

EXPLORATION AND PERFORMANCE SUMMARY **DEVELOPMENT** CAPITAL INVESTMENT YEAR ENDED DECEMBER 31, 2017 2016 2015 FINANCIAL (IN MILLIONS, EXCEPT PER SHARE DATA) \$1,417.5 Oil, Gas & NGL sales \$1,874.0 \$1,221.2 Net income (loss) 494.3 (408.8)(2,579.6)Net income (loss) per diluted share 5.19 (27.75)(4.38)Net cash provided by operating activities 1,096.6 625.8 725.7 E&D capital investment 1,281 DECEMBER 31, 2017 2015 2016 Total assets 5,042.6 4,237.7 4,708.4 Debt (principal) 2,568.3 YEAR ENDED DECEMBER 31, 2016 2015 2017 **OPERATIONAL NET INCOME AND** Proved reserves: **CASH FLOW** Oil (MMBbls) 137.2 105.9 107.8 (Millions of Dollars) 153.9 NGL (MMBbls) 130.6 124.3 NET CASH PROVIDED BY OPERATING ACTIVITIES 1,608 Gas (Bcf) 559.0 481.7 Total (MMBOE) 484.9 NET INCOME Proved developed (MMBOE) 462.8 382.0 365.0 Daily production: 51,132 Oil (Bbls) 57,153 45,158 38,797 35,789 47,600 Gas (MMcf) Total (BOE) 463 514 460 190,354 160,561 164,084 Realized price: Oil (per Bbl) NGL (per Bbl) Gas (per Mcf) -409 \$ 47.06 \$ 38.30 \$ 43.38 \$ 13.75 21.61 \$ 14.05 2.76 2.31 2.53

FELLOW SHAREHOLDERS

Cimarex had an outstanding operational year in 2017. We achieved excellent returns on invested capital across our asset base. We invested 59% of our capital in the Delaware Basin and 39% in the Anadarko Basin. Both basins provided excellent returns. We grew our total production 19%, with oil production increasing 27%. Our per share production growth, on a debt adjusted basis, was 15%. Our per share reserve growth, on a debt adjusted basis, was 13%. We reported net income of \$494 million, or \$5.19 per share.

My letter to shareholders last year reflected on the difficult conditions we encountered in 2016. Commodity prices hit painful lows, which decreased cash flow available for investment. Our organization responded by cutting costs and implementing creative innovations that significantly increased our well productivity. The excellent results we achieved in 2017 were, in no small part, a result of the progress that we made during the dark days of 2016. Today, Cimarex is healthy and active, with one of the best organizations and asset bases in our industry.

2017 was also a year in which many companies in our sector experienced operational hiccups. Cimarex had flawless execution. This was due, in no small part, to careful planning, a relentless focus on interdisciplinary cooperation, and organizational experience in executing complex projects. We met our goals and timelines and posted outstanding operational results. We accomplished this with an ongoing commitment to profitability, safety, and environmental responsibility. Our challenge now is to do it again in 2018.

We enter 2018 with a deep inventory of outstanding opportunities in both the Permian and Anadarko Basins. One of the key attributes we examine when allocating capital investments is the repeatability of our results. Are we consistently predicting the production performance of our wells? Are the costs in-line with

PRODUCTION

(MBOE/d



our pre-drill predictions? Are reserves matching our pre-drill estimates? Our 2017 program showed great consistency and repeatability, with results that tightly clustered around our pre-drill predictions. This has given us confidence to accelerate our program in 2018 and invest 70% of that capital in the Permian Basin. We are confident that we can deliver another year of very good returns on invested capital. This is our business.

We face headwinds in 2018. The logistics of managing a drilling and completion fleet, water sourcing, sand sourcing, water disposal, oil and gas takeaway, and managing midstream assets in competitive basins will become increasingly more difficult. Service cost inflation will be a factor. We will strive to find operational efficiencies that reduce costs, including the introduction of locally sourced sand into our Permian well completions. We do not seek to deliver the most productive wells. We seek to deliver the most profitable wells. As always, we view these challenges through a lens colored by rate of return. Our organization is up to the task.

As we move into the harvesting of our assets, we will analyze the optimum development plan for each area in order to maximize profitability. We do not subscribe to a "one size fits all" approach to resource development. Each area, each reservoir, and each pressure regime may suggest a different development plan in order to optimize profitability. Our culture, which is based upon a commitment to full cycle profitability, quickly focuses the discussion on critical elements.

I would like to address the issue raised by investors in 2017 that has permeated the E&P sector ever since — a renewed focus on full cycle returns rather than production growth. Our critics contend that the industry's historical emphasis on growth, coupled with management incentives that reward it, has contributed to the commodity price collapse and value destruction. Many have called for companies to grow slower, generate free cash flow, and return this cash to shareholders in the form of dividends and share buybacks. We have listened carefully to this criticism with great interest and open minds. We have never considered growth to be a goal. Growth is a consequence of prudent investment decisions,

RESERVES (MMBOE) 2015 485 2016 482

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not a primary driver. Prudent investment decisions coupled with capital discipline are the surest path to free cash flow. Cimarex welcomes this value conversation and expects to be measured by these principles.

At Cimarex, our corporate culture is built upon a value creation philosophy whose central pillar is return on capital investment. Our operating groups have clear and simple incentive systems based upon full cycle, fully burdened after-tax rates of return. Our executive team has an annual incentive system that contains strong value metrics, including return on capital invested, per share debt-adjusted growth in reserves and production, and balance sheet management. We are delighted to have restored our dividend to its previous high water mark. We cut our dividend in 2016 in the midst of the commodity price downdraft. Since then, our cost structure has reset, our investment returns are excellent, and we have reestablished strong profitability. Our Board of Directors was resolute in restoring the dividend with the intent of putting it on a growth track over time. We are deeply committed to the discipline our dividend forces upon us as we return cash to our shareholders.

We strive to increase shareholder value over time. We believe that the best way to achieve this is by investing our cash flow at the highest rates of return we can find We perform an annual lookback on our investment results, which takes every well we have drilled since we formed Cimarex and looks at the actual production, cash flow, and expenses from inception to current. The goal of the lookback is to use our results to guide us in making better decisions going forward. If something is working well, we want to do more of it. If something is not working, we want to either fix it or shut it down. We use the lookback to grade ourselves, adjust our decision-making, and make course corrections. The recent conversation around E&P value creation is entirely consistent with our own internal approach. We welcome it.

Cimarex recently unveiled more comprehensive Environmental, Social and Governance (ESG) disclosures on our website. Our operations group worked diligently in 2017 to define environmental and safety metrics which are objective, transparent, and meaningful. We want to report real metrics against which we can measure ourselves and become better. Cimarex has a deep and non-negotiable commitment to responsibility in every area we operate. Our core strategy is to be in business for the long term and responsibility to the environment, our employees and vendors, and the communities in which we operate is central to our long-term focus. Please review our new website ESG disclosure at your convenience.

Finally, I want to acknowledge and thank our employees for their service and dedication. Our excellent results in 2017 are a testament to an organization that is focused on continuous improvement and open and honest deliberation. Our employees embrace and define our culture of results. I also want to thank our Board of Directors for their wisdom and ongoing counsel.

We live in turbulent times. Our share price may fluctuate from time to time, yet we remain firm in our conviction that, if we have the right strategy and good execution, markets will reflect and reward our value creation in the long term. From time to time, we receive notes of support from shareholders. Some of them come from large owners; others from owners of a small number of shares. We cannot overstate how much these notes mean to us, and how much we appreciate them. Our owners, large and small, are the reason for everything we do. We never forget our purpose.

Sincerely

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THOMAS E. JORDEN Chairman of the Board, President and Chief Executive Officer March 2, 2018





CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

(IN THOUSANDS, EXCEPT PER SHARE DATA)	YEAR ENDED DECEMBER 31,					
		2017		2016		2015
REVENUES:						
Oil sales	\$	981,646	\$	632,934	\$	809,664
Gas sales		516,936		388,786		428,227
NGL sales		375,421		199,498		179,647
Gas gathering and other		43,751		36,033		34,688
Gas marketing		495		94		393
		1,918,249		1,257,345	1	,452,619
COSTS AND EXPENSES:						
Impairment of oil and gas properties		_		757,670	4	,033,295
Depreciation, depletion and amortization		446,031		392,348		731,460
Asset retirement obligation		15,624		7,828		9,121
Production		262,180		232,002		299,374
Transportation, processing and other operating		231,640		190,725		182,362
Gas gathering and other		35,840		31,785		38,138
Taxes other than income		89,864		61,946		84,764
General and administrative		79,996		73,901		74,688
Stock compensation		26,256		24,523		19,559
(Gain) loss on derivative instruments, net		(21,210)		55,749		(11,246)
Other operating expense, net		1,314		755		856
		1,167,535		1,829,232	5	,462,371
Operating income (loss)		750,714		(571,887)	(4	,009,752)
Other (income) and expense:						
Interest expense		74,821		83,272		85,746
Capitalized interest		(22,948)		(21,248)		(30,589)
Loss on early extinguishment of debt		28,187		_		_
Other, net		(11,342)		(10,707)		(13,576)
INCOME (LOSS) BEFORE INCOME TAX		681,996		(623,204)	(4	,051,333)
INCOME TAX EXPENSE (BENEFIT)		187,667		(214,401)	(1	,471,729)
Net income (loss)	\$	494,329	\$	(408,803)	\$(2	,579,604)
EARNINGS (LOSS) PER SHARE TO COMMON STOCKHOLDERS:						
Basic	\$	5.19	\$	(4.38)	\$	(27.75)
Diluted	\$	5.19	\$	(4.38)	\$	(27.75)
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Dividends declared per share	\$	0.32	\$	0.32	\$	0.64
COMPREHENSIVE INCOME (LOSS):						
Net income (loss)	\$	494,329	\$	(408,803)	\$(2	,579,604)
Other comprehensive income (loss):		,			. (-	
Change in fair value of investments, net of tax		1,254		504		(661)
Total comprehensive income (loss)	\$	495,583	\$	(408,299)	\$(2	,580,265)
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The notes in the accompanying Annual Report on Form 10-K are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(IN THOUSANDS)

YEAR ENDED DECEMBER 31,

	2017	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	\$ 494,329	\$ (408,803)	\$(2,579,604)
Adjustments to reconcile net income (loss) to net cash			
provided by operating activities:			
Impairment of oil and gas properties	_	757,670	4,033,295
Depreciation, depletion and amortization	446,031	392,348	731,460
Asset retirement obligation	15,624	7,828	9,121
Deferred income taxes	190,479	(213,286)	(1,486,439)
Stock compensation	26,256	24,523	19,559
(Gain) loss on derivative instruments, net	(21,210)	55,749	(11,246)
Settlements on derivative instruments	(1,633)	7,437	_
Loss on early extinguishment of debt	28,187	_	_
Changes in non-current assets and liabilities	1,891	3,867	23,230
Other, net	5,677	1,805	4,206
Changes in operating assets and liabilities:			
Accounts receivable	(186,157)	(49,340)	186,699
Other current assets	(17,931)	20,880	37,954
Accounts payable and other current liabilities	115,021	25,171	(242,507)
Net cash provided by operating activities	1,096,564	625,849	725,728
CASH FLOWS FROM INVESTING ACTIVITIES:			
Oil and gas capital expenditures	(1,233,126)	(699,558)	(979,044)
Other capital expenditures	(45,352)	(22,228)	(70,592)
Sales of oil and gas assets	11,680	21,487	39,853
Sales of other assets	901	7,889	1,178
Net cash used by investing activities	(1,265,897)	(692,410)	(1,008,605)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings of long-term debt	748,110	_	_
Repayments of long-term debt	(750,000)	_	_
Proceeds from sale of common stock	_	_	752,100
Financing and underwriting fees	(29,312)	(101)	(24,633)
Dividends paid	(30,532)	(38,024)	(58,281)
Employee withholding taxes paid upon the net settlement of			
equity-classified stock awards	(21,669)	(26,624)	(21,240)
Proceeds from exercise of stock options	394	4,804	8,451
Net cash (used) provided by financing activities	(83,009)	(59,945)	656,397
Net change in cash and cash equivalents	(252,342)	(126,506)	373,520
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	652,876	779,382	405,862
CASH AND CASH EQUIVALENTS AT END OF PERIOD	\$ 400,534	\$ 652,876	\$ 779,382

The notes in the accompanying Annual Report on Form 10-K are an integral part of these consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

(IN THOUSANDS, EXCEPT SHARE AND PER SHARE INFORMATION)		CEMBER 31,
ASSETS	2017	2016
CURRENT ASSETS:		
Cash and cash equivalents	\$ 400,534	\$ 652,876
Accounts receivable, net of allowance:	Ψ 100,551	Ψ 032,070
Trade	100,356	42,287
Oil and gas sales	344,552	217,395
Gas gathering, processing and marketing	15,266	14,888
Oil and gas well equipment and supplies	49,722	33,342
Derivative instruments	15,151	_
Prepaid expenses	8,518	7,335
Other current assets	1,536	1,181
Total current assets	935,635	969,304
Dil and gas properties at cost, using the full cost method of accounting:		, , , , , , ,
Proved properties	17,513,460	16,225,495
Unproved properties and properties under development, not being amortized	476,903	478,277
onproved properties and properties under development, not seeing amortized	17,990,363	16,703,772
Less — accumulated depreciation, depletion, amortization and impairment	(14,748,833)	(14,349,505)
Net oil and gas properties	3,241,530	2,354,267
Fixed assets, net of accumulated depreciation of \$290,114 and \$246,901, respectively	210,922	205,465
Goodwill	620,232	620,232
Derivative instruments	2,086	- 020,232
Deferred income taxes	2,000	55,835
Other assets	32,234	32,621
other assets	\$ 5,042,639	\$ 4,237,724
CURRENT LIABILITIES: Accounts Payable: Trade	\$ 68,883	
CURRENT LIABILITIES: Accounts Payable: Trade Gas gathering, processing and marketing	\$ 68,883 29,503	\$ 49,163 25,323
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities:	29,503	25,323
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development	29,503 115,762	25,323 82,320
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income	29,503 115,762 23,687	25,323 82,320 18,766
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other	29,503 115,762 23,687 212,400	25,323 82,320 18,766 177,695
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments	29,503 115,762 23,687 212,400 42,066	25,323 82,320 18,766 177,695 49,370
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable	29,503 115,762 23,687 212,400 42,066 187,273	25,323 82,320 18,766 177,695 49,370 119,715
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable Total current liabilities	29,503 115,762 23,687 212,400 42,066	25,323 82,320 18,766 177,695 49,370 119,715
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable Total current liabilities Long-term debt:	29,503 115,762 23,687 212,400 42,066 187,273 679,574	25,323 82,320 18,766 177,695 49,370 119,715 522,352
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable Total current liabilities ong-term debt: Principal	29,503 115,762 23,687 212,400 42,066 187,273 679,574	25,323 82,320 18,766 177,695 49,370 119,715 522,352 1,500,000
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable Total current liabilities .ong-term debt: Principal Less — unamortized debt issuance costs and discount	29,503 115,762 23,687 212,400 42,066 187,273 679,574 1,500,000 (13,080)	25,323 82,320 18,766 177,695 49,370 119,715 522,352 1,500,000 (12,061)
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable Total current liabilities .ong-term debt: Principal Less — unamortized debt issuance costs and discount Long-term debt, net	29,503 115,762 23,687 212,400 42,066 187,273 679,574 1,500,000 (13,080) 1,486,920	25,323 82,320 18,766 177,695 49,370 119,715 522,352 1,500,000
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable Total current liabilities Long-term debt: Principal Less — unamortized debt issuance costs and discount Long-term debt, net	29,503 115,762 23,687 212,400 42,066 187,273 679,574 1,500,000 (13,080) 1,486,920 101,618	25,323 82,320 18,766 177,695 49,370 119,715 522,352 1,500,000 (12,061) 1,487,939
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable Total current liabilities .ong-term debt: Principal Less — unamortized debt issuance costs and discount Long-term debt, net Deferred income taxes Asset retirement obligation	29,503 115,762 23,687 212,400 42,066 187,273 679,574 1,500,000 (13,080) 1,486,920 101,618 158,421	25,323 82,320 18,766 177,695 49,370 119,715 522,352 1,500,000 (12,061) 1,487,939 — 140,770
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable Total current liabilities Long-term debt: Principal Less — unamortized debt issuance costs and discount Long-term debt, net Deferred income taxes Asset retirement obligation Derivative instruments	29,503 115,762 23,687 212,400 42,066 187,273 679,574 1,500,000 (13,080) 1,486,920 101,618 158,421 4,268	25,323 82,320 18,766 177,695 49,370 119,715 522,352 1,500,000 (12,061) 1,487,939 — 140,770 2,570
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable Total current liabilities .ong-term debt: Principal Less — unamortized debt issuance costs and discount Long-term debt, net Deferred income taxes Asset retirement obligation Derivative instruments Other liabilities	29,503 115,762 23,687 212,400 42,066 187,273 679,574 1,500,000 (13,080) 1,486,920 101,618 158,421 4,268 43,560	25,323 82,320 18,766 177,695 49,370 119,715 522,352 1,500,000 (12,061 1,487,939 — 140,770 2,570 41,104
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable Total current liabilities ong-term debt: Principal Less — unamortized debt issuance costs and discount Long-term debt, net Deferred income taxes asset retirement obligation Derivative instruments Other liabilities Total liabilities Total liabilities	29,503 115,762 23,687 212,400 42,066 187,273 679,574 1,500,000 (13,080) 1,486,920 101,618 158,421 4,268	25,323 82,320 18,766 177,695 49,370 119,715 522,352 1,500,000 (12,061 1,487,939 — 140,770 2,570 41,104
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable Total current liabilities Ong-term debt: Principal Less — unamortized debt issuance costs and discount Long-term debt, net Deferred income taxes Asset retirement obligation Derivative instruments Other liabilities Total liabilities Total liabilities Commitments and contingencies	29,503 115,762 23,687 212,400 42,066 187,273 679,574 1,500,000 (13,080) 1,486,920 101,618 158,421 4,268 43,560	25,323 82,320 18,766 177,695 49,370 119,715 522,352 1,500,000 (12,061) 1,487,939 — 140,770 2,570 41,104
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable Total current liabilities Ong-term debt: Principal Less — unamortized debt issuance costs and discount Long-term debt, net Deferred income taxes Asset retirement obligation Derivative instruments Other liabilities Total liabilities Total liabilities Commitments and contingencies Stockholders' equity:	29,503 115,762 23,687 212,400 42,066 187,273 679,574 1,500,000 (13,080) 1,486,920 101,618 158,421 4,268 43,560	25,323 82,320 18,766 177,695 49,370 119,715 522,352 1,500,000 (12,061 1,487,939 — 140,770 2,570 41,104
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable Total current liabilities cong-term debt: Principal Less — unamortized debt issuance costs and discount Long-term debt, net Deferred income taxes asset retirement obligation Derivative instruments Other liabilities Total liabilities Commitments and contingencies tockholders' equity: Preferred stock, \$0.01 par value, 15,000,000 shares authorized, no shares issued	29,503 115,762 23,687 212,400 42,066 187,273 679,574 1,500,000 (13,080) 1,486,920 101,618 158,421 4,268 43,560	25,323 82,320 18,766 177,695 49,370 119,715 522,352 1,500,000 (12,061 1,487,939 — 140,770 2,570 41,104
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable Total current liabilities cong-term debt: Principal Less — unamortized debt issuance costs and discount Long-term debt, net Deferred income taxes Asset retirement obligation Derivative instruments Other liabilities Total liabilities Commitments and contingencies tockholders' 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, 95,437,434	29,503 115,762 23,687 212,400 42,066 187,273 679,574 1,500,000 (13,080) 1,486,920 101,618 158,421 4,268 43,560 2,474,361	25,323 82,320 18,766 177,695 49,370 119,715 522,352 1,500,000 (12,061) 1,487,939 — 140,770 2,570 41,104 2,194,735
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable Total current liabilities Long-term debt: Principal Less—unamortized debt issuance costs and discount Long-term debt, net Deferred income taxes Asset retirement obligation Derivative instruments Other liabilities Total liabilities Commitments and contingencies 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, 95,437,434 and 95,123,525 shares issued, respectively	29,503 115,762 23,687 212,400 42,066 187,273 679,574 1,500,000 (13,080) 1,486,920 101,618 158,421 4,268 43,560 2,474,361	25,323 82,320 18,766 177,695 49,370 119,715 522,352 1,500,000 (12,061) 1,487,939 — 140,770 2,570 41,104 2,194,735 — 951
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable Total current liabilities Long-term debt: Principal Less — unamortized debt issuance costs and discount Long-term debt, net Deferred income taxes Asset retirement obligation Derivative instruments Other liabilities Total liabilities Commitments and contingencies 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, 95,437,434 and 95,123,525 shares issued, respectively Additional paid-in capital	29,503 115,762 23,687 212,400 42,066 187,273 679,574 1,500,000 (13,080) 1,486,920 101,618 158,421 4,268 43,560 2,474,361	25,323 82,320 18,766 177,695 49,370 119,715 522,352 1,500,000 (12,061) 1,487,939 — 140,770 2,570 41,104 2,194,735 — 951 2,763,452
Accounts Payable: Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable Total current liabilities Long-term debt: Principal Less — unamortized debt issuance costs and discount Long-term debt, net Deferred income taxes Asset retirement obligation Derivative instruments Other liabilities Total liabilities Commitments and contingencies 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, 95,437,434 and 95,123,525 shares issued, respectively Additional paid-in capital Retained earnings (accumulated deficit)	29,503 115,762 23,687 212,400 42,066 187,273 679,574 1,500,000 (13,080) 1,486,920 101,618 158,421 4,268 43,560 2,474,361 954 2,764,384 (199,259)	25,323 82,320 18,766 177,695 49,370 119,715 522,352 1,500,000 (12,061) 1,487,939 — 140,770 2,570 41,104 2,194,735 — 951 2,763,452 (722,359)
Trade Gas gathering, processing and marketing Accrued liabilities: Exploration and development Taxes other than income Other Derivative instruments Revenue payable Total current liabilities Long-term debt: Principal Less — unamortized debt issuance costs and discount Long-term debt, net Deferred income taxes Asset retirement obligation Derivative instruments Other liabilities Total liabilities Commitments and contingencies 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, 95,437,434 and 95,123,525 shares issued, respectively Additional paid-in capital	29,503 115,762 23,687 212,400 42,066 187,273 679,574 1,500,000 (13,080) 1,486,920 101,618 158,421 4,268 43,560 2,474,361	25,323 82,320 18,766 177,695 49,370 119,715 522,352 1,500,000 (12,061) 1,487,939 — 140,770 2,570 41,104 2,194,735 — 951

 $The \ notes \ in \ the \ accompanying \ Annual \ Report \ on \ Form \ 10-K \ are \ an \ integral \ part \ of \ these \ consolidated \ financial \ statements.$

MANAGEMENT

Board of Directors

THOMAS E. JORDEN-CHAIRMAN

JOSEPH R. ALBI

HANS HELMERICH (**) (***)

DAVID A. HENTSCHEL (**) (***)

HAROLD R. LOGAN, JR.-LEAD DIRECTOR (*) (***)

FLOYD R. PRICE (**) (***)

MONROE W. ROBERTSON (*) (***)

LISA A. STEWART (*) (***)

MICHAEL J. SULLIVAN (**) (***)

FRANCES M. VALLEJO (*) (***)

- * MEMBER OF THE AUDIT COMMITTEE
- ** MEMBER OF THE COMPENSATION AND GOVERNANCE COMMITTEE
- *** MEMBER OF THE NOMINATING COMMITTEE

Corporate Management

THOMAS E. JORDEN

CHAIRMAN OF THE BOARD
PRESIDENT AND CHIEF EXECUTIVE OFFICER

JOSEPH R. ALBI

EXECUTIVE VICE PRESIDENT – OPERATIONS CHIEF OPERATING OFFICER

G. MARK BURFORD

VICE PRESIDENT CHIEF FINANCIAL OFFICER

STEPHEN P. BELL

EXECUTIVE VICE PRESIDENT - BUSINESS DEVELOPMENT

FRANCIS B. BARRON

SENIOR VICE PRESIDENT
GENERAL COUNSEL AND CORPORATE SECRETARY

JOHN A. LAMBUTH

SENIOR VICE PRESIDENT - EXPLORATION

GARY R. ABBOTT

VICE PRESIDENT - CORPORATE ENGINEERING

TIMOTHY A. FICKER

VICE PRESIDENT

CONTROLLER AND CHIEF ACCOUNTING OFFICER

KRISTA L. JOHNSON

VICE PRESIDENT – HUMAN RESOURCES, GOVERNMENT RELATIONS AND EXTERNAL AFFAIRS

Exploration Management

ROGER G. ALEXANDER

VICE PRESIDENT
REGIONAL MANAGER – PERMIAN BASIN

KEVIN W. SMITH

REGIONAL MANAGER - MID-CONTINENT

MARK HOLLAND

MANAGER - NEW VENTURES EXPLORATION

Operations Management

WAYNE C. CHANG

VICE PRESIDENT - MARKETING AND MIDSTREAM

THOMAS F. McCOY

VICE PRESIDENT - PRODUCTION

STEVEN J. SIMONTON

VICE PRESIDENT – DRILLING AND COMPLETION OPERATIONS

Investor Contact

KAREN ACIERNO

DIRECTOR - INVESTOR RELATIONS

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549 Form 10-K

(Mark O	ne)			
×	ANNUAL REPORT PURSUANT TO SI			ANGE ACT OF 1934
	For the fis	cal year ended December 3 OR	31, 2017	
	TRANSITION REPORT PURSUANT T		F THE SECURITIES EX	XCHANGE ACT OF 1934
_	Comm	nission file number 001-31	446	
	CIN	IAREX ENERGY C	0.	
		of registrant as specified in		
	Delaware		45-0466694	
	(State or other jurisdiction of incorporation or organization)		(I.R.S. Employ Identification N	ver No.)
	* * * * * * * * * * * * * * * * * * * *	eet, Suite 3700, Denver, Co		,
		ss of principal executive off		
	,	(303) 295-3995	,	
	(Re	gistrant's telephone number)	
	Securities Registered Pursuant to Section 1	2(b) of the Act:		
_	Title of each class	NamNam_	e of each exchange on whic	
	Common Stock (\$0.01 par value)		New York Stock Excha	nnge
	Securities Registered Pursuant to Section 1	2(g) of the Act: None		
YES 🗷	Indicate by check mark if the registrant is a NO \square	well-known seasoned issue	r, as defined in Rule 40	95 of the Securities Act.
YES 🗖	Indicate by check mark if the registrant is NO ■	not required to file reports p	ursuant to Section 13 o	r Section 15(d) of the Act.
	Indicate by check mark whether the registres Exchange Act of 1934 during the precedir orts), and (2) has been subject to such filing	ng 12 months (or for such she	orter period that the reg	sistrant was required to file
	Indicate by check mark whether the registr	ant has submitted electronic	cally and posted on its	corporate Web site, if any,
	teractive Data File required to be submitted ne preceding 12 months (or for such shorter			
	Indicate by check mark if disclosure of delir entained herein, and will not be contained, ats incorporated by reference in Part III of the	to the best of the registrant	's knowledge, in defini	itive proxy or information
	Indicate by check mark whether the registreporting company, or an emerging growth reporting company," and "emerging growth	company. See the definition	ns of "large accelerated	
Large a	accelerated filer 🗷 Accelerated filer 🗖	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company □	Emerging growth company
period fo	If an emerging growth company, indicate for complying with any new or revised finance			
AUI. 🔟	Indicate by check mark whether the registra	ant is a shall company (as do	ofined in Rule 10h 2 of	the Act). YES NO NO
	mulcate by check mark whether the legistic	ant is a shell company (as de	1111cu III Kult 120-2 01	inc Act). I ES 🗀 NO 🖪

Number of shares of Cimarex Energy Co. common stock outstanding as of January 31, 2018 was 95,438,121.

approximately \$8.82 billion.

Documents Incorporated by Reference: Portions of the Registrant's Proxy Statement for its 2018 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

Aggregate market value of the voting stock held by non-affiliates of Cimarex Energy Co. as of June 30, 2017 was

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GLOSSARY

Bbl/d—Barrels (of oil or natural gas liquids) per day **Bbls**—Barrels (of oil or natural gas liquids) Bcf-Billion cubic feet Bcfe—Billion cubic feet equivalent Btu—British thermal unit **GAAP**—Generally accepted accounting principles in the U.S. Gross Acres or Gross Wells—The total acres or wells, as the case may be, in which a working interest is owned. MBbls—Thousand barrels Mcf—Thousand cubic feet (of natural gas) Mcfe—Thousand cubic feet equivalent MMBbls—Million barrels MMBtu—Million British thermal units MMcf-Million cubic feet MMcf/d—Million cubic feet per day MMcfe—Million cubic feet equivalent MMcfe/d—Million cubic feet equivalent per day Net Acres or Net Wells—The sum of the fractional working interest owned in gross acres or gross wells expressed in whole numbers and fractions of whole numbers. Net Production—Gross production multiplied by net revenue interest NGL or NGLs—Natural gas liquids **PUD**—Proved undeveloped Tcf—Trillion cubic feet Tcfe—Trillion cubic feet equivalent Energy equivalent is determined using the ratio of one barrel of crude oil, condensate, or NGL to six Mcf of natural gas.

PART I

CAUTIONARY INFORMATION ABOUT FORWARD-LOOKING STATEMENTS

Throughout this Form 10-K, we make statements that may be deemed "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. In particular, in our Management's Discussion and Analysis of Financial Condition and Results of Operations, we provide projections of our 2018 capital expenditures. All statements, other than statements of historical facts, that address activities, events, outcomes, and other matters that Cimarex plans, expects, intends, assumes, believes, budgets, predicts, forecasts, projects, estimates, or anticipates (and other similar expressions) will, should, or may occur in the future are forward-looking statements. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Form 10-K. Forward-looking statements include statements with respect to, among other things:

- Fluctuations in the price we receive for our oil, gas, and NGL production;
- Operating costs and other expenses;
- Timing and amount of future production of oil, gas, and NGLs;
- Reductions in the quantity of oil, gas, and NGLs sold due to decreased industrywide demand and/or curtailments in production from specific properties or areas due to mechanical, transportation, marketing, weather, or other problems;
- Estimates of proved reserves, exploitation potential, or exploration prospect size;
- The effectiveness of our internal control over financial reporting;
- Cash flow and anticipated liquidity;
- Amount, nature, and timing of capital expenditures;
- Availability of financing and access to capital markets;
- Administrative, legislative, and regulatory changes;
- 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;
- Exploration and development opportunities that we pursue may not result in economic, productive oil and gas properties;
- Drilling of wells;
- Increased financing costs due to a significant increase in interest rates;
- De-risking of acreage; and
- Full cost ceiling test impairments to the carrying values of our oil and gas properties.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production, and sale of oil, gas, and NGLs.

These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures, and other risks described herein.

Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of such data by our engineers. As a result, estimates made by different engineers often vary from one another. In addition, the results of drilling, testing, and production activities may justify revisions of estimates that were made previously. If significant, such revisions could change the timing of future production and development drilling. Accordingly, reserve estimates are generally different from the quantities of oil and natural gas that are ultimately recovered.

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K cause our underlying assumptions to be incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, express or implied, included in this Form 10-K and attributable to Cimarex are qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that Cimarex or persons acting on its behalf may issue. Cimarex does not undertake any obligation to update any forward-looking statements to reflect events or circumstances after the date of filing this Form 10-K with the Securities and Exchange Commission, except as required by law.

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

General

Cimarex Energy Co., a Delaware corporation formed in 2002, is an independent oil and gas exploration and production company. Our operations are located mainly in Oklahoma, Texas, and New Mexico. On our website — www.cimarex.com — you will find our annual reports, proxy statements, and all of our Securities and Exchange Commission ("SEC") filings. Throughout this Form 10-K we use the terms "Cimarex," "company," "we," "our," and "us" to refer to Cimarex Energy Co. and its subsidiaries.

Our principal business objective is to profitably grow proved reserves and production for the long-term benefit of our shareholders 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 to reinvest in exploration and development opportunities. We consider merger and acquisition opportunities that enhance our competitive position and we occasionally divest non-core assets. Key elements to our approach include:

- Maintain a strong financial position;
- Investment in a diversified portfolio of drilling opportunities;
- Rate-of-return driven evaluation and ranking of investment decisions;
- Tracking predicted versus actual results in a centralized exploration management system, providing feedback to improve results;
- Attracting quality employees and maintaining integrated teams of geoscientists, landmen, and engineers; and
- · Maximizing profitability.

Conservative use of leverage has long been the key to our financial strategy. We believe that low leverage coupled with strong full-cycle returns enables us to better withstand volatility in commodity prices and provide competitive returns and growth to shareholders. See Item 5 Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities — Stock Performance Graph and Item 6 Selected Financial Data for additional financial and operating information for fiscal years 2013 - 2017.

Proved Oil and Gas Reserves

Our December 31,2017 total proved reserves grew 16% from prior year-end. Proved undeveloped reserves as a percentage of total proved reserves decreased to 17% from 21% a year ago. We added 940.7 Bcfe of new reserves through extensions and discoveries. Net negative revisions totaled 59.7 Bcfe, which consisted primarily of a decrease of 248.8 Bcfe for the removal of PUD reserves whose development will likely be delayed beyond five years of initial disclosure, offset by an increase of 187.2 Bcfe related to improved commodity prices. The change in our proved reserves is as follows (in Bcfe):

Reserves at December 31, 2016.	2,890.5
Revisions of previous estimates	
Extensions and discoveries	940.7
Purchases of reserves	1.4
Production	(416.9)
Sales of reserves	(1.8)
Reserves at December 31, 2017	3,354.2

A breakdown by commodity of our proved oil and gas reserves follows:

	December 31,			
_	2017	2016	2015	
Proved reserves:				
Gas (Bcf)	1,607.6	1,471.4	1,517.0	
Oil (MMBbls)	137.2	105.9	107.8	
NGL (MMBbls)	153.9	130.6	124.3	
Total (Bcfe)	3,354.2	2,890.5	2,909.4	
Percent developed	83%	79%	75%	

At December 31, 2017, 52% of our total proved reserves were located in the Mid-Continent region and 48% were in the Permian Basin. The following table summarizes our estimated proved oil and gas reserves by region as of December 31, 2017.

Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MMcfe)	% of Total Proved Reserves
1,032,695	31,853	85,292	1,735,565	52%
573,757	105,198	68,530	1,616,126	48%
1,183	187	38	2,531	%
1,607,635	137,238	153,860	3,354,222	100%
	(MMcf) 1,032,695 573,757 1,183	(MMcf) (MBbls) 1,032,695 31,853 573,757 105,198 1,183 187	(MMcf) (MBbls) (MBbls) 1,032,695 31,853 85,292 573,757 105,198 68,530 1,183 187 38	(MMcf) (MBbls) (MBbls) (MMcfe) 1,032,695 31,853 85,292 1,735,565 573,757 105,198 68,530 1,616,126 1,183 187 38 2,531

See SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED) in Item 8 for further information regarding our reserves.

Production Volumes, Prices, and Costs

Our 2017 production volumes totaled 1,142 MMcfe per day, a 19% increase from 2016, and were comprised of 45% gas, 30% oil, and 25% NGLs. The following tables show by region our total and average daily production volumes, the average commodity prices received, and production cost per unit of production. Separate data is also included for the Cana area, which comprises the majority of the production of our largest producing field, the Watonga-Chickasha in western Oklahoma.

	Total Production Volumes					Average Daily Production Volumes					
•	Gas	Oil	NGL	Total	Gas	Oil	NGL	Total			
Years Ended December 31,	(MMcf)	(MBbls)	(MBbls)	(MMcfe)	(MMcf)	(MBbls)	(MBbls)	(MMcfe)			
2017											
Permian Basin	79,521	16,271	8,858	230,293	217.9	44.6	24.3	630.9			
Mid-Continent	107,463	4,547	8,503	185,761	294.4	12.5	23.3	508.9			
Other	484	43	13	821	1.3	0.1	_	2.3			
Total company	187,468	20,861	17,374	416,875	513.6	57.2	47.6	1,142.1			
Cana area	89,471	4,168	7,813	161,354	245.1	11.4	21.4	442.1			
2016											
Permian Basin	65,191	13,183	6,677	184,351	178.1	36.0	18.2	503.7			
Mid-Continent	102,501	3,283	7,508	167,243	280.1	9.0	20.5	456.9			
Other	535	62	15	997	1.4	0.2	0.1	2.8			
Total company	168,227	16,528	14,200	352,591	459.6	45.2	38.8	963.4			
Cana area	82,423	2,848	6,855	140,647	225.2	7.8	18.7	384.3			
2015											
Permian Basin	66,006	15,719	6,220	197,644	180.8	43.1	17.0	541.5			
Mid-Continent	100,801	2,746	6,757	157,821	276.2	7.5	18.5	432.4			
Other	2,180	198	86	3,878	6.0	0.5	0.3	10.6			
Total company	168,987	18,663	13,063	359,343	463.0	51.1	35.8	984.5			
Cana area	77,882	2,206	5,957	126,865	213.4	6.0	16.3	347.6			

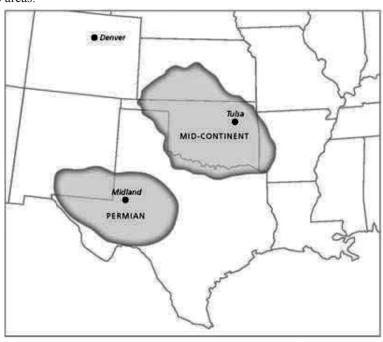
	Average Realized Price								
Years Ended December 31,		Gas (per Mcf)		Oil (per Bbl)		NGL (per Bbl)		Production Cost (per Mcfe)	
2017								_	
Permian Basin	\$	2.72	\$	46.96	\$	20.25	\$	0.78	
Mid-Continent	\$	2.78	\$	47.42	\$	23.02	\$	0.43	
Other	\$	2.74	\$	46.53	\$	23.11	\$	1.51	
Total Company	\$	2.76	\$	47.06	\$	21.61	\$	0.63	
Cana area	\$	2.76	\$	47.44	\$	23.27	\$	0.28	
2016									
Permian Basin	\$	2.35	\$	38.45	\$	12.32	\$	0.86	
Mid-Continent	\$	2.29	\$	37.65	\$	15.59	\$	0.43	
Other	\$	2.00	\$	38.86	\$	14.80	\$	1.59	
Total Company	\$	2.31	\$	38.30	\$	14.05	\$	0.66	
Cana area	\$	2.28	\$	37.73	\$	15.80	\$	0.23	
2015									
Permian Basin	\$	2.55	\$	43.58	\$	11.94	\$	1.06	
Mid-Continent	\$	2.51	\$	41.90	\$	15.41	\$	0.52	
Other	\$	3.16	\$	48.01	\$	14.72	\$	1.72	
Total Company	\$	2.53	\$	43.38	\$	13.75	\$	0.83	
Cana area	\$	2.51	\$	41.54	\$	15.59	\$	0.26	

Acquisitions and Divestitures

In 2017, we sold interests in various non-core oil and gas properties for cash proceeds of \$12 million and made various oil and gas property acquisitions for \$8 million.

Exploration and Development Overview

Cimarex has one reportable segment, exploration and production ("E&P"). Our E&P activities take place primarily in two areas: the Permian Basin and the Mid-Continent region. Almost all of our exploration and development ("E&D") capital is allocated between these two areas.



A summary of our 2017 exploration and development activity by region is as follows:

	E&D Capital						Gross Wells Completed	Net Wells Completed	% Completed As Producers
	(in	millions)							
Permian Basin	\$	760	97	55.2	98%				
Mid-Continent		500	222	42.8	99%				
Other		21	_		%				
	\$	1,281	319	98.0	98%				

The Permian Basin encompasses west Texas and southeast New Mexico. Cimarex's Permian Basin efforts are located in the western half of the Permian Basin known as the Delaware Basin. In 2017, we focused on drilling horizontal wells that yielded oil and liquids-rich gas from the Wolfcamp shale and the Bone Spring formation. Cimarex saw improved results in its Wolfcamp shale wells, as measured by production and reserves, with the further implementation of long laterals and continued improvement in well completion design and in the Bone Spring wells via upsized well completions.

The Permian Basin produced 630.9 MMcfe per day in 2017, which was 55% of our total company production. Total production from the region increased 25% in 2017 over 2016. In 2017, we invested \$760 million, or 59% of our total E&D investment, in the Permian Basin.

Our Mid-Continent region consists of Oklahoma and the Texas Panhandle. Our activity in 2017 in the Mid-Continent was focused in the Woodford shale and the Meramec horizon, both in Oklahoma. We continued to implement larger well completions in the Woodford shale and we applied those same techniques to delineate the Meramec horizon, located above the Woodford. Cimarex continues to evaluate the size and potential of the Meramec play.

During 2017, production from the Mid-Continent averaged 508.9 MMcfe per day, or 45% of total company production. Total production from the region increased 11% in 2017 over 2016. In 2017, we invested \$500 million, or 39% of our total E&D investment, in the Mid-Continent.

Drilling Activity

In 2017, we completed or participated in the completion of 319 gross (98.0 net) wells, of which we operated 118 gross (77.7 net) wells. At year-end, we were in the process of drilling or participating in 29 gross (13 net) wells and there were 91 gross (33.7 net) wells waiting on completion.

We completed the following number of developmental wells in the years indicated in the table below. During these years, we completed no exploratory wells.

	Wells Completed									
_	2017		2016	,	2015					
_	Gross	Net	Gross	Net	Gross	Net				
Developmental										
Productive	314	96.4	153	61.0	219	98.7				
Dry	5	1.6	1	_	3	1.7				
Total	319	98.0	154	61.0	222	100.4				

At December 31, 2017, we owned an interest in 10,373 gross (3,083 net) productive oil and gas wells. We had working interests in the following number of productive wells by region as of December 31, 2017:

	Gas	S	Oi	Oil		
_	Gross	Net	Gross	Net		
Mid-Continent	3,920	1,501	698	181		
Permian Basin	760	338	4,885	1,053		
Other	95	8	15	2		
	4,775	1,847	5,598	1,236		

Significant Properties

All of our oil and gas assets are located in the United States. We have varying levels of ownership interests in our properties consisting of working, royalty, and overriding royalty interests. Operated wells account for approximately 80% of our proved reserves. In 2017, proved reserves in the Cana area of the Watonga-Chickasha field were approximately 46% of Cimarex's total proved reserves. No other field had 15% or more of our total proved reserves.

At December 31, 2017, our ten largest fields by future net revenue discounted at 10% comprised 85% of our total proved reserves. Information regarding each of these fields is as follows:

Field	Region	% of Total Proved Reserves	Average Working Interest%	Approximate Average Depth (feet)	Primary Formation
Watonga-Chickasha	Mid-Continent	46.5%	26.6%	13,000'	Woodford
Ford, West	Permian Basin	12.4%	57.7%	9,500'	Wolfcamp
Grisham	Permian Basin	8.0%	98.3%	11,000'	Wolfcamp
Dixieland	Permian Basin	5.9%	96.0%	11,000'	Wolfcamp
Lusk	Permian Basin	4.2%	53.5%	8,000' - 11,000'	Bone Spring/Avalon
Cottonwood Draw	Permian Basin	2.5%	62.9%	3,000' - 10,000'	Delaware/Wolfcamp
Phantom	Permian Basin	1.8%	39.1%	11,500'	Bone Spring
Two Georges	Permian Basin	1.6%	90.9%	11,500'	Bone Spring
Stateline	Permian Basin	1.4%	48.5%	7,500'	Bone Spring
Quail Ridge	Permian Basin	1.0%	47.0%	8,000' - 13,000'	Bone Spring/Morrow
		85.3%			

Acreage

The following table sets forth the gross and net acres of both developed and undeveloped leases held by Cimarex as of December 31, 2017. Gross acres are the total number of acres in which we own a working interest. Net acres are the gross acres multiplied by our working interest.

	Acreage							
_	Undevel	oped	Develo	oped	Total			
	Gross	Net	Gross	Net	Gross	Net		
Mid-Continent								
Kansas	18,231	18,191	_	_	18,231	18,191		
Oklahoma	90,275	60,230	692,853	302,409	783,128	362,639		
Texas	22,845	12,101	131,119	55,796	153,964	67,897		
_	131,351	90,522	823,972	358,205	955,323	448,727		
Permian Basin								
New Mexico	77,297	56,796	173,756	118,355	251,053	175,151		
Texas	79,453	56,745	210,873	148,554	290,326	205,299		
_	156,750	113,541	384,629	266,909	541,379	380,450		
Other								
Arizona	2,097,201	2,097,201	17,847		2,115,048	2,097,201		
California	383,487	383,487			383,487	383,487		
Colorado	40,488	18,867	41,384	1,642	81,872	20,509		
Gulf of Mexico	25,000	13,000	28,848	6,381	53,848	19,381		
Louisiana	12,112	9,064	2,875	168	14,987	9,232		
Michigan	4,702	4,624	1,183	1,183	5,885	5,807		
Montana	31,422	7,687	7,688	1,721	39,110	9,408		
Nevada	1,007,167	1,007,167	440	1	1,007,607	1,007,168		
New Mexico	1,641,206	1,633,821	18,371	2,436	1,659,577	1,636,257		
Texas	10,476	3,722	27,115	6,107	37,591	9,829		
Utah	80,527	59,433	32,552	1,575	113,079	61,008		
Wyoming	96,837	13,744	43,826	4,217	140,663	17,961		
Other	194,359	171,191	9,772	3,499	204,131	174,690		
_	5,624,984	5,423,008	231,901	28,930	5,856,885	5,451,938		
Total	5,913,085	5,627,071	1,440,502	654,044	7,353,587	6,281,115		

The table below summarizes by year and region our undeveloped acreage expirations in the next five years. In most cases, the drilling of a commercial well will hold the acreage beyond the expiration.

	Acreage									
	2018		2019		2020		2021		2022	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	5,608	3,244	4,869	4,152	5,878	5,865	667	667	220	220
Permian Basin	5,322	4,563	16,999	16,837	8,744	6,584	4,318	4,318	2,148	2,148
Other	31,869	31,152	64,652	60,510	34,811	34,596	7,392	7,303	29,223	28,468
	42,799	38,959	86,520	81,499	49,433	47,045	12,377	12,288	31,591	30,836
% of undeveloped acreage.	0.7	0.7	1.5	1.4	0.8	0.8	0.2	0.2	0.5	0.5

At December 31, 2017, we had no proved undeveloped reserves scheduled for development beyond the expiration dates of our undeveloped acreage.

Marketing

Our oil and gas production is sold under short-term arrangements at market-responsive prices. We sell our oil at prices tied directly or indirectly to field postings. Our gas is sold under price mechanisms related to either monthly or daily index prices on pipelines where we deliver our gas. We sell our NGLs at prices tied to monthly index prices where we deliver our NGLs.

We sell our oil, gas, and NGLs to a broad portfolio of customers. Our major customers during 2017 were Energy Transfer Partners, L.P. and Plains All American Pipeline, L.P., which accounted for 21% and 13%, respectively, of our consolidated revenues.

If any one of our major customers were to stop purchasing our production, we believe there are a number of other purchasers to whom we could sell our production with some delay. If multiple significant customers were to discontinue purchasing our production, we believe there would be challenges initially, but ample markets to handle the disruption.

We regularly monitor the credit worthiness of all our customers and may require parent company guarantees, letters of credit, or prepayments when deemed necessary.

Corporate Headquarters and Employees

Our corporate headquarters is located at 1700 Lincoln St., Suite 3700, Denver, Colorado 80203. On December 31, 2017 and 2016, Cimarex had 910 and 856 employees, respectively. None of our employees are subject to collective bargaining agreements.

Competition

The oil and gas industry is highly competitive, particularly for prospective undeveloped leases and purchases of proved reserves. There is also competition for rigs and related equipment used to drill for and produce oil and gas, however, to a lesser extent in the current market environment. Our competitive position also is highly dependent on our ability to recruit and retain geological, geophysical, and engineering expertise. We compete for prospects, proved reserves, oil-field services, and qualified oil and gas professionals with major and diversified energy companies and other independent operators that have larger financial, human, and technological resources than we do.

We compete with integrated, independent, and other energy companies for the sale and transportation of our oil, gas, and NGLs to marketing companies and end users. The oil and gas industry competes with other energy industries that supply fuel and power to industrial, commercial, and residential consumers. Many of these competitors have greater financial and human resources. The effect of these competitive factors cannot be predicted.

Proved Reserves Estimation Procedures

Proved oil and gas reserve quantities are based on estimates prepared by Cimarex in accordance with the SEC's rules for reporting oil and gas reserves. Our reserve definitions conform with definitions of Rule 4-10(a) (1)-(32) of Regulation S-X of the SEC. All of our reserve estimates are maintained by our internal Corporate Reservoir Engineering group, which is comprised of reservoir engineers and engineering technicians. The objectives and management of this group are separate from and independent of the exploration and production functions of the company. The primary objective of our Corporate Reservoir Engineering group is to maintain accurate forecasts on all properties of the company through ongoing monitoring and timely updates of operating and economic parameters (production forecasts, prices and regional differentials, operating expenses, ownership, etc.) in accordance with guidelines established by the SEC. This separation of function and responsibility is a key internal control.

Cimarex engineers are responsible for estimates of proved reserves. Corporate engineers interact with the exploration and production departments to ensure all available engineering and geologic data is taken into account prior to establishing or revising an estimate. After preparing the reserves update, the corporate engineers review their recommendations with the Vice President of Corporate Engineering. After approval from the Vice President of Corporate Engineering, the revisions are entered into our reserves database by the engineering technician.

During the course of the year, the Vice President of Corporate Engineering presents summary reserves information to senior management and to our Board of Directors for their review. From time to time, the Vice President of Corporate Engineering also will confer with the Vice President of Exploration, Chief Operating Officer, and the Chief Executive Officer regarding specific reserves-related issues. In addition, Corporate Reservoir Engineering maintains a set of basic guidelines and procedures to ensure that critical checks and reviews of the reserves database are performed on a regular basis.

Together, these internal controls are designed to promote a comprehensive, objective, and accurate reserves estimation process. As an additional confirmation of the reasonableness of our internal estimates, DeGolyer and MacNaughton, an independent petroleum engineering consulting firm, reviewed reserves associated with greater than 80% of the total future net revenue discounted at 10% attributable to the total interests owned by Cimarex as of December 31, 2017. The individual primarily responsible for overseeing the review is a Senior Vice President with DeGolyer and MacNaughton and a Registered Professional Engineer in the State of Texas with over 33 years of experience in oil and gas reservoir studies and reserves evaluations.

The technical employee primarily responsible for overseeing the oil and gas reserves estimation process is Cimarex's Vice President of Corporate Engineering. This individual graduated from the Colorado School of Mines with a Bachelor of Science degree in Engineering and has more than 23 years of practical experience in oil and gas reservoir evaluation. He has been directly involved in the annual reserves reporting process of Cimarex since 2002 and has served in his current role for the past 13 years.

Title to Oil and Gas Properties

We undertake title examination and perform curative work at the time we lease undeveloped acreage, prepare for the drilling of a prospect, or acquire proved properties. We believe title to our properties is good and defensible, and is in accordance with industry standards. Nevertheless, we are involved in title disputes from time to time that result in litigation. Our oil and gas properties are subject to customary royalty interests, liens incidental to operating agreements, tax liens, and other burdens and minor encumbrances, easements, and restrictions.

Government Regulation

Oil and gas production and transportation is subject to extensive federal, state, and local laws and regulations. Compliance with existing laws often is difficult and costly, but has not had a significant adverse effect on our operations or financial condition. In recent years, we have been most directly impacted by federal and state environmental regulations and energy conservation rules. We are also impacted by federal and state regulation of pipelines and other oil and gas transportation systems.

The states in which we conduct operations establish requirements for drilling permits, the method of developing fields, the size of well spacing units, drilling density within productive formations and the unitization or pooling of properties. In addition, state conservation laws include requirements for waste prevention, establish limits on the maximum rate of production from wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability of production.

Environmental Regulation. Various federal, state, and local laws regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment, directly impact oil and gas exploration, development, and production operations, which consequently impact our operations and costs. These laws and regulations govern, among other things, emissions into the atmosphere, discharges of pollutants into waters, underground injection of waste water, the generation, storage, transportation, and disposal of waste materials, and protection of public health, natural resources, and wildlife. These laws and regulations may impose substantial liabilities for noncompliance and for any contamination resulting from our operations and may require the suspension or cessation of operations in affected areas.

Cimarex is committed to environmental protection and believes we are in material compliance with applicable environmental laws and regulations. We obtain permits for our facilities and operations in accordance with the applicable laws and regulations. There are no known issues that have a significant adverse effect on the permitting process or permit compliance status of any of our facilities or operations. Expenditures are required to comply with environmental regulations. These costs are a normal, recurring expense of operations and not an extraordinary cost of compliance with current government regulations.

We do not anticipate that we will be required under current environmental laws and regulations to expend amounts that will have a material adverse effect on our financial position or operations. However, due to continuing changes in these laws and regulations, we are unable to predict with any reasonable degree of certainty any potential delays in development plans that could arise, or our future costs of complying with governmental requirements. We maintain levels of insurance customary in the industry to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of oil, produced water, or other substances as well as additional coverage for certain other pollution events.

Gas Gathering and Transportation. The Federal Energy Regulatory Commission ("FERC") requires interstate gas pipelines to provide open access transportation. FERC also enforces the prohibition of market manipulation by any entity, and the facilitation of the sale or transportation of natural gas in interstate commerce. Interstate pipelines have implemented these requirements, providing us with additional market access and more fairly applied transportation services and rates. FERC continues to review and modify its open access and other regulations applicable to interstate pipelines.

Under the Natural Gas Policy Act ("NGPA"), natural gas gathering facilities are expressly exempt from FERC jurisdiction. What constitutes "gathering" under the NGPA has evolved through FERC decisions and judicial review of such decisions. We believe that our gathering systems meet the test for non-jurisdictional "gathering" systems under the NGPA and that our facilities are not subject to federal regulations. Although exempt from FERC oversight, our natural gas gathering systems and services may receive regulatory scrutiny by state and federal agencies regarding the safety and operating aspects of the transportation and storage activities of these facilities.

In addition to using our own gathering facilities, we may use third-party gathering services or interstate transmission facilities (owned and operated by interstate pipelines) to ship our gas to markets.

Additional proposals and proceedings that might affect the oil and gas industry are pending before the U.S. Congress, FERC, Bureau of Land Management ("BLM"), U.S. Environmental Protection Agency ("EPA"), state legislatures, state agencies, local governments, and the courts. We cannot predict when or whether any such proposals may become effective and what effect they will have on our operations. We do not anticipate that compliance with existing federal, state, and local laws, rules, or regulations will have a material adverse effect upon our capital expenditures, earnings, or competitive position.

Federal and State Income and Other Local Taxation

Cimarex and the petroleum industry in general are affected by both federal and state income tax laws, as well as other local tax regulations involving ad valorem, personal property, franchise, severance, and other excise taxes. We have considered the effects of these provisions on our operations and do not anticipate that there will be any material undisclosed impact on our capital expenditures, earnings, or competitive position.

Executive Officers of the Registrant

See Part III, Item 10, Directors, Executive Officers and Corporate Governance for information regarding our executive officers as of February 23, 2018.

ITEM 1A. RISK FACTORS

The following risks and uncertainties, together with other information set forth in this Form 10-K, should be carefully considered by current and future investors in our securities. These risks and uncertainties are not the only ones we face. Additional risks and uncertainties presently unknown to us or currently deemed immaterial also may impair our business operations. The occurrence of one or more of these risks or uncertainties could materially and adversely affect our business, financial condition, and results of operations, which in turn could negatively impact the value of our securities.

Oil, gas, and NGL prices fluctuate due to a number of factors beyond our control, creating a component of uncertainty in our development plans and overall operations. Declines in prices adversely affect our financial results and rate of growth in proved reserves and production.

Oil and gas markets are volatile. We cannot predict future prices. The prices we receive for our production heavily influence our revenue, profitability, access to capital, and future rate of growth. The prices we receive depend on numerous factors beyond our control. These factors include, but are not limited to, changes in domestic and global supply and demand for oil and gas, the level of domestic and global oil and gas exploration and production activity, geopolitical instability, the actions of the Organization of Petroleum Exporting Countries, weather conditions, technological advances affecting energy consumption, governmental regulations and taxes, and the price and technological advancement of alternative fuels.

Our proved oil and gas reserves and production volumes will decrease unless those reserves are replaced with new discoveries or acquisitions. Accordingly, for the foreseeable future, we expect to make substantial capital investments for the exploration and development of new oil and gas reserves. Historically, we have paid for these types of capital expenditures with cash flow provided by our production operations, our revolving credit facility, and proceeds from the sale of senior notes or equity. Low prices reduce our cash flow and the amount of oil and gas that we can economically produce and may cause us to curtail, delay, or defer certain exploration and development projects. Moreover, low prices may impact our abilities to borrow under our revolving credit facility and to raise additional debt or equity capital to fund acquisitions.

If prices decrease, we may be required to take write-downs of the carrying values of our oil and gas properties and/or our goodwill.

Accounting rules require that we periodically review the carrying value of our oil and gas properties and goodwill for possible impairment.

In 2016 and 2015, we recognized ceiling test impairments totaling \$757.7 million (\$481.4 million, net of tax) and \$4.03 billion (\$2.56 billion, net of tax), respectively. The impairments resulted primarily from the impact of decreases in the trailing twelve-month average prices for oil, gas, and NGLs utilized in determining the estimated future net cash flows from proved reserves. At December 31, 2017, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test, and no impairment was necessary. However, a decline of approximately 19% or more in the value of the ceiling limitation would have resulted in an impairment. Because the ceiling calculation uses trailing twelve-month average commodity prices, the effect of increases and decreases in period-over-period prices can significantly impact the ceiling limitation calculation. Impairment charges do not affect cash flow from operating activities, but do adversely affect our net income and various components of our balance sheet.

Ineffective internal controls could impact our business and financial results.

Our internal control over financial reporting may not prevent or detect misstatements because of its inherent limitations, including the possibility of human error, the circumvention or overriding of controls, or fraud. Even effective internal controls can provide only reasonable assurance with respect to the preparation and fair presentation of financial statements. If we fail to maintain the adequacy of our internal controls, including any failure to implement required new or improved controls, or if we experience difficulties in their implementation, our business and financial results could be harmed and we could fail to meet our financial reporting obligations. For example, at December 31, 2016, management concluded that a deficiency in the design of our internal controls related to the full cost ceiling test calculation represented a material weakness in our internal control over financial reporting and, therefore, that we did not maintain effective internal control over financial reporting as of December 31, 2016, as reported in our Form 10-K/A for that period. We have since remediated this material weakness, however, there is no guarantee that we won't experience material weaknesses in our internal control over financial reporting in the future or that we will be able to implement new controls to address such material weaknesses as necessary, which may result in untimely or inaccurate reporting of our financial statements.

U.S. or global financial markets may impact our business and financial condition.

A credit crisis or other turmoil in the U.S. or global financial system may have a negative impact on our business and our financial condition. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing. This could have an impact on our flexibility to react to changing economic and business conditions. Deteriorating economic conditions could have a negative impact on our lenders, the purchasers of our oil and gas production, and the working interest owners in properties we operate, causing them to fail to meet their obligations to us.

Failure to economically replace oil and gas reserves could negatively affect our financial results and future rate of growth.

In order to replace the reserves depleted by production and to maintain or increase our total proved reserves and overall production levels, we must either locate and develop new oil and gas reserves or acquire producing properties from others. This requires significant capital expenditures and can impose reinvestment risk for us, as we may not be able to continue to replace our reserves economically. While we occasionally may seek to acquire proved reserves, our main business strategy is to grow through exploration and drilling. Without successful exploration and development, our reserves, production, and revenues could decline rapidly, which would negatively impact the results of our operations.

Exploration and development involves numerous risks, including new governmental regulations and the risk that we will not discover any commercially productive oil or gas reservoirs. Additionally, it can be unprofitable, not only from drilling dry holes, but also from drilling productive wells that do not return a profit because of insufficient reserves or declines in commodity prices.

Our drilling operations may be curtailed, delayed, or canceled for many reasons. Factors such as unforeseen poor drilling conditions, title problems, unexpected pressure irregularities, equipment failures, accidents, adverse weather conditions, compliance with environmental and other governmental requirements, bans, moratoria, or other restrictions implemented by local governments and the cost of, or shortages or delays in the availability of, drilling and completion services could negatively impact our drilling operations.

Our proved reserve estimates may be inaccurate and future net cash flows are uncertain.

Estimates of total proved oil and gas reserves (consisting of proved developed and proved undeveloped reserves) and associated future net cash flow depend on a number of variables and assumptions. Refer to CAUTIONARY INFORMATION ABOUT FORWARD-LOOKING STATEMENTS in Part I of this report. Among others, changes in any of the following factors may cause actual results to vary considerably from our estimates:

- oil, gas, and NGL prices;
- timing of development expenditures;
- amount of required capital expenditures and associated economics;
- recovery efficiencies, decline rates, drainage areas, and reservoir limits;
- anticipated reservoir and production characteristics and interpretations of geologic and geophysical data;
- production rates, reservoir pressure, unexpected water encroachment, and other subsurface conditions;
- governmental regulation;
- access to assets restricted by local government action;
- operating costs;
- property, severance, excise, and other taxes incidental to oil and gas operations;
- workover and remediation costs; and
- federal and state income taxes.

Our proved oil and gas reserve estimates are prepared by Cimarex engineers in accordance with guidelines established by the SEC. DeGolyer and MacNaughton, independent petroleum engineers, reviewed our reserve estimates for properties that comprised at least 80% of the discounted future net cash flows before income taxes, using a 10% discount rate, as of December 31, 2017.

The cash flow amounts referred to in this filing should not be construed as the current market value of our proved reserves. In accordance with SEC guidelines, the estimated discounted net cash flow from proved reserves is based on the average of the previous twelve months' first-day-of-the-month prices and costs as of the date of the estimate, whereas actual future prices and costs may be materially different.

Our business depends on oil and gas pipeline and transportation facilities, some of which are owned by others.

In addition to the existence of adequate markets, our oil and gas production depends in large part on the proximity and capacity of pipeline systems, as well as storage, transportation, processing and fractionation facilities, most of which are owned by third parties. The inability to transport one commodity, such as gas, could also impair our ability to produce and sell other commodities, such as oil and NGLs, produced from the same wells. The lack of availability or the lack of capacity on these systems and facilities could result in the curtailment of production or the delay or discontinuance of drilling plans. This is more likely in remote areas with less established infrastructure, such as our Delaware Basin area where we and competitors have significant development activities. The lack of availability of or capacity in these facilities or the loss of these facilities due to construction delays, weather, fire, or other reasons, for an extended period of time could negatively affect our revenues.

A limited number of companies purchase a majority of our oil, gas, and NGLs. The loss of a significant purchaser could have a material adverse effect on our ability to sell production.

Federal and state regulation of oil and gas, local government activity, adverse court rulings, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines, and general economic conditions could adversely affect our ability to produce and market oil and natural gas.

Commodity price derivative transactions may limit our potential gains and involve other risks.

To limit our exposure to price risk, we enter into derivative agreements from time to time. Commodity price derivatives limit volatility and increase the predictability of a portion of our cash flow. These transactions also limit our potential gains when oil and gas prices exceed the prices established by the derivatives.

In certain circumstances, derivative transactions may expose us to the risk of financial loss, including instances in which:

- the counterparties to our derivative agreements fail to perform;
- there is a sudden unexpected event that materially increases oil and gas prices; or
- there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the derivative agreement.

Because we account for derivative contracts under mark-to-market accounting, during periods we have derivative transactions in place we expect continued volatility in derivative gains and losses on our statement of operations as changes occur in the relevant price indexes.

The adoption of derivatives legislation could have an adverse effect on our ability to use derivative instruments as hedges against fluctuating commodity prices.

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act called for various regulatory agencies, including the SEC and the Commodities Futures Trading Commission ("CFTC"), to establish regulations for implementation of many of its provisions. The Dodd-Frank Act contains significant derivatives regulations, including requirements that certain transactions be cleared on exchanges and that cash collateral (margin) be posted for such transactions. The Dodd-Frank Act provides for an exemption from the clearing and cash collateral requirements for commercial end-users, such as Cimarex, and it includes a number of defined terms used in determining how this exemption applies to particular derivative transactions and the parties to those transactions.

We have satisfied the requirements for the commercial end-user exception to the clearing requirement and intend to continue to engage in derivative transactions. In December 2015, the CFTC approved final rules on margin requirements that will have an impact on our derivative counterparties and an interim final rule exemption from the margin requirements for certain uncleared swaps with commercial end-users. The final rules did not impose additional requirements on commercial end-users. The ultimate effect of these new rules and any additional regulations is currently uncertain. New rules and regulations in this area may result in significant increased costs and disclosure obligations as well as decreased liquidity as entities that previously served as derivative counterparties exit the market.

We have been an early entrant into new or emerging resource plays. As a result, our drilling results in these areas are uncertain. The value of our undeveloped acreage may decline and we may incur impairment charges if drilling results are unsuccessful.

New or emerging oil and gas resource plays have limited or no production history. Consequently, in those areas it is difficult to predict our future drilling costs and results. Therefore, our cost of drilling, completing, and operating wells in these areas may be higher than initially expected. Similarly, our production may be lower than initially expected, and the value of our undeveloped acreage may decline if our results are unsuccessful. As a result, we may be required to impair the carrying value of our undeveloped acreage in new or emerging plays.

Furthermore, unless production is established during the primary term of certain of our undeveloped oil and gas leases, the leases will expire, and we will lose our right to develop those properties.

Competition in our industry is intense and many of our competitors have greater financial and technological resources.

We operate in the competitive area of oil and gas exploration and production. Many of our competitors are large, well-established companies that have larger operating staffs and greater capital resources. These competitors may be willing to pay more for exploratory prospects and productive oil and gas properties. They may also be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than our financial or human resources permit.

Because our activity is also concentrated in areas of heavy industry competition, there is heightened demand for personnel, equipment, power, services, facilities, and resources, resulting in higher costs than in other areas. Such intense competition also could result in delays in securing, or the inability to secure, the personnel, equipment, power, services, resources, or facilities necessary for our development activities, which could negatively impact our production volumes. We also face higher costs in remote areas where vendors can charge higher rates due to that remoteness and the inability to attract employees to those areas, as well as the vendors' ability to deploy their resources in easier-to-access areas.

We are subject to complex laws and regulations that can adversely affect the cost, manner, and feasibility of doing business.

Exploration, production, and the sale of oil and gas are subject to extensive laws and regulations, including those implemented to protect the environment, human health and safety, and wildlife. Federal, state, and local regulatory agencies frequently require permitting and impose conditions on our activities. During the permitting process, these regulatory agencies often exercise considerable discretion in both the timing and scope of the permits, and the public, including special interest groups, often has an opportunity to influence the timing and outcome of the process. The requirements or conditions imposed by these agencies can be costly and can delay the commencement of our operations. In addition, a number of initiatives had been put forth by the Obama administration in the form of Presidential or Secretarial Memoranda, which are still in effect, and have the potential to impact the cost of doing business or could result in substantial delays in permitting, drilling, and other oil and gas activities.

Failing to comply with any of the applicable laws and regulations, or Presidential initiatives, could result in the suspension or termination of our operations and subject us to administrative, civil, and criminal liabilities and penalties. Such costs could have a material adverse effect on both our financial condition and operations.

Environmental matters and costs can be significant.

As an owner, lessee, or operator of oil and gas properties, we are subject to various complex, stringent, and constantly evolving environmental laws and regulations. Our operations inherently create the risk of environmental liability to the government and private parties stemming from our use, generation, handling, and disposal of water and waste materials, as well as the release of hydrocarbons or other substances into the air, soil, or water. The environmental laws and regulations to which we are subject impose numerous obligations applicable to our operations, including: the acquisition of permits before conducting regulated activities associated with drilling for and producing oil and gas; the restriction of types, quantities, and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands, waters of the United States, and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, or criminal penalties, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining, or be unable to obtain, required permits, which may delay or interrupt our operations and limit our growth and revenue.

Liabilities under certain environmental laws can be joint and several and may in some cases be imposed regardless of fault on our part such as where we own a working interest in a property operated by another party. We also could be held liable for damages or remediating lands or facilities previously owned or operated by others regardless of whether such contamination resulted from our own actions and regardless if we were in compliance with all applicable law at the time. Further, claims for damages to persons or property, including natural resources, may result from the environmental, health, and safety impacts of our operations. Because these environmental risks generally are not fully insurable and can result in substantial costs, such liabilities could have a material adverse effect on both our financial condition and operations.

Our financial condition and results of operations may be materially adversely affected if we incur costs and liabilities due to a failure to comply with environmental regulations or a release of hazardous substances into the environment.

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, pollutants, solid and hazardous wastes, and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, discharge, transportation, and disposal of pollutants and solid and hazardous waste and may impose strict and, in some cases, joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. The most significant of these environmental laws are as follows:

- The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, referred to as CERCLA
 or the Superfund law, and comparable state laws, which imposes liability on generators, transporters, and arrangers
 of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur;
- The Oil Pollution Act of 1990 ("OPA"), under which owners and operators of onshore facilities and pipelines, lessees or permittees of an area in which an offshore facility is located, and owners and operators of vessels are liable for removal costs and damages that result from a discharge of oil into navigable waters of the United States;
- The Resource Conservation and Recovery Act ("RCRA"), as amended, and comparable state statutes, which governs the treatment, storage, and disposal of solid waste;
- The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act ("CWA"), which governs the discharge of pollutants, including natural gas wastes, into federal and state waters;
- The Safe Drinking Water Act ("SDWA"), which governs the disposal of wastewater in underground injection wells; and
- The Clean Air Act ("CAA") which governs the emission of pollutants into the air.

We believe we are in substantial compliance with the requirements of CERCLA, OPA, RCRA, CWA, SDWA, CAA and related state and local laws and regulations. We also believe we hold all necessary and up-to-date permits, registrations, and other authorizations required under such laws and regulations. Although the current costs of managing our wastes as they presently are classified are reflected in our budget, any legislative or regulatory reclassification of oil and gas exploration and production wastes could increase our costs to manage and dispose of such wastes and have a material adverse effect on our financial condition and operations.

Federal regulatory initiatives relating to the protection of threatened or endangered species could result in increased costs and additional operating restrictions or delays.

The Federal Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. The U.S. Fish and Wildlife Service ("FWS") may designate critical habitat and suitable habitat areas it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and gas development. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We conduct operations on federal oil and gas leases in areas where certain species are currently listed as threatened or endangered, or could be listed as such, under the ESA. Operations in areas where threatened or endangered species or their habitat are known to exist may require us to incur increased costs to implement mitigation or protective measures and also may restrict or preclude our drilling activities in those areas or during certain seasons, such as breeding and nesting seasons. On March 27, 2014, the FWS announced the listing of the lesser prairie chicken, whose habitat is over a five-state region, including Texas, New Mexico, and Oklahoma, where we conduct operations, as a threatened species under the ESA. Listing of the lesser prairie chicken as a threatened species imposes restrictions on disturbances to critical habitat by landowners and drilling companies that would harass, harm, or otherwise result in a "taking" of this species. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies ("WAFWA"), pursuant to which such parties agreed to take steps to protect the lesser prairie chicken's habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken's habitat. We entered into a voluntary Candidate Conservation Agreement ("CCA") with the WAFWA, whereby we agreed to take certain actions and limit certain activities, such as limiting drilling on certain portions of our acreage during nesting seasons, in an effort to protect the lesser prairie chicken. On February 9, 2018, the FWS announced the listing of the Texas Hornshell, a fresh water mussel species in areas including New Mexico and Texas where we operate in the Permian Basin, as an endangered species.

We also intend to enter into a CCA concerning voluntary conservation actions with respect to the Texas Hornshell. Participating in CCAs could result in increased costs to us from species protection measures, time delays or limitations on drilling activities, which costs, delays or limitations may be significant. While a federal judge in Texas vacated the listing of the lesser prairie chicken in 2015, listing petitions continue to be filed with the FWS which could impact our operations. Many non-governmental organizations ("NGOs") work closely with the FWS regarding the listing of many species, including species with broad and even nationwide ranges. The recent listing of the Mexican Long Nosed bat, whose habitat includes the Permian Basin where we operate, is an example of the NGOs' influence on ESA listing decisions. The increase in endangered species listings may impact our ability to explore for or produce oil and gas in certain areas and increase our costs.

Our hydraulic fracturing activities are subject to risks that could negatively impact our operations and profitability.

We use hydraulic fracturing for the completion of almost all of our wells. Hydraulic fracturing is a process that involves pumping fluid and proppant at high pressure into a hydrocarbon bearing formation to create and hold open fractures. Those fractures enable gas or oil to move through the formation's pores to the well bore. Typically, the fluid used in this process is primarily water. In plays where hydraulic fracturing is necessary for successful development, the demand for water may exceed the supply. A lack of readily available water or a significant increase in the cost of water could cause delays or increased completion costs.

While hydraulic fracturing historically has been regulated by state oil and gas commissions, the practice has become increasingly controversial in certain parts of the country, resulting in increased scrutiny and regulation from federal agencies. For example, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities under the SDWA involving the use of diesel fuels and published permitting guidance in February 2014 addressing the use of diesel in fracturing operations. Although the EPA has delegated the permitting authority for the SDWA's Underground Injection Control Class II programs in Oklahoma, Texas, and New Mexico where we maintain operational acreage, the EPA is encouraging state programs to review and consider use of such draft guidance.

In addition, on March 26, 2015, the federal BLM published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, development of appropriate plans for managing flowback water that returns to the surface, increased standards for interim storage of recovered waste fluids, and submission to the BLM of detailed information on the geology, depth, and location of preexisting wells. This rule originally was scheduled to take effect on June 24, 2015. However, the rule is the subject of several pending lawsuits filed by industry groups, two Indian tribes, and at least four states, alleging that federal law does not give the BLM authority to regulate hydraulic fracturing. The federal judge has enjoined the rule while the case is pending. The district court held that BLM did not have jurisdiction to promulgate the rule. The Obama Justice Department appealed and that appeal is pending.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The EPA prepared a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. The EPA's draft report was released on June 4, 2015. The findings of the report suggest that hydraulic fracturing does not pose a systemic risk to groundwater although there are risks to both groundwater and soils posed by inadequate water handling practices in certain situations. A public comment period on the report was open until August 28, 2015 and a series of public hearings were conducted by the EPA's Scientific Advisory Board ("SAB") throughout the fall of 2015. The EPA issued its final report and has reached two different topline conclusions, although the content of the study itself remains unchanged. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing.

Additionally, Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. Most producing states, including Texas and Colorado, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether.

Any of the above factors could have a material adverse effect on our financial position, results of operations, or cash flows and could make it more difficult or costly for us to perform fracturing to stimulate production from dense subsurface rock formations and, in the event of local prohibitions against commercial production of natural gas, may preclude our ability to drill wells. In addition, our fracturing activities could become subject to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and gas that we are ultimately able to produce from our reserves.

The adoption of climate change legislation or regulations restricting emission of greenhouse gases, investor pressure concerning climate-related disclosures, and lawsuits could result in increased operating costs and reduced demand for the oil and gas we produce as well as reductions in availability of capital.

Studies have suggested that emission of certain gases, commonly referred to as greenhouse gases ("GHGs"), may be impacting the earth's climate. Methane, a primary component of natural gas, and carbon dioxide, also present in natural gas as a secondary product, sometimes considered an impurity or a by-product of the burning of oil and natural gas, are examples of GHGs. The U.S. Congress and various states have been evaluating, and in some cases implementing, climate-related legislation and other regulatory initiatives that restrict emissions of GHGs. In December 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are contributing to the warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations under existing provisions of the Federal Clean Air Act that establish Prevention of Significant Deterioration ("PSD") and Title V permit reviews for GHG emissions from certain large stationary sources. Facilities required to obtain PSD and/or Title V permits under EPA's GHG Tailoring Rule for their GHG emissions also may be required to meet "Best Available Control Technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain oil and gas production facilities on an annual basis, which includes certain of our operations. In recent proposed rulemaking, EPA is widening the scope of annual GHG reporting to include not only activities associated with completion and workover of gas wells with hydraulic fracturing and activities associated with oil and gas production operations, but also completions and workovers of oil wells with hydraulic fracturing, gathering and boosting systems, and transmission pipelines.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. In January 2015, President Obama announced a series of administration actions to reduce methane emissions, including rulemaking by the EPA and the BLM as well as updating of standards by the Department of Transportation's Pipeline and Hazardous Materials Administration. The previous administration intended to promulgate proposed climate change rulemaking aimed at reducing GHG emissions by 45% by 2025 compared to 2012 levels. These proposals target both new and existing sources. On January 22, 2016, the Department of the Interior announced its proposed emissions mandate on oil and gas producers who operate on federal and Indian lands. While this rule was finalized in November of 2016, it is currently being challenged by several states and industry. While we expect new legislation and regulations to increase the cost of business, at this time it is not possible to quantify the impact on our business. Any such future laws and final regulations that require reporting of GHGs or otherwise limit emissions of GHGs from our equipment and operations could require us to incur costs to develop and implement best management practices aimed at reducing GHG emissions, install and maintain emissions control technologies, as well as monitor and report on GHG emissions associated with our operations, which would increase our operating costs, and such requirements also could adversely affect demand for the oil and gas that we produce.

The following is a summary of potential climate-related risks that could adversely affect Cimarex:

Transition Risks. Transition risks are risks related to the transition to a lower-carbon economy and include policy, legal, technology, and market risks.

Policy and Legal Risks. Policy risks include policy actions that attempt to contract actions that contribute to adverse effects of climate change or policy actions that seek to promote adaptation to climate change. Examples include implementing carbon-pricing mechanisms to reduce GHG emissions (which would increase the costs of our doing business), shifting energy use toward lower emission sources (which could lower demand for our oil and gas production, resulting in lower revenues), adopting energy-efficiency solutions (which also could lower demand for our oil and gas production, resulting in lower prices and lower revenues), encouraging greater water efficiency measures (which would increase our costs of production), and promoting more sustainable land-use practices (which also would increase our costs of production and could impact our ability to operate in certain areas). Policy actions also may include restrictions or bans on oil and gas activities, which could lead to write-downs or impairments of our assets. Legal and litigation risks include potential lawsuits claiming failure to mitigate impacts of climate change, failure to adapt to climate change, and the insufficiency of disclosure around material financial risks.

Technology Risk. Technological improvements or innovations that support the transition to a lower-carbon, more energy efficient economic system may have a significant impact on Cimarex. The development and use of emerging technologies such as renewable energy, battery storage, and energy efficiency may lower demand for oil and gas, resulting in lower prices and revenues, and increase our costs.

Market Risk. Markets could be affected by climate change through shifts in supply and demand for certain commodities, especially carbon-intensive commodities such as oil and gas and other products dependent on oil and gas, as climate-related risks and opportunities are increasingly taken into account. This could lower demand for our oil and gas production, resulting in lower prices and lower revenues. Market risk also may take the form of limited access to capital as investors shift investments to less carbon-intensive industries and alternative energy industries.

Reputation Risk. Climate change has been identified as a potential source of reputational risk tied to changing customer or community perceptions of an organization's contribution to or detraction from the transition to a lower-carbon economy. This could lower demand for our oil and gas production, resulting in lower prices and lower revenues as consumers avoid carbon-intensive industries. This may also put pressure on investment managers to shift investments to less carbon-intensive industries and alternative energy industries, limiting our access to capital.

Physical Risks. Potential physical risks resulting from climate change may be event driven (including increased severity of extreme weather events, such as hurricanes or floods) or longer-term shifts in climate patterns that may cause sea level rise or chronic heat waves. Potential physical risks may cause direct damage to assets and indirect impacts such as supply chain disruption. Potential physical risks also include changes in water availability, sourcing, and quality, which could impact drilling and completions operations. These physical risks could cause increased costs, production disruptions, and lower revenues.

Legislation or regulatory initiatives intended to address seismic activity could restrict our ability to engage in hydraulic fracturing during completion operations and to dispose of saltwater produced in connection with our oil and gas production, which could limit our ability to produce oil and gas economically and have a material adverse effect on our business.

We dispose of large volumes of saltwater produced in connection with our drilling and production operations pursuant to permits issued to us or third-party operators of disposal wells by governmental authorities overseeing produced water disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities.

There exists a growing concern that hydraulic fracturing during well completion operations and the injection of produced water into underground disposal wells triggers seismic activity in certain areas, including Oklahoma and Texas, where we operate. In response to these concerns, regulators in some states are pursuing initiatives designed to impose additional requirements in connection with hydraulic fracturing and in the permitting of saltwater disposal wells or otherwise to assess any relationship between seismicity and these oil and gas operations. For example, in 2014, the Oklahoma Corporation Commission began adopting rules for operators of saltwater disposal wells in certain seismically-active areas, or Areas of Interest, in the Arbuckle formation, requiring operators to monitor and record well pressure and discharge volume on a daily basis and further requiring operators of wells permitted for disposal of 20,000 barrels per day or more of saltwater to conduct mechanical integrity testing. Throughout 2015 and 2016, the Oklahoma Corporation Commission's Oil and Gas Conservation Division, or OGCD, issued a series of directives, expanding the areas of interest for induced seismicity and enhanced disposal restrictions and limiting the depths at which produced water could be injected or, in the alternative, reducing disposal volumes. Additional regulations and restrictions are possible as more is understood about this issue. In addition and separate from induced seismicity associated with injection, the OGCD has issued guidelines to operators to follow when engaged in well stimulation activities, which some studies now seem to correlate with a small number of low intensity seismic events.

In addition, in 2014 the Texas Railroad Commission, or TRC, published a new rule governing permitting of disposal wells in Texas that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections, and structure maps relating to the disposal area in question. If a permittee or a prospective permittee fails to demonstrate that the saltwater or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend, or terminate the permit application or existing operating permit for that well.

The adoption and implementation of any new laws, regulations, or directives that restrict our ability to stimulate wells or to dispose of produced water, by changing the depths of disposal wells, reducing the volume of oil and gas wastewater disposed in such wells, restricting disposal well locations or otherwise, or by requiring us or third parties who dispose of our saltwater to shut down disposal wells, could increase disposal costs or require us to shut in a substantial number of our oil and gas wells or otherwise have a material adverse effect on our ability to produce oil and gas economically and, accordingly, could materially and adversely affect our business, financial condition, and results of operations. We could also face lawsuits alleging that seismic activity occurred as a result of completions or water disposal activities, resulting in damage to persons and property.

A substantial portion of our producing properties are located in limited geographic areas, making us vulnerable to risks associated with having geographically concentrated operations.

A substantial portion of our producing properties are geographically concentrated in the Permian Basin in Texas and New Mexico and our Cana area in the Mid-Continent region in Oklahoma, with these two areas comprising approximately 55% and 45%, respectively, of our oil, gas, and NGL production and approximately 62% and 38%, respectively, of our oil, gas, and NGL revenues for the year ended December 31, 2017. Approximately 48% of our estimated proved reserves were located in the Permian Basin and approximately 52% of our estimated proved reserves were located in the Mid-Continent region as of December 31, 2017.

Because of this concentration in limited geographic areas, the success and profitability of our operations may be disproportionately exposed to regional factors relative to our competitors that have more geographically dispersed operations. These factors include, among others: (i) the prices of oil and gas produced from wells in the regions and other regional supply and demand factors, including gathering, pipeline, and rail transportation capacity constraints; (ii) the availability of rigs, equipment, oil field services, supplies, and labor; (iii) the availability of processing and refining facilities; and (iv) infrastructure capacity. In addition, our operations in the Permian Basin and Mid-Continent region, as well as other areas, may be adversely affected by severe weather events such as floods, lightning, ice and other storms, and tornadoes, which can intensify competition for the items described above during months when drilling is possible and may result in periodic shortages. The concentration of our operations in limited geographic areas also increases our exposure to changes in local laws and regulations including concerning hydraulic fracturing and wastewater disposal as discussed above in "Legislation or regulatory initiatives intended to address seismic activity could restrict our ability to engage in hydraulic fracturing during completion operations and to dispose of saltwater produced in connection with our oil and gas production, which could limit our ability to produce oil and gas economically and have a material adverse effect on our business", certain lease stipulations designed to protect wildlife, and unexpected events that may occur in the regions such as natural disasters, seismic events, industrial accidents, or labor difficulties. Any one of these events has the potential to cause producing wells to be shut-in, delay operations, decrease cash flows, increase operating and capital costs and prevent development of lease inventory before expiration. Any of the risks described above could have a material adverse effect on our financial condition, results of operations, and cash flows.

We use some of the latest available horizontal drilling and completion techniques, which involve risk and uncertainty in their application.

Our horizontal drilling operations utilize some of the latest drilling and completion techniques. The risks of such techniques include, but are not limited to, the following:

- landing the wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running casing the entire length of the wellbore;
- being able to run tools and other equipment consistently through the horizontal wellbore;
- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

Any of the above factors could have a material adverse effect on our financial position, results of operations, or cash flows.

Many of our properties are in areas that may have been partially depleted or drained by offset wells and certain of our wells may be adversely affected by actions other operators may take when drilling, completing, or operating wells that they own.

Many of our properties are in areas that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, which could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids toward the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations could cause a depletion of our proved reserves and may inhibit

our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells could cause production from our wells to be shut in for indefinite periods of time, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

We may be subject to information technology system failures, network disruptions, and breaches in data security and our business, financial position, results of operations, and cash flows could be negatively affected by such security threats and disruptions.

As an oil and gas producer, we face various security threats, including cybersecurity threats such as attempts to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as gathering and processing facilities, pipelines and refineries; and threats from terrorist acts. Cybersecurity attacks are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data, and "ransomware" attacks where data is locked unless a payment is made, any of which could have an adverse effect on our reputation, business, financial condition, results of operations, or cash flows. While we have not suffered any material losses relating to such attacks, there can be no assurance that we will not suffer such losses in the future.

We rely heavily on our information systems, and the availability and integrity of these systems are essential for us to conduct our business and operations. In addition to cybersecurity and data security threats, other information system failures and network disruptions could have a material adverse effect on our ability to conduct our business. We could experience system failures due to power or telecommunications failures, human error, natural disasters, fire, sabotage, hardware or software malfunction or defects, computer viruses, intentional acts of vandalism or terrorism and similar acts or occurrences. Such system failures could result in the unanticipated disruption of our operations, communications, or processing of transactions, as well as loss of, or damage to, sensitive information, facilities, infrastructure and systems essential to our business and operations, the failure to meet regulatory standards and the reporting of our financial results, and other disruptions to our operations, which, in turn, could have a material adverse effect on our business, financial position, results of operations, and cash flows.

A cyber attack involving our information systems and related infrastructure, or those of our business associates, could disrupt our business and negatively impact our operations in a variety of ways, including but not limited to:

- unauthorized access to seismic data, reserves information, strategic information, or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and gas resources;
- data corruption or operational disruption of production-related infrastructure could result in a loss of production, or accidental discharge;
- a cyber attack on a vendor or service provider could result in supply chain disruptions, which could delay or halt our major development projects;
- a cyber attack on third-party gathering, pipeline, or rail transportation systems could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues; and
- a cyber attack on our accounting or accounts payable systems could expose us to liability to employees and third parties if their personal identifying information is obtained.

These events could damage our reputation and lead to financial losses from remedial actions, loss of business, or potential liability, which could have a material adverse effect on our financial condition, results of operations, or cash flows.

While management has taken steps to address these concerns by implementing network security and internal control measures to monitor and mitigate security threats and to increase security for our information, facilities, and infrastructure, our implementation of such procedures and controls may result in increased costs, and there can be no assurance that a system failure or data security breach will not occur and have a material adverse effect on our business, financial condition, and results of operations. In addition, as cybersecurity threats continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate or remediate any cybersecurity or information technology infrastructure vulnerabilities.

Our limited ability to influence operations and associated costs on non-operated properties could result in economic losses that are partially beyond our control.

For the year ended December 31, 2017, other companies operated approximately 19% of our net production. Our success in properties operated by others depends upon a number of factors outside of our control. These factors include timing and amount of capital expenditures, the operator's expertise and financial resources, approval of other participants in drilling wells, selection of technology, and maintenance of safety and environmental standards. Our dependence on the operator and other working interest owners for these projects could prevent the realization of our targeted returns on capital in drilling or acquisition activities.

Our business involves many operating risks that may result in substantial losses for which insurance may be unavailable or inadequate.

Our operations are subject to hazards and risks inherent in drilling for oil and gas, such as fires, natural disasters, explosions, formations with abnormal pressures, casing collapses, uncontrollable flows of underground gas, blowouts, surface cratering, pipeline ruptures, or cement failures. Other such risks include theft, vandalism, and environmental hazards such as gas leaks, oil spills, and discharges of toxic gases. Any of these risks can cause substantial losses resulting from:

- injury or loss of life;
- damage to, loss of or destruction of, property, natural resources and equipment;
- pollution and other environmental damages;
- · regulatory investigations, civil litigation, and penalties;
- · damage to our reputation;
- suspension of our operations; and
- costs related to repair and remediation.

In addition, our liability for environmental hazards may include conditions created by the previous owners of properties that we purchase or lease.

We maintain insurance coverage against some, but not all, potential losses. We do not believe that insurance coverage for all environmental damages that could occur is available at a reasonable cost. Losses could occur for uninsurable or uninsured risks, or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could harm our financial condition and results of operation.

We may not be able to generate enough cash flow to meet our debt obligations.

At December 31, 2017, our long-term debt consisted of \$750 million of 4.375% senior notes due in 2024 and \$750 million of 3.90% senior notes due in 2027. In addition to interest expense and principal on our long-term debt, we have demands on our cash resources including, among others, capital expenditures, operating expenses, and contractual commitments.

Our ability to pay the principal and interest on our long-term debt and to satisfy our other liabilities will depend upon future performance and our ability to repay or refinance our debt as it becomes due. Our future operating performance and ability to refinance will be affected by economic and capital market conditions, results of operations, and other factors, many of which are beyond our control. Our ability to meet our debt service obligations also may be impacted by changes in prevailing interest rates, as borrowing under our existing revolving credit facility bears interest at floating rates.

We may not generate sufficient cash flow from operations. Without sufficient cash flow, there may not be adequate future sources of capital to enable us to service our indebtedness or to fund our other liquidity needs. If we are unable to service our indebtedness and fund our operating costs, we will be forced to adopt alternative strategies that may include:

- · reducing or delaying capital expenditures;
- seeking additional debt financing or equity capital;
- · selling assets; or
- restructuring or refinancing debt.

We may be unable to complete any such strategies on satisfactory terms, if at all. Our inability to generate sufficient cash flows to satisfy our debt obligations or contractual commitments, or to refinance our indebtedness on commercially reasonable terms, would materially and adversely affect our financial condition and results of operations.

The instruments governing our indebtedness contain various covenants limiting the discretion of our management in operating our business.

The indenture governing our senior notes and our credit agreement contain various restrictive covenants that may limit management's discretion in certain respects. In particular, these agreements limit Cimarex's and its subsidiaries' ability to, among other things:

- create certain liens;
- · consolidate, merge, or transfer all, or substantially all, of our assets and our restricted subsidiaries; or
- enter into sale and leaseback transactions.

In addition, our revolving credit agreement requires us to maintain a total debt to capitalization ratio (as defined in the credit agreement) of not more than 65%. See Note 3 to the Consolidated Financial Statements for further information.

If we fail to comply with the restrictions in the indenture governing our senior notes or the agreement governing our credit facility or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make available further funds.

Our acquisition activities may not be successful, which may hinder our replacement of reserves and adversely affect our results of operations.

The successful acquisition of properties requires an assessment of several factors, including:

- geological risks and recoverable reserves;
- future oil and gas prices and their appropriate market differentials;
- · operating costs; and
- potential environmental risks and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections will not likely be performed on every well or facility, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Furthermore, the seller may be unwilling or unable to provide effective contractual protection against all or part of the identified problems.

We may lose leases if production is not established within the time periods specified in the leases.

Unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire and the amounts spent for those leases will be lost. The combined net acreage expiring in the next three years represents approximately 3.0% of our total net undeveloped acreage at December 31, 2017. At that date, we had leases representing 38,959 net acres expiring in 2018, 81,499 net acres expiring in 2019, and 47,045 net acres expiring in 2020. Our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Our disposition activities may be subject to factors beyond our control, and in certain cases we may retain unforeseen liabilities for certain matters.

We regularly sell non-core assets in order to increase capital resources available for other core assets and to create organizational and operational efficiencies. We also occasionally sell interests in core assets for the purpose of accelerating the development and increasing efficiencies in such core assets. Various factors could materially affect our ability to dispose of such assets, including the approvals of governmental agencies or third parties, and the availability of purchasers willing to acquire the assets with terms we deem acceptable.

Sellers at times retain certain liabilities or agree to indemnify buyers for certain matters related to the sold assets. The magnitude of any such retained liability or of the indemnification obligation is difficult to quantify at the time of the transaction and ultimately could be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release the company from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a divestiture, the company may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations. In addition, with respect to offshore assets, if purchasers declare bankruptcy, the United States Department of Interior may pursue former owners for decommissioning expenses, which can be substantial. See Note 8 to the Consolidated Financial Statements for further discussion regarding our asset retirement obligations.

Competition for experienced technical personnel may negatively impact our operations.

Our exploratory and development drilling success depends, in part, on our ability to attract and retain experienced professional personnel. The loss of any key executives or other key personnel could have a material adverse effect on our operations. As we continue to develop our asset base and the scope of our operations, our future profitability will depend on our ability to attract and retain qualified personnel, particularly individuals with a strong background in geology, geophysics, engineering, and operations.

We are involved in various legal proceedings, the outcome of which could have an adverse effect on our liquidity.

In the normal course of business, we are involved with various lawsuits and related disputed claims, including but not limited to claims concerning title, royalty payments, environmental issues, personal injuries, and contractual issues. Although we currently believe the resolution of these lawsuits and claims, individually or in the aggregate, would not have a material adverse effect on our financial condition or results of operations, our assessment of our current litigation and other legal proceedings could change in light of the discovery of facts with respect to legal actions or other proceedings pending against us not presently known to us or determinations by judges, juries, or other finders of fact that are not in accord with our evaluation of the possible liability or outcome of such proceedings. Therefore, there can be no assurance that outcomes of future legal proceedings would not have an adverse effect on our liquidity and capital resources.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be limited or eliminated as a result of recently enacted or future legislation.

On December 22, 2017, the United States enacted H.R.1, commonly referred to as the Tax Cuts and Jobs Act or U.S. Tax Reform. H.R.1, among other things, includes changes to U.S. federal tax rates, imposes new limitations on the utilization of net operating losses and the deductibility of interest and executive compensation, allows for the expensing of capital expenditures, and eliminates the corporate Alternative Minimum Tax. In addition, various proposals have been made recommending the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies. While the tax law changes approved in December 2017 did not eliminate any of these incentives, in the future legislation may be introduced in Congress which would implement many of these proposals. These changes include, but are not limited to: (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of this legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could have an adverse effect on our financial position, results of operations, and cash flows, including the payment of cash taxes earlier than expected.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

The information set forth under the heading "Litigation" in Note 10 to the Consolidated Financial Statements included in Part II, Item 8 of this Form 10-K, is incorporated by reference in response to this item.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our \$0.01 par value common stock trades on the New York Stock Exchange ("NYSE") under the symbol XEC. A cash dividend was paid to stockholders in each quarter of 2017. Future dividend payments will depend on the company's level of earnings, financial requirements, and other factors considered relevant by the Board of Directors.

Stock Prices and Dividends by Quarter

The following tables set forth, for the periods indicated, the high and low sales price per share of our common stock on the NYSE and the per share dividends declared during the period.

2017	High	Low	Dividends eclared Per Share
First Quarter.	\$ 144.30	\$ 114.72	\$ 0.08
Second Quarter	\$ 123.92	\$ 91.22	\$ 0.08
Third Quarter	\$ 116.43	\$ 89.49	\$ 0.08
Fourth Quarter	\$ 127.89	\$ 109.55	\$ 0.08

2016	High	Low	Declared Per Share		
First Quarter.	\$ 100.07	\$ 72.77	\$	0.08	
Second Quarter	\$ 123.48	\$ 93.21	\$	0.08	
Third Quarter	\$ 136.95	\$ 112.19	\$	0.08	
Fourth Quarter	\$ 146.96	\$ 118.59	\$	0.08	

The closing price of Cimarex stock as reported on the NYSE on January 31, 2018, was \$112.20. At January 31, 2018, Cimarex's 95,438,121 shares of outstanding common stock were held by approximately 1,655 stockholders of record.

Equity Compensation Plan Information

The following table sets forth information with respect to the equity compensation plans available to directors, officers, and employees of the company at December 31, 2017:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	exer outsta	(b) hted-average reise price of nding options, nts, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))			
Equity compensation plans approved by security holders	382,688	\$	100.17	1,991,731			
Equity compensation plans not approved by security holders	_		_	_			
Total	382,688	\$	100.17	1,991,731			

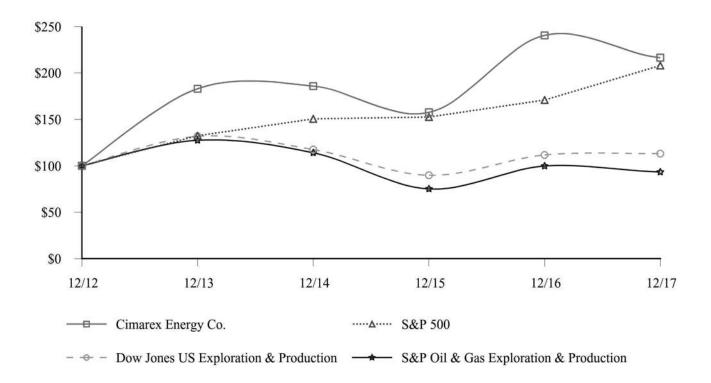
Stock Performance Graph

The following graph compares the cumulative five-year total return attained by stockholders on Cimarex Energy Co.'s common stock relative to the cumulative total returns of the S&P 500 index, the Dow Jones US Exploration & Production index, and the S&P Oil & Gas Exploration & Production index. The graph tracks the performance of a \$100 investment in our common stock and in each of the indexes (with the reinvestment of all dividends) from December 31, 2012 to December 31, 2017. The stock price performance included in this graph is not necessarily indicative of future stock price performance.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN*

Among Cimarex Energy Co., the S&P 500 Index,

the Dow Jones US Exploration & Production Index, and the S&P Oil & Gas Exploration & Production Index



^{* \$100} invested in 12/31/12 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

A tabular presentation of the data in the above graph is provided below.

_	2012		2013		2014		2015		2016		2017
Cimarex Energy Co	\$ 100.00	\$	182.98	\$	185.83	\$	157.57	\$	240.50	\$	216.52
S&P 500	\$ 100.00	\$	132.39	\$	150.51	\$	152.59	\$	170.84	\$	208.14
Dow Jones US Exploration & Production	\$ 100.00	\$	131.84	\$	117.64	\$	89.72	\$	111.69	\$	113.14
S&P Oil & Gas Exploration & Production	\$ 100.00	\$	127.49	\$	113.99	\$	75.06	\$	99.72	\$	93.43

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data set forth below should be read in conjunction with the Consolidated Financial Statements and accompanying notes thereto provided in Item 8 of this report.

					En	ded Decemb	er 3	1,		
		2017	2016 2015					2014		2013
			(in millions, except per share amounts)							
Operating results:						4 440				
Oil, gas, and NGL sales.		1,874	\$	1,221	\$	1,418	\$	2,373	\$	1,953
Total revenues (1)		1,918	\$	1,257	\$	1,453	\$	2,424	\$	1,998
Net income (loss) (2).	\$	494	\$	(409)	\$	(2,580)	\$	526	\$	462
Earnings (loss) per share to common stockholders:										
Basic	\$	5.19	\$	(4.38)	\$	(27.75)	\$	6.01	\$	5.30
Diluted	\$	5.19	\$	(4.38)	\$	(27.75)	\$	6.00	\$	5.29
Cash dividends declared per share	\$	0.32	\$	0.32	\$	0.64	\$	0.64	\$	0.56
Cash flow data:										
Net cash provided by operating activities (3)	\$	1,097	\$	626	\$	726	\$	1,633	\$	1,334
Net cash used by investing activities	\$	(1,266)	\$	(692)	\$	(1,009)	\$	(1,740)	\$	(1,531)
Net cash (used) provided by financing activities (3)	\$	(83)	\$	(60)	\$	656	\$	508	\$	132
	_	2017		2016	De	ecember 31,		2011		2012
	_	2017	- (in	2016 millions, ex		t proved rese		2014	_	2013
Balance sheet data:			(11	i illillions, cx	сер	t proved reso		s amounts)		
Cash and cash equivalents.	\$	401	\$	653	\$	779	\$	406	\$	5
Oil and gas properties, net (2)		3,242	\$	2,354	\$	2,741	\$	6,638	\$	5,669
Goodwill		620	\$	620	\$	620	\$	620	\$	620
Total assets (2) (4)		5,043	\$	4,238	\$	4,708	\$	8,443	\$	6,947
Deferred income tax liability (asset)		102	\$	(56)		157	\$	1,657	\$	1,351
Long-term obligations:				()				,		,
Long-term debt (principal)	\$	1,500	\$	1,500	\$	1,500	\$	1,500	\$	924
Other		206	\$	184	\$	197	\$	194	\$	164
Stockholders' equity		2,568	\$	2,043	\$	2,458	\$	4,332	\$	3,834
		,		,		,		,		,
Proved Reserves:										
Oil (MBbls)		137,238		105,878		107,798		118,992		108,533
Gas (Bcf)		1,608		1,471		1,517		1,667		1,294
NCI (MDhla)		152 060		130,633		104077		105070		00 011
NGL (MBbls)		153,860		130,033		124,277		125,273		92,044

⁽¹⁾ Prior to 2014, our average realized prices for gas and NGLs were net of certain processing fees. Beginning in 2014, these fees were no longer netted against realized prices, but were included in "Transportation, processing, and other operating" costs. The effect of this change in 2014 was that total revenue was \$51.4 million higher with an offsetting increase in total transportation, processing, and other operating costs. This change had no effect on operating income. Periods prior to 2014 were not reclassified to reflect this change in accounting treatment as it was impracticable to do so.

3,354

2,890

2,909

3,132

2,497

⁽²⁾ During 2016, 2015, and 2013, we recorded non-cash full cost ceiling test impairments of our oil and gas properties totaling \$757.7 million (\$481.4 million, net of tax), \$4.03 billion (\$2.56 billion, net of tax), and \$190.2 million (\$120.8 million, net of tax), respectively.

- (3) We adopted Accounting Standards Update 2016-09, *Improvements to Employee Share-Based Payment Accounting* ("ASU 2016-09") on January 1, 2017. Pursuant to ASU 2016-09, we adjusted the statements of cash flows for all prior periods presented. For the years ended December 31, 2016, 2015, 2014, and 2013, we decreased cash outflows for operating activities and cash inflows for financing activities by \$26.6 million, \$34.2 million, \$13.6 million, and \$10.1 million, respectively, for the payment of employee tax withholdings on the net settlement of equity-classified awards and for excess tax benefits, as applicable. See Note 6 to the Consolidated Financial Statements for further discussion regarding our adoption of ASU 2016-09.
- (4) At December 31, 2015, we adopted new accounting guidance which requires debt issuance costs (except for those related to revolving credit facilities) to be presented in the balance sheet as a direct deduction from the carrying amount of the related debt liability rather than as an asset. Such costs were previously recorded as deferred assets. Prior periods have been adjusted to conform to this guidance.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our Consolidated Financial Statements included in Item 8 of this report and also with **RISK FACTORS** in Item 1A of this report. This discussion also includes forward-looking statements. Refer to **CAUTIONARY INFORMATION ABOUT FORWARD-LOOKING STATEMENTS** in Part I of this report for important information about these types of statements.

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. 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.

Oil prices have improved from early 2016; however, they continue to be volatile and we expect this volatility to persist. During 2017, average NYMEX oil and gas prices were \$50.94 per barrel and \$3.11 per Mcf, respectively, representing an increase of 18% and 26%, respectively, from the average NYMEX oil and gas prices for 2016. 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. Compared to 2016, our realized oil price for 2017 increased 23% to \$47.06 per barrel. Similarly, our realized gas price increased 19% to \$2.76 per Mcf, while our realized NGL price increased 54% to \$21.61 per barrel. See **RESULTS OF OPERATIONS** *Revenues* below for further information regarding our realized commodity prices.

2017 Summary of Operating and Financial Results

The following is a summary of certain 2017 operating and financial results:

- Total daily production volumes increased 19% to 1,142.1 MMcfe per day.
- Oil volumes increased 27% to 57.2 MBbls per day.
- Gas volumes increased 12% to 513.6 MMcf per day.
- NGL volumes increased 23% to 47.6 MBbls per day.
- Total production revenue increased 53% to \$1.87 billion.
- Year-end proved reserves increased to 3.35 Tcfe, as compared to 2.89 Tcfe at year-end 2016.
- Exploration and development capital investments were \$1.28 billion, as compared to \$734.8 million in 2016.
- Cash flow provided by operating activities increased 75% to \$1.10 billion.
- Total debt at December 31, 2017 and 2016 consisted of \$1.50 billion of senior notes. During the second quarter 2017, we repaid our 5.875% \$750 million notes due 2022 and issued 3.90% \$750 million notes due 2027. Our 4.375% \$750 million notes are due 2024.
- Cash on hand at December 31, 2017 was \$400.5 million.

For the year ended December 31, 2017, we had net income of \$494.3 million (\$5.19 per diluted share), as compared to a net loss of \$408.8 million (\$4.38 per diluted share) in 2016. Production revenue in 2017 was positively impacted by increased realized commodity prices and production volumes. Lower commodity prices negatively impacted 2016, including resulting in \$757.7 million of impairments of our oil and gas properties in that year. Year-over-year changes are discussed further in the **RESULTS OF OPERATIONS** section that follows.

Proved Reserves

Our proved reserves by region at December 31, 2017 and 2016 were as follows:

		December	31, 2017	
_	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MMcfe)
Permian Basin	573,757	105,198	68,530	1,616,126
Mid-Continent	1,032,695	31,853	85,292	1,735,565
Other	1,183	187	38	2,531
Total	1,607,635	137,238	153,860	3,354,222

		December	31, 2016	
	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MMcfe)
Permian Basin	372,371	74,295	40,977	1,064,000
Mid-Continent	1,095,194	31,399	89,615	1,821,278
Other	3,855	184	41	5,209
Total	1,471,420	105,878	130,633	2,890,487

Year-end 2017 proved reserves increased approximately 16% to 3.35 Tcfe, compared to 2.89 Tcfe at year-end 2016. Proved gas reserves were 1.61 Tcf, proved oil reserves were 0.82 Tcfe, and proved NGL reserves were 0.92 Tcfe. Reserves in our Mid-Continent region accounted for 52% of total proved reserves with nearly all of the remainder in the Permian Basin.

During 2017, we added 940.7 Bcfe of new reserves through extensions and discoveries. Net negative revisions totaled 59.7 Bcfe, which consisted primarily of a decrease of 248.8 Bcfe for the removal of PUD reserves whose development will likely be delayed beyond five years of initial disclosure, offset by an increase of 187.2 Bcfe related to improved commodity prices. See **SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)** in Item 8 for a more detailed discussion regarding year-over-year changes in our proved reserves.

The process of estimating quantities of oil, gas, and NGL reserves is complex. Significant decisions are required in the evaluation of all available geological, geophysical, engineering, and economic data. Although every reasonable effort is made to ensure that our reserve estimates represent the most accurate assessments possible, subjective decisions and available data for our various fields make these estimates generally less precise than other estimates included in financial statement disclosures. See *Proved Reserves Estimation Procedures* in Items 1 and 2 for a discussion of our reserve estimation process and Item 1A RISK FACTORS, which includes a discussion of factors that affect our proved reserves estimates.

RESULTS OF OPERATIONS

2017 Compared to 2016

Revenue

Almost all our revenue is derived from sales of our oil, natural gas, and NGL production. Increases or decreases in our revenue, 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 Item 7A QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for more information regarding the sensitivity of our revenues to price fluctuations. Realized prices and production volumes were higher in 2017 as compared to 2016, which caused our revenue to increase by \$652.8 million, or 53%, from the prior year. The following table shows our production revenue for the years indicated as well as the change in revenue due to changes in prices and volumes.

		Ended ber 31,		Prio	e / Volume Vari	ance
Production Revenue (in thousands) · ·	2017	2016	Variance Between 2017 / 2016	Price	Volume	Total
Oil sales	\$ 981,646	\$ 632,934	\$ 348,712 55%	\$ 182,742	\$ 165,970	\$ 348,712
Gas sales	516,936	388,786	128,150 33%	84,361	43,789	128,150
NGL sales	375,421	199,498	175,923 88%	131,347	44,576	175,923
	\$1,874,003	\$1,221,218	\$ 652,785 53%	\$ 398,450	\$ 254,335	\$ 652,785

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 2017 and 2016, 78% and 80%, respectively, of our oil production was in the Permian Basin and 22% and 20%, respectively, was in the Mid-Continent region. Our realized prices do not include settlements of commodity derivative contracts.

	December 31,					Variance Betwee	n
		2017		2016	•	2017 / 2016	11
Oil							
Total volume — MBbls		20,861		16,528		4,333	26%
Total volume — MBbls per day		57.2		45.2		12.0	27%
Percentage of total production		30%)	28%)		
Average realized price — per barrel	\$	47.06	\$	38.30	\$	8.76	23%
Average WTI Midland price — per barrel	\$	50.45	\$	43.34	\$	7.11	16%
Average WTI Cushing price — per barrel	\$	50.94	\$	43.32	\$	7.62	18%
Gas							
Total volume — MMcf		187,468		168,227		19,241	11%
Total volume — MMcf per day		513.6		459.6		54.0	12%
Percentage of total production		45%)	48%)		
Average realized price — per Mcf	\$	2.76	\$	2.31	\$	0.45	19%
Average Henry Hub price — per Mcf	\$	3.11	\$	2.46	\$	0.65	26%
NGL							
Total volume — MBbls		17,374		14,200		3,174	22%
Total volume — MBbls per day		47.6		38.8		8.8	23%
Percentage of total production		25%)	24%)		
Average realized price — per barrel	\$	21.61	\$	14.05	\$	7.56	54%
Total							
Total production — MMcfe		416,875		352,591		64,284	18%
Total production — MMcfe per day		1,142.1		963.4		178.7	19%
Average realized price — per Mcfe	\$	4.50	\$	3.46	\$	1.04	30%

Years Ended

Our 2017 daily production volumes were 1,142.1 MMcfe, a 19% increase from 2016. This increase is the result of increased drilling and completion activity during 2017 as compared to 2016. See *Production Volumes, Prices, and Costs* and *Exploration and Development Overview* in Items 1 and 2 of this report for production information by region and a discussion of our drilling activities.

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.

	Y	ears Ended	Dece	mber 31,	ariance Setween
Gas Gathering and Marketing (in thousands):		2017		2016	 17 / 2016
Gas gathering and other	\$	43,751	\$	36,033	\$ 7,718
Gas marketing.	\$	495	\$	94	\$ 401

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. The increases from 2016 are primarily due to an increase in prices.

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 of \$1.17 billion in 2017 were 36% lower than the \$1.83 billion incurred in 2016. Most of the decrease resulted from ceiling test impairments of our oil and gas properties of \$757.7 million recorded in 2016; we recorded no ceiling test impairments in 2017. Also contributing to the decrease was the net gain on derivative instruments in 2017 compared to a net loss in 2016. Otherwise, all other categories of operating costs and expenses increased in 2017. The following table shows our operating costs and expenses for the years indicated and a discussion of year-over-year differences follows.

	Years Ended	December 31,	· Variance	Per Mcfe				
Operating Costs and Expenses (in thousands, except per Mcfe)	2017	2016	Between 2017 / 2016		2017		2016	
Impairment of oil and gas properties	\$ —	\$ 757,670	\$ (757,670)		N/A		N/A	
Depreciation, depletion, and amortization	446,031	392,348	53,683	\$	1.07	\$	1.11	
Asset retirement obligation	15,624	7,828	7,796	\$	0.04	\$	0.02	
Production	262,180	232,002	30,178	\$	0.63	\$	0.66	
Transportation, processing, and other operating	231,640	190,725	40,915	\$	0.56	\$	0.54	
Gas gathering and other	35,840	31,785	4,055	\$	0.09	\$	0.09	
Taxes other than income	89,864	61,946	27,918	\$	0.22	\$	0.18	
General and administrative	79,996	73,901	6,095	\$	0.19	\$	0.21	
Stock compensation	26,256	24,523	1,733	\$	0.06	\$	0.07	
(Gain) loss on derivative instruments, net	(21,210)	55,749	(76,959)		N/A		N/A	
Other operating expense, net	1,314	755	559		N/A		N/A	
	\$ 1,167,535	\$ 1,829,232	\$ (661,697)					

Ceiling Test Impairment

We use the full cost method of accounting for our oil and gas operations. Accounting rules require us to perform a quarterly ceiling test calculation to test our capitalized oil and gas property costs 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. Estimated future net revenues are determined based on trailing twelve-month average commodity prices and estimated proved reserve quantities, operating costs, and capital expenditures.

At each quarter-end date during the year ended December 31, 2017, the net capitalized cost of our oil and gas properties, as adjusted for income taxes, did not exceed the ceiling limitation, and, therefore, we did not recognize a ceiling test impairment during the year. The commodity prices used in the December 31, 2017 ceiling calculation, based on the required trailing twelve-month average prices, were \$2.98 per Mcf of gas and \$51.34 per barrel of oil. A decline of approximately 19% or more in the value of the ceiling limitation would have resulted in an impairment at December 31, 2017. During the year ended December 31, 2016, we recognized ceiling test impairments totaling \$757.7 million (\$481.4 million, net of tax). These impairments were primarily the result of decreases in the trailing twelve-month average prices for oil, gas, and NGLs utilized in determining the estimated future net revenues from proved reserves. Because the ceiling calculation uses trailing twelve-month average commodity prices, the effect of increases and decreases in period-over-period prices can significantly impact the ceiling limitation calculation. In addition, other factors that impact the ceiling limitation calculation include, but are not limited to, incremental proved reserves that may be added each period, revisions to previous reserve estimates, capital expenditures, operating costs, depletion expense, and all related tax effects. Depending on fluctuations in these factors, including a decline in prices, we may incur full cost ceiling test impairments in future quarters.

The calculated ceiling limitation is not intended to be indicative of the fair market value of our proved reserves or future results. 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.

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. Depletion is calculated quarterly before the ceiling test impairment calculation. While prices have increased in 2017 from 2016, thus increasing our reserves, so too have our exploration and development expenditures and activities, thus increasing our proved oil and gas properties and future development costs, causing 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 years indicated:

	1	Years Ended	Dec	ember 31,		/ariance Between	Per Mcfe					
DD&A Expense (in thousands, except per Mcfe)	2017		2016		2017 / 2016			2017	2016			
Depletion	\$	399,328	\$	346,003	\$	53,325	\$	0.96	\$	0.98		
Depreciation.		46,703		46,345		358		0.11		0.13		
	\$	446,031	\$	392,348	\$	53,683	\$	1.07	\$	1.11		

Asset Retirement Obligation

Asset retirement obligation expense is typically primarily comprised of accretion expense. In periods subsequent to the initial measurement of an asset retirement obligation liability at present value, a period-to-period increase in the carrying amount of the liability is recognized as accretion expense, which represents the effect of the passage of time on the amount of the liability. An equivalent amount is added to the carrying amount of the liability. Also included in asset retirement obligation expense are gains and losses recognized on the settlement of asset retirement obligation liabilities.

Asset retirement obligation expense includes \$10.5 million in 2017 for the estimated liability to decommission two offshore properties in the Gulf of Mexico in which we were a prior lessee. In January 2018, the Bureau of Safety and Environmental Enforcement ("BSEE") notified us and other prior lessees that the current lessee of the properties had filed a petition for relief under the bankruptcy code and, as a result, had defaulted on its obligation to decommission the properties. Consequently, BSEE ordered us and other prior lessees to decommission all wells, pipelines, platforms, and other facilities related to these properties. Our estimate of our liability may change as we refine our understanding of the extent of our obligations under the orders from BSEE and obtain additional information on decommissioning costs.

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:

	,	Years Ended December 31,				/ariance Between	Per Mcfe				
Production Expense (in thousands, except per Mcfe)	2017		2016		2017 / 2016		2017			2016	
Lease operating expense	\$	215,148	\$	189,291	\$	25,857	\$	0.52	\$	0.54	
Workover expense		47,032		42,711		4,321		0.11		0.12	
	\$	262,180	\$	232,002	\$	30,178	\$	0.63	\$	0.66	

Through efficiency gains and increasing daily production by 19% during 2017 as compared to 2016, we reduced our per unit lease operating expense by 4% between these two periods. On an absolute basis, lease operating expense in 2017 increased 14%, or \$25.9 million, compared to 2016. The increase was primarily caused by: (i) increased saltwater disposal costs primarily attributed to the addition of new wells and recompleted wells; (ii) increased labor costs primarily due to additional employees and salary and bonus increases; (iii) increased equipment maintenance costs, primarily the result of the addition of new wells; (iv) increased gas lift and fuel compression costs; and (v) increased chemicals and treating costs.

Workover expense increased 10%, or \$4.3 million, during 2017 as compared to 2016. During 2017, we had costlier major well workover projects than during 2016, which increased expense. This increase was partially offset by the receipt of partial insurance proceeds during 2017 related to a flooding event in 2015 and the subsequent remediation and repairs, the bulk of which took place in 2016. Generally, workover costs will fluctuate based on the amount of maintenance and remedial activity performed 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 2017 were 21%, or \$40.9 million, higher than in 2016. This increase was primarily due to increased production volumes and, to a lesser extent, increased transportation and processing rates in 2017 as compared to 2016.

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 2017 was 13%, or \$4.1 million, higher than in 2016. This increase was primarily due to higher product costs associated with processing third-party production due to higher commodity prices. These increased product costs were offset by increases in associated revenue.

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. In 2017, taxes other than income increased 45%, or \$27.9 million, from 2016. These increases are primarily due to the increase in revenue seen between the comparable periods. Taxes other than income were 4.8% and 5.1% of production revenues for 2017 and 2016, respectively. The percentage has decreased from 2016 due to the approval of reduced tax rates on several of our high-cost gas wells in the State of Texas and, as part of this process, approved severance tax refunds of \$9.1 million.

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 49% and 50% during 2017 and 2016, respectively. The table below shows our G&A costs.

		Years Ended	Decei	mber 31,	ariance Setween
General and Administrative Expense (in thousands):	2017 2016		2016	17 / 2016	
Gross G&A	\$	156,389	\$	146,432	\$ 9,957
Less amounts capitalized to oil and gas properties		(76,393)		(72,531)	(3,862)
G&A expense.	\$	79,996	\$	73,901	\$ 6,095

G&A expense during 2017 was 8%, or \$6.1 million, higher than during 2016. This increase is primarily due to the following increases: (i) other employee compensation, primarily due to increased incentive bonus expense; (ii) insurance; (iii) consulting; (iv) salaries and wages, due to additional employees and salary increases; and (v) charitable donations. These increases were partially offset by decreased severance expense due to a voluntary early retirement incentive program, which included severance pay, that was offered to certain employees during 2016.

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:

Years Ended		Variance			
2017		2016	Between 2017 / 2016		
\$ 26,020	\$	24,183	\$	1,837	
19,746		18,391		1,355	
45,766		42,574		3,192	
2,599		2,565		34	
48,365		45,139		3,226	
(22,109)		(20,616)		(1,493)	
\$ 26,256	\$	24,523	\$	1,733	
\$	\$ 26,020 19,746 45,766 2,599 48,365 (22,109)	\$ 26,020 \$ 19,746 45,766 2,599 48,365 (22,109)	\$ 26,020 \$ 24,183 19,746 18,391 45,766 42,574 2,599 2,565 48,365 45,139 (22,109) (20,616)	2017 2016 20 \$ 26,020 \$ 24,183 \$ 19,746 \$ 45,766 \$ 42,574 \$ 2,599 \$ 26,020 \$ 24,183 \$ 2,565 \$ 45,766 \$ 42,574 \$ 2,565 \$ 48,365 \$ 45,139 \$ (22,109) \$ (20,616) \$ (20,616)	

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 2017 as compared to 2016 is primarily due to awards granted either during or subsequent to 2016. These increases were partially offset by awards vesting prior to or during 2017.

We adopted Accounting Standards Update 2016-09, *Improvements to Employee Share-Based Payment Accounting* ("ASU 2016-09") on January 1, 2017 pursuant to which we made an accounting policy election to account for forfeitures in compensation cost when they occur, rather than including an estimate of the number of awards that are expected to vest in our compensation cost. See Note 6 to the Consolidated Financial Statements for further discussion regarding our stock-based compensation, including our adoption of ASU 2016-09.

(Gain) Loss on Derivative Instruments, Net

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 (Gain) loss on derivative instruments, net for the periods indicated. See Note 4 to the Consolidated Financial Statements for additional information regarding our derivative instruments.

	Years Ended		Variance Between		
(Gain) Loss on Derivative Instruments (in thousands):	2017	2016	2017 / 2016		
Change in fair value of derivative instruments, net:					
Gas contracts	\$ (40,226)	\$ 27,462	\$	(67,688)	
Oil contracts	17,383	35,724		(18,341)	
	(22,843)	63,186		(86,029)	
Cash (receipts) payments on derivative instruments, net:					
Gas contracts	(4,557)	(6,467)		1,910	
Oil contracts	6,190	(970)		7,160	
	1,633	(7,437)		9,070	
(Gain) loss on derivative instruments, net	\$ (21,210)	\$ 55,749	\$	(76,959)	

Other Income and Expense

		Years Ended	Variance Between	
Other Income and Expense (in thousands):		2017	2016	2017 / 2016
Interest expense	\$	74,821	\$ 83,272	\$ (8,451)
Capitalized interest		(22,948)	(21,248)	(1,700)
Loss on early extinguishment of debt		28,187	_	28,187
Other, net		(11,342)	(10,707)	(635)
	\$	68,718	\$ 51,317	\$ 17,401

The majority of our interest expense relates to interest on our senior unsecured notes. See **LIQUIDITY AND CAPITAL RESOURCES** *Long-Term Debt* below for further information regarding our debt. The decrease in interest expense in 2017 as compared to 2016 is due to the completion of a tender offer and redemption of \$750 million 5.875% senior notes and the issuance of \$750 million 3.90% senior notes, which occurred during the second quarter of 2017. The \$28.2 million loss on early extinguishment of debt incurred during 2017 was also associated with the debt tender offer and redemption. The loss was composed primarily of tender and redemption premiums of \$22.6 million and the write-off of \$5.3 million of unamortized debt issuance costs. The original maturity date of the 5.875% notes was May 1, 2022.

We capitalize interest on non-producing leasehold costs, the in-progress costs of drilling and completing wells, and constructing qualified assets. Capitalized interest will fluctuate based on the rates applicable to borrowings outstanding during the period and the amount of costs on which interest is capitalized. There have been higher capitalized costs upon which to capitalize interest in 2017 as compared to 2016 due to our increased capitalized expenditures. However, the impact of this increase in capitalized interest has been largely offset by the lower interest rate on borrowings outstanding due to the replacement of our 5.875% notes with 3.90% notes in the second quarter of 2017.

Components of Other, net consist of miscellaneous income and expense items that will 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:

	Years Ended	Variance Between	
Income Tax Expense (Benefit) (in thousands):	2017	2016	2017 / 2016
Current tax benefit	\$ (2,812)	\$ (1,115)	\$ (1,697)
Deferred tax expense (benefit)	190,479	(213,286)	403,765
	\$ 187,667	\$(214,401)	\$ 402,068
Combined federal and state effective income tax rate	27.5%	34.4%	

On December 22, 2017, the United States enacted H.R.1, commonly referred to as the Tax Cuts and Jobs Act or U.S. Tax Reform. H.R.1, among other things, includes changes to U.S. federal tax rates, imposes new limitations on the utilization of net operating losses and the deductibility of interest and executive compensation, allows for the expensing of capital expenditures, and eliminates the corporate Alternative Minimum Tax. We remeasured the 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 and, as a result of this remeasurement, we recorded an income tax benefit of \$61.1 million and a corresponding \$61.1 million decrease in the net deferred tax liabilities as of December 31, 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. It is not expected any such change will be material to the financial statements. 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. In addition, the limitations on utilization of net operating losses and deductibility of interest and executive compensation may result in the payment of cash taxes earlier than expected.

Our combined federal and state effective tax rates differ from the statutory rate of 35% primarily due to state income taxes, non-deductible expenses, revisions, and the impact of changes in tax law. See Note 9 to the Consolidated Financial Statements for further information regarding our income taxes.

RESULTS OF OPERATIONS

2016 Compared to 2015

Summary

For the year ended December 31, 2016, we had a net loss of \$408.8 million (\$4.38 per diluted share), down from a net loss of \$2.58 billion (\$27.75 per diluted share) in 2015. Production revenues in 2016 and 2015 were adversely affected by low realized commodity prices, which also brought about impairments of our oil and gas properties and net losses for each year. Although production revenue in 2016 was lower than in 2015, the decrease was more than offset by lower impairment, DD&A, and other operating costs in 2016. Year-over-year changes are discussed further as follows. Also refer to the "2017 Compared to 2016" section above for general information regarding various statement of operations line items.

Revenue

Our 2016 production revenue was 14% lower than that of 2015. Lower realized prices and production volumes for oil and gas were only partially offset by higher realized prices and production volumes for NGLs. The following table shows our production revenue for the years indicated as well as the change in revenue due to changes in prices and volumes.

		Ended ber 31,			Price	e / Volume Varia	ance
Production Revenue (in thousands)	2016	2015	Variance Betwee 2016 / 2015		Price	Volume	Total
Oil sales	\$ 632,934	\$ 809,664	\$ (176,730)	(22)%	\$ (83,962)	\$ (92,768)	\$ (176,730)
Gas sales	388,786	428,227	(39,441)	(9)%	(37,010)	(2,431)	(39,441)
NGL sales	199,498	179,647	19,851	11 %	4,260	15,591	19,851
	\$1,221,218	\$1,417,538	\$ (196,320)	(14)%	\$ (116,712)	\$ (79,608)	\$ (196,320)

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 2016 and 2015, 80% and 84%, respectively, of our oil production was in the Permian Basin and 20% and 15%, respectively, was in the Mid-Continent region. Our realized prices do not include settlements of commodity derivative contracts.

	Years Ended December 31,					Variance Bety	woon
		2016		2015	•	2016 / 201	
Oil							
Total volume — MBbls		16,528		18,663		(2,135)	(11)%
Total volume — MBbls per day		45.2		51.1		(5.9)	(12)%
Percentage of total production		28%)	31%)		
Average realized price — per barrel	\$	38.30	\$	43.38	\$	(5.08)	(12)%
Average WTI Midland price — per barrel	\$	43.34	\$	48.39	\$	(5.05)	(10)%
Average WTI Cushing price — per barrel	\$	43.32	\$	48.80	\$	(5.48)	(11)%
Gas							
Total volume — MMcf		168,227		168,987		(760)	— %
Total volume — MMcf per day		459.6		463.0		(3.4)	(1)%
Percentage of total production		48%)	47%)		
Average realized price — per Mcf	\$	2.31	\$	2.53	\$	(0.22)	(9)%
Average Henry Hub price — per Mcf	\$	2.46	\$	2.67	\$	(0.21)	(8)%
NGL							
Total volume — MBbls		14,200		13,063		1,137	9 %
Total volume — MBbls per day		38.8		35.8		3.0	8 %
Percentage of total production.		24%)	22%)		
Average realized price — per barrel	\$	14.05	\$	13.75	\$	0.30	2 %
Total							
Total production — MMcfe		352,591		359,343		(6,752)	(2)%
Total production — MMcfe per day		963.4		984.5		(21.1)	(2)%
Average realized price — per Mcfe	\$	3.46	\$	3.94	\$	(0.48)	(12)%

Years Ended

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.

	Y	Years Ended	Dece	ember 31,		/ariance Between
Gas Gathering and Marketing (in thousands):		2016		2015	_	16 / 2015
Gas gathering and other	\$	36,033	\$	34,688	\$	1,345
Gas marketing	\$	94	\$	393	\$	(299)

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

Operating Costs and Expenses

Total operating costs and expenses of \$1.83 billion in 2016 were 67% lower than the \$5.46 billion incurred in 2015. Most of the decrease resulted from lower ceiling test impairments of our oil and gas properties and lower DD&A expense. The following table shows our operating costs and expenses for the years indicated and a discussion of year-over-year differences follows.

	Years Ended	December 31,	*7 •	Per Mcfe					
Operating Costs and Expenses (in thousands, except per Mcfe)		2016	2015	Variance Between 2016 / 2015		2016		2015	
Impairment of oil and gas properties	\$	757,670	\$ 4,033,295	\$(3,275,625)		N/A		N/A	
Depreciation, depletion, and amortization		392,348	731,460	(339,112)	\$	1.11	\$	2.04	
Asset retirement obligation		7,828	9,121	(1,293)	\$	0.02	\$	0.03	
Production		232,002	299,374	(67,372)	\$	0.66	\$	0.83	
Transportation, processing, and other operating		190,725	182,362	8,363	\$	0.54	\$	0.51	
Gas gathering and other		31,785	38,138	(6,353)	\$	0.09	\$	0.11	
Taxes other than income		61,946	84,764	(22,818)	\$	0.18	\$	0.24	
General and administrative		73,901	74,688	(787)	\$	0.21	\$	0.21	
Stock compensation		24,523	19,559	4,964	\$	0.07	\$	0.05	
(Gain) loss on derivative instruments, net		55,749	(11,246)	66,995		N/A		N/A	
Other operating expense, net		755	856	(101)		N/A		N/A	
	\$ 1	1,829,232	\$ 5,462,371	\$(3,633,139)					

Ceiling Test Impairment

During the first three quarters of 2016, we recognized ceiling test impairments totaling \$757.7 million (\$481.4 million net of tax). We recognized ceiling test impairments in 2015 totaling \$4.03 billion (\$2.56 billion net of tax). The impairments resulted primarily from the impact of decreases in the trailing twelve-month average prices for oil, gas, and NGLs utilized in determining the estimated future net revenues from proved reserves. At December 31, 2016, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test, and no impairment was necessary. However, a decline of 7% or more in the value of the ceiling limitation would have resulted in an impairment.

Depreciation, Depletion, and Amortization

Depletion expense in 2016 decreased compared to 2015 due to the quarterly impairments of our oil and gas properties from the first quarter of 2015 through the third quarter of 2016. Depletion expense generally decreases following ceiling test impairments due to the decrease in the net proved properties balance. DD&A consisted of the following for the years indicated:

	1	Years Ended	d December 31,			Variance Between		Per Mcfe				
DD&A Expense (in thousands, except per Mcfe)	2016		2015		2016 / 2015			2016		2015		
Depletion	\$	346,003	\$	689,120	\$	(343,117)	\$	0.98	\$	1.92		
Depreciation		46,345		42,340		4,005		0.13		0.12		
	\$	392,348	\$	731,460	\$	(339,112)	\$	1.11	\$	2.04		

Production

Production costs consist of lease operating expense and workover expense as follows:

		Years Ended	Ended December 31,			Variance Between	Per Mcfe				
Production Expense (in thousands, except per Mcfe)	2016		2015		2016 / 2015			2016		2015	
Lease operating expense	\$	189,291	\$	249,744	\$	(60,453)	\$	0.54	\$	0.70	
Workover expense		42,711		49,630		(6,919)		0.12		0.13	
	\$	232,002	\$	299,374	\$	(67,372)	\$	0.66	\$	0.83	

Lease operating expense in 2016 declined 24% compared to 2015. In 2016, we incurred lower saltwater disposal costs due to implementation of operational efficiencies as well as lower costs associated with labor, rental equipment, and property divestitures.

Workover expense decreased by 14% in 2016 compared to 2015. Generally, these costs will fluctuate based on the amount of maintenance and remedial activity performed during the period.

Transportation, Processing, and Other Operating

Our 2016 transportation, processing, and other operating costs were 5%, or \$8.4 million, higher than those of 2015. These costs will vary by product type and region. The increase in 2016 is primarily a result of more gas production and higher fees associated with our Mid-Continent region.

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. The 17%, or \$6.4 million, year-over-year decrease is primarily attributable to higher repair and maintenance activities occurring in 2015.

Taxes Other than Income

Taxes other than income are assessed by state and local taxing authorities on production, revenues, or the value of properties. Revenue-based production and severance taxes are the largest components of these taxes. The 27%, or \$22.8 million, decrease in 2016 taxes is a result of lower production revenues due to lower realized commodity prices and lower production volumes.

General and Administrative

G&A costs consisted of the following for the years indicated:

	Years Ended December 31,			Variance Between		
General and Administrative Expense (in thousands):		2016		2015		2016 / 2015
Gross G&A	\$	146,432	\$	133,020	\$	13,412
Less amounts capitalized to oil and gas properties		(72,531)		(58,332)		(14,199)
G&A expense.	\$	73,901	\$	74,688	\$	(787)

G&A expense decreased slightly during 2016 as compared to 2015. The percentage of gross G&A capitalized was 50% and 44% during 2016 and 2015, respectively. The increased capitalization in 2016 offset the increase in gross G&A costs, which increased due to a combination of higher accruals in 2016 for short-term incentive based compensation together with severance payments in connection with a voluntary early retirement incentive program. These increases were partially offset by lower salaries and wages and lower corporate contributions and consulting fees.

Stock Compensation

We have recognized stock-based compensation cost as follows:

	Years Ended December 31,					Variance Between	
Stock Compensation Expense (in thousands):	2016		2015		2016 / 2015		
Restricted stock awards:							
Performance stock awards	\$	24,183	\$	18,991	\$	5,192	
Service-based stock awards		18,391		14,547		3,844	
		42,574		33,538		9,036	
Stock option awards		2,565		2,803		(238)	
Total stock compensation cost.		45,139		36,341		8,798	
Less amounts capitalized to oil and gas properties		(20,616)		(16,782)		(3,834)	
Stock compensation expense.	\$	24,523	\$	19,559	\$	4,964	

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 2016 stock compensation is primarily related to performance awards granted in December 2015, a portion of which were amortized during 2016, forfeiture rate adjustments on the service-based stock awards, and acceleration of expense on a portion of service-based awards for employees who participated in a voluntary early retirement incentive program. Historical amounts may not be representative of future amounts as the value of future awards may vary from historical amounts.

(Gain) Loss on Derivative Instruments, Net

The following table presents the components of (Gain) loss on derivative instruments, net for the periods indicated. See Note 4 to the Consolidated Financial Statements for additional information regarding our derivative instruments.

	Years Ended December 31,			nber 31,	Variance Between 2016 / 2015	
(Gain) Loss on Derivative Instruments (in thousands):	2016		2015			
Change in fair value of derivative instruments, net:						
Gas contracts	\$	27,462	\$	(4,472)	\$	31,934
Oil contracts		35,724		(6,774)		42,498
		63,186		(11,246)		74,432
Cash (receipts) payments on derivative instruments, net:						
Gas contracts		(6,467)		_		(6,467)
Oil contracts		(970)		_		(970)
		(7,437)				(7,437)
(Gain) loss on derivative instruments, net	\$	55,749	\$	(11,246)	\$	66,995

Other Income and Expense

		Years Ended December 31,				Variance Between		
Other Income and Expense (in thousands):		2016		2015	2	2016 / 2015		
Interest expense	\$	83,272	\$	85,746	\$	(2,474)		
Capitalized interest		(21,248)		(30,589)		9,341		
Other, net		(10,707)		(13,576)		2,869		
	\$	51,317	\$	41,581	\$	9,736		

The majority of our interest expense relates to interest on our senior unsecured notes. See **LIQUIDITY AND CAPITAL RESOURCES** *Long-Term Debt* below for further information regarding our debt.

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 on which interest is capitalized. The 31%, or \$9.3 million, decrease in year-over-year capitalized interest expense resulted from lower average unproved property costs in 2016.

Components of Other, net consist of miscellaneous income and expense items that will 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. The 21%, or \$2.9 million, decrease in 2016 income was primarily due to lower net gains on transactions related to oil and gas well equipment and supplies.

Income Tax Expense (Benefit)

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

	Years Ended December 31,			Variance — Between		
Income Tax Expense (Benefit) (in thousands):	2016		2016 2015		2016 / 2015	
Current tax (benefit) expense	\$	(1,115)	\$	14,710	\$	(15,825)
Deferred tax benefit		(213,286)		(1,486,439)		1,273,153
	\$	(214,401)	\$	(1,471,729)	\$	1,257,328
Combined federal and state effective income tax rate		34.4%		36.3%		

Our combined federal and state effective tax rates differ from the statutory rate of 35% primarily due to state income taxes, non-deductible expenses, and revisions. See Note 9 to the Consolidated Financial Statements for further 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** *Revenue* above for further information regarding the impact realized prices have had on our 2017 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 gathering, processing, and other infrastructure are expected to approximate an additional \$80 million to \$90 million for 2018. See *Capital Expenditures* below for information regarding our 2017 E&D activities.

We periodically use derivative instruments to mitigate volatility in commodity prices. At December 31, 2017, 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 4 to the 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 December 31, 2017 were \$400.5 million. At December 31, 2017, our long-term debt consisted of \$1.50 billion of senior unsecured notes, with \$750 million 4.375% notes due in 2024 and \$750 million 3.90% notes due in 2027. During the second quarter of 2017, we completed a tender offer and redemption of all of our \$750 million 5.875% notes due in 2022 and issued the aforementioned 3.90% notes. At December 31, 2017, 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 December 31, 2017 was 37%, down from 42% at December 31, 2016. 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 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 in 2018 and beyond.

Analysis of Cash Flow Changes

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

	Years Ended December 31,					
(in thousands)		2017		2016		2015
Net cash provided by operating activities	\$	1,096,564	\$	625,849	\$	725,728
Net cash used by investing activities	\$	(1,265,897)	\$	(692,410)	\$	(1,008,605)
Net cash (used) provided by financing activities	\$	(83,009)	\$	(59,945)	\$	656,397

Net cash provided by operating activities in 2017 was \$1.10 billion, up \$470.7 million, or 75%, from \$625.8 million for 2016. The increase was primarily a result of higher revenue due to higher realized prices and production volumes in 2017. This increase was partially offset by increased operating expenses and an increased investment in working capital. In 2016, net cash provided by operating activities was \$99.9 million, or 14%, lower than 2015, resulting primarily from a decrease in revenue due to lower realized prices and production volumes in 2016. This decrease was partially offset by lower operating costs and a decreased investment in working capital. See **RESULTS OF OPERATIONS** above for more information regarding year-over-year changes in revenue and operating expenses.

In 2017, net cash used by investing activities was \$1.27 billion, compared to \$692.4 million and \$1.01 billion in 2016 and 2015, respectively. Prevailing commodity prices have a significant impact on the amount of cash flow available to invest in E&D activities, which comprise the majority of our cash used by investing activities. Our E&D capital expenditures, as reflected in the statements of cash flows, were \$1.23 billion, \$699.6 million, and \$979.0 million in 2017, 2016, and 2015, respectively. Our other capital expenditures were \$45.4 million, \$22.2 million, and \$70.6 million in 2017, 2016, and 2015, respectively. These other capital expenditures are primarily for our gathering facilities. Capital expenditures were partially offset by proceeds from asset sales of \$12.6 million, \$29.4 million, and \$41.0 million in 2017, 2016, and 2015, respectively. From time-to-time we sell interests in various non-core assets.

Net cash used by financing activities in 2017 was \$83.0 million and includes \$772.9 million used for the early extinguishment of the \$750 million 5.875% senior notes due 2022, which included \$22.6 million of tender and redemption premiums. Additionally, the 2017 period includes \$741.8 million proceeds, net of underwriters' fees, discount, and issuance costs, that we received for the issuance of \$750 million 3.90% senior notes due 2027. The other primary components of net cash used by financing activities in 2017 are the payment of dividends of \$30.5 million (consisting of four quarterly \$0.08 per share dividends) and the payment of \$21.7 million of income tax withholdings made on behalf of our employees upon the net settlement of employee stock awards. Net cash used by financing activities in 2016 of \$59.9 million consisted primarily of \$38.0 million of dividends paid (consisting of one quarterly dividend of \$0.16 per share and three quarterly dividends of \$0.08 per share) and the payment of \$26.6 million of income tax withholdings made on behalf of our employees upon the net settlement of employee stock awards. Net cash provided by financing activities in 2015 was \$656.4 million, which was comprised primarily of \$729.5 million of net proceeds from the sale of common stock and \$8.5 million of proceeds from the exercise of stock options. These sources of cash were partially offset by \$58.3 million of dividends paid (consisting of four quarterly dividends of \$0.16 per share) and the payment of \$21.2 million of income tax withholdings made on behalf of our employees upon the net settlement of employee stock awards.

Capital Expenditures

The following table reflects capitalized expenditures for oil and gas acquisitions, exploration, and development activities, net of property sales:

	Years Ended December 31,			
(in thousands)	2017	2016	2015	
Acquisitions:				
Proved	\$ 938	\$ 2,678	\$ 30	
Unproved	6,853	11,865	6,666	
Net purchase price adjustments (1)	_	_	(11,653)	
	7,791	14,543	(4,957)	
Exploration and development:				
Land and seismic	140,516	61,870	52,049	
Exploration	_	40	1,073	
Development	1,140,548	672,842	823,830	
	1,281,064	734,752	876,952	
Property sales	(11,680)	(24,687)	(41,276)	
	\$1,277,175	\$ 724,608	\$ 830,719	

⁽¹⁾ The 2015 net purchase price adjustments relate to acquisitions occurring prior to 2015.

Capital expenditures in the table above are presented on an accrual basis. Oil and gas capital expenditures and sales of oil and gas assets in the Consolidated Statements of Cash Flows reflect capital expenditures on a cash basis, when payments are made and proceeds received.

Because of higher commodity prices, we increased our 2017 E&D expenditures 74% to \$1.28 billion compared to \$734.8 million in 2016. Approximately 59% of our 2017 E&D expenditures were in the Permian Basin and 39% were in our Mid-Continent region. During 2017, we completed or participated in the completion of 319 gross (98.0 net) wells, of which we operated 118 gross (77.7 net) wells. See Items 1 and 2 of this report for further information regarding our oil and gas properties.

Approximately 70% of our planned 2018 E&D capital investment of \$1.6 billion to \$1.7 billion is expected to be invested in the Permian Basin and most of the remainder in the Mid-Continent region.

As has been our historical practice, we regularly review 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 fund our 2018 capital 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.

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 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 December 31, 2017 and 2016 consisted of the following:

		December 31, 2017			December 31, 2016	
(in thousands)	Principal	Unamortized Debt Issuance Costs and Discount (1)	Long-term Debt, net	Principal	Unamortized Debt Issuance Costs	Long-term Debt, net
5.875% Senior Notes	\$ —	\$ —	\$ —	\$ 750,000	\$ (5,691)	\$ 744,309
4.375% Senior Notes	750,000	(5,383)	744,617	750,000	(6,370)	743,630
3.90% Senior Notes	750,000	(7,697)	742,303	_	_	
Total long-term debt	\$ 1,500,000	\$ (13,080)	\$ 1,486,920	\$ 1,500,000	\$ (12,061)	\$ 1,487,939

⁽¹⁾ 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

In October 2015, we entered into a new senior unsecured revolving credit facility ("Credit Facility") which matures October 16, 2020. The Credit Facility has aggregate commitments of \$1.0 billion, with an option to increase 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 December 31, 2017, 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 December 31, 2017, we were in compliance with all of the financial and non-financial covenants.

At December 31, 2017 and 2016, we had \$3.4 million and \$4.5 million, respectively, of unamortized debt issuance costs associated with our Credit Facility that were recorded as deferred assets and included in Other assets, net in our balance sheets. The costs are being amortized to interest expense ratably over the life of the Credit Facility.

Senior Notes

On April 10, 2017, we completed a cash tender offer to purchase any of our 5.875% senior unsecured notes for cash consideration of \$1,031.67 per \$1,000 principal amount of notes, plus any accrued and unpaid interest up to, but not including, the settlement date, with \$253.5 million aggregate principal amount of the notes validly tendered. We settled these tendered notes for \$268.1 million, including accrued interest. On May 12, 2017, we completed a redemption of the 5.875% notes remaining outstanding for \$1,029.38 per \$1,000 principal amount of notes, plus any accrued and unpaid interest up to, but not including, the redemption date, settling the notes for \$512.0 million, including accrued interest. We recognized a loss on early extinguishment of debt related to these transactions of \$28.2 million, composed primarily of tender and redemption premiums of \$22.6 million and the write-off of \$5.3 million of unamortized debt issuance costs. The original maturity date of the 5.875% notes was May 1, 2022.

On April 10, 2017, we issued \$750 million aggregate principal amount of 3.90% senior unsecured notes due May 15, 2027 at 99.748% of par to yield 3.93% per annum. We received \$741.8 million in net cash proceeds, after deducting underwriters' fees, discount, and debt issuance costs. The notes bear an annual interest rate of 3.90% and interest is payable semiannually on May 15 and November 15, with the first payment occurring November 15, 2017. Along with cash on hand, we used the proceeds to fund the settlement of the tendered and redeemed 5.875% notes.

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.

Each of our senior unsecured notes is governed by an indenture containing certain covenants, events of default, and other restrictive provisions with which we were in compliance as of December 31, 2017. The effective interest rate on the 4.375% notes and the 3.90% notes, including the amortization of debt issuance costs and discount, as applicable, is 4.50% and 4.01%, respectively.

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 carrying value of our derivative instruments.

At December 31, 2017, we had working capital of \$256.1 million, a decrease of \$190.9 million, or 43%, compared to working capital of \$447.0 million at December 31, 2016.

Working capital decreases consisted primarily of the following:

- Cash and cash equivalents decreased \$252.3 million.
- Operations-related accounts payable and accrued liabilities increased \$131.1 million.
- Accrued liabilities related to our E&D expenditures increased \$33.4 million.

Decreases in working capital were partially offset by the following primary increases:

- Operations-related accounts receivable increased \$185.6 million.
- Net derivative instrument current liability decreased \$22.5 million.
- Oil and gas well equipment and supplies increased \$16.4 million.

Cash on hand was used during 2017, along with cash flow from operations, primarily to fund our capital expenditures. 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. Our accounts receivable and operations-related accounts payable and accrued liabilities have increased primarily due to increased commodity prices and production volumes, as well as due to increased E&D activity. Our accrued liabilities related to our E&D expenditures also increased due to increased E&D activity. 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 2016, the quarterly dividend declared was decreased to \$0.08 per share, where it has remained through the fourth quarter of 2017, from \$0.16 per share. Future dividend payments will depend on our level of earnings, financial requirements, and other factors considered relevant by our Board of Directors. See Note 2 to the Consolidated Financial Statements for further information regarding dividends.

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 December 31, 2017, our material off-balance sheet arrangements consisted of operating lease agreements, which are included in the table below.

Contractual Obligations and Material Commitments

At December 31, 2017, 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)	94,676	15,410	24,346	22,275	32,645			
Unconditional purchase obligations (3)	38,269	8,943	9,469	8,675	11,182			
Derivative liabilities	46,334	42,066	4,268		_			
Asset retirement obligation (4)	169,469	11,048	— (4)	— (4)	— (4)			
Other long-term liabilities (5)	35,280	1,844	3,320	2,855	27,261			
	\$2,375,103	\$140,155	\$165,528	\$157,930	\$1,753,069			

- (1) The interest payments presented above include the accrued interest payable on our long-term debt as of December 31, 2017 as well as future payments calculated using the long-term debt's fixed rates and principal amounts outstanding as of December 31, 2017. See Note 3 to the 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, \$36.5 million represents obligations for firm transportation agreements for 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 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 December 31, 2017, we had estimated commitments of approximately: (i) \$252.6 million to finish drilling, completing, or performing other work on wells and various other infrastructure projects in progress and (ii) \$33.3 million to finish gathering system construction in progress.

At December 31, 2017, we had firm sales contracts to deliver approximately 217.6 Bcf of natural gas over the next 7.1 years. If we do not deliver this gas, our estimated financial commitment, calculated using the January 2018 index price, would be approximately \$476.7 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 8.3 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 December 31, 2017, would be approximately \$298.3 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 December 31, 2017, would be approximately \$11.4 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

Discussion and analysis of our financial condition and results of operation are based on our Consolidated Financial Statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues, and expenses. We analyze and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

Our significant accounting policies are described in Note 1 to our Consolidated Financial Statements. We have identified the following policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management.

Oil and Gas Reserves

The process of estimating quantities of oil and gas reserves is complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time due to numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that our reserve estimates represent the most accurate assessments possible, subjective decisions and available data for our various fields make these estimates generally less precise than other estimates included in financial statement disclosures.

At year-end 2017, 17% of our total proved reserves are categorized as proved undeveloped reserves. Our reserve engineers review and revise these reserve estimates regularly, as new information becomes available.

We use the units-of-production method to amortize the cost associated with our oil and gas properties. Changes in estimates of reserve quantities and commodity prices will cause corresponding changes in depletion expense, or in some cases, a full cost ceiling impairment charge in the period of the revision. See *Full Cost Accounting* below for further information regarding the ceiling limitation calculation. See **SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES** (UNAUDITED) in Item 8 for additional reserve data.

Full Cost Accounting

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. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities, and other costs incurred for the purpose of finding oil and gas reserves. Salaries and benefits paid to employees directly involved in the acquisition, exploration, and development of properties, as well as other internal costs that can be directly identified with acquisition, exploration, and development activities, are also capitalized. Under the full cost method of accounting, no gain or loss is recognized upon the disposition of oil and gas properties unless such disposition would significantly alter the relationship between capitalized costs and proved reserves. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

Under the full cost method of accounting, we are required to perform quarterly ceiling test calculations 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 quarterly ceiling test is primarily impacted by commodity prices, changes in estimated reserve quantities, reserves produced, overall exploration and development costs, depletion expense, and deferred taxes. 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. The calculated ceiling limitation is not intended to be indicative of the fair market value of our proved reserves or future results. 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.

Depletion of proved oil and gas properties is computed on the units-of-production method, whereby capitalized costs, including future development costs and asset retirement costs, are amortized over total estimated proved reserves. Changes in our estimate of proved reserve quantities, commodity prices, and impairment of oil and gas properties will cause corresponding changes in depletion expense in periods subsequent to these changes.

The capitalized costs of unproved properties, including those in wells in progress, are excluded from the costs being amortized. We do not have major development projects that are excluded from costs being amortized. On a quarterly basis, we evaluate excluded costs for inclusion in the costs to be amortized. Significant unproved properties are evaluated individually. Unproved properties that are not considered individually significant are aggregated for evaluation purposes and related costs are transferred to the costs to be amortized quarterly based on the application of historical factors.

Income Taxes

Our oil and gas exploration and production operations are subject to taxation on income in numerous jurisdictions. We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. Numerous judgments and assumptions are inherent in this assessment, including the determination of future taxable income, which is affected by factors such as future operating conditions (particularly as related to prevailing oil and gas prices) and changing tax laws. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized, the tax asset would be reduced by a valuation allowance.

We regularly assess and, if required, establish accruals for tax contingencies that could result from assessments of additional tax by taxing jurisdictions where the company operates. See Note 9 to the Consolidated Financial Statements for additional information regarding our income taxes.

Recently Issued Accounting Standards

See Note 1 to the Consolidated Financial Statements for a discussion of recent accounting pronouncements and their anticipated effect on our business.

ITEM 7A. 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. During 2017, our total production revenue was comprised of 52% oil sales, 28% gas sales, and 20% NGL sales. The following table shows how hypothetical changes in the realized prices we receive for our commodity sales would have impacted revenue for the periods indicated. See MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Market Conditions for further information regarding prices.

		Impact on Revenue
	Change in Realized Price	Year Ended December 31, 2017
		(in thousands)
Oil	\pm \$1.00 per barrel	± \$20,861
Gas	\pm \$0.10 per Mcf	± \$18,747
NGL	\pm \$1.00 per barrel	± \$17,374
	_	± \$56,982

We periodically enter into derivative contracts to hedge a portion of our price risk associated with our future oil and gas production. At December 31, 2017, 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 December 31, 2017, these derivatives had a gross asset fair value of \$17.2 million and a gross liability fair value of \$46.3 million. See Note 4 to the 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 would have impacted the fair value as of December 31, 2017.

		Impact on Fair Value
	Change in Forward Price	December 31, 2017
		(in thousands)
Oil	-\$1.00	\$ 7,288
Oil	+\$1.00	\$ (7,528)
Gas	-\$0.10	\$ 5,388
Gas	+\$0.10	\$ (5,160)

Interest Rate Risk

At December 31, 2017, 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 3 and Note 5 to the Consolidated Financial Statements for additional information regarding our debt.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CIMAREX ENERGY CO.

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All other supplemental information and schedules have been omitted because they are not applicable or the information required is shown in the consolidated financial statements or related notes thereto.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors

Cimarex Energy Co.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Cimarex Energy Co. and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of operations and comprehensive income (loss), stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes (collectively, the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 23, 2018 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

KPMG LLP

We have served as the Company's auditor since 2002.

Denver, Colorado February 23, 2018

CIMAREX ENERGY CO. CONSOLIDATED BALANCE SHEETS

(in thousands, except share and per share information)

	December 31,		1,	
	20	17		2016
Assets				
Current assets:	e	100 524	¢.	(52.97(
Cash and cash equivalents	2	400,534	\$	652,876
		100,356		42,287
Trade		344,552		217,395
Oil and gas sales		15,266		14,888
Oil and gas well equipment and supplies		49,722		33,342
Derivative instruments		15,151		33,342
Prepaid expenses.		8,518		7,335
Other current assets.		1,536		1,181
Total current assets		935,635		969,304
Oil and gas properties at cost, using the full cost method of accounting:		933,033		909,304
Proved properties	17	7,513,460		16,225,495
Unproved properties and properties under development, not being amortized		476,903 7.990,363		478,277 16,703,772
Loss communicated depreciation doubtion amortization and immainment		, ,		
Less—accumulated depreciation, depletion, amortization, and impairment	$\overline{}$	1,748,833)		(14,349,505)
Net oil and gas properties		3,241,530		2,354,267
Fixed assets, net of accumulated depreciation of \$290,114 and \$246,901, respectively		210,922		205,465
		620,232		620,232
Derivative instruments		2,086		
Deferred income taxes		32.234		55,835
Other assets	<u>e</u> 5		•	32,621
Y 1992 104 11 11 15 14	2 3	5,042,639	\$	4,237,724
Liabilities and Stockholders' Equity				
Current liabilities:				
Accounts payable:	e e	(0.002	e.	40.172
Trade	2	68,883	\$	49,163
Gas gathering, processing, and marketing		29,503		25,323
Accrued liabilities:		115.760		02.220
Exploration and development		115,762		82,320
Taxes other than income		23,687		18,766
Other		212,400		177,695
Derivative instruments		42,066		49,370
Revenue payable		187,273		119,715
Total current liabilities		679,574		522,352
Long-term debt:				
Principal	I	,500,000		1,500,000
Less—unamortized debt issuance costs and discount		(13,080)		(12,061)
Long-term debt, net.	1	,486,920		1,487,939
Deferred income taxes		101,618		
Asset retirement obligation.		158,421		140,770
Derivative instruments		4,268		2,570
Other liabilities		43,560		41,104
Total liabilities	2	2,474,361		2,194,735
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, 95,437,434 and 95,123,525 shares issued,		054		051
respectively	~	954		951
Additional paid-in capital		2,764,384		2,763,452
Retained earnings (accumulated deficit).		(199,259)		(722,359)
Accumulated other comprehensive income		2,199		945
Total stockholders' equity		2,568,278	Φ.	2,042,989
	\$ 5	5,042,639	\$	4,237,724

CIMAREX ENERGY CO. CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS) (in thousands, except per share data)

	Years Ended December 31,					
		2017		2016		2015
Revenues:						
Oil sales	\$	981,646	\$	632,934	\$	809,664
Gas sales		516,936		388,786		428,227
NGL sales		375,421		199,498		179,647
Gas gathering and other		43,751		36,033		34,688
Gas marketing		495		94		393
		1,918,249		1,257,345		1,452,619
Costs and expenses:						
Impairment of oil and gas properties		_		757,670		4,033,295
Depreciation, depletion, and amortization		446,031		392,348		731,460
Asset retirement obligation		15,624		7,828		9,121
Production		262,180		232,002		299,374
Transportation, processing, and other operating		231,640		190,725		182,362
Gas gathering and other		35,840		31,785		38,138
Taxes other than income		89,864		61,946		84,764
General and administrative		79,996		73,901		74,688
Stock compensation		26,256		24,523		19,559
(Gain) loss on derivative instruments, net		(21,210)		55,749		(11,246)
Other operating expense, net		1,314		755		856
r C . r		1,167,535		1,829,232		5,462,371
Operating income (loss)		750,714		(571,887)		(4,009,752)
Other (income) and expense:		,		, , ,		() , , ,
Interest expense		74,821		83,272		85,746
Capitalized interest		(22,948)		(21,248)		(30,589)
Loss on early extinguishment of debt				(=1,=10) —		_
Other, net		(11,342)		(10,707)		(13,576)
Income (loss) before income tax		681,996		(623,204)		(4,051,333)
Income tax expense (benefit)		187,667		(214,401)		(1,471,729)
Net income (loss)		494,329	\$	(408,803)	\$	(2,579,604)
1 (ct income (1055)	Ψ	171,327	Ψ	(100,003)	Ψ	(2,575,001)
Earnings (loss) per share to common stockholders:						
Basic	\$	5.19	\$	(4.38)	\$	(27.75)
Diluted	\$	5.19	\$	(4.38)	\$	(27.75)
Diluted	Ψ	3.17	Ψ	(4.30)	Ψ	(27.73)
Dividends declared per share	\$	0.32	\$	0.32	\$	0.64
Comprehensive income (loss):						
Net income (loss)	\$	494,329	\$	(408,803)	\$	(2,579,604)
Other comprehensive income (loss):	4	17 1,527	4	(100,005)	Ψ	(2,0,7,001)
Change in fair value of investments, net of tax of \$106,						
\$289, and (\$380), respectively		1,254		504		(661)
Total comprehensive income (loss)	\$	495,583	\$	(408,299)	\$	(2,580,265)

CIMAREX ENERGY CO. CONSOLIDATED STATEMENTS OF CASH FLOWS (in thousands)

	Years Ended December 31,				
	2017	2016	2015		
Cash flows from operating activities:					
Net income (loss)	\$ 494,329	\$ (408,803)	\$ (2,579,604)		
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Impairment of oil and gas properties	_	757,670	4,033,295		
Depreciation, depletion, and amortization	446,031	392,348	731,460		
Asset retirement obligation	15,624	7,828	9,121		
Deferred income taxes.	190,479	(213,286)	(1,486,439)		
Stock compensation.	26,256	24,523	19,559		
(Gain) loss on derivative instruments, net	(21,210)	55,749	(11,246)		
Settlements on derivative instruments	(1,633)	7,437	_		
Loss on early extinguishment of debt	28,187		_		
Changes in non-current assets and liabilities	1,891	3,867	23,230		
Other, net	5,677	1,805	4,206		
Changes in operating assets and liabilities:					
Accounts receivable	(186,157)	(49,340)	186,699		
Other current assets.	(17,931)	20,880	37,954		
Accounts payable and other current liabilities	115,021	25,171	(242,507)		
Net cash provided by operating activities	1,096,564	625,849	725,728		
Cash flows from investing activities:					
Oil and gas capital expenditures	(1,233,126)	(699,558)	(979,044)		
Other capital expenditures	(45,352)	(22,228)	(70,592)		
Sales of oil and gas assets	11,680	21,487	39,853		
Sales of other assets	901	7,889	1,178		
Net cash used by investing activities	(1,265,897)	(692,410)	(1,008,605)		
Cash flows from financing activities:					
Borrowings of long-term debt	748,110	_	_		
Repayments of long-term debt	(750,000)		_		
Proceeds from sale of common stock	_	_	752,100		
Financing and underwriting fees	(29,312)	(101)	(24,633)		
Dividends paid	(30,532)	(38,024)	(58,281)		
Employee withholding taxes paid upon the net settlement of equity-classified stock awards	(21,669)	(26,624)	(21,240)		
Proceeds from exercise of stock options	394	4,804	8,451		
Net cash (used) provided by financing activities	(83,009)	(59,945)	656,397		
Net change in cash and cash equivalents		(126,506)	373,520		
Cash and cash equivalents at beginning of period	652,876	779,382	405,862		
Cash and cash equivalents at end of period	\$ 400,534	\$ 652,876	\$ 779,382		

CIMAREX ENERGY CO. CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (in thousands)

-	Commo	n Stock Amount	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	
Balance, December 31, 2014	87,592	\$ 876	\$ 1,997,080	\$ 2,332,909	\$ 1,102	\$ 4,331,967	
Dividends paid on stock awards subsequently forfeited	_	_	_	109	_	109	
Dividends		_	_	(59,422)		(59,422)	
Net loss		_	_	(2,579,604)		(2,579,604)	
Unrealized change in fair value of investments, net of tax	_	_	_	_	(661)	(661)	
Issuance of common stock	6,900	69	729,468	_		729,537	
Issuance of restricted stock awards	471	5	(5)	_			
Common stock reacquired and retired	(194)	(2)	(21,238)	_		(21,240)	
Restricted stock forfeited and retired	(90)	(1)	1	_	_	_	
Exercise of stock options	142	1	8,450	_	_	8,451	
Stock-based compensation		_	36,232	_	_	36,232	
Stock-based compensation tax benefit		_	12,988	_	_	12,988	
Balance, December 31, 2015	94,821	948	2,762,976	(306,008)	441	2,458,357	
Dividends paid on stock awards subsequently forfeited	_		2	35	_	37	
Dividends		_	_	(7,583)		(7,583)	
Dividends in excess of retained earnings	_	_	(22,805)	_	_	(22,805)	
Net loss		_	_	(408,803)		(408,803)	
Unrealized change in fair value of investments, net of tax	_	_	_	<u> </u>	504	504	
Issuance of restricted stock awards	479	5	(5)	_	_		
Common stock reacquired and retired	(208)	(3)	(26,622)	_	_	(26,625)	
Restricted stock forfeited and retired	(32)	_	_	_	_	_	
Exercise of stock options	64	1	4,803	_	_	4,804	
Stock-based compensation		_	45,103	_	_	45,103	
Balance, December 31, 2016	95,124	951	2,763,452	(722,359)	945	2,042,989	
Dividends paid on stock awards subsequently forfeited	_	_	11	32		43	
Dividends in excess of retained earnings			(30,489)		_	(30,489)	
Net income.			(50,107)	494,329	_	494,329	
Unrealized change in fair value of investments, net of tax	_				1,254	1,254	
Issuance of restricted stock awards	552	5	(5)	_			
Common stock reacquired and retired	(204)	(2)	(21,667)	_	_	(21,669)	
Restricted stock forfeited and retired	(41)	(2)	(21,007)	_	_	(21,007)	
Exercise of stock options	6		394	_	_	394	
Stock-based compensation	_		48,321	_	_	48,321	
Cumulative effect adjustment of adopting ASU 2016-09 (Note 6)	_	_	4,393	28,739		33,132	
Other		_	(26)	20,137		(26)	
Balance, December 31, 2017	95,437	\$ 954		\$ (199,259)	\$ 2,199	\$ 2,568,278	
=	• • •	# 75 7	\$ 2,704,364	(177,237)	Ψ 2,177		

SUPPLEMENTAL QUARTERLY FINANCIAL DATA (UNAUDITED)

1. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cimarex Energy Co., a Delaware corporation, is an independent oil and gas exploration and production company. Our operations are mainly located in Texas, Oklahoma, and New Mexico.

Basis of Presentation

Our Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. Our significant accounting policies are discussed below. The accounts of Cimarex and its subsidiaries are presented in the accompanying Consolidated Financial Statements. All intercompany accounts and transactions were eliminated in consolidation. Certain amounts in the prior year financial statements have been reclassified to conform to the 2017 financial statement presentation.

Segment Information

We have determined that our business is comprised of only one segment because our gathering, processing, and marketing activities are ancillary to our production operations.

Use of Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues, and expenses. 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. We analyze our estimates and base them on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions.

The process of estimating quantities of oil and gas reserves is complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering, and economic data. The data for a given field may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that our reserve estimates represent the most accurate assessments possible, subjective decisions, and available data for our various fields make these estimates generally less precise than other estimates included in financial statement disclosures.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash in banks and investments readily convertible into cash, which have original maturities of three months or less. Cash equivalents are stated at cost, which approximates market value.

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 completion, 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities, and other costs incurred for the purpose of finding oil and gas reserves. Salaries and benefits paid to employees directly involved in the acquisition, exploration, and development of properties, as well as other internal costs that can be directly identified with acquisition, exploration and development activities, are also capitalized. Under the full cost method of accounting, no gain or loss is recognized upon the disposition of oil and gas properties unless such disposition would significantly alter the relationship between capitalized costs and proved reserves. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

Under the full cost method of accounting, we are required to perform quarterly ceiling test calculations 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.

At December 31, 2017, the carrying value of our oil and gas properties subject to the test did not exceed the calculated value of the ceiling limitation and, therefore, we did not recognize an impairment. However, a decline of approximately 19% or more in the value of the ceiling limitation would have resulted in an impairment. For the years ended December 31, 2016 and 2015, full year impairments totaled \$757.7 million (\$481.4 million, net of tax) and \$4.03 billion (\$2.56 billion, net of tax), respectively. These impairments resulted primarily from the impact of decreases in the trailing twelve-month average prices for oil, gas, and NGLs utilized in determining the future net revenues from proved reserves. The quarterly ceiling test is primarily impacted by commodity prices, changes in estimated reserve quantities, reserves produced, overall exploration and development costs, depletion expense, and deferred taxes. 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. The calculated ceiling limitation is not intended to be indicative of the fair market value of our proved reserves or future results. 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.

Depletion of proved oil and gas properties is computed on the units-of-production method, whereby capitalized costs, including future development costs and asset retirement costs, are amortized over total estimated proved reserves. Changes in our estimate of proved reserve quantities, commodity prices, and impairment of oil and gas properties will cause corresponding changes in depletion expense in periods subsequent to these changes.

The capitalized costs of unproved properties, including those in wells in progress, are excluded from the costs being amortized. We do not have major development projects that are excluded from costs being amortized. On a quarterly basis, we evaluate excluded costs for inclusion in the costs to be amortized. Significant unproved properties are evaluated individually. Unproved properties that are not considered individually significant are aggregated for evaluation purposes and related costs are transferred to the costs to be amortized quarterly based on the application of historical factors.

Fixed Assets

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.

Goodwill

Goodwill represents the excess of the purchase price of business combinations over the fair value of the net assets acquired and is tested for impairment at least annually. In performing the goodwill test, we compare the fair value of our reporting unit with its carrying amount. If the carrying amount of the reporting unit were to exceed its fair value, an impairment charge would be recognized in the amount of this excess, limited to the total amount of goodwill allocated to that reporting unit.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

We evaluate our goodwill for impairment in the fourth quarter of each year and whenever events or changes in circumstances indicate the possibility that goodwill may be impaired. We have historically tested goodwill for impairment as of December 31 each year; however, in 2017 we elected to change the date of our annual goodwill impairment test to October 31. We do not believe a change in the goodwill impairment testing date represents a material change to a method of applying an accounting principle because the change in impairment testing date does not have a material effect on our financial statements in light of the internal controls and requirements to assess goodwill impairment upon certain triggering events. Based upon our assessment as of October 31, 2017, goodwill was not impaired. It is possible that goodwill could become impaired in the future if commodity prices or other economic factors become unfavorable.

Revenue Recognition

Oil, Gas, and NGL Sales

Revenue is recognized from the sales of oil, gas, and NGLs when the product is delivered at a fixed or determinable price, title has transferred, and collectability is reasonably assured. There is a ready market for our products and sales occur soon after production.

Gas Gathering

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

Gas Marketing

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

Gas Imbalances

We use the sales method of accounting for 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.

General and Administrative Expenses

General and administrative expenses are reported net of amounts reimbursed by working interest owners of the oil and gas properties operated by Cimarex and net of amounts capitalized pursuant to the full cost method of accounting.

Derivatives

Our derivative contracts are recorded on the balance sheet at fair value. Our firm sales contracts qualify for the normal purchase and normal sale exception. Contracts that qualify for this treatment do not require mark-to-market accounting treatment. See Note 4 for additional information regarding our derivative instruments.

Income Taxes

We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in the financial statements and tax returns. We classify all deferred tax assets and liabilities as non-current. We routinely assess the realizability of our deferred tax assets. Numerous judgments and assumptions are inherent in this assessment, including the determination of future taxable income, which is affected by factors such as future operating conditions (particularly as related to prevailing oil and gas prices) and changing tax laws. If we conclude that it is more likely than not that some or all of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. We regularly assess and, if required, establish accruals for tax contingencies that could result from assessments of additional tax by taxing jurisdictions where the company operates. See Note 9 for additional information regarding

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

our income taxes, including the impact of H.R.1, commonly referred to as the Tax Cuts and Jobs Act, which the U.S. enacted on December 22, 2017.

Contingencies

A provision for contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is a complex estimation process that includes subjective judgment. In many cases, this judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. We closely monitor known and potential legal, environmental, and other contingencies and determine when we should record losses for these items based on information available to us. See Note 10 for additional information regarding our contingencies.

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 abandonment of wells, the removal of facilities and equipment, and site restorations. In periods subsequent to the initial measurement of an asset retirement obligation at present value, a period-to-period increase in the carrying amount of the liability is recognized as accretion expense, which represents the effect of the passage of time on the amount of the liability. An equivalent amount is added to the carrying amount of the liability. If the fair value of a recorded asset retirement obligation changes, 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 DD&A calculations. The current portion of our asset retirement obligations is recorded in "Accrued liabilities — Other" in the accompanying consolidated balance sheets and cash payments for settlements of retirement obligations are classified as cash used in operating activities in the accompanying consolidated statements of cash flows. See Note 8 for additional information regarding our asset retirement obligations.

Stock-based Compensation

We recognize compensation cost related to all stock-based awards in the financial statements based on their estimated grant date fair value. We grant various types of stock-based awards including stock options, restricted stock (including awards with service-based vesting and market condition-based vesting provisions), and restricted stock units. The fair value of stock option awards is determined using the Black-Scholes option pricing model. Service-based restricted stock and units are valued using the market price of our common stock on the grant date. The fair value of the market condition-based restricted stock is based on the grant date market value of the award utilizing a statistical analysis. Compensation cost is recognized ratably over the applicable vesting period. To the extent compensation cost relates to employees directly involved in oil and gas acquisition, exploration, and development activities, such amounts are capitalized to oil and gas properties. Amounts not capitalized to oil and gas properties are recognized as stock compensation expense. See Note 6 for additional information regarding our stock-based compensation.

Earnings (Loss) per Share

We calculate earnings (loss) per share recognizing that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are "participating securities" and, therefore, should be included in computing earnings per share using the two-class earnings allocation method. The two-class method is an earnings allocation formula that determines earnings per share for each class of common stock and participating security according to dividends declared (or accumulated) and participation rights in undistributed earnings. Our unvested share-based payment awards, consisting of restricted stock and units, qualify as participating securities. See Note 7 for additional information regarding our earnings per share.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, *Revenue from Contracts with Customers (Topic 606)*, which is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. The new revenue standard provides a five-step analysis of transactions to determine when and how revenue is recognized. The core principle of the guidance is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance in this update supersedes the revenue recognition requirements in Topic 605, *Revenue Recognition*, and most industry-specific guidance throughout the Industry Topics of the Codification. Entities can choose to adopt the standard using either the full retrospective approach or a modified retrospective approach. We will adopt the standard effective January 1, 2018, utilizing the modified retrospective approach, which will be applied to contracts that were not completed as of January 1, 2018. The new standard will not have an impact on net income (loss) or cash flows from operations; however, certain costs previously classified as Transportation, processing, and other operating expenses in the statement of operations will be reflected as deductions from revenue under the new standard. Had Topic 606 been in effect for the fourth quarter of 2017, Revenue and Transportation, processing and other operating expenses for the quarter would have each been reduced by an estimated range of \$15.0 million to \$16.0 million.

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842). The key provision of this ASU is that a lessee must recognize (i) liabilities to make lease payments and (ii) right-of-use assets on its balance sheet. The ASU permits lessees to make a policy election to not recognize lease assets and liabilities for leases with terms of less than twelve months. Under current GAAP, 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2. CAPITAL STOCK

Authorized capital stock consists of 200 million shares of common stock and 15 million shares of preferred stock. At December 31, 2017, there were 95.4 million shares of common stock and no shares of preferred stock outstanding. See our Consolidated Statements of Stockholders' Equity for detailed capital stock activity.

In May 2015, we completed an underwritten public offering of 6.9 million shares of common stock, which included 0.9 million shares of common stock issued pursuant to an overallotment option to purchase additional shares granted to the underwriters. The stock was sold to the public at \$109.00 per share, with a par value of \$0.01, and we received net proceeds of \$729.5 million from the sale, after deducting underwriting fees.

Dividends

A cash dividend has been paid to stockholders in every quarter since the first quarter of 2006. A quarterly dividend of \$0.08 per share was declared in each quarter of 2017 and 2016 and a quarterly dividend of \$0.16 per share was declared in each quarter of 2015. We typically declare dividends in one quarter and pay them in the next quarter. 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. Future dividend payments will depend on our level of earnings, financial requirements, and other factors considered relevant by our Board of Directors.

3. LONG-TERM DEBT

Long-term debt at December 31, 2017 and 2016 consisted of the following:

			Decen	nber 31, 2017		December 31, 2016							
(in thousands)	Unamortized Debt Issuance Costs Principal and Discount (1)			Long-term Debt, net		Principal	Unamortized Debt Issuance Costs		Long-term Debt, net				
5.875% Senior Notes	\$		\$		\$ 	\$	750,000	\$	(5,691)	\$	744,309		
4.375% Senior Notes		750,000		(5,383)	744,617		750,000		(6,370)		743,630		
3.90% Senior Notes		750,000		(7,697)	742,303		_		_				
Total long-term debt	\$	1,500,000	\$	(13,080)	\$ 1,486,920	\$	1,500,000	\$	(12,061)	\$	1,487,939		

⁽¹⁾ 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

In October 2015, we entered into a new senior unsecured revolving credit facility ("Credit Facility") which matures October 16, 2020. The Credit Facility has aggregate commitments of \$1.0 billion, with an option to increase 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 December 31, 2017, 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 December 31, 2017, we were in compliance with all of the financial covenants.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

At December 31, 2017 and 2016, we had \$3.4 million and \$4.5 million, respectively, of unamortized debt issuance costs associated with our Credit Facility which were recorded as deferred assets and included in Other assets, net in our balance sheets. The costs are being amortized to interest expense ratably over the life of the Credit Facility.

Senior Notes

On April 10, 2017, we completed a cash tender offer to purchase any of our 5.875% notes for cash consideration of \$1,031.67 per \$1,000 principal amount of notes, plus any accrued and unpaid interest up to, but not including, the settlement date, with \$253.5 million aggregate principal amount of the notes validly tendered. We settled these tendered notes for \$268.1 million, including accrued interest. On May 12, 2017, we completed a redemption of the 5.875% notes remaining outstanding for \$1,029.38 per \$1,000 principal amount of notes, plus any accrued and unpaid interest up to, but not including, the redemption date, settling the notes for \$512.0 million, including accrued interest. We recognized a loss on early extinguishment of debt related to these transactions of \$28.2 million, composed primarily of tender and redemption premiums of \$22.6 million and the write-off of \$5.3 million of unamortized debt issuance costs. The original maturity date of the 5.875% notes was May 1, 2022.

On April 10, 2017, we issued \$750 million aggregate principal amount of 3.90% senior unsecured notes due May 15, 2027 at 99.748% of par to yield 3.93% per annum. We received \$741.8 million in net cash proceeds, after deducting underwriters' fees, discount, and debt issuance costs. The notes bear an annual interest rate of 3.90% and interest is payable semiannually on May 15 and November 15, with the first payment occurring November 15, 2017. Along with cash on hand, we used the proceeds to fund the settlement of the tendered and redeemed 5.875% notes.

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.

Each of our senior unsecured notes is governed by an indenture containing certain covenants, events of default, and other restrictive provisions with which we were in compliance as of December 31, 2017. The effective interest rate on the 4.375% notes and the 3.90% notes, including the amortization of debt issuance costs and discount, as applicable, is 4.50% and 4.01%, respectively.

4. 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 December 31, 2017, 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 December 31, 2017:

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Oil Collars:		First Quarter		Second Quarter		Third Quarter		Fourth Quarter		Total
2018:										
WTI (1)										
Volume (Bbls)	2	2,610,000	2	2,093,000	1	,748,000]	1,196,000		7,647,000
Weighted Avg Price - Floor	\$	47.28	\$	47.26	\$	46.68	\$	48.00	\$	47.25
Weighted Avg Price - Ceiling	\$	56.33	\$	55.61	\$	54.90	\$	55.10	\$	55.62
2019:										
WTI (1)										
Volume (Bbls)		630,000		637,000		_		_		1,267,000
Weighted Avg Price - Floor	\$	48.00	\$	48.00	\$	_	\$	_	\$	48.00
Weighted Avg Price - Ceiling	\$	56.09	\$	56.09	\$	_	\$	_	\$	56.09

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

Gas Collars:		First uarter		econd uarter		Third Juarter	Fourth Quarter			Total
2018:										
PEPL (1)										
Volume (MMBtu)	11,	700,000	9,	100,000	6	,440,000	3	3,680,000	3	0,920,000
Weighted Avg Price - Floor	\$	2.57	\$	2.47	\$	2.43	\$	2.43	\$	2.49
Weighted Avg Price - Ceiling	\$	2.93	\$	2.81	\$	2.67	\$	2.66	\$	2.81
Perm EP (2)										
Volume (MMBtu)	8,	100,000	6,	370,000	4	,600,000	2	2,760,000	2	1,830,000
Weighted Avg Price - Floor	\$	2.52	\$	2.39	\$	2.34	\$	2.33	\$	2.42
Weighted Avg Price - Ceiling	\$	2.84	\$	2.67	\$	2.53	\$	2.52	\$	2.68
2019:										
PEPL (1)										
Volume (MMBtu)	2,	700,000	2,	730,000						5,430,000
Weighted Avg Price - Floor	\$	2.40	\$	2.40	\$	_	\$	_	\$	2.40
Weighted Avg Price - Ceiling	\$	2.67	\$	2.67	\$	_	\$	_	\$	2.67
Perm EP (2)										
Volume (MMBtu)	1,	800,000	1,	820,000		_				3,620,000
Weighted Avg Price - Floor	\$	2.30	\$	2.30	\$	_	\$	_	\$	2.30
Weighted Avg Price - Ceiling	\$	2.49	\$	2.49	\$	_	\$	_	\$	2.49

⁽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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Oil Basis Swaps:	First Quarter	Second Quarter	Third Fourth Quarter Quarter				Total	
2018:								
WTI Midland (1)								
Volume (Bbls)	1,170,000	1,183,000		1,196,000		736,000		4,285,000
Weighted Avg Differential (2)	\$ (0.72)	\$ (0.72)	\$	(0.72)	\$	(0.58) §	\$	(0.69)
2019:								
WTI Midland (1)								
Volume (Bbls)	450,000	455,000		_				905,000
Weighted Avg Differential (2)	\$ (0.47)	\$ (0.47)	\$	_	\$	_ 5	\$	(0.47)

⁽¹⁾ The index price we pay under these basis swaps is WTI Midland as quoted by Argus Americas Crude.

The following tables summarize our derivative contracts entered into subsequent to December 31, 2017 through February 22, 2018:

Oil Collars:	First Quarter	Second Quarter	Third Fourth Quarter Quarter				Total	
2018:								
WTI (1)								
Volume (Bbls)	_	546,000	552,000		552,000		1,650,000	
Weighted Avg Price - Floor	\$ _	\$ 50.00	\$ 50.00	\$	50.00	\$	50.00	
Weighted Avg Price - Ceiling.	\$ _	\$ 66.82	\$ 66.82	\$	66.82	\$	66.82	
2019:								
WTI (1)								
Volume (Bbls)	540,000	546,000	552,000		_		1,638,000	
Weighted Avg Price - Floor	\$ 50.00	\$ 50.00	\$ 50.00	\$	_	\$	50.00	
Weighted Avg Price - Ceiling.	\$ 66.82	\$ 66.82	\$ 66.82	\$		\$	66.82	

⁽¹⁾ The index price for these collars is WTI as quoted on the NYMEX.

⁽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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Gas Collars:	First Quarter	Second Quarter			Fourth Quarter		Total	
2018:								
PEPL (1)								
Volume (MMBtu)	_	1,820,000		1,840,000		1,840,000		5,500,000
Weighted Avg Price - Floor	\$ _	\$ 1.98	\$	1.98	\$	1.98	\$	1.98
Weighted Avg Price - Ceiling.	\$ _	\$ 2.16	\$	2.16	\$	2.16	\$	2.16
Perm EP (2)								
Volume (MMBtu)	_	1,820,000		1,840,000		1,840,000		5,500,000
Weighted Avg Price - Floor	\$ _	\$ 1.65	\$	1.65	\$	1.65	\$	1.65
Weighted Avg Price - Ceiling.	\$ _	\$ 1.80	\$	1.80	\$	1.80	\$	1.80
2019:								
PEPL (1)								
Volume (MMBtu)	1,800,000	1,820,000		1,840,000				5,460,000
Weighted Avg Price - Floor	\$ 1.98	\$ 1.98	\$	1.98	\$		\$	1.98
Weighted Avg Price - Ceiling.	\$ 2.16	\$ 2.16	\$	2.16	\$		\$	2.16
Perm EP (2)								
Volume (MMBtu)	1,800,000	1,820,000		1,840,000		_		5,460,000
Weighted Avg Price - Floor	\$ 1.65	\$ 1.65	\$	1.65	\$	_	\$	1.65
Weighted Avg Price - Ceiling.	\$ 1.80	\$ 1.80	\$	1.80	\$	_	\$	1.80

⁽¹⁾ The index price for these collars is PEPL as quoted in Platt's Inside FERC.

⁽²⁾ The index price for these collars is 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)	_	91,000	92,000		92,000		275,000		
Weighted Avg Differential (2)	\$ _	\$ (0.70)	\$ (0.70)	\$	(0.70)	\$	(0.70)		
2019:									
WTI Midland (1)									
Volume (Bbls)	90,000	91,000	92,000		_		273,000		
Weighted Avg Differential (2)	\$ (0.70)	\$ (0.70)	\$ (0.70)	\$	_	\$	(0.70)		

⁽¹⁾ The index price we pay under these basis swaps is WTI Midland as quoted by Argus Americas Crude.

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 (Gain) loss on derivative instruments, net for the periods indicated.

⁽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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Years Ended December 31,									
(in thousands)		2017		2016		2015				
Change in fair value of derivative instruments, net:										
Gas contracts	\$	(40,226)	\$	27,462	\$	(4,472)				
Oil contracts		17,383		35,724		(6,774)				
		(22,843)		63,186		(11,246)				
Cash (receipts) payments on derivative instruments, net:										
Gas contracts		(4,557)		(6,467)		_				
Oil contracts		6,190		(970)		_				
		1,633		(7,437)		_				
(Gain) loss on derivative instruments, net	\$	(21,210)	\$	55,749	\$	(11,246)				

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.

The following tables present the amounts and classifications of our derivative assets and liabilities as of December 31, 2017 and 2016, as well as the potential effect of netting arrangements on our recognized derivative asset and liability amounts.

		December	r 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 t	he balance sheet	(17,237)		(17,237)
Net amount		\$ 	\$	29,097

		Decembe	r 31,	31, 2016		
(in thousands)	Balance Sheet Location	Asset		Liability		
Oil contracts	Current liabilities — Derivative instruments	\$ _	\$	27,892		
Gas contracts	Current liabilities — Derivative instruments	_		21,478		
Oil contracts	Non-current liabilities — Derivative instruments	_		1,059		
Gas contracts	Non-current liabilities — Derivative instruments	_		1,511		
Total gross amounts presented in the b	palance sheet	_		51,940		
Less: gross amounts not offset in the	ne balance sheet	_		_		
Net amount		\$ _	\$	51,940		

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

5. 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.

The following table provides fair value measurement information for certain assets and liabilities as of December 31, 2017 and 2016.

		December	r 31,	2017	December 31, 2016				
(in thousands)		Book Value		Fair Value		Book Value		Fair Value	
Financial Assets (Liabilities):									
5.875% Notes due 2022	\$		\$	_	\$	(750,000)	\$	(782,835)	
4.375% Notes due 2024	\$	(750,000)	\$	(797,010)	\$	(750,000)	\$	(779,453)	
3.90% Notes due 2027	\$	(750,000)	\$	(767,813)	\$	_	\$	_	
Derivative instruments — assets	\$	17,237	\$	17,237	\$	_	\$	_	
Derivative instruments — liabilities	\$	(46,334)	\$	(46,334)	\$	(51,940)	\$	(51,940)	

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 4 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 December 31, 2017 are: (i) accrued operating expenses of approximately \$61.3 million and (ii) accrued general and administrative, primarily payroll-related, costs of approximately \$54.6 million. Included in "Accrued liabilities — other" at December 31, 2016 are: (i) accrued operating expenses of approximately \$53.9 million and (ii) accrued general and administrative, primarily payroll-related, costs of approximately \$43.5 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 December 31, 2017 and 2016, the allowance for doubtful accounts totaled \$2.2 million and \$1.6 million, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Major Customers

In 2017, our major customers were Energy Transfer Partners, L.P. ("Energy Transfer Partners") and Plains All American Pipeline, L.P. ("Plains All American"), which accounted for 21% and 13%, respectively, of our consolidated revenues that year. In 2017, the revenue totals for Energy Transfer Partners include revenue from Sunoco Logistics Partners L.P. ("Sunoco") since the two entities merged in 2017. Sunoco was our major customer in 2016, accounting for 20% of our consolidated revenues that year. In 2015, our major customers were Sunoco and Enterprise Products Partners L.P., which accounted for 21% and 17%, respectively, of our consolidated revenues that year.

If any one of our major customers was to stop purchasing our production, we believe there are a number of other purchasers to whom we could sell our production with some delay. If multiple significant customers were to discontinue purchasing our production, we believe there would be challenges initially, but ample markets to handle the disruption.

6. STOCK-BASED AND OTHER COMPENSATION

Equity Incentive Plan

Our 2014 Equity Incentive Plan (the "2014 Plan") was approved by stockholders in May 2014 and our previous plan was terminated at that time. Outstanding awards under the previous plan were not impacted. A total of 6.6 million shares of common stock may be issued under the 2014 Plan, including shares available from the previous plan. The 2014 Plan provides for grants of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, dividend equivalents, and other stock-based awards.

Stock-based Compensation Cost

We have recognized non-cash stock-based compensation cost as shown below. Historical amounts may not be representative of future amounts as the value of future awards may vary from historical amounts.

		2015
,183	\$	18,991
3,391		14,547
2,574		33,538
2,565		2,803
,139		36,341
),616)		(16,782)
,523	\$	19,559
8 2 5	4,183 8,391 2,574 2,565 5,139 0,616) 4,523	8,391 2,574 2,565 5,139 0,616)

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 2017 as compared to 2016 is primarily due to awards granted either during or subsequent to 2016. These increases were partially offset by awards vesting prior to or during 2017.

We adopted Accounting Standards Update 2016-09, *Improvements to Employee Share-Based Payment Accounting* ("ASU 2016-09") on January 1, 2017. ASU 2016-09 simplifies the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, accounting for forfeitures, and classification on the statement of cash flows. Pursuant to ASU 2016-09, we made an accounting policy election to account for forfeitures in compensation cost when they occur, rather than including an estimate of the number of awards that are expected to vest in our compensation cost. The amendments within ASU 2016-09 related to the timing of when excess tax benefits and tax benefits on dividends on nonvested equity shares are recognized and accounting for forfeitures were adopted using a modified retrospective method. In accordance with this method, we recorded a cumulative-effect adjustment that increased beginning deferred income tax assets by \$33.1 million, reduced beginning accumulated deficit by \$28.7 million, and increased beginning additional paid-in capital by \$4.4 million. The

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

amendments within ASU 2016-09 related to the presentation in the statement of cash flows of excess tax benefits and cash outflows attributable to the payment of employee tax withholdings on the net settlement of equity-classified awards were adopted using a retrospective method. In accordance with this method, we adjusted the statement of cash flows for the year ended December 31, 2016 by increasing both net cash provided by operating activities and net cash used by financing activities by \$26.6 million for the payment of employee tax withholdings on the net settlement of equity-classified awards. There were no cash flows related to excess tax benefits during the year ended December 31, 2016. For the year ended December 31, 2015, we adjusted the statement of cash flows for the payment of employee tax withholdings on the net settlement of equity-classified awards as well as for the classification of excess tax benefits by increasing net cash provided by operating activities and decreasing net cash provided by financing activities by \$34.2 million.

Restricted Stock

The following table provides information about restricted stock awards granted during the last three years.

				Years Ended	Dece	mber 31,			
-	20	17	-	20	16		20	15	
	Number of Shares		Weighted Average Grant Date Fair Value	Number of Shares	G	Weighted Average Grant Date Fair Value	Number of Shares	G	Veighted Average rant Date air Value
Performance stock awards	300,525	\$	89.46	269,915	\$	117.63	263,939	\$	87.12
Service-based stock awards	251,312	\$	94.04	208,724	\$	114.61	207,180	\$	114.80
Total restricted stock awards	551,837	\$	91.55	478,639	\$	116.31	471,119	\$	99.29

Performance stock awards were granted to eligible executives and are subject to service and market condition-based vesting determined by our stock price performance relative to a defined peer group's stock price performance. After three years of continued service, an executive will be entitled to vest in 50% to 100% of the award. In accordance with Internal Revenue Code Section 162(m), certain of the amounts awarded may not be deductible for tax purposes. Service-based stock awards granted to other eligible employees and non-employee directors have vesting schedules ranging from one to five years. The majority of our service-based stock awards cliff vest five years from the grant date.

Compensation cost for the performance stock awards is based on the grant date fair value of the award utilizing a Monte Carlo simulation model. Compensation cost for the service-based stock awards is based upon the grant date market value of the award. Such costs are recognized ratably over the applicable vesting period.

The following table provides information on restricted stock activity during the year.

	Service	-bas	ed	Perfor (subject to mar	
	Number of (Weighted Average Grant Date Fair Value	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding as of January 1, 2017.	934,723	\$	96.57	809,270	\$ 96.41
Vested	(234,468)	\$	63.49	(275,416)	\$ 84.50
Granted	251,312	\$	94.04	300,525	\$ 89.46
Forfeited	(41,316)	\$	105.83	_	\$ _
Outstanding as of December 31, 2017	910,251	\$	103.98	834,379	\$ 97.83

The total fair value of restricted stock that vested was \$54.4 million in 2017, \$67.9 million in 2016, and \$52.2 million in 2015.

Unrecognized compensation cost related to unvested restricted stock at December 31, 2017 was \$105.6 million. We expect to recognize that cost over a weighted average period of 2.8 years.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Restricted Units

As of December 31, 2017 and 2016, we had 8,838 restricted units outstanding. These represent restricted units held by a non-employee director who has elected to defer payment of common stock represented by the units until termination of his service on the Board of Directors.

Stock Options

Options outstanding as of December 31, 2017 expire seven to ten years from the grant date and have service-based vesting whereby the awards vest in increments of one-third on each of the first three anniversary dates of the grant. The exercise price for an option under the 2014 Plan is the closing price of our common stock as reported by the New York Stock Exchange ("NYSE") on the date of grant. The previous plans provided that all grants have an exercise price of the average of the high and low prices of our common stock as reported by the NYSE on the date of grant.

Compensation cost related to stock options is based on the grant date fair value of the award and is recognized ratably over the applicable vesting period. We estimate the fair value using the Black-Scholes option-pricing model. Expected volatilities are based on the historical volatility of our common stock. We also use historical data to estimate the expected years until exercise. We use U.S. Treasury bond rates in effect at the grant date for our risk-free interest rates.

The following summarizes information regarding options granted, including the assumptions used to determine the fair value of those options.

	Ye	ars En	ded Decembe	r 31,	
	2017		2016		2015
Options granted	 96,100		89,850		69,000
Weighted average grant date fair value	\$ 28.37	\$	33.38	\$	37.56
Weighted average exercise price	\$ 92.37	\$	114.07	\$	115.28
Total fair value (in thousands).	\$ 2,727	\$	2,999	\$	2,592
Expected years until exercise	4.5		4.0		5.0
Expected stock volatility	35.0%		36.7%		36.6%
Dividend yield	0.3%		0.3%		0.6%
Risk-free interest rate	1.7%		1.0%	ı	1.6%

Information about outstanding stock options is summarized below.

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Term	(i	Aggregate Intrinsic Value n thousands)
Outstanding as of January 1, 2017	307,810	\$ 101.72			
Exercised	(5,768)	\$ 68.33			
Granted	96,100	\$ 92.37			
Canceled	(1,665)	\$ 139.02			
Forfeited	(13,789)	\$ 88.92			
Outstanding as of December 31, 2017	382,688	\$ 100.17	4.4 years	\$	9,553
Exercisable as of December 31, 2017	209,782	\$ 98.55	3.2 years	\$	6,020

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table provides information regarding options exercised and the grant date fair value of options vested.

	Years Ended December 31,									
(in thousands)		2017		2016		2015				
Cash received from option exercises	\$	394	\$	4,804	\$	8,451				
Tax benefit from option exercises included in paid-in-capital	\$	_	\$		\$	4,442				
Intrinsic value of options exercised	\$	257	\$	2,994	\$	7,467				
Grant date fair value of options vested	\$	2,227	\$	2,486	\$	2,734				

The following summary reflects the status of non-vested stock options as of December 31, 2017 and changes during the year.

	Number of Options	Weighted Average Grant Date Fair Value	Weighted Average Exercise Price
Non-vested as of January 1, 2017	148,361	\$ 35.58	\$ 117.55
Vested	(57,766)	\$ 38.55	\$ 128.59
Granted	96,100	\$ 28.37	\$ 92.37
Forfeited	(13,789)	\$ 29.41	\$ 88.92
Non-vested as of December 31, 2017	172,906	\$ 31.08	\$ 102.15

As of December 31, 2017, there was \$4.1 million of unrecognized compensation cost related to non-vested stock options. We expect to recognize that cost over a weighted average period of 1.9 years.

Other Compensation

We maintain and sponsor a contributory 401(k) plan for our employees. Employer contributions related to the plan were \$10.4 million, \$6.7 million, and \$6.4 million for 2017, 2016, and 2015, respectively. Included in the 2017 amount are accrued employer discretionary contributions. No such employer discretionary contributions occurred in 2016 and 2015.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

7. EARNINGS (LOSS) PER SHARE

The calculations of basic and diluted net earnings (loss) per common share under the two-class method are presented below.

	Years Ended December 31,					
(in thousands, except per share data)		2017		2016		2015
Basic:						
Net income (loss)	\$	494,329	\$	(408,803)	\$	(2,579,604)
Participating securities' share in earnings (1)		(8,551)		_		_
Net income (loss) available to common stockholders	\$	485,778	\$	(408,803)	\$	(2,579,604)
Diluted:					_	
Net income (loss)	\$	494,329	\$	(408,803)	\$	(2,579,604)
Participating securities' share in earnings (1)		(8,548)		_		
Net income (loss) available to common stockholders	\$	485,781	\$	(408,803)	\$	(2,579,604)
Shares:						
Basic shares outstanding		93,466		93,379		92,992
Dilutive effect of stock options (2)		43		_		_
Fully diluted common stock		93,509		93,379		92,992
Earnings (loss) per share to common stockholders (3):					_	
Basic	\$	5.19	\$	(4.38)	\$	(27.75)
Diluted	\$	5.19	\$	(4.38)	\$	(27.75)

⁽¹⁾ Participating securities are not included in undistributed earnings when a loss exists.

8. ASSET RETIREMENT OBLIGATIONS

The following table reflects the components of the change in the carrying amount of the asset retirement obligation for the years ended December 31, 2017 and 2016.

(in thousands)	2017	2016
Asset retirement obligation at January 1,	\$ 154,523	\$ 164,105
Liabilities incurred	17,996	3,914
Liability settlements and disposals	(12,947)	(24,108)
Accretion expense.	7,534	7,595
Revisions of estimated liabilities	2,363	3,017
Asset retirement obligation at December 31,	169,469	154,523
Less current obligation	11,048	13,753
Long-term asset retirement obligation.	\$ 158,421	\$ 140,770

Liabilities incurred in 2017 includes \$10.5 million for the estimated liability to decommission two offshore properties in the Gulf of Mexico in which we were a prior lessee. In January 2018, the Bureau of Safety and Environmental Enforcement ("BSEE") notified us and other prior lessees that the current lessee of the properties had filed a petition for relief under the bankruptcy code and, as a result, had defaulted on its obligation to decommission the properties. Consequently, BSEE ordered us and other prior lessees to decommission all wells, pipelines, platforms, and other facilities related to these properties. Our estimate of our liability may change as we refine our understanding of the extent of our obligations under the orders from BSEE and obtain additional information on decommissioning costs.

⁽²⁾ Inclusion of certain shares would have an anti-dilutive effect; therefore, 302.9 thousand, 2.1 million, and 2.1 million shares were excluded from the calculations for the years ended December 31, 2017, 2016, and 2015, respectively.

⁽³⁾ Earnings (loss) per share are based on actual figures rather than the rounded figures presented.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

During 2017 and 2016, the liability settlements and disposals included \$0.5 million and \$14.9 million, respectively, related to properties that were sold.

9. INCOME TAXES

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

	Years Ended December 31,						
(in thousands)		2017	2016			2015	
Current taxes:							
Federal (benefit) expense	\$	(2,810)	\$	_	\$	14,417	
State (benefit) expense		(2)		(1,115)		293	
		(2,812)		(1,115)		14,710	
Deferred taxes:							
Federal expense (benefit)		173,859		(201,529)		(1,386,086)	
State expense (benefit)		16,620		(11,757)		(100,353)	
		190,479		(213,286)		(1,486,439)	
	\$	187,667	\$	(214,401)	\$	(1,471,729)	
			_				

Federal income tax expense (benefit) for the years presented differs from the amounts that would be provided by applying the U.S. federal income tax rate, primarily due to the effect of state income taxes, non-deductible expenses, revisions, and changes in tax laws and tax rates enacted in the period. Reconciliations of the income tax expense (benefit) calculated at the federal statutory rate of 35% to the total income tax expense (benefit) are as follows:

Years Ended December 31,						
	2017	2016		2015		
\$	238,699	\$	(218,122)	\$	(1,417,967)	
	10,074		(10,237)		(64,794)	
	_		7,181		5,997	
	5,442		5,296		5,035	
	486		1,481		_	
	(5,888)		_		_	
	(61,146)		_			
\$	187,667	\$	(214,401)	\$	(1,471,729)	
		\$ 238,699 10,074 	\$ 238,699 \$ 10,074 \$ 5,442 486 (5,888) (61,146)	2017 2016 \$ 238,699 \$ (218,122) 10,074 (10,237) — 7,181 5,442 5,296 486 1,481 (5,888) — (61,146) —	2017 2016 \$ 238,699 \$ (218,122) \$ 10,074 (10,237) - 7,181 5,442 5,296 486 1,481 (5,888) - (61,146) -	

The company recorded a \$33.1 million increase to the net operating loss deferred tax asset and corresponding increase to retained earnings in the first quarter of 2017 upon adoption of ASU 2016-09 for deductions taken for employee stock awards on the company's tax returns in excess of amounts expensed through the company's statement of operations. Pursuant to ASU 2016-09, excess tax benefits for employee share-based payments of \$5.9 million were recognized in income tax expense in 2017.

As a result of the enactment of H.R.1 on December 22, 2017, the company remeasured the 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. As a result of this remeasurement, we recorded an income tax benefit of \$61.1 million and a corresponding \$61.1 million decrease in net deferred tax liabilities as of December 31, 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. In addition, the limitations on utilization of net operating losses and deductibility of interest and executive compensation may result in the payment of cash taxes earlier than expected.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The components of net deferred taxes are as follows:

Decem	ber 3	1,
2017		2016
\$ 31,044	\$	58,306
313,738		399,912
3,995		6,016
348,777		464,234
(450,395)		(408,399)
\$ (101,618)	\$	55,835
\$	\$ 31,044 313,738 3,995 348,777 (450,395)	\$ 31,044 \$ 313,738 3,995 348,777

At December 31, 2017, we had a U.S. net tax operating loss carryforward of approximately \$1,377.7 million, which would expire in years 2031 through 2037. We believe that the carryforward will be utilized before it expires. We recorded a \$3.5 million increase to the net operating loss carryforward at December 31, 2017, for certain state losses and a corresponding increase in the state net operating loss valuation allowance of \$4.0 million. The net decrease in the state net operating losses after reduction for the valuation allowance was \$0.5 million. The total valuation allowance on state net operating losses at December 31, 2017 was \$103.7 million because it is not more likely than not that these additional state net operating losses will be utilized before they expire. There are no other valuation allowances. We also had an alternative minimum tax credit carryforward of approximately \$3.0 million and enhanced oil recovery and marginal well credits of \$0.9 million.

At December 31, 2017 and 2016, we had no unrecognized tax benefits that would impact our effective rate and we 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. We do not anticipate the need for any significant income tax payments in the near term.

10. COMMITMENTS AND CONTINGENCIES

Lease Commitments

We have various commitments for office space under operating lease arrangements. During the years ended December 31, 2017, 2016, and 2015, rent expense for these operating leases approximated \$13.1 million, \$12.9 million, and \$13.2 million, respectively.

Shown below are future minimum cash payments required under these leases as of December 31, 2017.

(in thousands)	
2018	\$ 9,742
2019	10,702
2020	10,836
2021	11,053
2022	11,222
Later years	32,645
Total future minimum lease payments	\$ 86,200

We have various commitments for compressor equipment under operating lease arrangements totaling \$8.5 million with lease terms expiring in the next 2 - 24 months.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Other Commitments

At December 31, 2017, we had estimated commitments of approximately: (i) \$252.6 million to finish drilling, completing, or performing other work on wells and various other infrastructure projects in progress and (ii) \$33.3 million to finish gathering system construction in progress.

At December 31, 2017, we had firm sales contracts to deliver approximately 217.6 Bcf of gas over the next 7.1 years. If we do not deliver this gas, our estimated financial commitment, calculated using the January 2018 index price, would be approximately \$476.7 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 8.3 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 December 31, 2017, would be approximately \$298.3 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 December 31, 2017, would be approximately \$11.4 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 December 31, 2017, we have various firm transportation agreements for pipeline capacity with end dates ranging from 2018 - 2025 under which we will have to pay an estimated \$36.5 million over the remaining terms of the agreements. These agreements were entered into to support our residue marketing efforts, and we believe we have sufficient reserves that will utilize this firm transportation.

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

Litigation

In the normal course of business, we are involved with various litigation matters. When a loss contingency exists, we assess whether it is probable that an asset has been impaired or a liability has been incurred and, if so, we determine if the amount of loss can be reasonably estimated, all in accordance with guidance established by the FASB, and adjust our accruals accordingly. Though some of the related claims may be significant, the resolution of them, we believe, 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.

H.B. Krug, et al. v. Helmerich & Payne, Inc.

In 2008, we recorded litigation expense of \$119.6 million for the *H.B. Krug, et al. v. Helmerich & Payne, Inc.* trial court verdict, and began accruing additional post-judgment interest and costs for this case.

On December 31, 2013, the Oklahoma Supreme Court reversed the trial court's \$119.6 million verdict and affirmed an alternative jury verdict for \$3.65 million. The Supreme Court also remanded the case back to the trial court for consideration of potential prejudgment interest, attorney's fees, and cost awards. Accordingly, on December 31, 2013 we reduced the previously recognized litigation expense, which included related interest and costs, and the associated long-term liability by \$142.8 million.

On April 1, 2014, Cimarex paid the Plaintiffs \$15.8 million in satisfaction of the \$3.65 million damages award, the post-judgment interest award, and the payment in lieu of bond, all of which are now final and not appealable. On June 24, 2014, the trial court ruled the Plaintiffs were not entitled to prejudgment interest but were entitled to attorney's fees and costs, the amount of which will be determined at a subsequent hearing. On November 3, 2015, the Oklahoma Supreme Court affirmed the trial court's denial of prejudgment interest. The only remaining issue is the amount of Plaintiffs' award of attorney's fees, which is subject to future trial, and appellate court proceedings and, therefore, cannot be determined at this time.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

11. RELATED PARTY TRANSACTIONS

Helmerich & Payne, Inc. ("H&P") provides contract drilling services to Cimarex. Cimarex incurred drilling costs of approximately \$52.6 million, \$18.3 million, and \$7.9 million related to these services during the years ended December 31, 2017, 2016, and 2015, respectively. Hans Helmerich, a director of Cimarex, is Chairman of the Board of Directors of H&P.

12. SUPPLEMENTAL CASH FLOW INFORMATION

<u> </u>	Years Ended December 31,							
(in thousands)		2017		2016		2015		
Cash paid during the period for:								
Interest expense (net of capitalized amounts of \$23,113, \$20,308, and \$28,819, respectively)	\$	52,245	\$	59,282	\$	51,966		
Income taxes	\$	3	\$	13	\$	558		
Cash received for income tax refunds	\$	111	\$	1,450	\$	1,503		

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

Oil and Gas Reserve Information—Proved reserve quantities are based on estimates prepared by Cimarex in accordance with guidelines established by the Securities and Exchange Commission ("SEC").

Reserve definitions comply with definitions of Rule 4-10(a) (1)-(32) of Regulation S-X of the SEC. All of our reserve estimates are maintained by our internal Corporate Reservoir Engineering group, which is comprised of reservoir engineers and engineering technicians. The objectives and management of this group are separate from and independent of the exploration and production functions of our company. The technical employee primarily responsible for overseeing the reserve estimation process is our company's Vice President of Corporate Engineering. This individual graduated from the Colorado School of Mines with a Bachelor of Science degree in Engineering and has more than 23 years of practical experience in reserve evaluation. He has been directly involved in the annual reserve reporting process of Cimarex since 2002 and has served in his current role for the past 13 years.

DeGolyer and MacNaughton, an independent petroleum engineering consulting firm, reviewed reserves associated with greater than 80% of the total future net revenue discounted at 10% attributable to the total interests owned by Cimarex as of December 31, 2017. The individual primarily responsible for overseeing the review is a Senior Vice President with DeGolyer and MacNaughton and a Registered Professional Engineer in the State of Texas with over 33 years of experience in oil and gas reservoir studies and reserves evaluations.

Proved reserves are those quantities of oil, gas, and NGLs which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

There are numerous uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production and the timing of development expenditures. The estimation of our proved reserves employs one or more of the following: production trend extrapolation, analogy, volumetric assessment, and material balance analysis. Techniques including review of production and pressure histories, analysis of electric logs and fluid tests, and interpretations of geologic and geophysical data are also involved in this estimation process.

The following table summarizes the trailing twelve-month index prices used in the reserves estimates for 2017, 2016, and 2015. These prices are prior to adjustments for fixed and determinable amounts under provisions in existing contracts, location, grade, and quality.

	December 31,								
	2017		2016		2015				
Gas price per Mcf	\$	2.98	\$	2.48	\$	2.59			
Oil price per Bbl	\$	51.34	\$	42.75	\$	50.28			
NGL price per Bbl	\$	19.09	\$	14.37	\$	14.41			

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

The following table sets forth our estimates of our proved, proved developed, and proved undeveloped oil, gas, and NGL reserves as of December 31, 2017, 2016, 2015, and 2014 and changes in our proved reserves for the years ended December 31, 2017, 2016, and 2015. All of our proved reserves are located entirely within the U.S.

	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MMcfe)
Total proved reserves:				
December 31, 2014	1,666,733	118,992	125,273	3,132,323
Revisions of previous estimates	(154,390)	(14,633)	(5,668)	(276,192)
Extensions and discoveries	183,084	22,859	18,079	428,714
Purchases of reserves	15	1	1	25
Production	(168,987)	(18,663)	(13,063)	(359,343)
Sales of reserves	(9,503)	(758)	(345)	(16,120)
December 31, 2015	1,516,952	107,798	124,277	2,909,407
Revisions of previous estimates	5,888	(4,357)	6,670	19,761
Extensions and discoveries	123,175	19,419	14,050	323,987
Purchases of reserves	959	1		965
Production	(168,227)	(16,528)	(14,200)	(352,591)
Sales of reserves	(7,327)	(455)	(164)	(11,042)
December 31, 2016	1,471,420	105,878	130,633	2,890,487
Revisions of previous estimates	(39,749)	(1,225)	(2,099)	(59,706)
Extensions and discoveries	363,774	53,464	42,692	940,714
Purchases of reserves	642	42	78	1,363
Production	(187,468)	(20,861)	(17,374)	(416,875)
Sales of reserves	(984)	(60)	(70)	(1,761)
December 31, 2017	1,607,635	137,238	153,860	3,354,222
Proved developed reserves:				
December 31, 2014	1,263,957	100,050	89,630	2,402,033
December 31, 2015	1,129,490	89,189	87,549	2,189,920
December 31, 2016	1,144,720	92,032	99,176	2,291,966
December 31, 2017	1,334,510	114,116	126,227	2,776,565
Proved undeveloped reserves:				
December 31, 2014	402,776	18,942	35,643	730,290
December 31, 2015	387,462	18,609	36,728	719,487
December 31, 2016	326,700	13,846	31,457	598,521
December 31, 2017	273,125	23,122	27,633	577,657

Year-end 2017 proved reserves increased approximately 16% from year-end 2016 proved reserves, to 3.35 Tcfe. Proved natural gas reserves were 1.61 Tcf, proved oil reserves were 0.82 Tcfe, and proved NGL reserves were 0.92 Tcfe. Our reserves in the Mid-Continent accounted for 52% of total proved reserves, with nearly all of the remainder in the Permian Basin.

During 2017, we added 940.7 Bcfe of proved reserves through extensions and discoveries, primarily in the Mid-Continent and Permian Basin where we added 282.9 Bcfe and 657.8 Bcfe, respectively. In addition, we had net negative revisions of 59.7 Bcfe. The revisions included decreases of 248.8 Bcfe for the removal of PUD reserves whose development will likely be delayed beyond five years of initial disclosure and 43.9 Bcfe related to increases in operating expenses. These decreases were partially offset by increases of 187.2 Bcfe in price-related revisions and 45.8 Bcfe of net technical revisions related primarily to better than expected performance from wells with initial production in late 2016.

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

During 2016, we added 324.0 Bcfe of proved reserves through extensions and discoveries, primarily in the Mid-Continent and Permian Basin where we added 121.6 Bcfe and 198.7 Bcfe, respectively. In addition, we had net positive revisions of 19.8 Bcfe. The revisions included increases of 126.2 Bcfe for net performance revisions and 138.5 Bcfe related to decreases in operating expenses, partially offset by negative revisions of 244.9 Bcfe due to lower commodity prices. The performance revisions resulted primarily from positive adjustments to previously booked PUD reserves (72.3 Bcfe) and better than expected performance from wells with initial production in late 2015.

During 2015, we added 428.7 Bcfe of proved reserves through extensions and discoveries, primarily in the Mid-Continent and Permian Basin, where we added 176.8 Bcfe and 251.1 Bcfe, respectively. During 2015, we had net negative reserve revisions of 276.2 Bcfe. The significant decrease in commodity prices seen in 2015 resulted in negative revisions of 398.8 Bcfe due to prices. In addition, 19.1 Bcfe of negative revisions were due to increases in operating expenses, which shortened the economic lives of properties. These decreases were partially offset by net positive performance revisions of 141.7 Bcfe, which included 47.4 Bcfe for better than expected performance of PUD reserves converted to proved developed reserves during the year and positive adjustments of 95.3 Bcfe to previously booked PUD reserves.

At December 31, 2017, we had PUD reserves of 577.7 Bcfe, down 20.8 Bcfe, or 3%, from 598.5 Bcfe of PUD reserves at December 31, 2016. Changes in our PUD reserves are summarized in the table below (in Bcfe).

PUD reserves at December 31, 2016	598.5
Converted to developed	(61.1)
Additions	307.3
Net revisions	(267.0)
PUD reserves at December 31, 2017	577.7

During 2017, we invested \$69.5 million to develop and convert 10% of our 2016 PUD reserves to proved developed reserves. During 2016, we invested \$108.8 million to develop PUD reserves, converting 14% of our 2015 PUD reserves to proved developed reserves. During 2015, we invested \$246.5 million to develop PUD reserves, converting 24% of our 2014 PUD reserves to proved developed reserves.

During 2017, 234.4 Bcfe, or 76%, of our 307.3 Bcfe of PUD reserve additions occurred in the Permian Basin, while the remainder of the additions were in our western Oklahoma Cana area. At December 31, 2017, 41% of our PUD reserves were in the Permian Basin, while the remainder were in our western Oklahoma Cana area. We have no PUD reserves that have remained undeveloped for five years or more after initial disclosure and we have no PUD reserves whose scheduled delay to initiation of development is beyond five years of initial disclosure.

During 2017, we had net negative PUD reserve revisions of 267.0 Bcfe. Of this total, 248.8 Bcfe was for the removal of PUD reserves whose development will likely be delayed beyond five years of initial disclosure. The remaining 18.2 Bcfe of net negative adjustments was comprised of negative technical revisions of 20.1 Bcfe to remaining previously booked PUD reserves and 4.5 Bcfe of negative revisions from higher projected operating expenses that were partially offset by 6.4 Bcfe of positive price-related revisions.

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

Costs Incurred—The following table sets forth the capitalized costs incurred in our oil and gas production, exploration, and development activities.

	Years Ended December 31,								
(in thousands)		2017	2016			2015			
Costs incurred during the year:									
Acquisition of properties									
Proved	\$	938	\$	2,678	\$	30			
Unproved		135,565		67,961		41,233			
Exploration		11,804		5,814		6,902			
Development		1,140,548		672,842		823,830			
Oil and gas expenditures		1,288,855		749,295		871,995			
Property sales		(11,680)		(24,687)		(41,276)			
		1,277,175		724,608		830,719			
Asset retirement obligation, net		9,416		(7,950)		(4,818)			
	\$	1,286,591	\$	716,658	\$	825,901			

Aggregate Capitalized Costs—The table below reflects the aggregate capitalized costs relating to our oil and gas producing activities at December 31, 2017.

(in thousands)	
Proved properties	\$ 17,513,460
Unproved properties and properties under development, not being amortized	476,903
	17,990,363
Less-accumulated depreciation, depletion, amortization, and impairments	(14,748,833)
Net oil and gas properties	\$ 3,241,530

Costs Not Being Amortized—The following table summarizes oil and gas property costs not being amortized at December 31, 2017, by year that the costs were incurred.

(in thousands)	
2017	\$ 266,124
2016	53,076
2015	32,592
2014 and prior.	125,111
	\$ 476,903

Of the costs not being amortized, \$140.0 million (29%) relates to unevaluated wells in progress and \$47.7 million (10%) is capitalized interest. The remaining \$289.2 million (61%) is for land and seismic expenditures, most of which were for costs invested in our Mid-Continent region (\$104.6 million) and our Permian Basin region (\$169.1 million). On a quarterly basis, we evaluate excluded costs for inclusion in the costs to be amortized. Significant unproved properties are evaluated individually. Unproved properties that are not considered individually significant are aggregated for evaluation purposes and related costs are transferred to the costs to be amortized quarterly based on the application of historical factors. We expect to include these costs in the amortization computation as we continue with our exploration and development plans.

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

Oil and Gas Operations—The following table contains direct revenue and cost information relating to our oil and gas exploration and production activities for the periods indicated. We have no long-term supply or purchase agreements with governments or authorities in which we act as producer. Income tax expense related to our oil and gas operations is computed using the effective tax rate for the period, with the 2017 effective tax rate adjusted to remove the impact of the reduction in the federal statutory rate.

	Years Ended December 31,						
(in thousands, except per Mcfe)	2017 2016					2015	
Oil, gas, and NGL revenues from production	\$	1,874,003	\$	1,221,218	\$	1,417,538	
Less operating costs and income taxes:							
Impairment of oil and gas properties				757,670		4,033,295	
Depletion		399,328		346,003		689,120	
Asset retirement obligation		15,624		7,828		9,121	
Production		262,180		232,002		299,374	
Transportation, processing, and other operating		254,730		210,144		183,134	
Taxes other than income		89,864		61,946		84,764	
Income tax expense (benefit)		310,937		(135,665)		(1,410,065)	
		1,332,663		1,479,928		3,888,743	
Results of operations from oil and gas producing activities	\$	541,340	\$	(258,710)	\$	(2,471,205)	
Depletion rate per Mcfe.	\$	0.96	\$	0.98	\$	1.92	

Standardized Measure of Future Net Cash Flows—The Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves ("Standardized Measure") is calculated in accordance with guidance provided by the FASB. The Standardized Measure does not purport, nor should it be interpreted, to present the fair value of a company's proved oil and gas reserves. Fair value would require, among other things, consideration of expected future economic and operating conditions, varying price and cost assumptions, and risks inherent in reserve estimates.

Under the Standardized Measure, future cash inflows are based upon the forecasted future production of year-end proved reserves. Future cash inflows are then reduced by estimated future production and development costs to determine net pre-tax cash flow. Future income taxes are computed by applying the statutory tax rate to the excess of pre-tax cash flow over our tax basis in the associated oil and gas properties. Tax credits and permanent differences are also considered in the future income tax calculation. Future net cash flow after income taxes is discounted using a 10% annual discount rate to arrive at the Standardized Measure.

The following summary sets forth our Standardized Measure.

	December 31,							
(in thousands)		2017		2016		2015		
Future cash inflows	\$	11,967,325	\$	7,576,211	\$	8,839,485		
Future production costs		(4,360,599)		(2,970,891)		(3,521,881)		
Future development costs		(948,735)		(794,298)		(1,058,020)		
Future income tax expenses.		(882,519)		(507,145)		(728,029)		
Future net cash flows		5,775,472		3,303,877		3,531,555		
10% annual discount for estimated timing of cash flows		(2,490,471)		(1,411,259)		(1,597,424)		
Standardized measure of discounted future net cash flows	\$	3,285,001	\$	1,892,618	\$	1,934,131		

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

The estimates of cash flows shown above are based upon the unweighted trailing twelve-month average first-day-of-themonth benchmark prices. See table above under *Oil and Gas Reserve Information* for prices used in determining the Standardized Measure. If future gas sales are covered by contracts at specified prices, the contract prices would be used. Prices are market driven and will fluctuate due to supply and demand factors, seasonality, and geopolitical and economic factors.

The following are the principal sources of change in the Standardized Measure.

	Years Ended December 31,					
(in thousands)		2017		2016		2015
Standardized Measure, beginning of period	\$	1,892,618	\$	1,934,131	\$	4,352,845
Sales, net of production costs		(1,267,229)		(717,126)		(850,267)
Net change in sales prices, net of production costs		855,024		(429,956)		(4,262,261)
Extensions and discoveries, net of future production and development costs		1,443,577		517,702		573,373
Changes in future development costs		298,819		167,387		280,163
Previously estimated development costs incurred during the period		78,398		110,945		214,749
Revision of quantity estimates		(65,376)		15,701		(240,063)
Accretion of discount		212,192		227,904		638,948
Change in income taxes.		(210,519)		115,609		1,691,721
Purchases of reserves in place		2,255		429		20
Sales of reserves		(1,666)		(9,440)		(26,225)
Change in production rates and other		46,908		(40,668)		(438,872)
Standardized Measure, end of period	\$	3,285,001	\$	1,892,618	\$	1,934,131

SUPPLEMENTAL QUARTERLY FINANCIAL DATA (UNAUDITED)

	Quarter										
2017 First			Second		Third	Fourth					
(in thousands, except per share data)											
Revenues	\$	447,176	\$	456,452	\$	463,681	\$	550,940			
Expenses, net		316,204		359,190		372,282		376,244			
Net income	\$	130,972	\$	97,262	\$	91,399	\$	174,696			
Earnings per share to common stockholders:											
Basic	\$	1.38	\$	1.02	\$	0.96	\$	1.83			
Diluted	\$	1.38	\$	1.02	\$	0.96	\$	1.83			

	Quarter										
2016	First		Second		Third			Fourth			
(in thousands, except per share data)											
Revenues	\$	240,600	\$	298,873	\$	335,717	\$	382,155			
Expenses, net (1)		472,059		513,327		346,390		334,372			
Net (loss) income	\$	(231,459)	\$	(214,454)	\$	(10,673)	\$	47,783			
Earnings (loss) per share to common stockholders:											
Basic	\$	(2.49)	\$	(2.31)	\$	(0.12)	\$	0.50			
Diluted	\$	(2.49)	\$	(2.31)	\$	(0.12)	\$	0.50			

⁽¹⁾ The 2016 quarterly expenses, net include non-cash impairments to our oil and gas properties of \$318.8 million (or \$3.43 per diluted share), \$333.3 million (or \$3.58 per diluted share), and \$105.6 million (or \$1.13 per diluted share) for the first quarter through the third quarter of 2016, respectively, as discussed in Note 1 to the Consolidated Financial Statements under *Oil and Gas Properties*.

The sum of the individual quarterly earnings (loss) per common share amounts may not agree with year-to-date earnings (loss) per common share because each quarter's computation is based on the number of shares outstanding at the end of the applicable quarter using the two-class method.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. 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 (Exchange Act)) as of December 31, 2017. 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.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Cimarex's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act). The company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Our internal control over financial reporting also includes those policies and procedures that:

- (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets;
- (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with authorizations of management and directors; and
- (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the consolidated financial statements.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of the effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As of December 31, 2017, Cimarex's management assessed the effectiveness of internal control over financial reporting based on the criteria set forth in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that assessment, management concluded that the internal control over financial reporting was effective as of December 31, 2017.

Our independent registered public accounting firm, KPMG LLP, has audited the effectiveness of our internal control over financial reporting and has issued a report as of December 31, 2017, which follows this report.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There was no change in our internal control over financial reporting that occurred during our most recent fiscal quarter ended December 31, 2017 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors

Cimarex Energy Co.:

Opinion on Internal Control Over Financial Reporting

We have audited Cimarex Energy Co. and subsidiaries' (the "Company") internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets of the Company as of December 31, 2017 and 2016, the related consolidated statements of operations and comprehensive income (loss), stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes (collectively, the consolidated financial statements), and our report dated February 23, 2018 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

KPMG LLP

Denver, Colorado February 23, 2018

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information concerning the directors of Cimarex and the late filing of a Form 5 required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 10, 2018 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2017. The executive officers of Cimarex as of February 23, 2018 were:

Name	Age	Office
Thomas E. Jorden	60	Chairman of the Board, Chief Executive Officer and President
Joseph R. Albi	59	Executive Vice President — Operations, Chief Operating Officer
Stephen P. Bell	63	Executive Vice President — Business Development
G. Mark Burford	50	Vice President and Chief Financial Officer
Francis B. Barron	55	Senior Vice President — General Counsel
John A. Lambuth	55	Senior Vice President — Exploration
Gary R. Abbott	45	Vice President — Corporate Engineering
Krista L. Johnson	47	Vice President — Human Resources, Governmental Relations, and External Affairs
Timothy A. Ficker	50	Vice President — Controller, Chief Accounting Officer, and Assistant Secretary

There are no family relationships by blood, marriage, or adoption among any of the above executive officers. All executive officers are elected annually by the board of directors to serve for one year or until a successor is elected and qualified. There is no arrangement or understanding between any of the officers and any other person pursuant to which he or she was selected as an executive officer.

THOMAS E. JORDEN was elected Chairman of the Board effective August 14, 2012 after being named President and Chief Executive Officer effective September 30, 2011. Since December 8, 2003, Mr. Jorden served as Executive Vice President of Exploration and had served in a similar capacity since September 30, 2002. Prior to September 2002, Mr. Jorden was with Key Production Company, Inc., where he served as Vice President of Exploration (October 1999 to September 2002) and Chief Geophysicist (November 1993 to September 1999). Prior to joining Key, Mr. Jorden was with Union Pacific Resources.

JOSEPH R. ALBI was named Executive Vice President and Chief Operating Officer effective September 30, 2011. Mr. Albi served as Executive Vice President of Operations since March 1, 2005. Since December 8, 2003, Mr. Albi served as Senior Vice President of Corporate Engineering. From September 30, 2002 to December 8, 2003, he served as Vice President of Engineering. From June 1994 to September 2002, Mr. Albi was with Key Production Company, Inc. where he served as Vice President of Engineering and Manager of Engineering.

STEPHEN P. BELL was named Executive Vice President, Business Development effective September 13, 2012. Since September 2002, Mr. Bell served as Senior Vice President of Business Development and Land. Prior to its merger with Cimarex, Mr. Bell was with Key Production Company, Inc. since February 1994. In September 1999, he was appointed Senior Vice President, Business Development and Land. From February 1994 to September 1999, he served as Vice President, Land.

G. MARK BURFORD was named Vice President and Chief Financial Officer in September 2015. He was appointed Vice President, Capital Markets and Planning in December 2010. Mr. Burford joined Cimarex in April 2005 as Director of Capital Markets. Prior to joining Cimarex, he was Director of Investor Relations for Whiting Petroleum and Tom Brown, Inc. His experience also includes equity research with Petrie Parkman & Co., an investment banking firm, and public accounting.

FRANCIS B. BARRON joined Cimarex as Senior Vice President, General Counsel in July 2013. From February 2004 until July 2013, Mr. Barron served in various capacities at Bill Barrett Corporation, a publicly traded, Denver-based oil and gas exploration and development company, including as Executive Vice President, General Counsel, and Secretary. He also served as Chief Financial Officer from November 2006 until March 2007. Prior to February 2004, Mr. Barron was a partner at the Denver, Colorado office of the law firm of Patton Boggs LLP as well as a partner at Bearman Talesnick & Clowdus Professional Corporation. Mr. Barron's practice included corporate, securities, and business law for publicly traded oil and gas companies.

JOHN A. LAMBUTH was named Senior Vice President of Exploration in December 2015. Prior to his promotion, he served as the Company's Vice President of Exploration since September 2012 and Chief Geophysicist, a position he held since joining Cimarex in 2004. Mr. Lambuth began his career in 1985 with Shell Oil Co., where he held various positions in exploration and in research and development. Immediately prior to joining Cimarex, he spent three years as onshore Exploration Manager of El Paso Energy Company.

GARYR. ABBOTT was elected Vice President of Corporate Engineering March 1, 2005. Since January 2002, Mr. Abbott served as manager, Corporate Reservoir Engineering. From April 1999 to January 2002, Mr. Abbott was a reservoir engineer with Key Production Company, Inc.

KRISTA L. JOHNSON joined Cimarex as Vice President of Governmental and External Affairs in November 2014. Previously she served at Shell Oil Company since 2006, her last role as Vice President, International Organizations. Prior to joining Shell, she spent eight years with Western Gas Resources, most recently as Director of Government and Media Relations. Her experience also includes private practice in oil and gas law, client based energy advocacy in Washington, work in the Federal Relations Department of the American Petroleum Institute, and in the office of former U.S. Senator Conrad Burns.

TIMOTHY A. FICKER was appointed Vice President, Controller, Chief Accounting Officer, and Assistant Secretary in December 2016 to be effective in February 2017 and previously served as the Company's Controller since September 2016. From February 2015 until September 2016, he served as Chief Financial Officer and Principal of Alcova Management LLC, a start-up oil and gas exploration and production company concentrating on the Powder River Basin of Wyoming. Mr. Ficker served as Chief Financial Officer of Venoco, Inc., and in other capacities from March 2007 to November 2014. From May 2005 to March 2007, he served as Vice President, Chief Financial Officer, Principal Accounting Officer, and Secretary of Infinity Energy Resources Inc. Mr. Ficker previously served as an audit partner in KPMG LLP's energy audit practice in Denver and as an audit partner for Arthur Andersen LLP, where he served clients primarily in the energy industry. His energy clients at KPMG and Arthur Andersen were principally domestic exploration and production companies.

ITEM 11. EXECUTIVE COMPENSATION

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 10, 2018 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2017.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 10, 2018 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2017.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 10, 2018 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2017.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 10, 2018 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2017.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

		Page
(a)(1)	The following financial statements are included in Item 8 to this 10-K:	
	Consolidated Balance Sheets as of December 31, 2017 and 2016	59
	Consolidated Statements of Operations and Comprehensive Income (Loss) for the years ended December 31, 2017, 2016, and 2015	60
	Consolidated Statements of Cash Flows for the years ended December 31, 2017, 2016, and 2015	61
	Consolidated Statements of Stockholders' Equity for the years ended December 31, 2017, 2016, and 2015	62
	Notes to Consolidated Financial Statements	63
(2)	Financial statement schedules—None	
(3)	Exhibits:	

Exhibits not incorporated by reference to a prior filing are designated by an asterisk (*) and are filed herewith; all exhibits not so designated are incorporated by reference to a prior SEC filing as indicated.

Exhibit Title

- 3.1 Amended and Restated Certificate of Incorporation of Cimarex Energy Co. (filed as Exhibit 3.1 to Registrant's Form 8-K (Commission File no. 001-31446) dated June 7, 2005 and incorporated herein by reference).
- 3.2 Amended and Restated By-laws of Cimarex Energy Co. dated December 11, 2013 (filed on December 16, 2013 (Commission File No. 001-31446) and incorporated herein by reference).
- 3.3 Amended and Restated By-laws of Cimarex Energy Co. dated November 11, 2015 (filed as Exhibits 3.1 and 3.2 to the Current Report on Form 8-K filed on November 12, 2015 (Commission File No. 001-31446) and incorporated herein by reference).
- 4.1 Specimen Certificate of Cimarex Energy Co. common stock (filed as Exhibit 4.3 to Registration Statement on Form S-3 filed September 17, 2012 (Registration No. 333-183939) and incorporated herein by reference).
- 4.2 Debt Securities Indenture dated as of April 5, 2012, by and among Cimarex Energy Co. and U.S. Bank National Association, as trustee included as Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on April 5, 2012 and incorporated herein by reference.
- 4.3 First Supplemental Indenture dated as of April 5, 2012, by and among Cimarex Energy Co., the Subsidiary Guarantors party thereto and U.S. Bank National Association, as trustee included as Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on April 5, 2012 and incorporated herein by reference.
- 4.4 Form of 5.875% Senior Notes due 2022 included in Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on April 5, 2012 and incorporated herein by reference.
- 4.5 Indenture dated as of June 4, 2014, by and between Cimarex Energy Co. and U.S. Bank National Association, as trustee included as Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on June 4, 2014 and incorporated herein by reference.
- 4.6 First Supplemental Indenture dated as of June 4, 2014, by and among Cimarex Energy Co., the Subsidiary Guarantors party thereto and U.S. Bank National Association, as trustee included as Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on June 4, 2014 and incorporated herein by reference.
- 4.7 Form of 4.375% Senior Notes due 2024 included in Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on June 4, 2014 and incorporated herein by reference.

Exhibit Title

4.8 Form of Indenture by and among Cimarex Energy Co. and U.S. Bank National Association, as trustee (filed as Exhibit 4.7 to Registration Statement on Form S-3 filed September 21, 2015 (Registration No. 333-183939) and incorporated herein by reference).

- 4.9 Indenture dated as of April 10, 2017, by and between Cimarex Energy Co. and U.S. Bank National Association, as trustee included as Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on April 10, 2017 and incorporated herein by reference.
- 4.10 First Supplemental Indenture dated as of April 10, 2017, by and between Cimarex Energy Co. and U.S. Bank National Association, as trustee included as Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on April 10, 2017 and incorporated herein by reference.
- 4.11 Form of 3.90% Senior Notes due 2027 included in Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on April 10, 2017 and incorporated herein by reference.
- 10.1 Credit Agreement dated as of July 14, 2011, among Cimarex, the Administrative Agent, the Co-Syndication Agents, the Co-Documentation Agents and the Lenders filed on July 18, 2011 as Exhibit 10.1 to the Registrant's Current Report on Form 8-K and incorporated herein by reference.
- 10.2 First Amendment to Credit Agreement dated as of July 19, 2012, among Cimarex, the Guarantors, the Administrative Agent, and the Lenders filed on May 5, 2014 as Exhibit 10.1 to the Registrant's Current Report on Form 8-K and incorporated herein by reference.
- 10.3 Second Amendment to Credit Agreement dated as of May 1, 2014, among Cimarex, the Guarantors, the Administrative Agent, and the Lenders filed on May 5, 2014 as Exhibit 10.2 to the Registrant's Current Report on Form 8-K and incorporated herein by reference.
- 10.4 Employment Agreement, dated September 7, 1999, by and between Paul Korus and Key Production Company, Inc. (filed as Exhibit 10.6 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).
- 10.5 Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Paul Korus (filed as Exhibit 10.9 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
- 10.6 Employment Agreement, dated October 25, 1993, by and between Thomas E. Jorden and Key Production Company, Inc. (filed as Exhibit 10.7 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).
- 10.7 Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Thomas E. Jorden (filed as Exhibit 10.11 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
- 10.8 Employment Agreement, dated February 2, 1994, by and between Stephen P. Bell and Key Production Company, Inc. (filed as Exhibit 10.8 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).
- 10.9 Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Stephen P. Bell (filed as Exhibit 10.13 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
- 10.10 Employment Agreement, dated March 11, 1994, by and between Joseph R. Albi and Key Production Company, Inc. (filed as Exhibit 10.9 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

Exhibit Title

10.11 Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Joseph R. Albi (filed as Exhibit 10.15 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

- 10.12 Amended and Restated 2002 Stock Incentive Plan of Cimarex Energy Co. effective January 1, 2009 (filed as Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001- 31446) and incorporated herein by reference).
- 10.13 2011 Equity Incentive Plan adopted May 18, 2011 (filed as Appendix A to the Definitive Proxy Statement 14-A filed on March 23, 2011 (Commission File No. 001-31446) and incorporated herein by reference).
- 10.14 Form of Notice of Grant of Award of Performance Stock and Award Agreement (filed as Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 filed on August 4, 2011 (Commission File no. 001-31446) and incorporated herein by reference).
- 10.15 Form of Notice of Grant of Restricted Stock and Award Agreement (filed as Exhibit 10.3 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 filed on August 4, 2011 (Commission File no. 001-31446) and incorporated herein by reference).
- 10.16 Form of Notice of Grant of Nonqualified Stock Option and Award Agreement (filed as Exhibit 10.4 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 filed on August 4, 2011 (Commission File no. 001-31446) and incorporated herein by reference).
- 10.17 Form of Notice of Grant and Award Agreement (Other Stock Award with performance conditions) (filed as Exhibit 10.15 to the Annual Report on Form 10-K for the year ended December 31, 2013 filed on February 26, 2014 (Commission File No. 001-31446) and incorporated herein by reference).
- 10.18 2014 Equity Incentive Plan adopted May 15, 2014 (filed as Appendix A to the Definitive Proxy Statement 14-A filed on April 1, 2014 (Commission File No. 001-31446) and incorporated herein by reference.
- 10.19 Form of Notice of Grant of Restricted Stock (Director) and Award Agreement (filed as Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 filed on August 6, 2014 (Commission File No. 001-31446) and incorporated herein by reference).
- 10.20 Form of Notice of Grant of Nonqualified Stock Option and Award Agreement (filed as Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 filed on August 6, 2014 (Commission File No. 001-31446) and incorporated herein by reference).
- 10.21 Form of Notice of Grant of Restricted Stock and Award Agreement (filed as Exhibit 10.3 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 filed on August 6, 2014 (Commission File No. 001-31446) and incorporated herein by reference).
- 10.22 Form of Notice of Grant of Restricted Stock and Award Agreement (Performance Award) (filed as Exhibit 10.4 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 filed on August 6, 2014 (Commission File No. 001-31446) and incorporated herein by reference).
- 10.23 Form of Notice of Grant of Restricted Stock and Award Agreement (Performance Award) (filed as Exhibit 10.23 to the Annual Report on Form 10-K for the year ended December 31, 2014 filed on February 25, 2015 (Commission File No. 001-31446) and incorporated herein by reference).
- 10.24 Deferred Compensation Plan for Nonemployee Directors adopted May 19, 2004, as amended and restated effective January 1, 2009 (filed as Exhibit 10.18 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

Exhibit Title 10.25 Cimarex Energy Co. Supplemental Savings Plan (amended and restated, effective January 1, 2009) (filed as Exhibit 10.19 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference). Cimarex Energy Co. Change in Control Severance Plan dated effective April 1, 2005, amended and restated effective January 1, 2009 (filed as Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference). Amendment to Cimarex Energy Co. Change in Control Severance Plan dated effective March 19, 2013 (filed as Exhibit 10.1 to the Current Report on Form 8-K filed on March 20, 2013 (Commission File No. 001-31446) and incorporated herein by reference). 10.28 Form of Indemnification Agreement between Cimarex Energy Co. and each of its executive officers and directors (filed as Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2012 filed on February 26, 2013 (Commission File No. 001-31446) and incorporated herein by reference). 10.29 Retention Agreement dated June 9, 2010 (filed as Exhibit 10.21 to the Annual Report on Form 10-K for the year ended December 31, 2013 filed on February 26, 2014 (Commission File No. 001-31446) and incorporated herein by reference). 10.30 Credit Agreement Dated as of October 16, 2015, by and among Cimarex, the Administrative Agent, the Syndication Agent, the Documentation Agents, and the Lenders (filed on October 19, 2015 as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Commission File No. 001-31446) and incorporated herein by reference). Form of Notice of Grant of Restricted Stock (Director) and Award Agreement (filed as Exhibit 10.2 to Registrant's Form 8-K (Commission File No. 001-31446) dated November 2, 2015 and incorporated herein by reference). Succession Agreement dated August 17, 2015 (filed as Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015 filed on November 4, 2015 (Commission File No. 001-31446) and incorporated herein by reference). 10.33 Form of Notice of Grant of Restricted Stock (Director) and Award Agreement (filed as Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q filed on August 9, 2017 and incorporated herein by reference). Code of Ethics for Chief Executive Officer and Senior Financial Officers (filed as Exhibit 14.1 to the Annual Report on Form 10-K for the year ended December 31, 2003 filed on March 11, 2004 (Commission File No. 001-31446) and incorporated herein by reference). Revised Code of Business Conduct and Ethics for Directors, Officers, and Employees dated August 30, 2016 (filed as Exhibit 14.1 and 14.2 to the Current Report on Form 8-K filed September 1, 2016 (Commission File No. 001-31446) and incorporated herein by reference). Significant subsidiaries of the Registrant.* 21.1 23.1 Consent of KPMG LLP.* 23.2 Consent of DeGolyer and MacNaughton.*

31.1 Certification of Thomas E. Jorden, Chief Executive Officer of Cimarex Energy Co., pursuant to Section 302 of

Power of Attorney of directors of the Registrant.*

the Sarbanes-Oxley Act of 2002.*

24.1

Exhibit	Title
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.*
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.*
99.1	Letter dated January 16, 2018 from DeGolyer and MacNaughton, independent petroleum engineering consulting firm, reporting the results of its audit of Cimarex reserves as of December 31, 2017 of certain selected properties.*
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. *

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) 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.

Date: February 23, 2018

CIMAREX ENERGY CO.

By:	/s/ Thomas E. Jorden
	Thomas E. Jorden Chairman of the Board, Chief Executive Officer, and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Thomas E. Jorden	Chairman of the Board, Director,	
Thomas E. Jorden	Chief Executive Officer, and President (Principal Executive Officer)	February 23, 2018
*	Director, Executive Vice President —	
Attorney-in-Fact	Operations, Chief Operating Officer	February 23, 2018
Joseph R. Albi		
/s/ G. Mark Burford	Vice President and Chief	
G. Mark Burford	Financial Officer (Principal Financial Officer)	February 23, 2018
/s/ Timothy A. Ficker	Vice President, Controller, Chief	
Timothy A. Ficker	Accounting Officer (Principal Accounting Officer)	February 23, 2018
*		
Attorney-in-Fact	 Director	February 23, 2018
Hans Helmerich		-
*		
Attorney-in-Fact	— Director	February 23, 2018
David A. Hentschel		
*		
Attorney-in-Fact	— Director	February 23, 2018
Harold R. Logan, Jr.		
*		
Attorney-in-Fact	— Director	February 23, 2018
Floyd R. Price		
*		
Attorney-in-Fact	Director	February 23, 2018
Monroe W. Robertson		

* Attorney-in-Fact Lisa A. Stewart	Director	February 23, 2018
* Attorney-in-Fact Michael J. Sullivan	Director	February 23, 2018
* Attorney-in-Fact Frances M. Vallejo	Director	February 23, 2018
*By: /s/ G. Mark Burford G. Mark Burford Attorney-in-Fact	Vice President and Chief Financial Officer (Principal Financial Officer)	February 23, 2018

CORPORATE INFORMATION

Cimarex Energy Co. common stock trades on the New York Stock Exchange under the symbol XEC.

Corporate Headquarters

1700 Lincoln Street, Suite 3700 Denver, Colorado 80203-4537

Tel: (303) 295-3995 Fax: (303) 295-3494

Website

www.cimarex.com

Stock Transfer Agent

Continental Stock Transfer & Trust Company 1 State Street, 30th Floor New York, New York 10004 Tel: (888) 509-5580

Communications regarding transfers, lost certificates, duplicate mailings or changes of address should be directed to our transfer agent.

Independent Registered Public Accounting Firm

KPMG LLP

Independent Reservoir Engineers

DeGolyer and MacNaughton



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