higher across all three products during the three months ended March 31, 2018 as compared to the three months ended March 31, 2017. Realized oil prices also were higher, while realized gas and NGL prices were lower. These changes caused our revenue to increase by $119.0 million, or 27%, during the three months ended March 31, 2018 as compared to the three months ended March 31, 2017. The following table shows our production revenue for the periods indicated as well as the change in revenues due to changes in volumes and prices.

	Three Months Ended March 31,		Variance Between 2018 / 2017		Price/Volume Variance		
Production Revenue (in thousands)	2018	2017			Price	Volume	Total
Oil sales	$351,723	$224,066	$127,657	57%	$71,720	$55,937	$127,657
Gas sales	109,721	131,945	(22,224)	(17)%	(35,131)	12,907	(22,224)
NGL sales	93,997	80,426	13,571	17%	(977)	14,548	13,571
	$555,441	$436,437	$119,004	27%	$35,612	$83,392	$119,004

The table below presents our production volumes by region.

Production Volumes	Three Months Ended March 31, 2018	2017
Oil (Bbls per day)		
Permian Basin	49,845	41,039
Mid-Continent	15,225	11,053
Other	142	89
	65,212	52,181
Gas (MMcf per day)		
Permian Basin	237.9	200.9
Mid-Continent	295.5	285.0
Other	1.3	1.3
	534.7	487.2
NGL (Bbls per day)		
Permian Basin	24,725	21,624
Mid-Continent	26,959	22,151
Other	35	29
	51,719	43,804
Total (BOE per day)		
Permian Basin	114,218	96,140
Mid-Continent	91,433	80,697
Other	399	353
	206,050	177,190

Our total production increased by 16% or 28,860 BOE per day during the three months ended March 31, 2018, as compared to the three months ended March 31, 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.

Table of Contents

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 the three months ended March 31, 2018 and 2017, 76% and 79%, respectively, of our oil production was in the Permian Basin. Our realized prices do not include settlements of commodity derivative contracts.

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Variance Between 2018 / 2017	
Oil				
Total volume — MBbls	5,869	4,696	1,173	25%
Total volume — MBbls per day	65.2	52.2	13.0	25%
Percentage of total production	32 %	29 %		
Average realized price — per barrel	$59.93	$47.71	$12.22	26%
Average WTI Midland price — per barrel	$63.26	$51.68	$11.58	22%
Average WTI Cushing price — per barrel	$62.87	$51.04	$11.83	23%
Gas				
Total volume — MMcf	48,125	43,850	4,275	10%
Total volume — MMcf per day	534.7	487.2	47.5	10%
Percentage of total production	43 %	46 %		
Average realized price — per Mcf	$2.28 (1)	$3.01	$(0.73)	(24)%
Average Henry Hub price — per Mcf	$3.01	$3.32	$(0.31)	(9)%
NGL				
Total volume — MBbls	4,655	3,942	713	18%
Total volume — MBbls per day	51.7	43.8	7.9	18%
Percentage of total production	25 %	25 %		
Average realized price — per barrel	$20.19 (2)	$20.40	$(0.21)	(1)%
Total				
Total production — MBOE	18,545	15,947	2,598	16%
Total production — MBOE per day	206.1	177.2	28.9	16%
Average realized price — per BOE	$29.95 (3)	$27.37	$2.58	9%

(1) ASC 606 reduced the average realized gas price by $0.06 per Mcf for the 2018 period.
(2) ASC 606 reduced the average realized NGL price by $2.50 per barrel for the 2018 period.
(3) ASC 606 reduced the average realized total price by $0.79 per BOE for the 2018 period.

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 March 31, 2018	Three Months Ended March 31, 2017	Variance Between 2018 / 2017
Gas gathering and other	$11,452	$10,625	$ 827
Gas marketing, net of related costs	$241	$114	$ 127

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.

Table of Contents

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 March 31, 2018 were higher by 40% compared to the three months ended March 31, 2017. The primary reasons for the increase are: (i) the $39.7 million decrease in net gains on derivative instruments and (ii) the $37.0 million increase in depreciation, depletion, and amortization.

	Three Months Ended March 31,		Variance Between	Per BOE	
Operating Costs and Expenses (in thousands, except per BOE)	2018	2017	2018 / 2017	2018	2017
Depreciation, depletion, and amortization	$132,859	$95,816	$37,043	$7.16	$6.01
Asset retirement obligation	1,060	1,620	(560)	$0.06	$0.10
Production	71,271	62,421	8,850	$3.84	$3.91
Transportation, processing, and other operating	45,165	55,023	(9,858)	$2.44	$3.45
Gas gathering and other	9,823	8,427	1,396	$0.53	$0.53
Taxes other than income	30,188	21,313	8,875	$1.63	$1.34
General and administrative	23,321	18,034	5,287	$1.26	$1.13
Stock compensation	6,730	6,288	442	$0.36	$0.39
Loss (gain) on derivative instruments, net	(4,159)	(43,861)	39,702	N/A	N/A
Other operating expense, net	203	616	(413)	N/A	N/A
	$316,461	$225,697	$90,764		

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 overall prices have increased from 2017 to 2018, thus increasing our reserves, the increase in production combined with our ongoing exploration and development expenditures throughout 2017 and into 2018, which have increased our proved oil and gas properties and future development costs, 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 March 31,		Variance Between	Per BOE	
DD&A Expense (in thousands, except per BOE)	2018	2017	2018 / 2017	2018	2017
Depletion	$120,390	$85,011	$35,379	$6.49	$5.33
Depreciation	12,469	10,805	1,664	0.67	0.68
	$132,859	$95,816	$37,043	$7.16	$6.01

Table of Contents

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 consists of lease operating expense and workover expense as follows:

Production Expense (in thousands, except per BOE)	Three Months Ended March 31, 2018	2017	Variance Between 2018 / 2017	Per BOE 2018	2017
Lease operating expense	$60,476	$45,535	$14,941	$3.26	$2.86
Workover expense	10,795	16,886	(6,091)	0.58	1.05
	$71,271	$62,421	$8,850	$3.84	$3.91

Lease operating expense in the first quarter 2018 increased 33%, or $14.9 million, compared to the first quarter of 2017. The increase has 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: (i) equipment rental, primarily flowback equipment and compressors, (ii) saltwater disposal, (iii) chemicals and treating due to increased water volumes, (iv) labor, and (v) equipment and maintenance.

Workover expense during the three months ended March 31, 2018 decreased 36%, or $6.1 million, compared to the three months ended March 31, 2017. The 2017 period included costlier major well workover activity than the 2018 period. Additionally, during the three months ended March 31, 2018, we received insurance proceeds related to the remediation and repairs incurred as a result of a 2015 flooding event. These insurance proceeds reduced workover expense during the 2018 period. Generally, workover costs will fluctuate based on the amount of maintenance and remedial activity planned and/or 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 first quarter 2018 were 18%, or $9.9 million, lower than transportation, processing, and other operating costs in the first quarter 2017. This decrease was 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 $14.6 million in the first quarter 2018. This reduction was 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.

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 March 31, 2018 was 17%, or $1.4 million, higher than gas gathering and other in the three months ended March 31, 2017. The increase is primarily due to an overall increase 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 $8.9 million, or 42%, in the first quarter of 2018 as compared to the first quarter of 2017. The increase is due to the increase in revenue seen between the comparable periods. Both periods included credits for tax refunds related to high-cost gas wells in the State of Texas, with 2018 including $1.1 million and 2017 including $2.1 million. Taxes other than income was 5.4% and 4.9% of production revenues for the three months ended March 31, 2018 and 2017, respectively.

Table of Contents

General and Administrative

General and administrative ("G&A") expense consists primarily of salaries and related benefits, office rent, legal and consultant 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 was 43% and 47% during the three months ended March 31, 2018 and 2017, respectively. The table below shows our G&A costs.

General and Administrative Expense (in thousands)	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Variance Between 2018 / 2017
Gross G&A	$40,848	$34,090	$6,758
Less amounts capitalized to oil and gas properties	(17,527)	(16,056)	(1,471)
G&A expense	$23,321	$18,034	$5,287

G&A expense for the first quarter of 2018 was 29%, or $5.3 million, higher than for the first quarter of 2017. This increase is primarily due to increased salaries and wages, other compensation, primarily consisting of incentive bonuses, and benefits.

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 March 31, 2018	Three Months Ended March 31, 2017	Variance Between 2018 / 2017
Restricted stock awards:			
Performance stock awards	$6,729	$6,402	$ 327
Service-based stock awards	5,072	4,924	148
	11,801	11,326	475
Stock option awards	617	666	(49)
Total stock compensation cost	12,418	11,992	426
Less amounts capitalized to oil and gas properties	(5,688)	(5,704)	16
Stock compensation expense	$6,730	$6,288	$ 442

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 increase in total stock compensation cost in 2018 as compared to 2017 is primarily due to awards granted either during or subsequent to the 2017 period, partially offset by awards vesting prior to or during the 2018 period.

Table of Contents

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 March 31, 2018	2017	Variance Between 2018 / 2017
Change in fair value of derivative instruments, net:			
Gas contracts	$(11,789)	$(22,191)	$10,402
Oil contracts	(4,759)	(27,730)	22,971
	(16,548)	(49,921)	33,373
Cash (receipts) payments on derivative instruments, net:			
Gas contracts	(5,119)	2,444	(7,563)
Oil contracts	17,508	3,616	13,892
	12,389	6,060	6,329
Loss (gain) on derivative instruments, net	$(4,159)	$(43,861)	$39,702

Other Income and Expense

Other Income and Expense (in thousands)	Three Months Ended March 31, 2018	2017	Variance Between 2018 / 2017
Interest expense	$16,783	$21,052	$(4,269)
Capitalized interest	(4,810)	(6,641)	1,831
Other, net	(4,567)	(2,210)	(2,357)
	$7,406	$12,201	$(4,795)

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 2018 as compared to 2017 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.

We capitalize interest on non-producing leasehold costs, the in-progress costs of drilling and completing wells, and constructing qualified 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 first quarter of 2018 as compared to the first quarter of 2017, thus reducing our capitalized interest. Also contributing to lower capitalized interest in 2018 was 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 gain or loss related to the sale or value of oil and gas well equipment and supplies, gain or loss on miscellaneous asset sales, interest income, 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 March 31, 2018	2017	Variance Between 2018 / 2017
Current tax benefit	$—	$(6)	$6
Deferred tax expense	56,949	78,312	(21,363)

	$56,949	$78,306	$(21,357)
Combined federal and state effective income tax rate	23.4 %	37.4 %	

Table of Contents

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.

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 months ended March 31, 2018 and 2017.

We periodically use derivative instruments to mitigate volatility in commodity prices. At March 31, 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 March 31, 2018 were $463.8 million. At March 31, 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 March 31, 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 March 31, 2018 was 35%, 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.

	Three Months Ended March 31,	
(in thousands)	2018	2017
Net cash provided by operating activities	$383,093	$249,514
Net cash used by investing activities	$(312,255)	$(314,977)
Net cash used by financing activities	$(7,562)	$(8,505)

29

Table of Contents

Net cash provided by operating activities for the first quarter of 2018 was $383.1 million, up $133.6 million or 54% from $249.5 million for the first quarter of 2017. The $133.6 million increase resulted primarily from a quarter-over-quarter increase in production revenue, which increased due to increased production volumes and realized oil 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 three months ended March 31, 2018 and 2017 was $312.3 million and $315.0 million, respectively. The majority of our cash flows used by investing activities are for E&D expenditures. Total cash flows used for capital expenditures for the three months ended March 31, 2018 and 2017 were $342.5 million and $319.9 million, respectively. Proceeds from sales of non-core assets slightly offset capital expenditure cash flows in both quarters.

Net cash used by financing activities for the three months ended March 31, 2018 and 2017 was $7.6 million and $8.5 million, respectively. The primary components of net cash used by financing activities during these periods are: (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 each of these periods, we paid an $0.08 per share dividend, totaling $7.6 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 March 31,	
(in thousands)	2018	2017
Acquisitions:		
Proved	$62	$5
Unproved	2,159	3,033
	2,221	3,038
Exploration and development:		
Land and seismic	10,097	77,185
Exploration and development	303,372	228,467
	313,469	305,652
Property sales:		
Proved	(24,964)	65
Unproved	(4,860)	(4,966)
	(29,824)	(4,901)
	$285,866	$303,789

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.

30

Table of Contents

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

	Three Months Ended March 31, 2018	2017
Gross wells		
Permian Basin	17	25
Mid-Continent	37	45
	54	70
Net wells		
Permian Basin	9	16
Mid-Continent	6	10
	15	26

As of March 31, 2018, we had 29 gross (13 net) wells in the process of being drilled: 10 gross (7 net) in the Permian Basin and 19 gross (6 net) in the Mid-Continent region. As of March 31, 2018, there were 125 gross (48 net) wells waiting on completion: 52 gross (28 net) in the Permian Basin and 73 gross (20 net) in the Mid-Continent region. As of March 31, 2018, we had 14 operated rigs running: ten in the Permian Basin and four 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 March 31, 2018 and December 31, 2017 consisted of the following:

	March 31, 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	$ (5,143)	$744,857	$750,000	$ (5,383)	$744,617
3.90% Senior Notes	750,000	(7,527)	742,473	750,000	(7,697)	742,303
Total long-term debt	$1,500,000	$ (12,670)	$1,487,330	$1,500,000	$ (13,080)	$1,486,920

(1) At March 31, 2018, the unamortized debt issuance costs and discount related to the 3.90% notes were $5.8 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 March 31, 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%,

Table of Contents

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 March 31, 2018, we were in compliance with all of the financial and non-financial covenants.

At March 31, 2018 and December 31, 2017, we had $3.0 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 March 31, 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 March 31, 2018, we had working capital of $319.7 million, an increase of $63.6 million or 25% compared to working capital of $256.1 million at December 31, 2017.

Working capital increases consisted primarily of the following:

- Cash and cash equivalents increased by $63.3 million.
- Operations-related accounts payable and accrued liabilities decreased by $21.2 million.
- Accrued liabilities related to our E&D expenditures decreased by $12.2 million.
- Current derivative instrument net liability decreased by $8.9 million.
- Oil and gas well equipment and supplies increased by $4.5 million.

Working capital decreases consisted primarily of the following:

- Operations-related accounts receivable decreased by $44.9 million.

Accounts receivable are a major component of our working capital and include 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 February 2018, a $0.16 per share dividend was declared, which is payable on or before June 1, 2018 to stockholders of record on May 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.

Table of Contents

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 March 31, 2018, our material off-balance sheet arrangements consisted of operating lease agreements, which are included in the table below.

Contractual Obligations and Material Commitments

At March 31, 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)	491,075	60,844	124,125	124,125	181,981
Operating leases (2)	92,714	14,982	25,548	22,394	29,790
Unconditional purchase obligations (3)	83,020	22,892	40,754	9,260	10,114
Derivative liabilities	58,148	54,168	3,980	—	—
Asset retirement obligation (4)	164,641	8,387	— (4)	— (4)	— (4)
Other long-term liabilities (5)	36,184	1,912	3,425	2,587	28,260
	$2,425,782	$163,185	$197,832	$158,366	$1,750,145

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(1) The interest payments presented above include the accrued interest payable on our long-term debt as of March 31, 2018 as well as future payments calculated using the long-term debt's fixed rates, stated maturity dates, and principal amounts outstanding as of March 31, 2018. See Note 2 to the Condensed Consolidated Financial Statements for additional information regarding our debt.

(2) Operating leases include various commitments for office space and compressor equipment.

(3) Of the total Unconditional purchase obligations, $47.3 million represents obligations for the purchase of sand and $34.2 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, which may include potential future cash payments if we fail to meet various performance obligations. These are not reflected in the table above.

At March 31, 2018, we had estimated commitments of approximately: (i) $292.8 million to finish drilling, completing, or performing other work on wells and various other infrastructure projects in progress and (ii) $32.0 million to finish gathering system construction in progress.

At March 31, 2018, we had firm sales contracts to deliver approximately 238.4 Bcf of gas over the next 6.8 years. If we do not deliver this gas, our estimated financial commitment, calculated using the April 2018 index price, would be approximately $407.6 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 9.8 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 March 31, 2018, would be approximately $325.9 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.

Table of Contents

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 March 31, 2018, would be approximately $8.9 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.

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 March 31, 2018, our total production revenue was comprised of 63% oil sales, 20% gas sales, and 17% 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.

			Three Months Ended March 31, 2018
	Change in Realized Price		Impact on Revenue
			(in thousands)
Oil	± $1.00	per barrel	± $5,869
Gas	± $0.10	per Mcf	± $4,813
NGL	± $1.00	per barrel	± $4,655
			± $15,337

We periodically enter into financial derivative contracts to hedge a portion of our price risk associated with our future oil and gas production. At March 31, 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 March 31, 2018, our oil and gas derivatives had a gross asset fair value of $45.6 million and a gross liability fair value of $58.1 million. See Note 3 to the Condensed Consolidated Financial Statements for additional information regarding our derivative instruments. 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 March 31, 2018.

Table of Contents

Change in Forward Price		March 31, 2018 Impact on Fair Value (in thousands)
Oil	-$1.00	$ 7,811
Oil	+$1.00	$ (8,059)
Gas	-$0.10	$ 6,592
Gas	+$0.10	$ (6,389)

Interest Rate Risk

At March 31, 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 March 31, 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 March 31, 2018 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

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

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

Table of Contents

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.

May 8, 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)