PDC ENERGY, INC.
Form 10-Q
August 08, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2017

or

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

For the transition period from __________ to _________

Commission File Number 001-37419
PDC ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	95-2636730
(State of incorporation)	(I.R.S. Employer Identification No.)

1775 Sherman Street, Suite 3000
Denver, Colorado 80203
(Address of principal executive offices) (Zip code)

Registrant's telephone number, including area code: (303) 860-5800

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

Emerging growth company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 65,865,441 shares of the Company's Common Stock ($0.01 par value) were outstanding as of July 20, 2017.

Table of contents

PDC ENERGY, INC.

TABLE OF CONTENTS

Table of contents

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act"), Section 21E of the Securities Exchange Act of 1934 ("Exchange Act"), and the United States ("U.S.") Private Securities Litigation Reform Act of 1995 regarding our business, financial condition, results of operations, and prospects. All statements other than statements of historical fact included in and incorporated by reference into this report are "forward-looking statements." Words such as expects, anticipates, intends, plans, believes, seeks, estimates, and similar expressions or variations of such words are intended to identify forward-looking statements herein. Forward-looking statements may include, among other things, statements regarding future: reserves, production, costs, cash flows, and earnings; drilling locations and growth opportunities; capital investments and projects, including expected lateral lengths of wells, drill times and number of rigs employed; rates of return; operational enhancements and efficiencies; management of lease expiration issues; financial ratios; and midstream capacity and related curtailments.

The above statements are not the exclusive means of identifying forward-looking statements herein. Although forward-looking statements contained in this report reflect our good faith judgment, such statements can only be based on facts and factors currently known to us. Forward-looking statements are always subject to risks and uncertainties, and become subject to greater levels of risk and uncertainty as they address matters further into the future. Throughout this report or accompanying materials, we may use the terms “projection” or similar terms or expressions, or indicate that we have “modeled” certain future scenarios. We typically use these terms to indicate our current thoughts on possible outcomes relating to our business or our industry in periods beyond the current fiscal year. Because such statements relate to events or conditions further in the future, they are subject to increased levels of uncertainty.

Important factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- changes in worldwide production volumes and demand, including economic conditions that might impact demand and prices for the products we produce;
- volatility of commodity prices for crude oil, natural gas, and natural gas liquids ("NGLs") and the risk of an extended period of depressed prices;
- reductions in the borrowing base under our revolving credit facility;
- impact of governmental policies and/or regulations, including changes in environmental and other laws, the interpretation and enforcement of those laws and regulations, liabilities arising thereunder, and the costs to comply with those laws and regulations;
- declines in the value of our crude oil, natural gas, and NGLs properties resulting in impairments;
- changes in estimates of proved reserves;
- inaccuracy of reserve estimates and expected production rates;
- potential for production decline rates from our wells being greater than expected;
- timing and extent of our success in discovering, acquiring, developing, and producing reserves;
- availability of sufficient pipeline, gathering, and other transportation facilities and related infrastructure to process and transport our production and the impact of these facilities and regional capacity on the prices we receive for our production;
- timing and receipt of necessary regulatory permits;
- risks incidental to the drilling and operation of crude oil and natural gas wells;
- losses from our gas marketing business exceeding our expectations;
- difficulties in integrating our operations as a result of any significant acquisitions, including our recent acquisitions in the Delaware Basin;

- increases or changes in operating costs, severance and ad valorem taxes, and increases or changes in drilling, completion, and facilities costs;
- potential losses of acreage due to lease expirations or otherwise;
- increases or adverse changes in construction costs and procurement costs associated with future build out of midstream-related assets;
- future cash flows, liquidity, and financial condition;
- competition within the oil and gas industry;
- availability and cost of capital;
- our success in marketing crude oil, natural gas, and NGLs;
- effect of crude oil and natural gas derivatives activities;
- impact of environmental events, governmental and other third-party responses to such events, and our ability to insure adequately against such events;

Table of contents

- cost of pending or future litigation, including recent environmental litigation;
- effect that acquisitions we may pursue have on our capital investments;
- our ability to retain or attract senior management and key technical employees; and
- success of strategic plans, expectations, and objectives for our future operations.

Further, we urge you to carefully review and consider the cautionary statements and disclosures, specifically those under the heading "Risk Factors," made in this Quarterly Report on Form 10-Q, our Annual Report on Form 10-K for the year ended December 31, 2016 (the "2016 Form 10-K"), filed with the U.S. Securities and Exchange Commission ("SEC") on February 28, 2017, and our other filings with the SEC for further information on risks and uncertainties that could affect our business, financial condition, results of operations, and prospects, which are incorporated by this reference as though fully set forth herein. We caution you not to place undue reliance on the forward-looking statements, which speak only as of the date of this report. We undertake no obligation to update any forward-looking statements in order to reflect any event or circumstance occurring after the date of this report or currently unknown facts or conditions or the occurrence of unanticipated events. All forward-looking statements are qualified in their entirety by this cautionary statement.

REFERENCES

Unless the context otherwise requires, references in this report to "PDC Energy," "PDC," "the Company," "we," "us," "our," or "ours" refer to the registrant, PDC Energy, Inc. and all subsidiaries consolidated for the purposes of its financial statements, including our proportionate share of the financial position, results of operations, cash flows and operating activities of our affiliated partnerships.

Table of contents

PART I - FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

PDC ENERGY, INC.
Condensed Consolidated Balance Sheets
(unaudited; in thousands, except share and per share data)

	June 30, 2017		December 31, 2016	
Assets				
Current assets:				
Cash and cash equivalents	$	202,291	$	244,100
Accounts receivable, net	135,203		143,392	
Fair value of derivatives	52,105		8,791	
Prepaid expenses and other current assets	6,619		3,542	
Total current assets	396,218		399,825	
Properties and equipment, net	4,165,572		4,008,266	
Fair value of derivatives	16,397		2,386	
Goodwill	56,331		62,041	
Other assets	22,410		13,324	
Total Assets	$	4,656,928	$	4,485,842
Liabilities and Stockholders' Equity				
Liabilities				
Current liabilities:				
Accounts payable	$	152,492	$	66,322
Production tax liability	35,296		24,767	
Fair value of derivatives	10,138		53,595	
Funds held for distribution	86,846		71,339	
Accrued interest payable	15,955		15,930	
Other accrued expenses	29,939		38,625	
Total current liabilities	330,666		270,578	
Long-term debt	1,049,004		1,043,954	
Deferred income taxes	452,028		400,867	
Asset retirement obligations	77,867		82,612	
Fair value of derivatives	2,311		27,595	

Other liabilities	30,610	37,482
Total liabilities	1,942,486	1,863,088
Commitments and contingent liabilities		
Stockholders' equity		
Common shares - par value $0.01 per share, 150,000,000 authorized, 65,927,104 and 65,704,568 issued as of June 30, 2017 and December 31, 2016, respectively	659	657
Additional paid-in capital	2,495,940	2,489,557
Retained earnings	221,604	134,208
Treasury shares - at cost, 64,024 and 28,763 as of June 30, 2017 and December 31, 2016, respectively	(3,761)	(1,668)
Total stockholders' equity	2,714,442	2,622,754
Total Liabilities and Stockholders' Equity	$ 4,656,928	$ 4,485,842

See accompanying Notes to Condensed Consolidated Financial Statements
1

Table of contents

PDC ENERGY, INC.
Condensed Consolidated Statements of Operations
(unaudited; in thousands, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Revenues				
Crude oil, natural gas, and NGLs sales	$213,602	$110,841	$403,294	$186,208
Commodity price risk management gain (loss), net of settlements	57,932	(92,801)	138,636	(81,745)
Other income	3,624	2,057	6,935	6,465
Total revenues	275,158	20,097	548,865	110,928
Costs, expenses and other				
Lease operating expenses	20,028	13,675	39,817	29,005
Production taxes	15,042	6,043	27,441	10,114
Transportation, gathering and processing expenses	6,488	4,465	12,390	8,506
General and administrative expense	29,531	23,579	55,846	46,358
Exploration, geologic, and geophysical expense	1,033	237	1,987	447
Depreciation, depletion and amortization	126,013	107,014	235,329	204,402
Impairment of properties and equipment	27,566	4,170	29,759	5,171
Accretion of asset retirement obligations	1,666	1,811	3,434	3,623
(Gain) loss on sale of properties and equipment	(532)	260	(692)	176
Provision for uncollectible notes receivable	(40,203)	—	(40,203)	44,738
Other expenses	3,890	2,125	7,418	4,703
Total costs, expenses and other	190,522	163,379	372,526	357,243
Income (loss) from operations	84,636	(143,282)	176,339	(246,315)
Interest expense	(19,617)	(10,672)	(39,084)	(22,566)
Interest income	768	177	1,008	1,735
Income (loss) before income taxes	65,787	(153,777)	138,263	(267,146)
Income tax (expense) benefit	(24,537)	58,327	(50,867)	100,166
Net income (loss)	$41,250	$(95,450)	$87,396	$(166,980)
Earnings per share:				
Basic	$0.63	$(2.04)	$1.33	$(3.78)
Diluted	$0.62	$(2.04)	$1.32	$(3.78)
Weighted-average common shares outstanding:				
Basic	65,859	46,742	65,804	44,175
Diluted	66,019	46,742	66,066	44,175

See accompanying Notes to Condensed Consolidated Financial Statements

Table of contents

PDC ENERGY, INC.
Condensed Consolidated Statements of Cash Flows
(unaudited; in thousands)

	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Cash flows from operating activities:		
Net income (loss)	$87,396	$(166,980)
Adjustments to net income (loss) to reconcile to net cash from operating activities:		
Net change in fair value of unsettled commodity derivatives	(126,070)	201,825
Depreciation, depletion and amortization	235,329	204,402
Impairment of properties and equipment	29,759	5,171
Provision for uncollectible notes receivable	(40,203)	44,738
Accretion of asset retirement obligations	3,434	3,623
Non-cash stock-based compensation	9,826	11,126
(Gain) loss on sale of properties and equipment	(692)	176
Amortization of debt discount and issuance costs	6,399	3,077
Deferred income taxes	50,767	(102,319)
Other	670	(1,287)
Changes in assets and liabilities	6,582	(5,754)
Net cash from operating activities	263,197	197,798
Cash flows from investing activities:		
Capital expenditures for development of crude oil and natural gas properties	(334,406)	(234,677)
Capital expenditures for other properties and equipment	(2,299)	(1,030)
Acquisition of crude oil and natural gas properties, including settlement adjustments	5,372	—
Proceeds from sale of properties and equipment	1,293	4,903
Sale of promissory note	40,203	—
Restricted cash	(9,250)	—
Sale of short-term investments	49,890	—
Purchase of short-term investments	(49,890)	—
Net cash from investing activities	(299,087)	(230,804)
Cash flows from financing activities:		
Proceeds from issuance of equity, net of issuance cost	—	296,575
Proceeds from revolving credit facility	—	85,000
Repayment of revolving credit facility	—	(122,000)
Redemption of convertible notes	—	(115,000)
Purchase of treasury shares	(5,274)	(4,055)
Other	(645)	735
Net cash from financing activities	(5,919)	141,255
Net change in cash and cash equivalents	(41,809)	108,249
Cash and cash equivalents, beginning of period	244,100	850
Cash and cash equivalents, end of period	$202,291	$109,099
Supplemental cash flow information:		
Cash payments (receipts) for:		
Interest, net of capitalized interest	$32,647	$19,988
Income taxes	(39)	167
Non-cash investing and financing activities:		

Change in accounts payable related to purchases of properties and equipment	$81,891	$(28,999)
Change in asset retirement obligations, with a corresponding change to crude oil and natural gas properties, net of disposals	2,415	843
Purchase of properties and equipment under capital leases	2,160	1,074

See accompanying Notes to Condensed Consolidated Financial Statements
3

Table of contents

PDC ENERGY, INC.
Condensed Consolidated Statement of Equity
(unaudited; in thousands, except share data)

	Common Stock			Treasury Stock				
	Shares	Amount	Additional Paid-in Capital	Shares	Amount	Retained Earnings		Total Stockholders' Equity
Balance, December 31, 2016	65,704,568	$ 657	$ 2,489,557	(28,763)	$ (1,668)	$ 134,208		$ 2,622,754
Net income	—	—	—	—	—	87,396	87,396,000	87,396
Issuance pursuant to acquisition	—	—	(82)	—	—	—		(82)
Issuance pursuant to sale of equity	—	—	(7)	—	—	—		(7)
Convertible debt discount, net of issuance costs and tax	—	—	(2)	—	—	—		(2)
Purchase of treasury shares	—	—	—	(79,381)	(5,274)	—		(5,274)
Issuance of treasury shares	(46,822)	2	(3,350)	46,822	3,350	—		2
Non-employee directors' deferred compensation plan	—	—	(2)	(2,702)	(169)	—		(171)
Issuance of stock awards, net of forfeitures	269,358	—	—	—	—	—		—
Stock-based compensation expense	—	—	9,826	—	—	—		9,826
Balance, June 30, 2017	65,927,104	$ 659	$ 2,495,940	(64,024)	$ (3,761)	$ 221,604		$ 2,714,442

See accompanying Notes to Condensed Consolidated Financial Statements
4

Table of Contents
PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2017
(unaudited)

NOTE 1 - NATURE OF OPERATIONS AND BASIS OF PRESENTATION

PDC Energy, Inc. ("PDC", the "Company," "we," "us," or "our") is a domestic independent exploration and production company that produces, develops, and explores for crude oil, natural gas, and NGLs, with primary operations in the Wattenberg Field in Colorado and, beginning in December 2016, the Delaware Basin in Reeves and Culberson Counties, Texas. We also have operations in the Utica Shale in Southeastern Ohio. Subsequent to June 30, 2017, as part of plans to divest the Utica Shale properties, we engaged an investment banking group to assist in marketing them for sale; therefore, these properties will be classified as held-for-sale upon meeting the criteria for such classification in the third quarter of 2017. Our operations in the Wattenberg Field are focused in the horizontal Niobrara and Codell plays and our Delaware Basin operations are currently focused in the Wolfcamp zones. As of June 30, 2017, we owned an interest in approximately 2,900 gross productive wells. We are engaged in two operating segments: our oil and gas exploration and production segment and our gas marketing segment. Beginning in 2017, our gas marketing segment does not meet the quantitative thresholds to require disclosure as a separate reportable segment. All of our material operations are attributable to our exploration and production business; therefore, all of our operations are presented as a single segment for all periods presented.

The accompanying unaudited condensed consolidated financial statements include the accounts of PDC, our wholly-owned subsidiaries, and our proportionate share of our two affiliated partnerships. Pursuant to the proportionate consolidation method, our accompanying condensed consolidated financial statements include our pro rata share of assets, liabilities, revenues and expenses of the entities which we proportionately consolidate. All material intercompany accounts and transactions have been eliminated in consolidation.

In our opinion, the accompanying condensed consolidated financial statements contain all adjustments, consisting of normal recurring adjustments, necessary for a fair statement of our financial statements for interim periods in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, pursuant to such rules and regulations, certain notes and other financial information included in audited financial statements have been condensed or omitted. The December 31, 2016 condensed consolidated balance sheet data was derived from audited statements, but does not include all disclosures required by U.S. GAAP. The information presented in this Quarterly Report on Form 10-Q should be read in conjunction with our audited consolidated financial statements and notes thereto included in our 2016 Form 10-K. Our results of operations and cash flows for the three and six months ended June 30, 2017 are not necessarily indicative of the results to be expected for the full year or any other future period.

Certain immaterial reclassifications have been made to our prior period statement of operations to conform to the current period presentation. The reclassifications had no impact on previously reported cash flows, net earnings, earnings per share or stockholders' equity.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Recently Issued Accounting Standards

In May 2014, the FASB and the International Accounting Standards Board issued their converged standard on revenue recognition that provides a single, comprehensive model that entities will apply to determine the measurement of revenue and timing of when it is recognized. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The standard outlines a five-step approach to apply the underlying principle: (1) identify the contract with the customer, (2) identify the separate performance obligations in the contract, (3) determine the transaction price, (4) allocate the transaction price to separate performance obligations, and (5) recognize revenue when or as each performance obligation is satisfied. In March 2016, the FASB issued an update to the standard intended to improve the operability and understandability of the implementation guidance on principal versus agent considerations when recognizing revenue. In December 2016, the FASB issued technical corrections and improvements to the standard. The revenue standard is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. The revenue standard can be adopted under the full retrospective method or simplified transition method. Entities are permitted to adopt the revenue standard early, beginning with annual reporting periods after December 15, 2016. We are in the process of assessing potential impacts of the new standard on our existing revenue recognition criteria, as well as on related revenue recognition disclosures.

In February 2016, the FASB issued an accounting update aimed at increasing the transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet and disclosing key information about related leasing arrangements. For leases with terms of more than 12 months, the accounting update requires lessees to recognize a right-of-use asset and lease liability for its right to use the underlying asset and the corresponding lease obligation. Both the lease asset and liability will initially be measured at the present value of the future minimum lease payments over the lease term. Subsequent measurement, including the presentation of expenses and cash flows, will depend upon the classification of the lease as either a finance or operating lease. The guidance is effective for fiscal years beginning after December 15, 2018, and interim periods within those years, with early adoption permitted, and is to be applied as of the beginning of the earliest period presented using a modified retrospective approach. We are in the process of assessing the impact these changes may have on our consolidated financial statements.

In August 2016, the FASB issued an accounting update on statements of cash flows to address diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The update addresses eight specific cash flow issues with the objective of reducing the existing diversity in practice. The guidance is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. We are currently evaluating the impact these changes may have on our consolidated financial statements.

In November 2016, the FASB issued an accounting update on statements of cash flows to address diversity in practice in the classification and presentation of changes in restricted cash. The accounting update requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash or restricted cash equivalents should be included with cash and cash equivalents when reconciling beginning-of-period and end-of-period amounts shown on the statement of cash flows. The guidance is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. We are currently evaluating the impact these changes may have on our consolidated financial statements.

In January 2017, the FASB issued an accounting update to simplify the subsequent measurement of goodwill. The update eliminates the two-step process that required identification of potential impairment and a separate measure of actual impairment. The annual and/or interim assessments are still required to be completed. The guidance is effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years, with early adoption permitted. We elected to early adopt this standard in the second quarter of 2017 and will implement the new guidance accordingly in performing impairment testing in 2017. Our annual evaluation of goodwill for impairment is expected to occur in the fourth quarter of 2017, at which time we will apply this accounting update and the impact can be determined.

In May 2017, the FASB issued an accounting update clarifying when to account for a change to the terms or conditions of a share-based payment award as a modification. The guidance is effective for fiscal years beginning on or after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. Adoption of this standard is not expected to have a significant impact on our condensed consolidated financial statements.

NOTE 3 - BUSINESS COMBINATION

Delaware Basin Acquisition. On December 6, 2016, we closed on an acquisition which has been accounted for as a business combination. The transaction was for the purchase of approximately 57,900 net acres, approximately 30 completed and producing wells and related midstream infrastructure in Reeves and Culberson Counties, Texas, for an aggregate consideration to the sellers of approximately $1.64 billion, after preliminary post-closing adjustments, comprised of approximately $946.0 million in cash, including the payment of $40.0 million of debt of the seller at closing and other purchase price adjustments, and 9.4 million shares of our common stock valued at approximately $690.7 million at the time the acquisition closed. The estimated fair value of assets acquired and liabilities assumed in the acquisition presented below are preliminary and subject to customary additional post-closing adjustments as more detailed analysis associated with the acquired properties is completed. The final settlement statement has been agreed upon with the sellers; however, we are in the process of finalizing the fair values of the assets acquired and liabilities assumed and expect to keep the transaction open through the third quarter of 2017 to ensure that any final allocation adjustments associated with the period through final settlement are appropriately reflected in the final purchase price allocation. The most significant item to be completed is the allocation of the per acre values across the acquisition. There were a significant number of leases acquired with complex lease terms and evaluation of these terms may impact the manner in which the purchase price allocation across the acquired acreage is finalized based upon lease expiration timing. We expect that the completion of this process will adjust our final determination of the value of goodwill.

The details of the estimated purchase price and the preliminary allocation of the purchase price for the transaction, which reflects certain post-closing adjustments, are presented below (in thousands):

	June 30, 2017
Acquisition costs:	
Cash, net of cash acquired	$905,962
Retirement of seller's debt	40,000
Total cash consideration	945,962
Common stock, 9.4 million shares	690,702
Other purchase price adjustments	1,025
Total acquisition costs	$1,637,689
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Assets acquired:	
Current assets	$6,561
Crude oil and natural gas properties - proved	216,000
Crude oil and natural gas properties - unproved	1,721,334
Infrastructure, pipeline, and other	33,695
Construction in progress	12,148
Goodwill	56,331
Total assets acquired	2,046,069
Liabilities assumed:	
Current liabilities	(23,844)
Asset retirement obligations	(4,248)
Deferred tax liabilities, net	(380,288)
Total liabilities assumed	(408,380)
Total identifiable net assets acquired	$1,637,689

The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market, and therefore represent Level 3 inputs. The fair values of crude oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of crude oil and natural gas properties include estimates of reserves, future operating and development costs, future commodity prices, estimated future cash flows, lease terms and expirations, and a market-based weighted-average cost of capital rate. These inputs require significant judgments and estimates by management at the time of the valuation and are the most sensitive and subject to change.

This acquisition was accounted for under the acquisition method. Accordingly, we conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while transaction and integration costs associated with the acquisition were expensed as incurred.

Goodwill. Goodwill is calculated as the excess of the purchase price over the fair value of net assets acquired and represents the future economic benefits arising from other assets acquired that could not be individually identified and separately recognized. Among the factors that contributed to a purchase price in excess of the fair value of the net tangible and intangible assets acquired were the acquisition of an element of a workforce and the expected value from operations of the Delaware Basin acquisition to be derived in the future. The amount of goodwill that was recorded on a preliminary basis related to the Delaware Basin acquisition has decreased as compared to the initial estimated amount recorded as of December 31, 2016, due to customary purchase price allocations, primarily related to a refund from the sellers in connection with a revised valuation of certain acquired leases and the retirement of estimated environmental remediation liabilities. Such amounts will be finalized with final purchase accounting, as described above. Any value assigned to goodwill is not expected to be deductible for income tax purposes.

Table of contents
PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2017
(unaudited)

The following table presents the changes in goodwill:

	Amount (in thousands)
Balance at December 31, 2016	$ 62,041
Purchase price adjustments, net of tax	(5,710)
Balance at June 30, 2017	$ 56,331

With the creation of goodwill from this transaction, we will perform our evaluation of goodwill for impairment annually or when a triggering event is deemed to have occurred. We evaluate goodwill for impairment by either performing a qualitative evaluation or a quantitative test, which involves comparing the estimated fair value to the carrying value. In either case, the valuation of goodwill will be a significant estimate as such methods incorporate forward-looking assumptions and estimates.

NOTE 4 - PROPERTIES AND EQUIPMENT

The following table presents the components of properties and equipment, net of accumulated depreciation, depletion, and amortization ("DD&A"):

	June 30, 2017	December 31, 2016
	(in thousands)	
Properties and equipment, net:		
Crude oil and natural gas properties		
Proved	$3,842,942	$3,499,718
Unproved	1,841,589	1,874,671
Total crude oil and natural gas properties	5,684,531	5,374,389
Infrastructure, pipeline, and other	94,654	62,093
Land and buildings	15,274	12,165
Construction in progress	171,600	122,591
Properties and equipment, at cost	5,966,059	5,571,238
Accumulated DD&A	(1,800,487)	(1,562,972)
Properties and equipment, net	$4,165,572	$4,008,266

The following table presents impairment charges recorded for crude oil and natural gas properties:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(in thousands)			

Impairment of unproved properties	$27,463	$1,084	$29,565	$2,053
Amortization of individually insignificant unproved properties	103	54	194	86
Impairment of crude oil and natural gas properties	27,566	1,138	29,759	2,139
Land and buildings	—	3,032	—	3,032
Total impairment of properties and equipment	$27,566	$4,170	$29,759	$5,171

During the three months ended June 30, 2017, we impaired certain unproved Delaware Basin leasehold positions totaling $27.0 million that expired during the three months ending June 30, 2017, or are projected to expire between June 30, 2017 and December 31, 2017. Subsequent to closing the acquisitions in the Delaware Basin, it was determined that development of certain acreage tracts would not meet our internal expectations for acceptable rates of return due to a combination of weakening commodity prices; higher per well development and operational costs; and updated technical analysis. As a result, we allowed or expect to allow certain acreage to expire, and in other circumstances we were unable to obtain necessary lease term extensions.

NOTE 5 - COMMODITY DERIVATIVE FINANCIAL INSTRUMENTS

Our results of operations and operating cash flows are affected by changes in market prices for crude oil, natural gas, and NGLs. To manage a portion of our exposure to price volatility from producing crude oil, natural gas, and propane, which is an element of our NGLs, we enter into commodity derivative contracts to protect against price declines in future periods. While we structure these commodity derivatives to reduce our exposure to decreases in commodity prices, they also limit the benefit we might otherwise receive from price increases.

We believe our commodity derivative instruments continue to be effective in achieving the risk management objectives for which they were intended. As of June 30, 2017, we had derivative instruments, which were comprised of collars, fixed-price swaps, and basis protection swaps, in place for a portion of our anticipated 2017 and 2018 production for a total of 12,896 MBbls of crude oil, 82,030 BBtu of natural gas, and 643 MBbls of propane. Our commodity derivative contracts have been entered into at no cost to us as we hedge our anticipated production at the then-prevailing commodity market prices, without adjustment for premium or discount.

We have not elected to designate any of our derivative instruments as cash flow hedges, and therefore these instruments do not qualify for hedge accounting. Accordingly, changes in the fair value of our derivative instruments are recorded in the condensed consolidated statements of operations.

The following table presents the balance sheet location and fair value amounts of our derivative instruments on the condensed consolidated balance sheets:

Derivative instruments:		Condensed consolidated balance sheet line item	Fair Value June 30, 2017	December 31, 2016
			(in thousands)	
Derivative assets:	Current			
	Commodity derivative contracts	Fair value of derivatives	$49,540	$ 8,490
	Basis protection derivative contracts	Fair value of derivatives	2,565	301
			52,105	8,791
	Non-current			
	Commodity derivative contracts	Fair value of derivatives	15,051	1,123
	Basis protection derivative contracts	Fair value of derivatives	1,346	1,263
			16,397	2,386
Total derivative assets			$68,502	$ 11,177
Derivative liabilities:	Current			
	Commodity derivative contracts	Fair value of derivatives	$9,943	$ 53,565
	Basis protection derivative contracts	Fair value of derivatives	195	30
			10,138	53,595
	Non-current			

Commodity derivative contracts	Fair value of derivatives	2,311	27,595
		2,311	27,595
Total derivative liabilities		$12,449	$ 81,190

Table of contents
PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2017
(unaudited)

The following table presents the impact of our derivative instruments on our condensed consolidated statements of operations:

Condensed consolidated statement of operations line item	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
	(in thousands)			
Commodity price risk management gain, net				
Net settlements	$12,015	$53,301	$12,566	$120,132
Net change in fair value of unsettled derivatives	45,917	(146,102)	126,070	(201,877)
Total commodity price risk management gain, net	$57,932	$(92,801)	$138,636	$(81,745)

Net settlements of commodity derivatives decreased for the three and six months ended June 30, 2017 as compared to the three and six months ended June 30, 2016. We entered into agreements for the derivative instruments that settled throughout 2016 prior to commodity prices becoming depressed in late 2014. Substantially all of these higher-value agreements settled by the end of 2016. Net settlements for the three and six months ended June 30, 2017 reflect derivative instruments entered into since 2015, which more closely approximate recent realized prices. Based upon the forward strip pricing at June 30, 2017, we expect that settlements will continue to be substantially lower in 2017 on a relative basis as compared to those in 2016.

All of our financial derivative agreements contain master netting provisions that provide for the net settlement of all contracts through a single payment in the event of early termination. We have elected not to offset the fair value positions recorded on our condensed consolidated balance sheets.

The following table reflects the impact of netting agreements on gross derivative assets and liabilities:

As of June 30, 2017	Derivative instruments, recorded in condensed consolidated balance sheet, gross	Effect of master netting agreements	Derivative instruments, net
	(in thousands)		
Asset derivatives:			
Derivative instruments, at fair value	$68,502	$(10,974)	$57,528
Liability derivatives:			
Derivative instruments, at fair value	$12,449	$(10,974)	$1,475

As of December 31, 2016	Derivative instruments,	Effect of master	Derivative instruments,

	recorded in condensed consolidated balance sheet, gross	netting agreements	net
	(in thousands)		
Asset derivatives:			
Derivative instruments, at fair value	$11,177	$(10,930)	$247
Liability derivatives:			
Derivative instruments, at fair value	$81,190	$(10,930)	$70,260

10

NOTE 6 - FAIR VALUE OF FINANCIAL INSTRUMENTS

Determination of Fair Value

Our fair value measurements are estimated pursuant to a fair value hierarchy that requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability, and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels. The three levels of inputs that may be used to measure fair value are defined as:

Level 1 – Quoted prices (unadjusted) for identical assets or liabilities in active markets.

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity.

Derivative Financial Instruments

We measure the fair value of our derivative instruments based upon a pricing model that utilizes market-based inputs, including, but not limited to, the contractual price of the underlying position, current market prices, crude oil and natural gas forward curves, discount rates such as the LIBOR curve for a similar duration of each outstanding position, volatility factors, and nonperformance risk. Nonperformance risk considers the effect of our credit standing on the fair value of derivative liabilities and the effect of our counterparties' credit standings on the fair value of derivative assets. Both inputs to the model are based on published credit default swap rates and the duration of each outstanding derivative position.

We validate our fair value measurement through the review of counterparty statements and other supporting documentation, determination that the source of the inputs is valid, corroboration of the original source of inputs through access to multiple quotes, if available, or other information, and monitoring changes in valuation methods and assumptions. While we use common industry practices to develop our valuation techniques and believe our valuation method is appropriate and consistent with those used by other market participants, changes in our pricing methodologies or the underlying assumptions could result in significantly different fair values.

Our crude oil and natural gas fixed-price swaps are included in Level 2. Our collars, physical sales, and propane fixed-price swaps are included in Level 3. Our basis swaps are included in Level 2 and Level 3. The following table presents, for each applicable level within the fair value hierarchy, our derivative assets and liabilities, including both current and non-current portions, measured at fair value on a recurring basis:

	June 30, 2017			December 31, 2016		
	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)					
Assets:						
Total assets	$58,226	$ 10,276	$68,502	$6,350	$ 4,827	$11,177
Total liabilities	(10,792)	(1,657)	(12,449)	(66,789)	(14,401)	(81,190)
Net asset (liability)	$47,434	$ 8,619	$56,053	$(60,439)	$ (9,574)	$(70,013)

11

Table of contents
PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2017
(unaudited)

The following table presents a reconciliation of our Level 3 assets measured at fair value:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(in thousands)			
Fair value of Level 3 instruments, net asset (liability) beginning of period	$2,316	$73,195	$(9,574)	$91,288
Changes in fair value included in condensed consolidated statement of operations line item:				
Commodity price risk management gain (loss), net	9,262	(26,422)	22,622	(20,257)
Settlements included in condensed consolidated statement of operations line items:				
Commodity price risk management gain (loss), net	(2,959)	(19,398)	(4,429)	(43,656)
Fair value of Level 3 instruments, net asset end of period	$8,619	$27,375	$8,619	$27,375
Net change in fair value of Level 3 unsettled derivatives included in condensed consolidated statement of operations line item:				
Commodity price risk management gain (loss), net	$8,161	$(18,210)	$17,194	$(13,105)

The significant unobservable input used in the fair value measurement of our derivative contracts is the implied volatility curve, which is provided by a third-party vendor. A significant increase or decrease in the implied volatility, in isolation, would have a directionally similar effect resulting in a significantly higher or lower fair value measurement of our Level 3 derivative contracts. There has been no change in the methodology we apply to measure the fair value of our Level 3 derivative contracts during the periods covered by this report.

Non-Derivative Financial Assets and Liabilities

The carrying value of the financial instruments included in current assets and current liabilities approximate fair value due to the short-term maturities of these instruments.

We utilize fair value on a nonrecurring basis to review our crude oil and natural gas properties and goodwill for possible impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such assets. The fair value of the properties is determined based upon estimated future discounted cash flow, a Level 3 input, using estimated production and prices at which we reasonably expect the crude oil and natural gas will be sold. The fair value of the goodwill is determined using either a qualitative method or a quantitative method, both of which utilize market data, a Level 2 input, in the derivation of the value estimation.

The portion of our long-term debt related to our revolving credit facility approximates fair value due to the variable nature of related interest rates. We have not elected to account for the portion of our debt related to our senior notes under the fair value option; however, we have determined an estimate of the fair values based on measurements of trading activity and broker and/or dealer quotes, respectively, which are published market prices, and therefore are Level 2 inputs. The table below presents these estimates of the fair value of the portion of our long-term debt related to our senior notes and convertible notes as of June 30, 2017.

	Estimated Fair Value (in millions)	Percent of Par
Senior notes:		
2021 Convertible Notes	$ 180.8	90.4 %
2022 Senior Notes	520.6	104.1 %
2024 Senior Notes	406.0	101.5 %

The carrying value of our capital lease obligations approximates fair value due to the variable nature of the imputed interest rates and the duration of the related vehicle lease.

Concentration of Risk

Derivative Counterparties. A portion of our liquidity relates to commodity derivative instruments that enable us to manage a portion of our exposure to price volatility from producing crude oil and natural gas. These arrangements expose us to credit risk of nonperformance by our counterparties. We primarily use financial institutions who are also major lenders under our revolving credit facility as counterparties to our commodity derivative contracts. An insignificant portion of our commodity derivative instruments may be with other counterparties. To date, we have had no derivative counterparty default losses. We have evaluated the credit risk of our derivative assets from our counterparties using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the potential impact of nonperformance of our current counterparties on the fair value of our derivative instruments is not significant at June 30, 2017, taking into account the estimated likelihood of nonperformance.

Cash and Cash Equivalents. We consider all highly liquid instruments purchased with an original maturity of three months or less to be cash equivalents. Cash and cash equivalents potentially subject us to a concentration of credit risk as substantially all of our deposits held in financial institutions were in excess of the FDIC insurance limits at June 30, 2017. We maintain our cash and cash equivalents in the form of money market and checking accounts with financial institutions that we believe are creditworthy and are also major lenders under our revolving credit facility.

Notes Receivable. In October 2014, we sold our entire 50 percent ownership interest in PDC Mountaineer, LLC to an unrelated third-party. As part of the consideration, we received a promissory note (the “Promissory Note”) for a principal sum of $39.0 million, bearing varying interest rates. The interest was to be paid quarterly, in arrears and at the option of the issuer, could be paid-in-kind (“PIK Interest”) and any such PIK Interest would be subject to the then current interest rate.

We regularly analyzed the Promissory Note for evidence of collectability, evaluating factors such as the creditworthiness of the issuer of the Promissory Note and the value of the underlying assets that secure the Promissory Note. Based upon this analysis, during the quarter ended March 31, 2016, we recognized a provision and recorded an allowance for uncollectible notes receivable for the $44.0 million accumulated outstanding balance, including interest. Commencing in the second quarter of 2016, we ceased recognizing interest income on the Promissory Note and began accounting for the interest on the Promissory Note under the cash basis method.

We performed this analysis as of March 31, 2017 and evaluated preliminary 2016 year-end financial statements of the note issuer which were available at such time, related information about the operations of the issuer, and existing market conditions for natural gas. Based upon this evaluation, it was determined that collection of the Promissory Note and PIK Interest continued to be doubtful and the full valuation allowance on the Promissory Note remained appropriate as of that date. This evaluation assumed repayment of the Promissory Note would be made exclusively from the existing operations of the issuer of the Promissory Note based on the latest available information.

In April 2017, we sold the Promissory Note to an unrelated third-party buyer for approximately $40.2 million in cash. The sales agreement transferred all of our legal rights to collect from the issuer of the Promissory Note. Accordingly, we reversed $40.2 million of the provision for uncollectible notes receivable during the three months ended June 30, 2017.

NOTE 7 - INCOME TAXES

We evaluate and update our estimated annual effective income tax rate on a quarterly basis based on current and forecasted operating results and tax laws. Consequently, based upon the mix and timing of our actual annual earnings compared to annual projections, our effective tax rate may vary quarterly and may make quarterly comparisons not meaningful. The quarterly income tax provision is generally comprised of tax expense on income or benefit on loss at the most recent estimated annual effective income tax rate, adjusted for the effect of discrete items.

The effective income tax rates for the three and six months ended June 30, 2017 was 37.3 percent and 36.8 percent expense on income, respectively, compared to 37.9 percent and 37.5 percent benefit on loss for the three and six months ended June 30, 2016. The effective income tax rates for the three and six months ended June 30, 2017 include discrete income tax benefits of $0.2 million and $1.8 million relating to the excess income tax basis recognized with the vesting of stock awards during the three and six months ended June 30, 2017, which resulted in a 0.3 percent and 1.3 percent reduction to our effective income tax rates.

The effective income tax rates for the three and six months ended June 30, 2017, are based upon a full year forecasted tax provision on income and are greater than the statutory federal income tax rate, primarily due to state income taxes, nondeductible officers' compensation and nondeductible lobbying expenses, partially offset by stock-based compensation tax deductions. We anticipate the potential for increased periodic volatility in future effective income tax rates from the impact of stock-based compensation tax deductions as they are treated as discrete tax items. The effective income tax rates for the three and six months ended June 30, 2016, were based upon a full year forecasted income tax benefit on loss and were greater than the statutory federal income tax rate, primarily due to state income taxes and percentage depletion, partially offset by nondeductible officers' compensation and nondeductible lobbying expenses. There were no significant discrete income tax items recorded during the three and six months ended June 30, 2016.

As of June 30, 2017, there is no liability for unrecognized income tax benefits. As of the date of this report, we are current with our income tax filings in all applicable state jurisdictions and are not currently under any state income tax examinations. We continue to voluntarily participate in the Internal Revenue Service's Compliance Assurance Program for the 2016 and 2017 tax years, and received final acceptance of our 2015 federal income tax return during the six months ended June 30, 2017.

NOTE 8 - LONG-TERM DEBT

Long-term debt consisted of the following as of:

	June 30, 2017	December 31, 2016
	(in thousands)	
Senior notes:		
1.125% Convertible Notes due 2021:		
Principal amount	$200,000	$200,000
Unamortized discount	(33,952)	(37,475)
Unamortized debt issuance costs	(4,103)	(4,584)
1.125% Convertible Notes due 2021, net of unamortized discount and debt issuance costs	161,945	157,941
7.75% Senior Notes due 2022:		
Principal amount	500,000	500,000
Unamortized debt issuance costs	(5,882)	(6,443)
7.75% Senior Notes due 2022, net of unamortized debt issuance costs	494,118	493,557
6.125% Senior Notes due 2024:		
Principal amount	400,000	400,000

Unamortized debt issuance costs	(7,060)	(7,544)
6.125% Senior Notes due 2024, net of unamortized debt issuance costs	392,940	392,456
Total senior notes	1,049,003	1,043,954
Revolving credit facility	—	—
Total long-term debt, net of unamortized discount and debt issuance costs	$1,049,003	$1,043,954

Table of contents
PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2017
(unaudited)

Senior Notes

2021 Convertible Notes. In September 2016, we issued $200 million of 1.125% convertible senior notes due 2021 (the "2021 Convertible Notes") in a public offering. The maturity for the payment of principal is September 15, 2021. Interest at the rate of 1.125% per year is payable in cash semiannually in arrears on each March 15 and September 15. The conversion stock price at maturity is $85.39 per share. We allocated the gross proceeds of the 2021 Convertible Notes between the liability and equity components of the debt. The initial $160.5 million liability component was determined based on the fair value of similar debt instruments, excluding the conversion feature, priced on the same day we issued the 2021 Convertible Notes. Approximately $4.8 million in costs associated with the issuance of the 2021 Convertible Note have been capitalized as debt issuance costs. As of June 30, 2017, the unamortized debt discount will be amortized over the remaining contractual term to maturity of the 2021 Convertible Notes using an effective interest rate of 5.8 percent.

Upon conversion, the 2021 Convertible Notes may be settled, at our sole election, in shares of our common stock, cash, or a combination of cash and shares of our common stock. We have initially elected a combination settlement method to satisfy our conversion obligation, which allows us to settle the principal amount of the 2021 Convertible Notes in cash and to settle the excess conversion value, if any, in shares of our common stock, as well as cash in lieu of fractional shares.

2022 Senior Notes. In October 2012, we issued $500 million aggregate principal amount 7.75% senior notes due October 15, 2022 (the “2022 Senior Notes”). The 2022 Senior Notes accrue interest from the date of issuance and interest is payable semi-annually in arrears on April 15 and October 15. Approximately $11.0 million in costs associated with the issuance of the 2022 Senior Notes have been capitalized as debt issuance costs and are being amortized as interest expense over the life of the notes using the effective interest method.

2024 Senior Notes. In September 2016, we issued $400 million aggregate principal amount of 6.125% senior notes due September 15, 2024 (the “2024 Senior Notes”) in a private placement to qualified institutional buyers. In May 2017, in accordance with the registration rights agreement that we entered into with the initial purchasers when we issued the 2024 Senior Notes, we filed a registration statement with the SEC relating to an offer to exchange the 2024 Senior Notes for registered notes with substantially identical terms. The 2024 Senior Notes accrue interest from the date of issuance and interest is payable semi-annually in arrears on March 15 and September 15. Approximately $7.8 million in costs associated with the issuance of the 2024 Senior Notes have been capitalized as debt issuance costs and are being amortized as interest expense over the life of the notes using the effective interest method.

In January 2017, pursuant to the filing of supplemental indentures for the 2021 Convertible Notes, 2022 Senior Notes, and the 2024 Senior Notes (collectively, the "Notes"), our wholly-owned subsidiary, PDC Permian, Inc., became a guarantor of our obligations under the Notes. Accordingly, condensed consolidating financial information for PDC and PDC Permian, Inc. is presented in the footnote titled Subsidiary Guarantor.

As of June 30, 2017, we were in compliance with all covenants related to the Notes, and expect to remain in compliance throughout the next 12-month period.

Revolving Credit Facility

Revolving Credit Facility. The revolving credit facility is available for working capital requirements, capital investments, acquisitions, general corporate purposes and to support letters of credit. The revolving credit facility matures in May 2020 and provides for a maximum of $1 billion in allowable borrowing capacity, subject to the borrowing base and certain limitations under our senior notes. The borrowing base is based on, among other things, the loan value assigned to the proved reserves attributable to our crude oil and natural gas interests. The borrowing base is subject to a semi-annual redetermination on November 1 and May 1 based upon quantification of our reserves at June 30 and December 31, and is also subject to a redetermination upon the occurrence of certain events. The revolving credit facility is secured by a pledge of the stock of certain of our subsidiaries, mortgages of certain producing crude oil and natural gas properties and substantially all of our and such subsidiaries' other assets. Our affiliated partnerships are not guarantors of our obligations under the revolving credit facility.

In May 2017, we entered into a Fifth Amendment to the Third Amended and Restated Credit Agreement. The amendment, among other things, amends the revolving credit facility to reflect an increase in the borrowing base from $700 million to $950 million. We have elected to maintain a $700 million commitment level as of the date of this report. In addition, the Fifth Amendment made changes to certain of the financial and non-financial covenants in the existing agreement, as well as other administrative changes.

As of June 30, 2017 and December 31, 2016, debt issuance costs related to our revolving credit facility were $7.5 million and $8.8 million, respectively, and are included in other assets on the condensed consolidated balance sheets. We had no outstanding balance on our revolving credit facility as of June 30, 2017 or December 31, 2016. The outstanding principal amount under the revolving credit facility accrues interest at a varying interest rate that fluctuates with an alternate base rate (equal to the greatest of JPMorgan Chase Bank, N.A.'s prime rate, the federal funds rate plus a premium and the rate for dollar deposits in the London interbank market (“LIBOR”) for one month plus a premium), or at our election, a rate equal to LIBOR for certain time periods. Additionally, commitment fees, interest margin, and other bank fees, charged as a component of interest, vary with our utilization of the facility. As of June 30, 2017, the applicable interest margin is 1.25 percent for the alternate base rate option or 2.25 percent for the LIBOR option, and the unused commitment fee is 0.50 percent. No principal payments are generally required until the revolving credit facility expires in May 2020, or in the event that the borrowing base falls below the outstanding balance.

The revolving credit facility contains covenants customary for agreements of this type, with the most restrictive being certain financial tests on a quarterly basis. The financial tests, as defined per the revolving credit facility, include requirements to: (a) maintain a minimum current ratio of 1.0:1.0 and (b) not exceed a maximum leverage ratio of 4.0:1.0. As of June 30, 2017, we were in compliance with all the revolving credit facility covenants and expect to remain in compliance throughout the next 12-month period. As defined by the revolving credit facility, our current ratio was 3.3 and our leverage ratio was 1.9 as of June 30, 2017.

In May 2017, we replaced our $11.7 million irrevocable standby letter of credit that we held in favor of a third-party transportation service provider for surety of an existing firm transportation obligation with a $9.3 million deposit, which is classified as restricted cash and is included in other assets on the condensed consolidated balance sheet. As of June 30, 2017, available funds under our revolving credit facility were $700 million based on our elected commitment level.

NOTE 9 - OTHER ACCRUED EXPENSES

Other Accrued Expenses. The following table presents the components of other accrued expenses as of:

	June 30, 2017	December 31, 2016
	(in thousands)	
Employee benefits	$12,148	$ 22,282
Asset retirement obligations	12,938	9,775
Other	4,853	6,568
Other accrued expenses	$29,939	$ 38,625

NOTE 10 - CAPITAL LEASES

We periodically enter into non-cancelable lease agreements for vehicles utilized by our operations and field personnel. These leases are being accounted for as capital leases, as the present value of minimum monthly lease payments, including the residual value guarantee, exceeds 90 percent of the fair value of the leased vehicles at inception of the lease.

The following table presents vehicles under capital lease as of:

	June 30, 2017	December 31, 2016
	(in thousands)	
Vehicles	$5,097	$ 2,975
Accumulated depreciation	(1,240)	(776)
	$3,857	$ 2,199

16

Future minimum lease payments by year and in the aggregate, under non-cancelable capital leases with terms of one year or more, consist of the following:

For the Twelve Months Ending June 30,	Amount (in thousands)
2018	$ 1,836
2019	1,527
2020	1,195
	4,558
Less executory cost	(189)
Less amount representing interest	(491)
Present value of minimum lease payments	$ 3,878
Short-term capital lease obligations	$ 1,474
Long-term capital lease obligations	2,404
	$ 3,878

Short-term capital lease obligations are included in other accrued expenses on the condensed consolidated balance sheets and long-term capital lease obligations are included in other liabilities on the condensed consolidated balance sheets.

NOTE 11 - ASSET RETIREMENT OBLIGATIONS

The following table presents the changes in carrying amounts of the asset retirement obligations associated with our working interests in crude oil and natural gas properties:

	Amount (in thousands)
Balance at December 31, 2016	$ 92,387
Obligations incurred with development activities	2,415
Accretion expense	3,434
Obligations discharged with asset retirements	(7,431)
Balance at June 30, 2017	90,805
Less current portion	(12,938)
Long-term portion	$ 77,867

Our estimated asset retirement obligations liability is based on historical experience in plugging and abandoning wells, estimated economic lives and estimated plugging and abandonment costs considering federal and state regulatory requirements in effect. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. As of June 30, 2017, the credit-adjusted risk-free rates used to discount our plugging and abandonment liabilities ranged from 6.5 percent to 8.2 percent. In periods subsequent to initial measurement of the liability, we must recognize period-to-period changes in the liability resulting from the passage of time, revisions to either the amount of the original estimate of undiscounted cash flows or changes in inflation factors, and changes to our credit-adjusted risk-free rate as market conditions warrant. Short-term asset retirement obligations are included in other accrued expenses on the condensed consolidated balance sheets.

NOTE 12 - COMMITMENTS AND CONTINGENCIES

Firm Transportation and Processing Agreements. We enter into contracts that provide firm transportation and processing on pipeline systems through which we transport or sell crude oil and natural gas. Satisfaction of the volume requirements includes volumes produced by us, purchased from third parties, and produced by our affiliated partnerships and other third-party working, royalty, and overriding royalty interest owners whose volumes we market on their behalf. Our condensed consolidated statements of operations reflect our share of these firm transportation and processing costs. These contracts require us to pay these transportation and processing charges whether or not the required volumes are delivered.

The following table presents gross volume information related to our long-term firm transportation and processing agreements for pipeline capacity:

	For the Twelve Months Ending June 30,						
Area	2018	2019	2020	2021	2022 and Through Expiration	Total	Expiration Date
Natural gas (MMcf)							
Wattenberg Field	—	9,734	18,849	18,798	79,979	127,360	March 31, 2026
Delaware Basin	14,600	14,600	14,640	7,360	—	51,200	December 31, 2020
Gas Marketing	7,117	7,117	7,136	7,117	8,021	36,508	August 31, 2022
Utica Shale	2,737	2,737	2,745	2,737	5,709	16,665	July 22, 2023
Total	24,454	34,188	43,370	36,012	93,709	231,733	
Crude oil (MBbls)							
Wattenberg Field	2,413	2,414	2,420	—	—	7,247	June 30, 2020
Dollar commitment (in thousands)	$18,583	$28,104	$36,564	$22,665	$ 81,560	$187,476	

In December 2016, in anticipation of our future drilling activities in the Wattenberg Field, we entered into a facilities expansion agreement with our primary midstream provider to expand and improve its natural gas gathering pipelines and processing facilities. The midstream provider is expected to construct a new 200 MMcfd cryogenic plant. We will be bound to the volume requirements in this agreement on the first day of the calendar month after the actual in-service date of the plant, which in the above table is estimated to be in October 2018. The agreement requires a baseline volume commitment, consisting of our gross wellhead volume delivered in November 2016, to this midstream provider and an incremental wellhead volume commitment of 51.5 MMcfd for seven years. We may be required to pay a shortfall fee for any volumes under the 51.5 MMcfd incremental commitment. Any shortfall of this volume commitment may be offset by additional third party producers’ volumes sold to the midstream provider that are greater than a certain total baseline volume. We are also required for the first three years of the contract to guarantee a certain target profit margin to the midstream provider on these incremental volumes. We expect that our development plan will support the utilization of that capacity.

In April 2017, we entered into a transportation service agreement for delivery of 40,000 dekatherms per day of our Delaware Basin natural gas production to the Waha market hub in West Texas.

For each of the three and six months ended June 30, 2017, commitments for long-term transportation volumes, net to our interest, for Wattenberg Field crude oil, Delaware Basin natural gas, and Utica Shale natural gas were $2.6 million and $4.8 million, respectively, and were recorded in transportation, gathering, and processing expense in our condensed consolidated statements of operations. For each of the three and six months ended June 30, 2016, commitments for long-term transportation volumes for Wattenberg Field crude oil and Utica Shale natural gas were $2.3 million and $4.7 million, respectively.

During the three and six months ended June 30, 2017, long-term firm transportation costs for our gas marketing business associated with the commitments shown above were $0.9 million and $1.7 million, respectively, and were recorded in other expenses in our condensed consolidated statements of operations. During the three and six months ended June 30, 2016, long-term firm transportation costs for our gas marketing business associated with the commitments shown above were $0.9 million and $1.7 million, respectively.

Litigation and Legal Items. The Company is involved in various legal proceedings. The Company reviews the status of these proceedings on an ongoing basis and, from time to time, may settle or otherwise resolve these matters on terms and conditions that management believes are in the best interests of the Company. Management has provided the necessary estimated accruals in the accompanying balance sheets where deemed appropriate for litigation and legal related items that are ongoing and not yet concluded. However, the liability ultimately incurred with respect to a matter may exceed the related accrual. Although the results cannot be known with certainty, we believe that the ultimate results of such proceedings will not have a material adverse effect on our financial position, results of operations, or liquidity.

Environmental. Due to the nature of the natural gas and oil industry, we are exposed to environmental risks. We have various policies and procedures to minimize and mitigate the risks from environmental contamination. We conduct periodic reviews and simulated drills to identify changes in our environmental risk profile. Liabilities are recorded when environmental damages resulting from past events are probable and the costs can be reasonably estimated. Except as discussed herein, we are not aware of any environmental claims existing as of June 30, 2017 which have not been provided for or would otherwise have a material impact on our financial statements; however, there can be no assurance that current regulatory requirements will not change or that unknown past non-compliance with environmental laws will not be discovered on our properties. However, the liability ultimately incurred with respect to a matter may exceed the related accrual. Accrued environmental liabilities are recorded in other accrued expenses on the condensed consolidated balance sheets.

In August 2015, we received a Clean Air Act Section 114 Information Request (the "Information Request") from the U.S. Environmental Protection Agency ("EPA"). The Information Request sought, among other things, information related to the design, operation, and maintenance of our Wattenberg Field production facilities in the Denver-Julesburg Basin of Colorado. The Information Request focuses on historical operation and design information for 46 of our production facilities and asks that we conduct sampling and analyses at the identified 46 facilities. We responded to the Information Request with the requested data in January 2016.

In addition, in December 2015, we received a Compliance Advisory pursuant to C.R.S. 25-7-115(2) from the Colorado Department of Public Health and Environment's (“CDPHE”) Air Quality Control Commission's Air Pollution Control Division alleging that we failed to design, operate, and maintain certain condensate collection, storage, processing, and handling operations to minimize leakage of volatile organic compounds at 65 facilities consistent with applicable standards under Colorado law.

For more than a year, we held a series of meetings with the EPA, Department of Justice (“DOJ”) and CDPHE on the above matters. On June 26, 2017, the DOJ on behalf of the EPA and the State of Colorado filed a complaint against us based on the above matters. We continue to schedule meetings with these agencies in working toward a resolution of the matters. The ultimate outcome related to these combined actions is not known at this time.

NOTE 13 - COMMON STOCK

Sale of Equity Securities

During December 2016, we issued 9.4 million shares of our common stock as partial consideration for 100 percent of the common stock of Arris Petroleum and for the acquisition of certain Delaware Basin properties. Pursuant to the terms of previously-disclosed lock-up agreements, these shares were restricted for sale. The lock-up period ended on June 4, 2017. We have registered the 9.4 million shares of our common stock for resale.

Stock-Based Compensation Plans

The following table provides a summary of the impact of our outstanding stock-based compensation plans on the results of operations for the periods presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(in thousands)			
Stock-based compensation expense	$5,372	$6,444	$9,826	$11,126
Income tax benefit	(2,010)	(2,452)	(3,676)	(4,233)
Net stock-based compensation expense	$3,362	$3,992	$6,150	$6,893

Stock Appreciation Rights

The stock appreciation right ("SARs") vest ratably over a three-year period and may be exercised at any point after vesting through ten years from the date of issuance. Pursuant to the terms of the awards, upon exercise, the executive officers will receive, in shares of common stock, the excess of the market price of the award on the date of exercise over the market price of the award on the date of issuance.

The Compensation Committee of our Board of Directors awarded SARs to our executive officers during the six months ended June 30, 2017 and 2016. The fair value of each SAR award was estimated on the date of grant using a Black-Scholes pricing model using the following assumptions:

	Six Months Ended June 30,	
	2017	2016
Expected term of award (in years)	6	6
Risk-free interest rate	2.0 %	1.8 %
Expected volatility	53.3 %	54.5 %
Weighted-average grant date fair value per share	$38.58	$26.96

The expected term of the award was estimated using historical stock option exercise behavior data. The risk-free interest rate was based on the U.S. Treasury yields approximating the expected life of the award in effect at the time of grant. Expected volatilities were based on our historical volatility. We do not expect to pay or declare dividends in the foreseeable future.

The following table presents the changes in our SARs for the six months ended June 30, 2017:

	Number of SARs	Weighted-Average Exercise Price	Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2016	244,078	$ 41.36	6.9	$ 7,620
Awarded	54,142	74.57	—	—
Outstanding at June 30, 2017	298,220	47.39	7.0	1,158
Exercisable at June 30, 2017	186,248	39.38	5.8	1,093

Total compensation cost related to SARs granted and not yet recognized in our condensed consolidated statement of operations as of June 30, 2017 was $2.8 million. The cost is expected to be recognized over a weighted-average period of 2.1 years.

Restricted Stock Awards

Time-Based Awards. The fair value of the time-based restricted shares is amortized ratably over the requisite service period, primarily three years. The time-based shares generally vest ratably on each anniversary following the grant date provided that a participant is continuously employed.

Table of contents
PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2017
(unaudited)

The following table presents the changes in non-vested time-based awards to all employees, including executive officers, for the six months ended June 30, 2017:

	Shares	Weighted-Average Grant Date Fair Value
Non-vested at December 31, 2016	479,642	$ 56.09
Granted	248,946	67.02
Vested	(202,427)	56.43
Forfeited	(5,311)	67.20
Non-vested at June 30, 2017	520,850	61.06

The following table presents the weighted-average grant date fair value per share and related information as of/for the periods presented:

	As of/Six Months Ended June 30,	
	2017	2016
	(in thousands, except per share data)	
Total intrinsic value of time-based awards vested	$ 13,103	$ 13,314
Total intrinsic value of time-based awards non-vested	22,454	31,506
Market price per common share as of June 30,	43.11	57.61
Weighted-average grant date fair value per share	67.02	57.11

Total compensation cost related to non-vested time-based awards and not yet recognized in our condensed consolidated statements of operations as of June 30, 2017 was $25.7 million. This cost is expected to be recognized over a weighted-average period of 2.1 years.

Market-Based Awards. The fair value of the market-based restricted shares is amortized ratably over the requisite service period, primarily three years. The market-based shares vest if the participant is continuously employed throughout the performance period and the market-based performance measure is achieved, with a maximum vesting period of three years. All compensation cost related to the market-based awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved.

The Compensation Committee of our Board of Directors awarded a total of 28,069 market-based restricted shares to our executive officers during the six months ended June 30, 2017. In addition to continuous employment, the vesting of these shares is contingent on our total stockholder return ("TSR"), which is essentially our stock price change including any dividends as compared to the TSR of a group of peer companies. The shares are measured over a three-year period ending on December 31, 2019, and can result in a payout between 0 percent and 200 percent of the total shares awarded. The weighted-average grant date fair value per market-based share for these awards was computed using the Monte Carlo pricing model using the following assumptions:

	Six Months Ended June 30,	
	2017	2016
Expected term of award (in years)	3	3
Risk-free interest rate	1.4 %	1.2 %
Expected volatility	51.4 %	52.3 %
Weighted-average grant date fair value per share	$94.02	$72.54

The expected term of the awards was based on the requisite service period. The risk-free interest rate was based on the U.S. Treasury yields in effect at the time of grant and extrapolated to approximate the life of the award. The expected volatility was based on our historical volatility.

Table of contents
PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2017
(unaudited)

The following table presents the change in non-vested market-based awards during the six months ended June 30, 2017:

	Shares	Weighted-Average Grant Date Fair Value per Share
Non-vested at December 31, 2016	48,420	$ 64.97
Granted	28,069	94.02
Non-vested at June 30, 2017	76,489	75.63

The following table presents the weighted-average grant date fair value per share and related information as of/for the periods presented:

	As of /Six Months Ended June 30,	
	2017	2016
	(in thousands, except per share data)	
Total intrinsic value of market-based awards vested	$ —	$ 1,174
Total intrinsic value of market-based awards non-vested	3,297	4,871
Market price per common share as of June 30,	43.11	57.61
Weighted-average grant date fair value per share	94.02	72.54

Total compensation cost related to non-vested market-based awards, not yet recognized in our condensed consolidated statements of operations as of June 30, 2017, was $3.4 million. This cost is expected to be recognized over a weighted-average period of 2.1 years.

Treasury Share Purchases

In June 2010, our stockholders approved a long-term equity compensation plan for our employees and non-employee directors (the "2010 Plan"). In accordance with the 2010 Plan, as amended in June 2013, up to 3,000,000 new shares of our common stock are authorized for issuance. Shares granted may be either authorized but unissued shares, treasury shares, or any combination of these shares. Additionally, the 2010 Plan permits the reuse or reissuance of shares of common stock which were canceled, expired, forfeited or, in the case of SARs, paid out in the form of cash. In accordance with our stock-based compensation plans, employees and directors may surrender shares of our common stock to pay tax withholding obligations upon the vesting and exercise of share-based awards. Shares acquired that had been issued pursuant to the 2010 Plan are reissued for new grants. For shares reissued for new grants under the 2010 Plan, shares are recorded at cost and upon reissuance we reduce the carrying value of shares acquired and held pursuant to the 2010 Plan by the weighted-average cost per share with an offsetting charge to additional paid-in capital. As of December 31, 2016, we had 10,397 shares remaining available for reissuance pursuant to our 2010 plan. Additionally, as of December 31, 2016, we had 18,366 of shares of treasury stock related to a rabbi trust. During the six months ended June 30, 2017, we acquired 79,381 shares pursuant to our stock-based compensation plans for payment of tax liabilities, of which 46,822 shares were reissued and 42,956 shares are available for reissuance pursuant to our 2010 Plan.

Preferred Stock

We are authorized to issue 50,000,000 shares of preferred stock, par value $0.01 per share, which may be issued in one or more series, with such rights, preferences, privileges, and restrictions as shall be fixed by our Board from time to time. Through June 30, 2017, no preferred shares have been issued.

Table of contents
PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2017
(unaudited)

NOTE 14 - EARNINGS PER SHARE

Basic earnings per share is computed by dividing net earnings by the weighted-average number of common shares outstanding for the period. Diluted earnings per share is similarly computed, except that the denominator includes the effect, using the treasury stock method, of unvested restricted stock, outstanding SARs, stock options, convertible notes, and shares held pursuant to our non-employee director deferred compensation plan, if including such potential shares of common stock is dilutive.

The following table presents a reconciliation of the weighted-average diluted shares outstanding:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(in thousands)			
Weighted-average common shares outstanding - basic	65,859	46,742	65,804	44,175
Dilutive effect of:				
Restricted stock	94	—	176	—
Other equity-based awards	66	—	86	—
Weighted-average common shares and equivalents outstanding - diluted	66,019	46,742	66,066	44,175

We reported a net loss for the three and six months ended June 30, 2016. As a result, our basic and diluted weighted-average common shares outstanding were the same for that period because the effect of the common share equivalents was anti-dilutive.

The following table presents the weighted-average common share equivalents excluded from the calculation of diluted earnings per share due to their anti-dilutive effect:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(in thousands)			
Weighted-average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:				
Restricted stock	376	768	119	745
Convertible notes	—	358	—	478
Other equity-based awards	1	103	10	105
Total anti-dilutive common share equivalents	377	1,229	129	1,328

In September 2016, we issued the 2021 Convertible Notes, which give the holders, at our election, the right to convert the aggregate principal amount into 2.3 million shares of our common stock at a conversion price of $85.39 per share. The 2021 Convertible Notes could be included in the diluted earnings per share calculation using the treasury stock method if the average market share price exceeds the $85.39 conversion price during the periods presented. During the three and six months ended June 30, 2017, the average market price of our common stock did not exceed the conversion price; therefore, shares issuable upon conversion of the 2021 Convertible Notes were not included in the diluted earnings per share calculation.

In November 2010, we issued $115.0 million aggregate principal amount of 3.25% convertible senior notes that were due in 2016 ("2016 Convertible Notes"), which gave the holders the right to convert the aggregate principal amount into 2.7 million shares of our common stock at a conversion price of $42.40 per share. The 2016 Convertible Notes matured in May 2016. Prior to maturity, the 2016 Convertible Notes were included in the diluted earnings per share calculation using the treasury stock method when the average market share price exceeded the $42.40 conversion price during the periods presented.

Table of contents
PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2017
(unaudited)

NOTE 15 - SUBSIDIARY GUARANTOR

Our subsidiary PDC Permian, Inc. guarantees our obligations under our publicly-registered Notes. The following presents the condensed consolidating financial information separately for:

(i) PDC Energy, Inc. ("Parent"), the issuer of the guaranteed obligations, including non-material subsidiaries;
(ii) PDC Permian, Inc., the guarantor subsidiary ("Guarantor"), as specified in the indentures related to our Notes;
(iii) Eliminations representing adjustments to (a) eliminate intercompany transactions between or among Parent, Guarantor, and our other subsidiaries and (b) eliminate the investments in our subsidiaries;
(iv) Parent and subsidiaries on a consolidated basis ("Consolidated").

The Guarantor is 100% owned by the Parent beginning in December 2016. The Notes are fully and unconditionally guaranteed on a joint and several basis by the Guarantor. The guarantee is subject to release in limited circumstances only upon the occurrence of certain customary conditions. Each entity in the condensed consolidating financial information follows the same accounting policies as described in the notes to the condensed consolidated financial statements.

The following condensed consolidating financial statements have been prepared on the same basis of accounting as our condensed consolidated financial statements. Investments in subsidiaries are accounted for under the equity method. Accordingly, the entries necessary to consolidate the Parent and Guarantor are reflected in the eliminations column.

	Condensed Consolidating Balance Sheets			
	June 30, 2017			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Assets				
Current assets	$381,313	$14,905	$—	$396,218
Properties and equipment, net	1,945,252	2,220,320	—	4,165,572
Intercompany receivable	120,106	—	(120,106)	—
Investment in subsidiaries	1,733,615	—	(1,733,615)	—
Goodwill	—	56,331	—	56,331
Noncurrent assets	37,966	841	—	38,807
Total Assets	$4,218,252	$2,292,397	$(1,853,721)	$4,656,928
Liabilities and Stockholders' Equity				
Current liabilities	$277,443	$53,223	$—	$330,666
Intercompany payable	—	120,106	(120,106)	—
Long-term debt	1,049,004	—	—	1,049,004
Other noncurrent liabilities	177,363	373,872	11,581	562,816
Stockholders' equity	2,714,442	1,745,196	(1,745,196)	2,714,442
Total Liabilities and Stockholders' Equity	$4,218,252	$2,292,397	$(1,853,721)	$4,656,928

24

Table of contents
PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2017
(unaudited)

	Condensed Consolidating Balance Sheets December 31, 2016			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Assets				
Current assets	$387,309	$12,516	$—	$ 399,825
Properties and equipment, net	1,889,419	2,118,847	—	4,008,266
Intercompany receivable	9,415	—	(9,415)	—
Investment in subsidiaries	1,765,092	—	(1,765,092)	—
Goodwill	—	62,041	—	62,041
Noncurrent assets	15,539	171	—	15,710
Total Assets	$4,066,774	$2,193,575	$(1,774,507)	$ 4,485,842
Liabilities and Stockholders' Equity				
Current liabilities	$235,121	$35,457	$—	$ 270,578
Intercompany payable	—	9,415	(9,415)	—
Long-term debt	1,043,954	—	—	1,043,954
Other noncurrent liabilities	164,945	383,611	—	548,556
Stockholders' equity	2,622,754	1,765,092	(1,765,092)	2,622,754
Total Liabilities and Stockholders' Equity	$4,066,774	$2,193,575	$(1,774,507)	$ 4,485,842

	Condensed Consolidating Statements of Operations Three Months Ended June 30, 2017			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Operating and other revenues	$252,346	$22,812	$ —	$ 275,158
Operating expenses	39,915	7,700	—	47,615
General and administrative	26,617	2,914	—	29,531
Depreciation depletion and amortization	108,727	17,286	—	126,013
Impairment of properties and equipment	531	27,035	—	27,566
Provision for uncollectible notes receivable	(40,203)	—	—	(40,203)
Interest (expense) income	(19,032)	183	—	(18,849)
Income (loss) before income taxes	97,727	(31,940)	—	65,787
Income tax expense	(36,285)	11,748	—	(24,537)
Equity in loss of subsidiary	(20,192)	—	20,192	—
Net income (loss)	$41,250	$(20,192)	$ 20,192	$ 41,250

	Condensed Consolidating Statements of Operations Six Months Ended June 30, 2017			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			

Operating and other revenues	$507,087	$41,778	$ —	$ 548,865
Operating expenses	77,415	14,380	—	91,795
General and administrative	50,146	5,700	—	55,846
Depreciation depletion and amortization	210,465	24,864	—	235,329
Impairment of properties and equipment	1,134	28,625	—	29,759
Provision for uncollectible notes receivable	(40,203)	—	—	(40,203)
Interest (expense) income	(38,389)	313	—	(38,076)
Income (loss) before income taxes	169,741	(31,478)	—	138,263
Income tax expense	(62,448)	11,581	—	(50,867)
Equity in loss of subsidiary	(19,897)	—	19,897	—
Net income (loss)	$87,396	$(19,897)	$ 19,897	$ 87,396

25

Table of contents
PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2017
(unaudited)

Net losses of the Guarantor for the three and six months ended June 30, 2017 are primarily the result of the impairment of certain unproved Delaware Basin leasehold positions during the respective periods.

	Condensed Consolidating Statements of Cash Flows			
	Six Months Ended June 30, 2017			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Cash flows from operating activities	$246,128	$17,069	$ —	$263,197
Cash flows from investing activities:				
Capital expenditures for development of crude oil and natural properties	(198,954)	(135,452)	—	(334,406)
Capital expenditures for other properties and equipment	(1,792)	(507)	—	(2,299)
Acquisition of crude oil and natural gas properties, including settlement adjustments	—	5,372	—	5,372
Proceeds from sale of properties and equipment	1,293	—	—	1,293
Sale of promissory note	40,203	—	—	40,203
Restricted cash	(9,250)	—	—	(9,250)
Purchases of short-term investments	(49,890)	—	—	(49,890)
Sales of short-term investments	49,890	—	—	49,890
Intercompany transfers	(109,923)	—	109,923	—
Net cash from investing activities	(278,423)	(130,587)	109,923	(299,087)
Cash flows from financing activities:				
Proceeds from issuance of equity, net of issuance costs	—	—	—	—
Purchase of treasury stock	(5,274)	—	—	(5,274)
Other	(627)	(18)	—	(645)
Intercompany transfers	—	109,923	(109,923)	—
Net cash from financing activities	(5,901)	109,905	(109,923)	(5,919)
Net change in cash and cash equivalents	(38,196)	(3,613)	—	(41,809)
Cash and cash equivalents, beginning of period	240,487	3,613	—	244,100
Cash and cash equivalents, end of period	$202,291	$—	$ —	$202,291

Table of contents
PDC ENERGY, INC.

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

The following discussion and analysis, as well as other sections in this report, should be read in conjunction with our condensed consolidated financial statements and related notes included elsewhere in this report. Further, we encourage you to review the Special Note Regarding Forward-Looking Statements.

EXECUTIVE SUMMARY

Financial Overview

Production volumes increased to 8.0 MMboe and 14.7 MMboe for the three and six months ended June 30, 2017, respectively, representing increases of 54 percent and 50 percent as compared to the three and six months ended June 30, 2016, respectively. The increases in production volumes were primarily attributable to the continued success of our horizontal Niobrara and Codell drilling program in the Wattenberg Field and our first full six months of production from our recently-acquired Delaware Basin properties. Crude oil production increased 62 percent and 47 percent for the three and six months ended June 30, 2017, respectively, compared to the three and six months ended June 30, 2016. Crude oil production comprised approximately 40 percent and 39 percent of total production in the three and six months ended June 30, 2017, respectively. NGL production increased 66 percent and 70 percent for the three and six months ended June 30, 2017, respectively, compared to the three and six months ended June 30, 2016. Natural gas production increased 40 percent and 43 percent in the three and six months ended June 30, 2017, respectively, compared to the three and six months ended June 30, 2016. On a combined basis, total liquids production comprised 63 percent and 59 percent of our total production during the three months ended June 30, 2017 and June 30, 2016, respectively, and 62 percent and 60 percent of total production during the six months ended June 30, 2017 and June 30, 2016, respectively. For the three months ended June 30, 2017, we maintained an average daily production rate of approximately 88,100 Boe per day, up from approximately 57,100 Boe per day for the three months ended June 30, 2016.

On a sequential quarterly basis, total production volumes for the three months ended June 30, 2017, as compared to the three months ended March 31, 2017, increased by 21 percent, while crude oil production increased by 30 percent during the same period. The increase in production was primarily related to 84 wells in our Wattenberg Field being turned-in-line during the first six months of 2017 and a 47 percent increase in our average daily production in the Delaware Basin from the first quarter, to approximately 10,000 Boe per day in the quarter ended June 30, 2017. We expect that we will see modest sequential production growth in the third quarter of 2017 and leveling off of production in the fourth quarter of 2017, based on the adjusted timing for our turn-in-lines, and expected capacity considerations associated with gathering system line pressures in the Wattenberg Field.

Crude oil, natural gas, and NGLs sales increased to $213.6 million and $403.3 million in the three and six months ended June 30, 2017, respectively, compared to $110.8 million and $186.2 million in the three and six months ended June 30, 2016, respectively. These 93 percent and 117 percent increases in sales revenues were driven by the 54 percent and 50 percent increases in production and 25 percent and 44 percent increases in realized commodity prices.

We had positive net settlements from our commodity derivative contracts of $12.0 million for the three months ended June 30, 2017 as compared to positive net settlements of $53.3 million for the three months ended June 30, 2016. We had positive net settlements of $12.6 million for the six months ended June 30, 2017, as compared to positive net settlements of $120.1 million for the six months ended June 30, 2016. We entered into agreements for the derivative instruments that settled throughout 2016 prior to commodity prices becoming depressed in late 2014. Substantially all of these higher-value derivatives settled by the end of 2016. Net settlements for the three and six months ended

June 30, 2017 reflect derivative instruments entered into since 2015, which more closely approximate recent realized prices. Based upon the forward strip pricing at June 30, 2017, we expect that settlements will continue to be substantially lower in 2017 than in 2016. See Results of Operations - Commodity Price Risk Management, Net for further details of our settlements of derivatives and changes in the fair value of unsettled derivatives.

The combined revenue from crude oil, natural gas, and NGLs sales and net settlements received on our commodity derivative instruments increased 37 percent to $225.6 million in the three months ended June 30, 2017, from $164.1 million in the three months ended June 30, 2016, and increased 36 percent to $415.9 million in the six months ended June 30, 2017, from $306.3 million in the six months ended June 30, 2016.

During the three months ended June 30, 2017, we impaired certain unproved Delaware Basin leasehold positions totaling $27.0 million that expired during the three months ending June 30, 2017, or are projected to expire between June 30, 2017 and December 31, 2017. Subsequent to closing the acquisitions in the Delaware Basin, it was determined that development of certain acreage tracts would not meet our internal expectations for acceptable rates of return due to a combination of weakening commodity prices; higher per well development and operational costs; and updated technical analysis. As a result, we allowed or expect to allow certain acreage to expire, and in other circumstances we were unable to obtain necessary lease term extensions. As of June 30, 2017, our current leasehold position in the Delaware Basin is approximately 60,000 net acres.

In the three and six months ended June 30, 2017, we generated net income of $41.2 million and $87.4 million, respectively, or $0.62 and $1.32 per diluted share, respectively. During the same periods, our adjusted EBITDAX, a non-U.S. GAAP financial measure, was $200.4 million and $330.6 million, respectively. Our net income and adjusted EBITDAX were positively impacted by the sale of the $40.2 million Promissory Note and the collection of the related cash proceeds in April 2017, as further described below in Results of Operations - Provision for Uncollectible Notes Receivable. Beginning in 2017, we have included non-cash stock-based compensation and exploration, geologic and geophysical expense in our reconciliation of adjusted EBITDAX. In prior periods, we included adjusted EBITDA, a non-U.S. GAAP financial measure, which did not include these adjustments. All prior periods have been conformed for comparability of this updated presentation. In the three and six months ended June 30, 2016, our net loss per diluted share was $2.04 and $3.78, respectively, and our adjusted EBITDAX, a non-GAAP financial measure, was $122.4 million and $180.2 million, respectively. Our cash flow from operations was $263.2 million and our adjusted cash flow from operations, a non-U.S. GAAP financial measure, was $256.6 million in the six months ended June 30, 2017. See Reconciliation of Non-U.S. GAAP Financial Measures, below, for a more detailed discussion of these non-U.S. GAAP financial measures and a reconciliation of these measures to the most comparable U.S. GAAP measures.

Available liquidity as of June 30, 2017 was $902.3 million, which is comprised of $202.3 million of cash and cash equivalents and $700.0 million available for borrowing under our revolving credit facility at our current commitment level. We expect decreases in our cash balance over the course of 2017 as we continue planned development in the core Wattenberg Field and further capital investment in our Delaware Basin assets.

We intend to continue to manage our liquidity position by a variety of means, including through the generation of cash flows from operations, investment in projects with attractive rates of return, protection of cash flows on a portion of our anticipated sales through the use of an active commodity derivative hedging program, potential utilization of our borrowing capacity under our revolving credit facility, and when warranted, capital markets transactions from time to time.

Operational Overview

During the six months ended June 30, 2017, we continued to execute our strategic plan to grow production while preserving our financial strength and liquidity. During the second quarter of 2017, we operated four drilling rigs in the Wattenberg Field and four drilling rigs in the Delaware Basin. Our drilling efficiency in the Wattenberg Field over the last two quarters has resulted in shorter drill cycle times; therefore, we expect to decrease our rig count to three rigs beginning in the fourth quarter of 2017. Because of the shorter drill times, the impact of the reduced rig count on our expected turn-in-line count in the Wattenberg Field is expected to be minimal in 2017. In the Delaware Basin, one rig contract expired in August 2017, and we expect to utilize three drilling rigs through the end of 2017. Our active drilling program in the Delaware Basin in the first half of 2017 provided us with a degree of flexibility with respect to holding acreage in the area on a near-term basis and allows us to shift immediate focus to improving drill cycle times and the per well costs of our Delaware Basin wells.

Table of contents
PDC ENERGY, INC.

The following tables summarizes our drilling and completion activity for the six months ended June 30, 2017:

	Wells Operated by PDC					
	Wattenberg Field		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
In-process as of December 31, 2016	64	52.7	5	4.8	69	57.5
Wells spud	73	65.7	12	11.0	85	76.7
Wells turned-in-line to sales	(72)	(59.2)	(9)	(8.7)	(81)	(67.9)
In-process as of June 30, 2017	65	59.2	8	7.1	73	66.3

	Wells Operated by Others					
	Wattenberg Field		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
In-process as of December 31, 2016	18	3.4	—	—	18	3.4
Wells spud	71	9.0	3	0.8	74	9.8
Wells turned-in-line to sales	(12)	(1.9)	—	—	(12)	(1.9)
In-process as of June 30, 2017	77	10.5	3	0.8	80	11.3

Our in-process wells represent wells that are in the process of being drilled and/or have been drilled and are waiting to be fractured and/or for gas pipeline connection. Our drilled but uncompleted wells ("DUCs") are generally completed and turned in-line to sales within three to nine months of drilling. The majority of the in-process wells at each period end are DUCs, as we do not begin the completion process until the entire well pad is drilled. As we continue to monitor our capital investment and due to the efficiencies gained by our operating team in the Wattenberg Field, we expect that we will have an increase of approximately 25 wells in our in-process well count at December 31, 2017, as compared to December 31, 2016, resulting from faster than expected drill cycle times. All appropriate costs incurred through the end of the period have been capitalized, while the capital investment to complete the wells will be incurred in the period in which the wells are completed.

2017 Operational Outlook

Based on our revised timing and the estimated productivity of wells associated with our capital investment program, we currently believe that our 2017 production will be approximately 32 MMBoe. We expect that approximately 40 percent of our 2017 production will be crude oil and approximately 23 percent will be NGLs, for total liquids of approximately 63 percent. The anticipated percentage of production from NGLs has increased due to the success of field recovery efforts and improved yields by our third-party processors in the Wattenberg Field.

We expect our capital expenditures to be approximately $800 million in 2017, an estimate that we have increased to account for higher per well costs in the Delaware Basin and increases in the total expected number of wells to be spud in the Wattenberg Field during the year. We also added a third and fourth rig in the first quarter of 2017 in the Delaware Basin, which was sooner than initially contemplated in our budget, in order to protect certain leasehold positions and to create greater future operational flexibility. This flexibility as it relates to holding acreage in the Delaware Basin is particularly important given the volatility of commodity prices and potential further service cost increases in the Delaware Basin as it should allow us to adjust our drilling program to two rigs in this area if necessary for a period of time without risk of losing significant additional acreage.

Further, some additional capital investment has been included in our forecast for an anticipated Wattenberg Field acreage trade that would, if completed, increase our working interest in certain wells. The trade is expected to close in the second half of 2017.

Wattenberg Field. The 2017 investment forecast has been reduced to approximately $450 million in the Wattenberg Field with three rigs running in the fourth quarter of 2017. Approximately $445 million of our 2017 capital investment program is expected to be allocated to development activities, comprised of approximately $425 million for our operated drilling program and approximately $20 million for wells drilled and operated by others. The remainder of the

Wattenberg Field capital investment program is expected to be used for miscellaneous well equipment and capital projects. Wells in the Wattenberg Field typically have productive horizons at a depth of approximately 6,500 to 7,500 feet below the surface. In 2017, our revised investment forecast anticipates spudding approximately 155 and turning-in-line approximately 133 horizontal operated wells with lateral lengths of 4,000 to 10,000 feet.

Delaware Basin. Our 2017 investment forecast contemplates the operation of a three-rig program for the remainder of 2017 in the Delaware Basin. Total capital investment in the Delaware Basin has been increased to approximately $345 million, of which approximately $285 million is allocated to spud 24 and turn-in-line an estimated 20 wells. Expected per well drilling costs in the Delaware Basin have increased by approximately 15 to 20 percent during the second quarter of 2017 as compared to the first quarter of 2017, primarily due to higher costs of services and supplies and longer than anticipated drill cycle times. To enhance our understanding of the geology in the Delaware Basin, we initiated various engineering studies on most of our Delaware Basin wells, including expanded depth pilot holes and logging/seismic services. These studies are providing important information to our operating team; however, they have come with additional unexpected costs. Additionally, mechanical issues have resulted in cost overruns for certain wells. Of the 20 planned turn-in-lines during 2017, 9 are expected to have extended laterals of approximately 10,000 horizontal feet with an estimated 70 to 75 completion stages per well. Similarly spaced completion stages are anticipated for the remaining 11 turn-in-lines. Wells in the Delaware Basin typically have productive horizons at a depth of approximately 9,000 to 11,000 feet below the surface. We plan to invest approximately $15 million for leasing, seismic, and technical studies with an additional $35 million for midstream-related projects including gas connections and surface location infrastructure. The remaining $10 million of the Delaware Basin capital investment program is expected to be used for non-operated capital projects.

We expect to incur costs associated with the purchase of seismic data and pilot hole exploratory work in the Delaware Basin, which will be accounted for as exploration, geologic, and geophysical expense. We estimate that this will result in approximately $5 million to $10 million of exploration expense in 2017.

Utica Shale. As a result of our evaluation of our strategic alternatives with respect to our Utica Shale position, we are working toward a divestiture of these properties during 2017. As of June 30, 2017, these assets did not meet the accounting criteria to be classified as held-for-sale; therefore, they continue to be included in properties and equipment on our condensed consolidated balance sheets. Subsequent to June 30, 2017, we engaged an investment banking group to assist in marketing the Utica properties for sale; therefore, these operations are expected to be classified as held-for-sale upon meeting the criteria for such classification in the third quarter of 2017.

Table of contents
PDC ENERGY, INC.

Results of Operations

Summary Operating Results

The following table presents selected information regarding our operating results:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2017	2016	Percentage Change	2017	2016	Percentage Change
	(dollars in millions, except per unit data)					
Production						
Crude oil (MBbls)	3,237	1,993	62.4 %	5,745	3,900	47.3 %
Natural gas (MMcf)	17,783	12,673	40.3 %	33,367	23,351	42.9 %
NGLs (MBbls)	1,814	1,092	66.1 %	3,357	1,975	70.0 %
Crude oil equivalent (MBoe)	8,015	5,197	54.2 %	14,663	9,767	50.1 %
Average Boe per day (Boe)	88,078	57,111	54.2 %	81,011	53,664	50.9 %
Crude Oil, Natural Gas and NGLs Sales						
Crude oil	$148.8	$80.4	85.1 %	$271.8	$134.4	102.2 %
Natural gas	38.3	17.4	120.1 %	75.3	32.3	133.1 %
NGLs	26.5	13.0	103.8 %	56.2	19.5	188.2 %
Total crude oil, natural gas, and NGLs sales	$213.6	$110.8	92.8 %	$403.3	$186.2	116.6 %
Net Settlements on Commodity Derivatives						
Crude oil	$5.1	$38.7	(86.8)%	$1.9	$92.0	(97.9)%
Natural gas	6.8	14.6	(53.4)%	10.6	28.1	(62.3)%
NGLs (propane portion)	0.1	—	*	0.1	—	*
Total net settlements on derivatives	$12.0	$53.3	(77.5)%	$12.6	$120.1	(89.5)%
Average Sales Price (excluding net settlements on derivatives)						
Crude oil (per Bbl)	$45.97	$40.37	13.9 %	$47.31	$34.46	37.3 %
Natural gas (per Mcf)	2.16	1.37	57.7 %	2.26	1.38	63.8 %
NGLs (per Bbl)	14.59	11.93	22.3 %	16.75	9.89	69.4 %
Crude oil equivalent (per Boe)	26.65	21.33	24.9 %	27.50	19.07	44.2 %
Average Costs and Expenses (per Boe)						
Lease operating expenses	$2.50	$2.63	(4.9)%	$2.72	$2.97	(8.4)%
Production taxes	1.88	1.16	62.1 %	1.87	1.04	79.8 %
Transportation, gathering and processing expenses	0.81	0.86	(5.8)%	0.84	0.87	(3.4)%
General and administrative expense	3.68	4.54	(18.9)%	3.81	4.75	(19.8)%
Depreciation, depletion and amortization	15.72	20.59	(23.7)%	16.05	20.93	(23.3)%
Lease Operating Expenses by Operating Region (per Boe)						
Wattenberg Field	$2.22	$2.66	(16.5)%	$2.42	$3.00	(19.3)%
Delaware Basin	4.88	—	*	5.53	—	*
Utica Shale	1.34	2.08	(35.6)%	1.48	2.28	(35.1)%

*Percentage change is not meaningful.
Amounts may not recalculate due to rounding.

Crude Oil, Natural Gas, and NGLs Sales

For the three and six months ended June 30, 2017, crude oil, natural gas, and NGLs sales revenue increased compared to the three and six months ended June 30, 2016 due to the following (in millions):

	June 30, 2017	
	Three Months Ended	Six Months Ended
	(in millions)	
Increase in production	$65.9	$91.1
Increase in average crude oil price	18.2	73.8
Increase in average natural gas price	13.9	29.2
Increase in average NGLs price	4.8	23.0
Total increase in crude oil, natural gas and NGLs sales revenue	$102.8	$217.1

Crude Oil, Natural Gas, and NGLs Production

The following tables present crude oil, natural gas, and NGLs production. Our acquisitions of assets in the Delaware Basin closed in December 2016; therefore, there is no comparative data for the three and six months ended June 30, 2016:

	Three Months Ended June 30,			Six Months Ended June 30,		
Production by Operating Region	2017	2016	Percentage Change	2017	2016	Percentage Change
Crude oil (MBbls)						
Wattenberg Field	2,798	1,894	47.7 %	4,940	3,712	33.1 %
Delaware Basin	364	—	*	639	—	*
Utica Shale	75	99	(24.4)%	166	188	(12.1)%
Total	3,237	1,993	62.4 %	5,745	3,900	47.3 %
Natural gas (MMcf)						
Wattenberg Field	15,192	12,098	25.6 %	28,906	22,268	29.8 %
Delaware Basin	2,025	—	*	3,271	—	*
Utica Shale	566	575	(1.6)%	1,190	1,083	9.9 %
Total	17,783	12,673	40.3 %	33,367	23,351	42.9 %
NGLs (MBbls)						
Wattenberg Field	1,551	1,047	48.1 %	2,909	1,888	54.1 %
Delaware Basin	212	—	*	343	—	*
Utica Shale	51	45	11.9 %	105	87	19.8 %
Total	1,814	1,092	66.1 %	3,357	1,975	70.0 %
Crude oil equivalent (MBoe)						
Wattenberg Field	6,882	4,957	38.8 %	12,667	9,311	36.0 %
Delaware Basin	914	—	*	1,527	—	*
Utica Shale	219	240	(8.5)%	469	456	2.8 %
Total	8,015	5,197	54.2 %	14,663	9,767	50.1 %
Average crude oil equivalent per day (Boe)						
Wattenberg Field	75,621	54,478	38.8 %	69,984	51,159	36.8 %
Delaware Basin	10,047	—	*	8,437	—	*

Utica Shale	2,410	2,633	(8.5)%	2,590	2,505	3.4 %
Total	88,078	57,111	54.2 %	81,011	53,664	51.0 %

* Percentage change is not meaningful.
Amounts may not recalculate due to rounding.

In the Wattenberg Field, we rely on third-party midstream service providers to construct gathering, compression, and processing facilities to keep pace with our, and the overall field's natural gas production growth. From time to time, our production has been adversely affected by high line pressures on the gas gathering facilities, primarily due to higher ambient temperatures and increases in field-wide production volumes. In 2015, our primary midstream service provider added additional facilities which significantly reduced production constraints from late 2015 to mid-2017. However, we are starting to experience higher line pressures due primarily to continued growth in field-wide production volumes. As a result, we anticipate higher production curtailments in the second half of 2017 and through most of 2018 until our primary midstream provider completes construction of an additional midstream plant and facilities. We believe that our 2017 production guidance range appropriately reflects the foreseeable impact of such higher gathering line pressures in the Wattenberg Field; however, such curtailment estimations may differ from the actual impact to production due to incremental uncertainties.

We continue work closely with our third party midstream providers in an effort to ensure adequate system capacity going forward in the Wattenberg Field. For example, we along with other operators, made a commitment with DCP Midstream, LP ("DCP") in December 2016 in connection with DCP's construction of additional gathering, compression, and processing facilities in the field. This expansion is expected to increase DCP's system capacity, assist in the control of line pressures on its natural gas gathering facilities, and reduce production curtailments in the field. We will be bound to the incremental volume requirements in this agreement on the first day of the calendar month after the actual in-service date of the plant, which is currently expected to occur in late 2018. The agreement imposes a baseline volume commitment and we are required for the first three years of the contract to guarantee a certain target profit margin to DCP on these volumes sold. Under our current drilling plans, we expect to meet both the baseline and incremental volume commitments, and we believe that the contractual target profit margin will be achieved without an additional payment from us. See footnote titled Commitments and Contingencies for additional details regarding the agreement. We also seek to negotiate construction of incremental projects designed to add capacity to our primary third-party midstream service provider's system between major new facility expansions.

The ultimate timing and availability of adequate infrastructure is not within our control and if our midstream service provider’s construction projects are delayed, we could experience higher gathering line pressures that may negatively impact our ability to fulfill our growth plans. Total system infrastructure performance may also be affected by a number of other factors, including potential additional increases in production from the Wattenberg Field.

Table of contents
PDC ENERGY, INC.

Crude Oil, Natural Gas, and NGLs Pricing

Our results of operations depend upon many factors. Key factors are the price of crude oil, natural gas, and NGLs and our ability to market our production effectively. Crude oil, natural gas, and NGL prices have a high degree of volatility and our realizations can change substantially. Our realized prices for crude oil, natural gas, and NGLs increased during the three and six months ended June 30, 2017 compared to the three and six months ended June 30, 2016. NYMEX crude oil increased 6 percent and 27 percent, and natural gas prices increased 63 percent and 61 percent, respectively, as compared to the three and six months ended June 30, 2016. The realized NGL prices in the Wattenberg Field are reflected in the tables below, net of the processing and transport costs that are embedded in the applicable percent-of-proceeds contracts, as are a portion of our Delaware Basin NGL sales.

The following tables present weighted-average sales prices of crude oil, natural gas, and NGLs for the periods presented. Our acquisitions of assets in the Delaware Basin closed in December 2016; therefore, there is no comparative data for the three and six months ended June 30, 2016:

Weighted-Average Realized Sales Price by Operating Region (excluding net settlements on derivatives)	Three Months Ended June 30,				Six Months Ended June 30,			
	2017	2016	Percentage Change		2017	2016	Percentage Change	
Crude oil (per Bbl)								
Wattenberg Field	$46.19	$40.41	14.3	%	$47.46	$34.51	37.5	%
Delaware Basin	44.81	—	*		46.73	—	*	
Utica Shale	43.19	39.57	9.1	%	45.05	33.44	34.7	%
Weighted-average price	45.97	40.37	13.9	%	47.31	34.46	37.3	%
Natural gas (per Mcf)								
Wattenberg Field	$2.24	$1.36	64.7	%	$2.30	$1.38	66.7	%
Delaware Basin	1.37	—	*		1.60	—	*	
Utica Shale	2.76	1.58	74.7	%	2.88	1.51	90.7	%
Weighted-average price	2.16	1.37	57.7	%	2.26	1.38	63.8	%
NGLs (per Bbl)								
Wattenberg Field	$14.13	$11.87	19.0	%	$16.24	$9.78	66.1	%
Delaware Basin	17.33	—	*		19.33	—	*	
Utica Shale	17.10	13.27	28.9	%	22.58	12.29	83.7	%
Weighted-average price	14.59	11.93	22.3	%	16.75	9.89	69.4	%
Crude oil equivalent (per Boe)								
Wattenberg Field	$26.91	$21.27	26.5	%	$27.50	$19.03	44.5	%
Delaware Basin	24.91	—	*		27.32	—	*	
Utica Shale	25.72	22.59	13.9	%	28.29	19.75	43.2	%
Weighted-average price	26.65	21.33	24.9	%	27.50	19.07	44.2	%

* Percentage change is not meaningful.
Amounts may not recalculate due to rounding.

Our crude oil, natural gas, and NGLs sales are recorded under either the “net-back” or "gross" method of accounting, depending upon the related purchase agreement. We use the net-back method of accounting for natural gas and NGLs, as well as the majority of our crude oil production from the Wattenberg Field, for all of our crude oil, NGLs, and a portion of our natural gas in the Delaware Basin, and for crude oil from the Utica Shale, as the purchasers of these commodities also provide transportation, gathering, and processing services. In these situations, the purchaser pays us proceeds based on a percent of the proceeds, or have fixed our sales price at index less specified deductions. We sell our commodities at the wellhead, or what is equivalent to the wellhead in situations where we gather multiple wells into larger pads, and collect a price and recognize revenues based on the wellhead sales price, as transportation and processing costs downstream of the wellhead are incurred by the purchaser and therefore embedded in the wellhead price. The net-back method results in the recognition of a net sales price that is lower than the indices for which the production is based because the operating costs and profit of the midstream facilities are embedded in the net price we earn.

Table of contents
PDC ENERGY, INC.

We use the gross method of accounting for Wattenberg Field crude oil delivered through certain pipelines, a portion of our natural gas in the Delaware Basin, and for natural gas and NGLs sales related to production from the Utica Shale, as the purchasers do not provide transportation, gathering or processing services as a function of the price we earn. Rather, we contract separately with midstream providers for the applicable transport and processing based on a per unit basis. Under this method, we recognize revenues based on the gross selling price and recognize transportation, gathering, and processing expenses.

As discussed above, we enter into agreements for the sale and transportation, gathering and processing of our production, the terms of which can result in variances in the per unit realized prices that we receive for our crude oil, natural gas and NGLs. Information related to the components and classifications in the condensed consolidated statements of operations is shown below. For crude oil, the average NYMEX prices shown below are based upon average daily prices throughout each month and our natural gas average NYMEX pricing is based upon first-of-the-month index prices as this is the method used to sell the majority of each of these commodities pursuant to terms of the respective sales agreements. For NGLs, we use the NYMEX crude oil price as a reference for presentation purposes. The average realized price before transportation, gathering, and processing expenses shown in the table below represents our approximate composite per barrel price for NGLs.

For the three months ended June 30, 2017	Average NYMEX Price	Average Realization Percentage Before Transportation, Gathering and Processing Expenses		Average Realized Price Before Transportation, Gathering and Processing Expenses	Average Transportation, Gathering and Processing Expenses	Average Realized Price After Transportation, Gathering and Processing Expenses
Crude oil (per Bbl)	$ 48.28	95	%	$ 45.97	$ 1.38	$ 44.59
Natural gas (per MMBtu)	3.18	68	%	2.16	0.08	2.08
NGLs (per Bbl)	48.28	30	%	14.59	0.31	14.28
Crude oil equivalent (per Boe)	37.48	71	%	26.65	0.81	25.84

For the three months ended June 30, 2016	Average NYMEX Price	Average Realization Percentage Before Transportation, Gathering and Processing Expenses		Average Realized Price Before Transportation, Gathering and Processing Expenses	Average Transportation, Gathering and Processing Expenses	Average Realized Price After Transportation, Gathering and Processing Expenses
Crude oil (per Bbl)	$ 45.59	89	%	$ 40.37	$ 1.63	$ 38.74
Natural gas (per MMBtu)	1.95	70	%	1.37	0.07	1.30
NGLs (per Bbl)	45.59	26	%	11.93	0.26	11.67
Crude oil equivalent (per Boe)	31.82	67	%	21.33	0.86	20.47

For the six months ended June 30, 2017	Average NYMEX Price	Average Realization Percentage Before Transportation, Gathering and Processing Expenses		Average Realized Price Before Transportation, Gathering and Processing Expenses	Average Transportation, Gathering and Processing Expenses	Average Realized Price After Transportation, Gathering and Processing Expenses
Crude oil (per Bbl)	$ 50.10	94	%	$ 47.31	$ 1.44	$ 45.87
Natural gas (per MMBtu)	3.25	70	%	2.26	0.09	2.17
NGLs (per Bbl)	50.10	33	%	16.75	0.35	16.40
Crude oil equivalent (per Boe)	38.50	71	%	27.50	0.84	26.66

For the six months ended June 30, 2016	Average NYMEX Price	Average Realization Percentage Before Transportation, Gathering and Processing Expenses		Average Realized Price Before Transportation, Gathering and Processing Expenses	Average Transportation, Gathering and Processing Expenses	Average Realized Price After Transportation, Gathering and Processing Expenses
Crude oil (per Bbl)	$ 39.52	87	%	$ 34.46	$ 1.58	$ 32.88
Natural gas (per MMBtu)	2.02	68	%	1.38	0.08	1.30
NGLs (per Bbl)	39.52	25	%	9.89	0.28	9.61
Crude oil equivalent (per Boe)	28.60	67	%	19.07	0.87	18.20

Commodity Price Risk Management, Net

We use commodity derivative instruments to manage fluctuations in crude oil, natural gas, and NGLs prices. We have in place a variety of collars, fixed-price swaps, and basis swaps on a portion of our estimated crude oil, natural gas, and propane production. Because we sell all of our crude oil, natural gas, and NGLs production at prices related to the indexes inherent in our underlying derivative instruments, we ultimately realize value related to our collars of no less than the floor and no more than the ceiling. For our commodity swaps, we ultimately realize the fixed price value related to the swaps. See the footnote titled Commodity Derivative Financial Instruments for a detailed presentation of our derivative positions as of June 30, 2017.

Commodity price risk management, net, includes cash settlements upon maturity of our derivative instruments and the change in fair value of unsettled commodity derivatives related to our crude oil, natural gas, and propane production. Commodity price risk management, net, does not include derivative transactions related to our gas marketing, which are included in other income and other expenses.

Net settlements of commodity derivative instruments are based on the difference between the crude oil, natural gas, and propane index prices at the settlement date of our commodity derivative instruments compared to the respective strike prices contracted for the settlement months that were established at the time we entered into the commodity derivative transaction. The net change in fair value of unsettled commodity derivatives is comprised of the net value increase or decrease in the beginning-of-period fair value of commodity derivative instruments that settled during the period, and the net change in fair value of unsettled commodity derivatives during the period or from inception of any new contracts entered into during the applicable period. The corresponding impact of settlement of the commodity derivative instruments during the period is included in net settlements for the period. The net change in fair value of unsettled commodity derivatives during the period is primarily related to shifts in the crude oil, natural gas, and NGLs forward curves and changes in certain differentials.

The following table presents net settlements and net change in fair value of unsettled derivatives included in commodity price risk management, net:

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
	(in millions)			
Commodity price risk management gain (loss), net:				
Net settlements of commodity derivative instruments:				
Crude oil fixed price swaps and collars	$5.1	$38.7	$1.9	$92.0
Natural gas fixed price swaps and collars	4.8	14.6	8.5	28.1
Natural gas basis protection swaps	2.0	—	2.0	—
NGLs (propane portion) fixed price swaps	0.1	—	0.1	—
Total net settlements of commodity derivative instruments	12.0	53.3	12.5	120.1
Change in fair value of unsettled commodity derivative instruments:				
Reclassification of settlements included in prior period changes in fair value of commodity derivative instruments	(5.1)	(60.8)	18.4	(115.5)
Crude oil fixed price swaps and collars	43.1	(57.8)	88.7	(62.8)
Natural gas fixed price swaps and collars	8.3	(27.5)	16.7	(23.1)
Natural gas basis protection swaps	(0.2)	—	2.3	(0.4)
NGLs (propane portion) fixed price swaps	(0.2)	—	—	—
Net change in fair value of unsettled commodity derivative instruments	45.9	(146.1)	126.1	(201.8)
Total commodity price risk management gain (loss), net	$57.9	$(92.8)	$138.6	$(81.7)

Net settlements of commodity derivatives decreased for the three and six months ended June 30, 2017 as compared to the three and six months ended June 30, 2016. We entered into agreements for the derivative instruments that settled throughout 2016 prior to commodity prices becoming depressed in late 2014. Substantially all of these higher-value agreements had settled by the end of 2016. Net settlements for the three and six months ended June 30, 2017 reflect derivative instruments entered into since 2015, which more closely approximate recent realized prices. Based upon the forward strip pricing at June 30, 2017, we expect that settlements will continue to be substantially lower in 2017 on a relative basis as compared to those in 2016.

Lease Operating Expenses

Lease operating expenses improved to $2.50 per Boe and $2.72 per Boe during the three and six months ended June 30, 2017, respectively, compared to $2.63 per Boe and $2.97 per Boe during the three and six months ended June 30, 2016, respectively. The improvement in lease operating expense per Boe was predominately driven by production growth of 54 percent and 50 percent during the three and six months ended June 30, 2017, respectively, which was partially offset by higher lease operating expense of $4.88 per Boe and $5.53 per Boe in the Delaware Basin during the three and six months ended June 30, 2017, respectively.

Aggregate lease operating expenses during the three months ended June 30, 2017 increased $6.4 million as compared to the three months ended June 30, 2016, of which $4.5 million related to our recently-acquired properties in the Delaware Basin. The increase of $6.4 million is primarily due to increases of $2.4 million for payroll and employee benefits related to increases in headcount for 2017 as compared to 2016, $1.0 million for water hauling, $1.0 million related to compressor rentals, and $0.5 million for workover projects. These increases were partially offset by a decrease of $0.4 million in environmental remediation costs.

Aggregate lease operating expenses during the six months ended June 30, 2017 increased $10.8 million as compared to the six months ended June 30, 2016, of which $8.4 million related to our recently-acquired properties in the Delaware Basin. The increase of $10.8 million is primarily due to increases of $4.2 million for payroll and employee benefits related to increases in headcount for 2017 as compared to 2016, $1.8 million for water hauling, $1.7 million for workover projects, and $1.7 million related to compressor rentals. These increases were partially offset by a decrease of $1.6 million in environmental remediation costs. We expect continued increases in our headcount through the remainder of 2017 as we grow our Delaware

Table of contents

Basin production base and production team. We expect much of this increased cost of personnel will be offset by increases in our production.

Production Taxes

Production taxes are comprised mainly of severance tax and ad valorem tax and are directly related to crude oil, natural gas, and NGLs sales and are generally assessed as a percentage of net revenues. There are a number of adjustments to the statutory rates for these taxes based upon certain credits that are determined based upon activity levels and relative commodity prices from year-to-year. The $9.0 million and $17.3 million increases in production taxes during the three and six months ended June 30, 2017, respectively, compared to the three and six months ended June 30, 2016 were primarily related to the 93 percent and 117 percent increases in crude oil, natural gas, and NGLs sales, and an increase in our effective tax rate to approximately seven percent for the three and six months ended June 30, 2017 as compared to five percent for the three and six months ended June 30, 2016.

Transportation, Gathering, and Processing Expenses

Transportation,gathering, and processing expenses increased $2.0 million and $3.9 million during the three and six months ended June 30, 2017, respectively, compared to the three and six months ended June 30, 2016. The primary drivers of these increases were $1.2 million and $2.2 million increases in oil transportation costs due to increased volumes delivered through a pipeline in the Wattenberg Field and increases of $0.7 million and $1.4 million related to natural gas gathering operations in our recently acquired properties in the Delaware Basin, respectively. When feasible, we use pipelines in the Wattenberg Field to deliver crude oil to the market in an effort to decrease field truck traffic and air emissions. Transportation, gathering, and processing expenses per Boe improved to $0.81 and $0.84 for the three and six months ended June 30, 2017, respectively, compared to $0.86 and $0.87 for the three and six months ended June 30, 2016, respectively.

Impairment of Properties and Equipment

Impairment of proved and unproved properties. Amounts represent the retirement or expiration of certain leases that are no longer part of our development plan or that we are not able to extend prior to termination of the lease. Deterioration of commodity prices or other operating circumstances could result in additional impairment charges as such a change could decrease the number of wells drilled in future periods.

During the three months ended June 30, 2017, we impaired certain unproved Delaware Basin leasehold positions totaling $27.0 million that expired during the three months ending June 30, 2017, or are projected to expire between June 30, 2017 and December 31, 2017. Subsequent to closing the acquisitions in the Delaware Basin, it was determined that development of certain acreage tracts would not meet our internal expectations for acceptable rates of return due to a combination of weakening commodity prices; higher per well development and operational costs; and updated technical analysis. As a result, we allowed or expect to allow certain acreage to expire, and in other circumstances we were unable to obtain necessary lease term extensions.

The following table sets forth the major components of our impairment of properties and equipment expense:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016

	(in millions)			
Impairment of unproved properties	$27.5	$1.1	$29.6	$2.1
Amortization of individually insignificant unproved properties	0.1	0.1	0.2	0.1
Impairment of crude oil and natural gas properties	27.6	1.2	29.8	2.2
Land and buildings	—	3.0	—	3.0
Total impairment of properties and equipment	$27.6	$4.2	$29.8	$5.2

General and Administrative Expense

General and administrative expense increased $6.0 million for the three months ended June 30, 2017 as compared to the three months ended June 30, 2016, of which $2.9 million is related to the Delaware Basin. The increase of $6.0 million was primarily attributable to increases of $1.5 million in payroll and employee benefits related to an increase in headcount for 2017 as compared to 2016, $1.1 million related to professional services, and $0.4 million in software maintenance agreements and subscriptions.

General and administrative expense increased $9.5 million for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016, of which $5.7 million is related to the Delaware Basin. The increase of $9.5 million was primarily attributable to increases of $3.8 million in payroll and employee benefits due to an increase in headcount for 2017 as compared to 2016, $1.8 million related to professional services, $0.7 million in software maintenance agreements and subscriptions, and $0.7 million in rent expense. We expect continued increases in our headcount through the remainder of 2017 as we build out our Delaware Basin operations.

Depreciation, Depletion and Amortization Expense

Crude oil and natural gas properties. DD&A expense related to crude oil and natural gas properties is directly related to proved reserves and production volumes. DD&A expense related to crude oil and natural gas properties was $124.4 million and $232.2 million for the three and six months ended June 30, 2017, respectively, compared to $106.1 million and $202.4 million for the three and six months ended June 30, 2016, respectively. Through June 30, 2017, our capital investment in the Delaware Basin has not yet resulted in the addition of related proved reserves, resulting in an elevated DD&A expense rate for the three and six months ended June 30, 2017.

The period-over-period change in DD&A expense related to crude oil and natural gas properties was primarily due to the following:

	June 30, 2017	
	Three Months Ended	Six Months Ended
	(in millions)	
Increase in production	$56.2	$94.9
Decrease in weighted-average depreciation, depletion and amortization rates	(37.9)	(65.1)
Total increase in DD&A expense related to crude oil and natural gas properties	$18.3	$29.8

The following table presents our per Boe DD&A expense rates for crude oil and natural gas properties:

	Three Months Ended June 30,		Six Months Ended June 30,	
Operating Region/Area	2017	2016	2017	2016
	(per Boe)			
Wattenberg Field	$15.30	$20.73	$16.05	$21.19
Delaware Basin	18.14	—	15.46	—
Utica Shale	11.27	13.84	11.26	11.16
Total weighted-average	15.51	20.41	15.83	20.72

Non-crude oil and natural gas properties. Depreciation expense for non-crude oil and natural gas properties was $1.7 million and $3.2 million for the three and six months ended June 30, 2017, respectively, compared to $0.9 million and $2.0 million for the three and six months ended June 30, 2016, respectively.

Provision for Uncollectible Notes Receivable

In the first quarter of 2016, we recorded a provision for uncollectible notes receivable of $44.7 million to impair two third-party notes receivable whose collection was not reasonably assured. As described in the footnote titled Fair Value of Financial Instruments, in April 2017, we signed a definitive agreement and simultaneously closed on the sale of one of the associated notes receivable to an unrelated third-party. Accordingly, we reversed $40.2 million of the provision for uncollectible notes receivable during the three months ended June 30, 2017, since all cash was collected in April 2017 from the sale of the Promissory Note.

Interest Expense

Interest expense increased $8.9 million to $19.6 million for the three months ended June 30, 2017 compared to $10.7 million for the three months ended June 30, 2016. The increase is primarily attributable to a $6.4 million increase in interest relating to the issuance of our 2024 Senior Notes, a $2.6 million increase in interest expense relating to the issuance of our 2021 Convertible Notes, and a $0.9 million increase related to fees for the redetermination of the borrowing base under our revolving credit facility. These increases were partially offset by a $1.3 million decrease in interest expense on our 2016 Convertible Notes, which were settled in May 2016.

Interest expense increased $16.5 million to $39.1 million for the six months ended June 30, 2017 compared to $22.6 million for the six months ended June 30, 2016. The increase is primarily attributable to a $12.7 million increase in interest relating to the issuance of our 2024 Senior Notes, a $5.1 million increase in interest expense relating to the issuance of our 2021 Convertible Notes, and a $1.6 million increase related to fees for the redetermination of the borrowing base under our revolving credit facility. These increases were partially offset by a $3.4 million decrease in interest expense on our 2016 Convertible Notes, which were settled in May 2016.

Provision for Income Taxes

The effective income tax rates for the three and six months ended June 30, 2017 were 37.3 percent and 36.8 percent expense on income, respectively, compared to 37.9 percent and 37.5 percent benefit on loss for the three and six months ended June 30, 2016, respectively. The effective income tax rates are based upon a full year forecasted pre-tax income for the year adjusted for permanent differences. The forecasted full year effective income tax rate has been applied to the quarter-to-date pre-tax income, resulting in an income tax expense for the period. Because the estimate of full-year income or loss may change from quarter to quarter, the effective income tax rate for any particular quarter may not have a meaningful relationship to pre-tax income or loss for the quarter or the actual annual effective income tax rate that is determined at the end of the year. The effective income tax rates for the three and six months ended June 30, 2017 include discrete income tax benefits of $0.2 million and $1.8 million relating to the excess income tax basis recognized with the vesting of stock awards during the three and six months ended June 30, 2017, which resulted in a 0.3 percent and 1.3 percent reduction to our effective income tax rates. There were no significant discrete income tax items recorded during the three months ended June 30, 2016.

Net Income (Loss)/Adjusted Net Income (Loss)

The factors resulting in changes in net income in the three and six months ended June 30, 2017 of $41.2 million and $87.4 million, respectively, and a net loss in the three and six months ended June 30, 2016 of $95.5 million and $167.0 million, respectively, are discussed above. These same reasons similarly impacted adjusted net income (loss), a non-U.S. GAAP financial measure, with the exception of the net change in fair value of unsettled derivatives, adjusted for taxes, of $28.7 million and $78.9 million for the three and six months ended June 30, 2017, respectively, and $90.5 million and $125.1 million for the three and six months ended June 30, 2016, respectively. Adjusted net income (loss), a non-U.S. GAAP financial measure, was $12.5 million and $8.5 million for the three and six months ended June 30, 2017, respectively, and adjusted net loss of $5.0 million and $41.9 million for the three and six months ended June 30, 2016, respectively. See Reconciliation of Non-U.S. GAAP Financial Measures, below for a more detailed discussion of this non-U.S. GAAP financial measure and a reconciliation of this measure to the most comparable U.S. GAAP measure.

Financial Condition, Liquidity and Capital Resources

Our primary sources of liquidity are cash flows from operating activities, our revolving credit facility, proceeds raised in debt and equity capital market transactions, and asset sales. For the six months ended June 30, 2017, our net cash flows from operating activities were $263.2 million.

Our primary source of cash flows from operating activities is the sale of crude oil, natural gas, and NGLs. Fluctuations in our operating cash flows are principally driven by commodity prices and changes in our production volumes. Commodity prices have historically been volatile and we manage this volatility through our use of derivative instruments. We enter into commodity derivative instruments with maturities of no greater than five years from the date of the instrument. Our revolving credit agreement imposes limits on the amount of our production we can hedge, and we may choose not to hedge the maximum amounts permitted. Therefore, we may still have significant fluctuations in our cash flows from operating activities due to the remaining non-hedged portion of our future production. Based upon our hedge position and assuming forward strip pricing as of June 30, 2017, our derivatives may not be a significant source of cash flow in the near term.

Our working capital fluctuates for various reasons, including, but not limited to, changes in the fair value of our commodity derivative instruments and changes in our cash and cash equivalents due to our practice of utilizing excess cash to reduce the outstanding borrowings under our revolving credit facility. At June 30, 2017, we had working capital of $65.6 million compared to $129.2 million at December 31, 2016. The decrease in working capital as of June 30, 2017 is primarily the result of a decrease in cash and cash equivalents of $41.8 million related to capital investment exceeding operating cash flows and an increase in accounts payable of $86.2 million related to increased development and exploration activity, which was partially offset by an increase in the net fair value of our unsettled commodity derivative instruments of $86.8 million.

Our cash and cash equivalents were $202.3 million at June 30, 2017 and availability under our revolving credit facility was $700.0 million, providing for a total liquidity position of $902.3 million as of June 30, 2017. We anticipate that our capital investments will exceed our cash flows from operating activities in 2017, resulting in cash and cash equivalents estimated to be between $100 million to $150 million as of December 31, 2017.

Based on our expected cash flows from operations, our cash and cash equivalents and availability under our revolving credit facility, we believe that we have sufficient capital to fund our planned activities during 2017. Our liquidity was further augmented by the $40.2 million of proceeds received in the second quarter of 2017 from the sale of the Promissory Note, as described previously.

Our revolving credit facility is a borrowing base facility and availability under the facility is subject to redetermination each May and November, based upon a quantification of our proved reserves at each June 30 and December 31, respectively. The maturity date of our revolving credit facility is May 2020. Our ability to borrow under the revolving credit facility is limited under our 2022 Senior Notes to the greater of $700 million or the calculated value under an Adjusted Consolidated Tangible Net Asset test, as defined.

In May 2017, we entered into a Fifth Amendment to the Third Amended and Restated Credit Agreement. The amendment, among other things, amends the revolving credit facility to reflect an increase of the borrowing base from $700 million to $950 million. We have elected to maintain a $700 million commitment level as of the date of this report. In addition, the Fifth Amendment made changes to certain of the covenants in the existing agreement as well as other administrative changes.

Amounts borrowed under the revolving credit facility bear interest at either an alternate base rate option or a LIBOR option as defined in the revolving credit facility plus an applicable margin, depending on the percentage of the commitment that has been utilized. As of June 30, 2017, the applicable margin is 1.25 percent for the alternate base rate option or 2.25 percent for the LIBOR option, and the unused commitment fee is 0.50 percent.

We had no balance outstanding on our revolving credit facility as of June 30, 2017. In May 2017, we replaced our $11.7 million irrevocable standby letter of credit that we held in favor of a third-party transportation service provider to secure a firm transportation obligation with a $9.3 million deposit, which is classified as restricted cash and is included in other assets on the condensed consolidated balance sheet. As of June 30, 2017, the available funds under our revolving credit facility was $700 million based on our elected commitment level.

Our revolving credit facility contains financial maintenance covenants. The covenants require that we maintain (i) a leverage ratio defined as total debt of less than 4.0 times the trailing 12 months earnings before interest, taxes, depreciation, depletion and amortization, change in fair value of unsettled commodity derivatives, exploration expense, gains (losses) on sales of assets and other non-cash gains (losses) and (ii) an adjusted current ratio of at least 1.0:1.0. Our adjusted current ratio is adjusted by eliminating the impact on our current assets and liabilities of recording the fair value of crude oil and natural gas commodity derivative instruments. Additionally, available borrowings under our revolving credit facility are added to the current asset calculation and the current portion of our revolving credit facility debt is eliminated from the current liabilities calculation. At June 30, 2017, we were in compliance with all debt covenants, as defined by the revolving credit agreement, with a leverage ratio of 1.9 and a current ratio of 3.3. We expect to remain in compliance throughout the next 12-month period.

The indentures governing our 2022 Senior Notes and 2024 Senior Notes contain customary restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (a) incur additional debt including under our revolving credit facility, (b) make certain investments or pay dividends or distributions on our capital stock or purchase, redeem, or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) restrict the payment of dividends or other payments by restricted subsidiaries to us, (e) create liens that secure debt, (f) enter into transactions with affiliates, and (g) merge or consolidate with another company. At June 30, 2017, we were in compliance with all covenants and expect to remain in compliance throughout the next 12-month period.

In January 2017, pursuant to the filing of the supplemental indentures for the 2021 Convertible Senior Notes, the 2022 Senior Notes, and the 2024 Senior Notes, our subsidiary PDC Permian, Inc. became a guarantor of the notes.

Cash Flows

Operating Activities. Our net cash flows from operating activities are primarily impacted by commodity prices, production volumes, net settlements from our commodity derivative positions, operating costs, and general and administrative expenses. Cash flows from operating activities increased by $65.4 million for the six months ended June 30, 2017 compared to the six months ended June 30, 2016, primarily due to increases in crude oil, natural gas and NGLs sales of $217.1 million and an increase in changes in assets and liabilities of $12.3 million related to the timing of cash payments and receipts. These increases were offset in part by a decrease in commodity derivative settlements of $107.6 million and increases in production taxes of $17.3 million, interest expense of $16.5 million, lease operating expenses of $10.8 million, and general and administrative expenses of $9.5 million.

Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased $53.0 million during the six months ended June 30, 2017 compared to the six months ended June 30, 2016. The increase was primarily due to the same factors mentioned above for changes in cash flows provided by operating activities, without regard to timing of cash payments and receipts of assets and liabilities. Adjusted EBITDAX, a non-U.S. GAAP financial measure, increased by $150.4 million during the six months ended June 30, 2017, compared to the six months ended June 30, 2016. The increase was primarily the result of increases in crude oil, natural gas and NGLs sales of $217.1 million, the recording of a provision for uncollectible notes receivable of $44.7 million during the six months ended June 30, 2016, and the reversal of a provision for uncollectible notes receivable of $40.2 million during the six months ended June 30, 2017. These increases were partially offset by a decrease in commodity derivative settlements of $107.6 million and increases in production taxes of $17.3 million, lease operating expenses of $10.8 million, and general and administrative expenses of $9.5 million. See Reconciliation of Non-U.S. GAAP Financial Measures, below, for a more detailed discussion of non-U.S. GAAP financial measures.

Investing Activities. Because crude oil and natural gas production from a well declines rapidly in the first few years of production, we need to continue to commit significant amounts of capital in order to maintain and grow our production and replace our reserves. If capital is not available or is constrained in the future, we will be limited to our cash flows from operations and liquidity under our revolving credit facility as the sources for funding our capital investments.

Cash flows from investing activities primarily consist of the acquisition, exploration, and development of crude oil and natural gas properties, net of dispositions of crude oil and natural gas properties. Net cash used in investing activities of $299.1 million during the six months ended June 30, 2017, was primarily related to cash utilized for our drilling operations, including completion activities of $334.4 million, purchases of short-term investments of $49.9 million, and a $9.3 million deposit with a third-party transportation service provider for surety of an existing firm transportation obligation previously secured by a letter of credit. Partially offsetting these investments was the receipt of approximately $49.9 million related to the sale of short-term investments, $40.2 million from the sale of the Promissory Note, and $5.4 million related to post-closing settlements of properties acquired in 2016.

Financing Activities. Net cash from financing activities for the six months ended June 30, 2017 decreased by approximately $147.2 million compared to the six months ended June 30, 2016. Certain capital markets and financing activities occurred in 2016 including $296.6 million received from an issuance of our common stock. These amounts were partially offset by the $115.0 million payment of principal amounts owed upon the maturity of the 2016 Convertible Notes and net payments of approximately $37.0 million to pay down amounts borrowed under our revolving credit facility in the first quarter of 2016.

Off-Balance Sheet Arrangements

At June 30, 2017, we had no off-balance sheet arrangements, as defined under SEC rules, which have or are reasonably likely to have a material current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital investments, or capital resources.

Commitments and Contingencies

See the footnote titled Commitments and Contingencies to the accompanying condensed consolidated financial statements included elsewhere in this report.

Table of contents

Recent Accounting Standards

See the footnote titled Summary of Significant Accounting Policies to the accompanying condensed consolidated financial statements included elsewhere in this report.

Recent Regulatory Developments

On May 2, 2017, in response to an incident in Firestone, Colorado, the Colorado Oil & Gas Conservation Commission ("COGCC") issued a Notice to Operators (the "Notice"). Among other things, the Notice included requirements for all operators of oil and gas wells in Colorado to inspect all existing flowlines and pipelines located within 1,000 feet of a building unit; inspect any abandoned flowlines or pipelines, regardless of distance to ensure proper abandonment; and test integrity of all connected flowlines. Additional regulations or mandates from the COGCC or other regulators related to this matter are expected to arise.

We timely complied with both phases of the Notice. We have an existing Flowline Integrity Management Program to inspect all Denver-Julesburg Basin wells and related pipelines on an annual basis, and will continue to engage in this process.

Critical Accounting Policies and Estimates

The preparation of the accompanying condensed consolidated financial statements in conformity with U.S. GAAP required management to use judgment in making estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities, and the reported amounts of revenue and expenses.

There have been no significant changes to our critical accounting policies and estimates or in the underlying accounting assumptions and estimates used in these critical accounting policies from those disclosed in the condensed consolidated financial statements and accompanying notes contained in our 2016 Form 10-K filed with the SEC on February 28, 2017.

Reconciliation of Non-U.S. GAAP Financial Measures

We use "adjusted cash flows from operations," "adjusted net income (loss)" and "adjusted EBITDAX," non-U.S. GAAP financial measures, for internal management reporting, when evaluating period-to-period changes and, in some cases, providing public guidance on possible future results. Beginning in 2017, we have included non-cash stock-based compensation and exploration, geologic and geophysical expense to our reconciliation of adjusted EBITDAX calculation. In prior periods, we included adjusted EBITDA, a non-U.S. GAAP financial measure that did not include these adjustments. We have elected to disclose Adjusted EBITDAX rather than Adjusted EBITDA in this report and other public disclosures because we believe it is more comparable to similar metrics presented by others in the industry. All prior periods have been conformed for comparability of this information. These measures are not measures of financial performance under U.S. GAAP and should be considered in addition to, not as a substitute for, net income (loss) or cash flows from operations, investing or financing activities, and should not be viewed as liquidity measures or indicators of cash flows reported in accordance with U.S. GAAP. The non-U.S. GAAP financial measures that we use may not be comparable to similarly titled measures reported by other companies. Also, in the future, we may disclose different non-U.S. GAAP financial measures in order to help our investors more meaningfully evaluate and compare our future results of operations to our previously reported results of operations. We strongly encourage investors to review our financial statements and publicly filed reports in their entirety and not rely on any single financial measure.

Adjusted cash flows from operations. We define adjusted cash flows from operations as the cash flows earned or incurred from operating activities, without regard to changes in operating assets and liabilities. We believe it is important to consider adjusted cash flows from operations, as well as cash flows from operations, as we believe it often provides more transparency into what drives the changes in our operating trends, such as production, prices, operating costs, and related operational factors, without regard to whether the related asset or liability was received or paid during the same period. We also use this measure because the timing of cash received from our assets, cash paid to obtain an asset or payment of our obligations has generally been a timing issue from one period to the next as we have not had significant accounts receivable collection problems, nor been unable to purchase assets or pay our obligations.

Adjusted net income (loss). We define adjusted net income (loss) as net income (loss), plus loss on commodity derivatives, less gain on commodity derivatives, and net settlements on commodity derivatives, each adjusted for tax effect. We believe it is important to consider adjusted net income (loss), as well as net income (loss). We believe this measure often provides more transparency into our operating trends, such as production, prices, operating costs, net settlements from derivatives, and related factors, without regard to changes in our net income (loss) from our mark-to-market adjustments resulting from net changes in the fair value of unsettled derivatives. Additionally, other items which are not indicative of future results may be excluded to clearly identify operating trends.

Adjusted EBITDAX. We define adjusted EBITDAX as net income (loss), plus loss on commodity derivatives, interest expense, net of interest income, income taxes, impairment of properties and equipment, exploration, geologic, and geophysical expense, depreciation, depletion and amortization expense, accretion of asset retirement obligations, and non-cash stock-based compensation, less gain on commodity derivatives and net settlements on commodity derivatives. Adjusted EBITDAX is not a measure of financial performance or liquidity under U.S. GAAP and should be considered in addition to, not as a substitute for, net income (loss), and should not be considered an indicator of cash flows reported in accordance with U.S. GAAP. Adjusted EBITDAX includes certain non-cash costs incurred by us and does not take into account changes in operating assets and liabilities. Other companies in our industry may calculate adjusted EBITDAX differently than we do, limiting its usefulness as a comparative measure. We believe adjusted EBITDAX is relevant because it is a measure of our operational and financial performance, as well as a measure of our liquidity, and is used by our management, investors, commercial banks, research analysts, and others to analyze such things as:

- operating performance and return on capital as compared to our peers;
- financial performance of our assets and our valuation without regard to financing methods, capital structure, or historical cost basis;
- our ability to generate sufficient cash to service our debt obligations; and
- the viability of acquisition opportunities and capital expenditure projects, including the related rate of return.

Table of contents
PDC ENERGY, INC.

The following table presents a reconciliation of each of our non-U.S. GAAP financial measures to its most comparable U.S. GAAP measure:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(in millions)			
Adjusted cash flows from operations:				
Net cash from operating activities	$123.7	$96.6	263.2	$197.8
Changes in assets and liabilities	19.2	16.0	(6.6)	5.8
Adjusted cash flows from operations	$142.9	$112.6	$256.6	$203.6
Adjusted net income (loss):				
Net income (loss)	$41.2	$(95.5)	$87.4	$(167.0)
(Gain) loss on commodity derivative instruments	(57.9)	92.8	(138.6)	81.7
Net settlements on commodity derivative instruments	12.0	53.3	12.5	120.2
Tax effect of above adjustments	17.2	(55.6)	47.2	(76.8)
Adjusted net income (loss)	$12.5	$(5.0)	$8.5	$(41.9)
Net income (loss) to adjusted EBITDAX:				
Net income (loss)	$41.2	$(95.5)	$87.4	$(167.0)
(Gain) loss on commodity derivative instruments	(57.9)	92.8	(138.6)	81.7
Net settlements on commodity derivative instruments	12.0	53.3	12.5	120.2
Non-cash stock-based compensation	5.4	6.4	9.8	11.1
Interest expense, net	18.9	10.5	38.1	20.8
Income tax expense (benefit)	24.5	(58.3)	50.9	(100.2)
Impairment of properties and equipment	27.6	4.2	29.8	5.2
Exploration, geologic, and geophysical expense	1.0	0.2	2.0	0.4
Depreciation, depletion, and amortization	126.0	107.0	235.3	204.4
Accretion of asset retirement obligations	1.7	1.8	3.4	3.6
Adjusted EBITDAX	$200.4	$122.4	$330.6	$180.2
Cash from operating activities to adjusted EBITDAX:				
Net cash from operating activities	$123.7	$96.6	$263.2	$197.8
Interest expense, net	18.9	10.5	38.1	20.8
Amortization of debt discount and issuance costs	(3.2)	(1.3)	(6.4)	(3.1)
Gain (loss) on sale of properties and equipment	0.5	(0.3)	0.7	(0.2)
Exploration, geologic, and geophysical expense	1.0	0.2	2.0	0.4
Other	40.3	0.7	39.6	(41.3)
Changes in assets and liabilities	19.2	16.0	(6.6)	5.8
Adjusted EBITDAX	$200.4	$122.4	$330.6	$180.2

Table of contents

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market-Sensitive Instruments and Risk Management

We are exposed to market risks associated with interest rate risks, commodity price risk and credit risk. We have established risk management processes to monitor and manage these market risks.

Interest Rate Risk

Changes in interest rates affect the amount of interest we earn on our interest bearing cash, cash equivalents, and restricted cash accounts and the interest we pay on borrowings under our revolving credit facility. Our 2021 Convertible Notes, 2024 Senior Notes, and 2022 Senior Notes have fixed rates, and therefore near-term changes in interest rates do not expose us to risk of earnings or cash flow loss; however, near-term changes in interest rates may affect the fair value of our fixed-rate debt.

As of June 30, 2017, our interest-bearing deposit accounts included money market accounts, certificates of deposit, and checking and savings accounts with various banks. The amount of our interest-bearing cash, cash equivalents, and restricted cash as of June 30, 2017 was $201.5 million with a weighted-average interest rate of 0.9 percent. Based on a sensitivity analysis of our interest-bearing deposits as of June 30, 2017 and assuming we had $201.5 million outstanding throughout the period, we estimate that a one percent increase in interest rates would have increased interest income for the six months ended June 30, 2017 by approximately $1.0 million.

As of June 30, 2017, we had no outstanding balance on our revolving credit facility.

Commodity Price Risk

We are exposed to the potential risk of loss from adverse changes in the market price of crude oil, natural gas, natural gas basis, and NGLs. Pursuant to established policies and procedures, we manage a portion of the risks associated with these market fluctuations using commodity derivative instruments. These instruments help us predict with greater certainty the effective crude oil, natural gas, natural gas basis, and propane prices we will receive for our hedged production. We believe that our commodity derivative policies and procedures are effective in achieving our risk management objectives.

Table of contents
PDC ENERGY, INC.

The following table presents our commodity and basis derivative positions related to crude oil, natural gas, and propane in effect as of June 30, 2017:

Commodity/ Index/ Maturity Period	Collars			Fixed-Price Swaps		Fair Value June 30, 2017 (1) (in millions)
	Quantity (Gas - BBtu Oil - MBbls)	Weighted-Average Contract Price Floors	Weighted-Average Contract Price Ceilings	Quantity (Oil - MBbls Gas and Basis-BBtu Propane - MBbls)	Weighted-Average Contract Price	
Crude Oil						
NYMEX						
2017	1,232.0	$ 49.54	$ 62.32	3,680.1	$ 50.13	$ 18.3
2018	1,512.0	41.85	54.31	6,472.0	52.54	26.5
Total Crude Oil	2,744.0			10,152.1		$ 44.8
Natural Gas						
NYMEX						
2017	5,900.2	$ 3.38	$ 4.02	19,620.0	$ 3.40	$ 8.3
2018	5,230.0	3.00	3.54	51,280.0	2.95	(1.1)
Total Natural Gas	11,130.2			70,900.0		$ 7.2
Basis Protection						
CIG						
2017	—	—	—	25,128.4	$ (0.33)	$ 1.0
2018	—	—	—	30,200.0	(0.34)	2.7
Waha						
2018	—	—	—	1,825.0	(0.43)	—
Total Basis Protection	—			57,153.4		$ 3.7
Propane						
Mont Belvieu						
2017	—	—	—	642.9	$ 26.29	$ 0.3
Commodity Derivatives Fair Value						$ 56.0

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(1) Approximately 15.0 percent of the fair value of our commodity derivative assets and 13.4 percent of the fair value of our commodity derivative liabilities were measured using significant unobservable inputs (Level 3).

Table of contents
PDC ENERGY, INC.

In addition to our commodity derivative positions as of June 30, 2017, we entered into the following commodity derivative positions subsequent to June 30, 2017 that are effective as of August 3, 2017:

Commodity/ Index/ Maturity Period	Fixed-Price Swaps Quantity (Oil - MBbls Gas and Basis- BBtu Propane - MBbls)	Weighted- Average Contract Price
Crude Oil		
NYMEX		
2018	500.0	$ 49.75
2019	800.0	49.75
Total Crude Oil	1,300.0	
Basis Protection		
Waha		
2018	4,175.0	$ (0.53)
Propane		
Mont Belvieu		
2017	114.3	$ 30.56
2018	285.7	27.25
Total Propane	400.0	

Our realized prices vary regionally based on local market differentials and our transportation agreements. The following table presents average market index prices for crude oil and natural gas for the periods identified, as well as the average sales prices we realized for our crude oil, natural gas, and NGLs production:

	Three Months Ended June 30, 2017	Six Months Ended June 30, 2017	Year Ended December 31, 2016
Average NYMEX Index Price:			
Crude oil (per Bbl)	$ 48.28	$ 50.10	$ 43.32
Natural gas (per MMBtu)	3.18	3.25	2.46
Average Sales Price Realized:			
Excluding net settlements on commodity derivatives			
Crude oil (per Bbl)	$ 45.97	$ 47.31	$ 39.96
Natural gas (per Mcf)	2.16	2.26	1.77

NGLs (per Bbl)	14.59	16.75	11.80

Based on a sensitivity analysis as of June 30, 2017, we estimate that a ten percent increase in natural gas, crude oil, and the propane portion of NGLs prices, inclusive of basis, over the entire period for which we have commodity derivatives in place, would have resulted in a decrease in the fair value of our derivative positions of $74.8 million, whereas a ten percent decrease in prices would have resulted in an increase in fair value of $74.2 million.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform its contractual obligations. We attempt to reduce credit risk by diversifying our counterparty exposure and entering into transactions with high-quality counterparties. When exposed to significant credit risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. We monitor the creditworthiness of significant counterparties through our credit committee, which utilizes a number of qualitative and quantitative tools to assess credit risk and takes mitigative actions if deemed necessary. While we believe that our credit risk analysis and monitoring procedures are reasonable, no amount of analysis can assure performance by our counterparties.

Our oil and gas exploration and production business's crude oil, natural gas, and NGLs sales are concentrated with a few predominately large customers. This concentrates our credit risk exposure with a small number of large customers.

Amounts due to our gas marketing business are from a diverse group of entities, including major upstream and midstream energy companies, financial institutions, and end-users in various industries. The underlying operations of these entities are geographically concentrated in the same region, which increases the credit risk associated with this business. As natural gas prices continue to remain depressed, certain third-party producers relating to our gas marketing business continue to experience financial distress, which has led to certain contractual defaults and litigation; however, to date, we have had no material counterparty default losses. We have initiated several legal actions for breach of contract, collection and related claims against certain third-party producers that are delinquent in their payment obligations, which have to date resulted in two default judgments. We expect this trend to continue for this business.

We primarily use financial institutions which are lenders in our revolving credit facility as counterparties for our derivative financial instruments. Disruption in the credit markets, changes in commodity prices and other factors may have a significant adverse impact on a number of financial institutions. To date, we have had no material counterparty default losses from our commodity derivative financial instruments. See the footnote titled Commodity Derivative Financial Instruments to our condensed consolidated financial statements included elsewhere in this report for more detail on our commodity derivative financial instruments.

Disclosure of Limitations

Because the information above included only those exposures that existed at June 30, 2017, it does not consider those exposures or positions which could arise after that date. As a result, our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, our commodity price risk management strategies at the time, and interest rates and commodity prices at the time.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of June 30, 2017, we carried out an evaluation under the supervision and with the participation of management, including the Chief Executive Officer and the Principal Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rules 13a-15(e) and 15d-15(e).

Based on the results of this evaluation, the Chief Executive Officer and the Principal Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2017.

Changes in Internal Control over Financial Reporting

During the three months ended June 30, 2017, we made no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II
ITEM 1. LEGAL PROCEEDINGS

From time to time, we are a party to various legal proceedings in the ordinary course of business. We are not currently a party to any litigation that we believe would have a materially adverse effect on our business, financial condition, results of operations, or liquidity.

Environmental

Due to the nature of the natural gas and oil industry, we are exposed to environmental risks. We have various policies and procedures to minimize and mitigate the risks from environmental contamination. We conduct periodic reviews and simulated drills to identify changes in our environmental risk profile. Liabilities are recorded when environmental damages resulting from past events are probable and the costs can be reasonably estimated. Except as discussed herein, we are not aware of any environmental claims existing as of June 30, 2017, which have not been provided for or would otherwise have a material impact on our financial statements; however, there can be no assurance that current regulatory requirements will not change or that unknown past non-compliance with environmental laws will not be discovered on our properties. Accrued environmental liabilities are recorded in other accrued expenses on the condensed consolidated balance sheets.

In August 2015, we received a Clean Air Act Section 114 Information Request (the "Information Request") from the U.S. Environmental Protection Agency ("EPA"). The Information Request sought, among other things, information related to the design, operation, and maintenance of our Wattenberg Field production facilities in the Denver-Julesburg Basin of Colorado. The Information Request focuses on historical operation and design information for 46 of our production facilities and asks that we conduct sampling and analyses at the identified 46 facilities. We responded to the Information Request with the requested data in January 2016.

In addition, in December 2015, we received a Compliance Advisory pursuant to C.R.S. 25-7-115(2) from the Colorado Department of Public Health and Environment's (“CDPHE”) Air Quality Control Commission's Air Pollution Control Division alleging that we failed to design, operate, and maintain certain condensate collection, storage, processing, and handling operations to minimize leakage of volatile organic compounds at 65 facilities consistent with applicable standards under Colorado law.

For more than a year, we held a series of meetings with the EPA, Department of Justice (“DOJ”) and CDPHE on the above matters. On June 26, 2017, the DOJ on behalf of the EPA and the State of Colorado filed a complaint against us based

Table of contents

on the above matters. We continue to schedule meetings with these agencies in working toward a resolution of the matters. The ultimate outcome related to these combined actions is not known at this time.

Action Regarding Firm Transportation Contracts

In June 2016, a group of 42 independent West Virginia natural gas producers filed a lawsuit in Marshall County, West Virginia, naming Dominion Transmission, Inc. ("Dominion"), certain entities affiliated with Dominion, and our subsidiary RNG as defendants, alleging various contractual, fiduciary and related claims against the defendants, all of which are associated with firm transportation contracts entered into by plaintiffs and relating to pipelines owned and operated by Dominion and its affiliates. The case has been transferred to the Business Court Division of the Circuit Court of Marshall County, West Virginia, and the parties are awaiting that court's ruling on previously-filed pre-trial pleadings. RNG is unable to estimate any potential damages associated with the claims, but believes the complaint is without merit and intends to vigorously pursue its defenses.

ITEM 1A. RISK FACTORS

We face many risks. Factors that could materially adversely affect our business, financial condition, operating results, or liquidity and the trading price of our common stock are described under Item 1A, Risk Factors, of our 2016 Form 10-K. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

There have been no material changes from the risk factors previously disclosed in our 2016 Form 10-K.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share
April 1 - 30, 2017	52,518	$ 62.35
May 1 - 31, 2017	—	—
June 1 - 30, 2017	—	—
Total second quarter 2017 purchases	52,518	$ 62.35

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(1) Purchases primarily represent shares purchased from employees for the payment of their tax liabilities related to the vesting of securities issued pursuant to our stock-based compensation plans.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES - None.

ITEM 4. MINE SAFETY DISCLOSURES - Not applicable.

ITEM 5. OTHER INFORMATION - None.

Table of contents
PDC ENERGY, INC.

ITEM 6. EXHIBITS

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1*	Certifications by Chief Executive Officer and Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.					
101.INS	XBRL Instance Document					X
101.SCH	XBRL Taxonomy Extension Schema Document					X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document					X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document					X
101.LAB	XBRL Taxonomy Extension Label Linkbase Document					X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document					X

* Furnished herewith.

SIGNATURES

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

PDC Energy, Inc.
(Registrant)

Date: August 8, 2017 /s/ Barton R. Brookman
Barton R. Brookman
President and Chief Executive Officer
(principal executive officer)

/s/ David W. Honeyfield
David W. Honeyfield
Senior Vice President and Chief Financial Officer
(principal financial officer)