PDC ENERGY, INC.
Form 10-Q
May 03, 2018
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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 March 31, 2018

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: 66,065,856 shares of the Company's Common Stock ($0.01 par value) were outstanding as of April 20, 2018.

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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 expect, anticipate, intend, plan, believe, seek, estimate, and similar expressions or variations of such words are intended to identify forward-looking statements herein. Forward-looking statements include, among other things, statements regarding future: production, costs, and cash flows; drilling locations and zones and growth opportunities; commodity prices and differentials; capital expenditures and projects, including the number of rigs employed and the number of completion crews; renegotiation of our credit facility; management of lease expiration issues; financial ratios; certain accounting and tax change impacts; midstream capacity and related curtailments; our ability to meet our volume commitments to midstream providers; ongoing compliance with our consent decree; and the timing and adequacy of infrastructure projects of our midstream providers.

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 term “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;
- volatility and widening of differentials;
- 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;

- difficulties in integrating our operations as a result of any significant acquisitions and acreage exchanges;
- increases or changes in expenses;
- availability of supplies, materials, contractors, and services that may delay the drilling or completion of our wells;
- 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;

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- impact of environmental events, governmental and other third-party responses to such events, and our ability to insure adequately against such events;
- cost of pending or future litigation;
- effect that acquisitions we may pursue have on our capital requirements;
- 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, 2017 (the "2017 Form 10-K"), filed with the U.S. Securities and Exchange Commission ("SEC") on February 27, 2018 and amended on May 1, 2018, 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.

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PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	March 31, 2018	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$45,923	$180,675
Accounts receivable, net	181,025	197,598
Fair value of derivatives	28,610	14,338
Prepaid expenses and other current assets	8,897	8,613
Total current assets	264,455	401,224
Properties and equipment, net	4,231,257	3,933,467
Assets held-for-sale, net	1,647	40,084
Other assets	24,798	45,116
Total Assets	$4,522,157	$4,419,891
Liabilities and Stockholders' Equity		
Liabilities		
Current liabilities:		
Accounts payable	$195,703	$150,067
Production tax liability	36,650	37,654
Fair value of derivatives	110,683	79,302
Funds held for distribution	97,611	95,811
Accrued interest payable	13,760	11,815
Other accrued expenses	33,777	42,987
Total current liabilities	488,184	417,636
Long-term debt	1,154,528	1,151,932
Deferred income taxes	187,183	191,992
Asset retirement obligations	73,905	71,006
Fair value of derivatives	26,426	22,343
Other liabilities	94,557	57,333
Total liabilities	2,024,783	1,912,242
Commitments and contingent liabilities		
Stockholders' equity		
Common shares - par value $0.01 per share, 150,000,000 authorized, 65,999,010 and 65,955,080 issued as of March 31, 2018 and December 31, 2017, respectively	660	659
Additional paid-in capital	2,504,663	2,503,294
Retained earnings (deficit)	(6,435)	6,704
Treasury shares - at cost, 29,255 and 55,927 as of March 31, 2018 and December 31, 2017, respectively	(1,514)	(3,008)
Total stockholders' equity	2,497,374	2,507,649

Total Liabilities and Stockholders' Equity	$4,522,157	$4,419,891

See accompanying Notes to Condensed Consolidated Financial Statements

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

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Revenues		
Crude oil, natural gas, and NGLs sales	$305,225	$189,692
Commodity price risk management gain (loss), net	(47,240)	80,704
Other income	2,615	3,311
Total revenues	260,600	273,707
Costs, expenses and other		
Lease operating expenses	29,636	19,789
Production taxes	20,169	12,399
Transportation, gathering, and processing expenses	7,313	5,902
Exploration, geologic, and geophysical expense	2,646	954
Impairment of properties and equipment	33,188	2,193
General and administrative expense	35,696	26,315
Depreciation, depletion, and amortization	126,788	109,316
Accretion of asset retirement obligations	1,288	1,768
(Gain) loss on sale of properties and equipment	1,432	(160)
Other expenses	2,768	3,528
Total costs, expenses and other	260,924	182,004
Income (loss) from operations	(324)	91,703
Interest expense	(17,529)	(19,467)
Interest income	148	240
Income (loss) before income taxes	(17,705)	72,476
Income tax (expense) benefit	4,566	(26,330)
Net income (loss)	$(13,139)	$46,146
Earnings per share:		
Basic	$(0.20)	$0.70
Diluted	$(0.20)	$0.70
Weighted-average common shares outstanding:		
Basic	65,957	65,749
Diluted	65,957	66,117

See accompanying Notes to Condensed Consolidated Financial Statements

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

	Three Months Ended March 31,	
	2018	2017
Cash flows from operating activities:		
Net income (loss)	$(13,139)	$46,146
Adjustments to net income (loss) to reconcile to net cash from operating activities:		
Net change in fair value of unsettled commodity derivatives	21,202	(80,153)
Depreciation, depletion and amortization	126,788	109,316
Impairment of properties and equipment	33,188	2,193
Accretion of asset retirement obligations	1,288	1,768
Non-cash stock-based compensation	5,261	4,454
(Gain) loss on sale of properties and equipment	1,432	(160)
Amortization of debt discount and issuance costs	3,246	3,184
Deferred income taxes	(4,809)	26,280
Other	515	722
Changes in assets and liabilities	30,177	25,750
Net cash from operating activities	205,149	139,500
Cash flows from investing activities:		
Capital expenditures for development of crude oil and natural gas properties	(196,917)	(129,826)
Capital expenditures for other properties and equipment	(1,066)	(821)
Acquisition of crude oil and natural gas properties, including settlement adjustments	(180,825)	6,181
Proceeds from sale of properties and equipment	20	737
Proceeds from divestiture	39,023	—
Restricted cash	1,249	—
Purchase of short-term investments	—	(49,890)
Net cash from investing activities	(338,516)	(173,619)
Cash flows from financing activities:		
Proceeds from revolving credit facility	35,000	—
Repayment of revolving credit facility	(35,000)	—
Purchase of treasury stock	(2,255)	(2,017)
Other	(379)	(340)
Net cash from financing activities	(2,634)	(2,357)
Net change in cash, cash equivalents, and restricted cash	(136,001)	(36,476)
Cash, cash equivalents, and restricted cash, beginning of period	189,925	244,100
Cash, cash equivalents, and restricted cash, end of period	$53,924	$207,624
Supplemental cash flow information:		
Cash payments (receipts) for:		
Interest, net of capitalized interest	$12,343	$13,224
Income taxes	193	(39)
Non-cash investing and financing activities:		
Change in accounts payable related to capital expenditures	$51,093	$69,604
Change in asset retirement obligations, with a corresponding change to crude oil and natural gas properties, net of disposals	5,354	1,233
Purchase of properties and equipment under capital leases	348	1,190

See accompanying Notes to Condensed Consolidated Financial Statements

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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 (Deficit)	Total Stockholders' Equity
Balance, December 31, 2017	65,955,080	$ 659	$ 2,503,294	(55,927)	$ (3,008)	$ 6,704	$ 2,507,649
Net loss	—	—	—	—	—	(13,139)	(13,139)
Purchase of treasury shares	—	—	—	(41,357)	(2,255)	—	(2,255)
Issuance of treasury shares	—	—	(3,891)	70,603	3,891	—	—
Non-employee directors' deferred compensation plan	—	—	—	(2,574)	(142)	—	(142)
Issuance of stock awards, net of forfeitures	43,930	1	(1)	—	—	—	—
Stock-based compensation expense	—	—	5,261	—	—	—	5,261
Other	—	—	—	—	—	—	—
Balance, March 31, 2018	65,999,010	$ 660	$ 2,504,663	(29,255)	$ (1,514)	$ (6,435)	$ 2,497,374

See accompanying Notes to Condensed Consolidated Financial Statements

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PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
March 31, 2018
(unaudited)

NOTE 1 - NATURE OF OPERATIONS AND BASIS OF PRESENTATION

PDC Energy, Inc. is a domestic independent exploration and production company that acquires, explores, and develops properties for the production of crude oil, natural gas, and NGLs, with operations in the Wattenberg Field in Colorado and the Delaware Basin in Texas. 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. We previously operated properties in the Utica Shale in Southeastern Ohio; however, we divested these properties during the three months ended March 31, 2018. As of March 31, 2018, we owned an interest in approximately 3,000 gross productive wells. We are engaged in two operating segments: our oil and gas exploration and production segment and our gas marketing segment. 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 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, 2017 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 2017 Form 10-K. Our results of operations and cash flows for the three months ended March 31, 2018 are not necessarily indicative of the results to be expected for the full year or any other future period.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Recently Adopted Accounting Standard

In May 2014, the Financial Accounting Standards Board ("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 standard has been updated and now includes technical corrections. 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. We adopted the standard effective January 1, 2018. In order to evaluate the impact that the adoption of the revenue standard had on our consolidated financial statements, we performed a comprehensive review of our significant revenue streams. The focus of this review included, among other things, the identification of the significant contracts and other arrangements we have with our customers to identify performance obligations and principal versus agent considerations, and factors affecting the determination of the transaction price. We also reviewed our current accounting policies, procedures, and controls with respect to these contracts and arrangements to determine what changes, if any, would be required by the adoption of the revenue standard. We determined that we would adopt the standard under the modified retrospective method. Upon adoption, no adjustment to our opening balance of retained earnings was deemed necessary.

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 the 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

PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
March 31, 2018
(unaudited)

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. The adoption of this standard impacted our condensed consolidated statements of cash flows. The following table provides a reconciliation of cash and cash equivalents and restricted cash reported on the condensed consolidated balance sheets at March 31, 2018 and December 31, 2017, which sum to the total of cash, cash equivalents, and restricted cash in the condensed consolidated statements of cash flows:

	March 31, 2018	December 31, 2017
	(in thousands)	
Cash and cash equivalents	$45,923	$ 180,675
Restricted cash	8,001	9,250
Cash, cash equivalents, and restricted cash shown in the condensed consolidated statements of cash flows	$53,924	$ 189,925

Restricted cash is included in other assets on the condensed consolidated balance sheets at March 31, 2018 and December 31, 2017. We did not have any cash classified as restricted cash at March 31, 2017 or December 31, 2016.

Recently Issued Accounting Standards

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. The standard has been updated and now includes amendments. 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. The update does not apply to leases of mineral rights to explore for or use crude oil and natural gas. We are currently evaluating the impact these changes may have on our condensed consolidated financial statements.

In August 2017, the FASB issued an accounting update to provide guidance for various components of hedge accounting, including hedge ineffectiveness, the expansion of types of permissible hedging strategies, reduced complexity in the application of the long-haul method for fair value hedges and reduced complexity in assessment of effectiveness. The guidance is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years, with early adoption permitted. We are currently evaluating the impact these changes may have on our condensed consolidated financial statements.

NOTE 3 - BUSINESS COMBINATION

In January 2018, we closed the acquisition of properties from Bayswater Exploration and Production LLC (the "Bayswater Acquisition") for approximately $201.8 million in cash, including $21.0 million deposited into an escrow account in September 2017, subject to certain customary post-closing adjustments. The $21.0 million deposit was included in other assets on our December 31, 2017 condensed consolidated balance sheet. We acquired approximately 7,400 net acres, approximately 220 gross drilling locations, and 24 operated horizontal wells that were either drilled uncompleted wells ("DUCs") or in-process wells at the time of closing.

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March 31, 2018
(unaudited)

The details of the estimated purchase price and the preliminary allocation of the purchase price for the transaction, are presented below (in thousands):

	March 31, 2018
Acquisition costs:	
Cash	$171,091
Deposit made in prior period	21,000
Total cash consideration	192,091
Other purchase price adjustments	9,734
Total acquisition costs	$201,825
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Assets acquired:	
Current assets	$517
Crude oil and natural gas properties - proved	208,279
Other assets	2,796
Total assets acquired	211,592
Liabilities assumed:	
Current liabilities	(5,080)
Asset retirement obligations	(4,687)
Total liabilities assumed	(9,767)
Total identifiable net assets acquired	$201,825

This acquisition was accounted for under the acquisition method. Accordingly, we conducted assessments of the 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. 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. Within the unproved properties, the allocation of the value to the underlying leases also requires significant judgment and is based on a combination of comparable market transactions, the term and conditions associated with the individual leases, our ability and intent to develop specific leases, and our initial assessment of the underlying relative value of the leases given our knowledge of the geology at the time of closing. These inputs require significant judgments and estimates by management at the time of the valuation and were the most sensitive and subject to change.

The results of operations for the Bayswater Acquisition for the three months ended March 31, 2018 have been included in our condensed consolidated financial statements. Pro forma results of operations for the Bayswater Acquisition showing results as if the acquisition had been completed as of January 1, 2017 would not have been material to our condensed consolidated financial statements for the three months ended March 31, 2017.

NOTE 4 - REVENUE RECOGNITION

On January 1, 2018, we adopted the new accounting standard that was issued by the FASB and the International Accounting Standards Board that converged their standard on revenue recognition and provides a single, comprehensive model to determine the measurement of revenue and timing of when it is recognized and all the related amendments (“new revenue standard”) using the modified retrospective method. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods. Based upon our review, we determined that the adoption of the standard would have reduced our crude oil, natural gas, and NGLs sales by approximately $2.5 million in the first quarter of 2017 with a corresponding decrease in transportation, gathering, and processing expenses and no impact on net earnings. To determine the impact on our crude oil, natural gas, and NGLs sales and our transportation, processing, and gathering expenses for the three months ended March 31, 2017, we applied the new guidance to contracts that were not completed as of December 31, 2017. We do not expect adoption of the new standard to have a significant impact on our net income going forward.

Crude oil, natural gas, and NGLs revenues are recognized when we have transferred control of crude oil, natural gas, or NGLs production to the purchaser. We consider the transfer of control to have occurred when the purchaser has the ability to direct the use of, and obtain substantially all of the remaining benefits, from the crude oil, natural gas, or NGLs production. We record sales revenue based on an estimate of the volumes delivered at estimated prices as determined by the applicable sales agreement. We estimate our sales volumes based on company-measured volume readings. We then adjust our crude oil, natural gas, and NGLs sales in subsequent periods based on the data received from our purchasers that reflects actual volumes and prices received. We receive payment for sales from one to two months after actual delivery has occurred. The differences in sales estimates and actual sales are recorded one to two months later. Historically, these differences have not been material. We account for natural gas imbalances using the sales method. For the three months ended March 31, 2018 and 2017 the impact of any natural gas imbalances was not significant. If a sale is deemed uncollectible, an allowance for doubtful collection is recorded.

Our crude oil, natural gas, and NGLs sales are recorded using either the “net-back” or "gross" method of accounting, depending upon the related purchase agreement. We use the net-back method when control of the crude oil, natural gas, or NGLs has been transferred to the purchasers of these commodities that are providing transportation, gathering, or 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. 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 are paid.

We use the gross method of accounting when control of the crude oil, natural gas, or NGLs is not transferred to the purchaser and the purchaser does not provide transportation, gathering, or processing services as a function of the price we receive. Rather, we contract separately with midstream providers for the applicable transport and processing on a per unit basis. Under this method, we recognize revenues based on the gross selling price and recognize transportation, gathering, and processing expenses.

Based on our evaluation of when control of crude oil and natural gas sales are transferred to the customer under the guidance of the new revenue recognition standard, certain crude oil sales in the Wattenberg Field that were recognized using the gross method prior to the adoption of the new revenue standard will be recognized using the net-back method. In the Delaware Basin, certain crude oil and natural gas sales that were recognized using the gross method prior to the adoption of the new revenue standard will be recognized using the net-back method.

As discussed above, we enter into agreements for the sale, transportation, gathering, and processing of our production. The terms of these agreements can result in variances in the per unit realized prices that we receive for our crude oil, natural gas and NGLs. For crude oil, the average NYMEX prices 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 how the majority of each of these commodities is sold pursuant to terms of the respective sales agreements. For NGLs, we use the NYMEX crude oil price as a reference for presentation purposes.

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Disaggregated Revenue. The following table presents crude oil, natural gas, and NGLs sales disaggregated by commodity and operating region for the three months ended March 31, 2018 and 2017 (in thousands):

	Three Months Ended March 31,		
Revenue by Commodity and Operating Region	2018	2017 (2)	Percentage Change
Crude oil			
Wattenberg Field	$170,306	$105,188	61.9 %
Delaware Basin	53,418	13,538	294.6 %
Utica Shale (1)	2,696	4,270	(36.9)%
Total	$226,420	$122,996	84.1 %
Natural gas			
Wattenberg Field	$29,772	$32,614	(8.7)%
Delaware Basin	7,679	2,468	211.1 %
Utica Shale (1)	1,110	1,860	(40.3)%
Total	$38,561	$36,942	4.4 %
NGLs			
Wattenberg Field	$28,770	$25,318	13.6 %
Delaware Basin	10,635	2,947	260.9 %
Utica Shale (1)	839	1,489	(43.7)%
Total	$40,244	$29,754	35.3 %
Revenue by Operating Region			
Wattenberg Field	$228,848	$163,120	40.3 %
Delaware Basin	71,732	18,953	278.5 %
Utica Shale (1)	4,645	7,619	(39.0)%
Total	$305,225	$189,692	60.9 %

(1) In March 2018, we completed the sale of our Utica Shale properties.
(2) As we have elected the modified retrospective method of adoption, revenues for the three months ended March 31, 2017 have not been restated for the new revenue recognition standard. Such amounts would not have been material.

Contract Assets. Contract assets include material contributions in aid of construction ("CIAC"), which are common in purchase/purchase and processing agreements with midstream service providers that are our customers. Generally, the intent of the payments is to reimburse the customer for actual costs incurred related to the construction of its gathering and processing infrastructure. Contract assets that are classified as current assets are included in prepaid expenses and other current assets on our condensed consolidated balance sheet. Contract assets that are classified as long-term are included in other assets on our condensed consolidated balance sheet. The contract assets will be amortized as a reduction to crude oil, natural gas, or NGLs sales revenue during the periods that the related production is transferred to the customer.

The following table presents the changes in carrying amounts of the contract assets associated with our crude oil, natural gas, and NGLs sales revenue for the three months ended March 31, 2018:

	Amount

	(in thousands)
Beginning balance, January 1, 2018	$ 4,446
Contract assets amortized as a reduction to crude oil, natural gas, and NGLs sales	(1,233)
Ending balance, March 31, 2018	$ 3,213

Customer Accounts Receivable. Our accounts receivable include amounts billed and currently due from sales of our crude oil, natural gas, and NGLs production. Our gross accounts receivable balance from crude oil, natural gas, and NGLs sales at March 31, 2018 and December 31, 2017 was $145.3 million and $154.3 million, respectively. Historically, we have not recorded a significant amount of write-offs related to our accounts receivable from sales of our crude oil, natural gas, and NGLs sales, therefore; we did not record an allowance for doubtful accounts for these receivables at March 31, 2018 or December 31, 2017.

NOTE 5 - 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 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:

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	March 31, 2018			December 31, 2017		
	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	$22,467	$ 6,143	$28,610	$12,949	$ 1,389	$14,338
Total liabilities	122,133	14,976	137,109	90,569	11,076	101,645
Net liability	$(99,666)	$ (8,833)	$(108,499)	$(77,620)	$ (9,687)	$(87,307)

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

	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Fair value of Level 3 instruments, net liability beginning of period	$(9,687)	$(9,574)
Changes in fair value included in condensed consolidated statement of operations line item:		
Commodity price risk management gain (loss), net	(2,152)	13,360
Settlements included in condensed consolidated statement of operations line items:		
Commodity price risk management gain (loss), net	3,006	(1,470)
Fair value of Level 3 instruments, net asset (liability) end of period	$(8,833)	$2,316
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	$1,205	$11,427

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 proved crude oil and natural gas properties 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.

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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 March 31, 2018.

	Estimated Fair Value (in millions)	Percent of Par
Senior notes:		
2021 Convertible Notes	$ 194.0	97.0 %
2024 Senior Notes	409.0	102.3 %
2026 Senior Notes	593.3	98.9 %

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 March 31, 2018, 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 March 31, 2018 and December 31, 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.

NOTE 6 - 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 March 31, 2018, we had derivative instruments, which were comprised of collars, fixed-price swaps, and basis protection swaps, in place for a portion of our anticipated 2018 and 2019 production. 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.

As of March 31, 2018, we had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

Commodity/ Index/ Maturity Period	Collars			Fixed-Price Swaps		Fair Value March 31, 2018 (1) (in millions)
	Quantity (Gas - BBtu Oil - MBbls)	Weighted-Average Contract Price Floors	Ceilings	Quantity (Oil - MBbls Gas and Basis- BBtu Propane - MBbls)	Weighted-Average Contract Price	
Crude Oil						
NYMEX						
2018	1,784.0	$ 46.64	$ 57.53	7,704.0	$ 52.54	$ (91.4)
2019	400.0	50.00	60.67	7,800.0	53.20	(42.9)
Total Crude Oil	2,184.0			15,504.0		$ (134.3)
Natural Gas						
NYMEX						
2018	2,735.0	$ 3.00	$ 3.56	40,335.0	$ 2.94	$ 5.1
2019	—	—	—	4,004.0	2.77	(0.1)
Total Natural Gas	2,735.0			44,339.0		$ 5.0
Basis Protection - Crude Oil						
Midland Cushing						
2018	—	$ —	$ —	1,456.1	$ (0.10)	$ 5.4
Total Basis Protection - Crude Oil	—			1,456.1		$ 5.4
Basis Protection - Natural Gas						
CIG						
2018	—	$ —	$ —	31,409.9	$ (0.43)	$ 12.3
2019	—	—	—	4,004.0	(0.88)	(0.1)
Waha						
2018	—	—	—	4,923.8	(0.50)	3.4
El Paso						
2018	—	—	—	2,450.0	(0.62)	1.6
Total Basis Protection - Natural Gas	—			42,787.7		$ 17.2
Propane						
Mont Belvieu						
2018	—	$ —	$ —	714.4	$ 32.52	$ —
Total Propane	—			714.4		$ —

Rollfactor (2)						
Crude Oil CMA						
2018	—	$ —	$ —	4,192	$ 0.12	$ (1.8)
Total Rollfactor	—			4,192		$ (1.8)
Commodity Derivatives Fair Value						$ (108.5)

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(1) Approximately 21.5 percent of the fair value of our commodity derivative assets and 10.9 percent of the fair value of our commodity derivative liabilities were measured using significant unobservable inputs (Level 3).

(2) These positions hedge the timing risk associated with our physical sales. We generally sell crude oil for the delivery month at a sales price based on the average NYMEX West Texas Intermediate price during that month, plus an adjustment calculated as a spread between the weighted average prices of the delivery month, the next month and the following month during the period when the delivery month is the first month.

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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 March 31, 2018	December 31, 2017
			(in thousands)	
Derivative assets:	Current			
	Commodity derivative contracts	Fair value of derivatives	$5,958	$7,340
	Basis protection derivative contracts	Fair value of derivatives	22,652	6,998
			28,610	14,338
	Non-current		—	—
Total derivative assets			$28,610	$14,338
Derivative liabilities:	Current			
	Commodity derivative contracts	Fair value of derivatives	108,763	77,999
	Basis protection derivative contracts	Fair value of derivatives	122	234
	Rollfactor derivative contracts	Fair value of derivatives	1,798	1,069
			110,683	79,302
	Non-current			
	Commodity derivative contracts	Fair value of derivatives	26,447	22,343
	Basis protection derivative contracts	Fair value of derivatives	(21)	—
			26,426	22,343
Total derivative liabilities			$137,109	$101,645

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 March 31, 2018	2017
	(in thousands)	
Commodity price risk management gain (loss), net		
Net settlements	$(26,038)	$551
Net change in fair value of unsettled derivatives	(21,202)	80,153
Total commodity price risk management gain (loss), net	$(47,240)	$80,704

Net settlements of commodity derivatives and net change in fair value of unsettled derivatives decreased for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017 as a result of the increase in future commodity prices during the first quarter of 2018 compared to a decrease during the first quarter of 2017.

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.

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

As of March 31, 2018	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	$28,610	$(27,971)	$639
Liability derivatives:			
Derivative instruments, at fair value	$137,109	$(27,971)	$109,138

As of December 31, 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	$14,338	$(14,173)	$165
Liability derivatives:			
Derivative instruments, at fair value	$101,645	$(14,173)	$87,472

NOTE 7 - PROPERTIES AND EQUIPMENT

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

	March 31, 2018	December 31, 2017
	(in thousands)	
Properties and equipment, net:		
Crude oil and natural gas properties		

Proved	$4,706,258	$4,356,922
Unproved	1,055,774	1,097,317
Total crude oil and natural gas properties	5,762,032	5,454,239
Infrastructure, pipeline, and other	125,529	109,359
Land and buildings	12,679	10,960
Construction in progress	294,311	196,024
Properties and equipment, at cost	6,194,551	5,770,582
Accumulated DD&A	(1,963,294)	(1,837,115)
Properties and equipment, net	$4,231,257	$3,933,467

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

	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Impairment of proved and unproved properties	$33,130	$2,102
Amortization of individually insignificant unproved properties	58	91
Impairment of crude oil and natural gas properties	$33,188	$2,193

During the three months ended March 31, 2018, we recorded impairment charges of $26.9 million, primarily related to certain unproved Delaware Basin leasehold positions that expired during the three months ended March 31, 2018.

Additionally, we corrected an error in our calculation of the unproved properties and goodwill impairment originally reported in the quarter ended September 30, 2017. The correction of the error resulted in an additional impairment charge of $6.3 million, recorded in the three months ended March 31, 2018, which we have included in the impairment of properties and equipment expense line in our condensed consolidated statement of operations. We evaluated the error under the guidance of Accounting Standards Codification 250, Accounting Changes and Error Corrections ("ASC 250"). Based on the guidance in ASC 250, we determined that the impact of the error did not have a material impact to our previously-issued financial statements or those of the period of correction.

Utica Shale Divestiture. In March 2018, we completed the sale of our Utica Shale properties (the "Utica Shale Divestiture") for net cash proceeds of approximately $39.0 million, subject to certain customary post-closing adjustments. We recorded a loss on sale of properties and equipment of $1.4 million for the three months ended March 31, 2018. The divestiture of the Utica Shale properties did not represent a strategic shift in our operations or have a significant impact on our operations or financial results; therefore, we did not account for it as a discontinued operation.

Classification of Assets as Held-for-Sale. Assets held-for-sale as of March 31, 2018 were $1.6 million for a field office facility. We subsequently sold the field office facility in April 2018 for $1.9 million and will record a gain on sale of properties and equipment of $0.3 million during the second quarter of 2018. Assets held-for-sale as of December 31, 2017 included $36.8 million and $3.3 million, representing our Utica Shale properties and field office facilities and a separate parcel of land, respectively.

The following table presents balance sheet data related to assets held-for-sale. Assets held-for-sale represents the assets that are expected to be sold, net of liabilities that are expected to be assumed by the purchasers:

	March 31, 2018	December 31, 2017
	(in thousands)	
Assets		
Properties and equipment, net	$1,647	$ 40,583
Total assets	$1,647	$ 40,583
Liabilities		
Asset retirement obligation	$—	$ 499
Total liabilities	$—	$ 499
Assets held-for-sale, net	$1,647	$ 40,084

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Suspended Well Costs. We have spud three wells in the Delaware Basin for which we are unable to make a final determination regarding whether proved reserves can be associated with the wells as of March 31, 2018 as the wells had not been completed as of that date. Therefore, we have classified the capitalized costs of the wells as suspended well costs as of March 31, 2018 while we continue to conduct completion and testing operations to determine the existence of proved reserves.

The following table presents the capitalized exploratory well cost pending determination of proved reserves and included in properties and equipment, net on the condensed consolidated balance sheets:

	March 31, 2018	December 31, 2017
	(in thousands, except for number of wells)	
Beginning balance	$15,448	$—
Additions to capitalized exploratory well costs pending the determination of proved reserves	17,143	51,776
Reclassifications to proved properties	—	(36,328)
Ending balance	$32,591	$15,448
Number of wells pending determination at period end	3	3

Exploration, geologic, and geophysical expense. Exploration, geologic, and geophysical expense of $2.6 million during the three months ended March 31, 2018 was primarily related to the purchase of seismic data related to unproved acreage and lease costs associated with certain delayed drilling in the Delaware Basin. Exploration, geologic, and geophysical expense of $1.0 million during the three months ended March 31, 2017 was primarily related to drilling pilot holes in the Delaware Basin.

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NOTE 8 - OTHER ACCRUED EXPENSES AND OTHER LIABILITIES

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

	March 31, 2018	December 31, 2017
	(in thousands)	
Employee benefits	$ 10,901	$ 22,383
Asset retirement obligations	15,944	15,801
Environmental expenses	2,074	1,374
Short-term deferred oil gathering credit	2,010	—
Other	2,848	3,429
Other accrued expenses	$ 33,777	$ 42,987

Other Liabilities. The following table presents the components of other liabilities as of:

	March 31, 2018	December 31, 2017
	(in thousands)	
Production taxes	$ 63,454	$ 50,476
Long-term deferred oil gathering credit	21,608	—
Other	9,495	6,857
Other liabilities	$ 94,557	$ 57,333

On January 31, 2018, we received a payment of $24.1 million from Saddle Butte Rockies Midstream, LLC for the execution of an amendment to an existing crude oil purchase and sale agreement signed in December 2017. The amendment was effective contingent upon certain events which occurred in late January 2018. The amendment, among other things, dedicates crude oil from the majority of our Wattenberg Field acreage to Saddle Butte's gathering lines and extends the term of the agreement through December 2029. Subsequent to the receipt of this payment, Saddle Butte was purchased by Black Diamond Gathering, LLC. The short-term portion of the deferred oil gathering credit is included in other accrued expenses and the long-term portion is included in other liabilities on our condensed consolidated balance sheet as of March 31, 2018. The payment will be amortized using the straight-line method over the life of the amendment. Amortization charges totaling approximately $0.4 million for the three months ended March 31, 2018 related to the deferred oil gathering credit are included as a reduction to transportation, gathering, and processing expenses on our condensed consolidated statements of operations.

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NOTE 9 - LONG-TERM DEBT

Long-term debt consisted of the following as of:

	March 31, 2018	December 31, 2017
	(in thousands)	
Senior notes:		
1.125% Convertible Notes due 2021:		
Principal amount	$200,000	$200,000
Unamortized discount	(28,478)	(30,328)
Unamortized debt issuance costs	(3,371)	(3,615)
1.125% Convertible Notes due 2021, net of unamortized discount and debt issuance costs	168,151	166,057
5.75% Senior Notes due 2026:		
Principal amount	600,000	600,000
Unamortized debt issuance costs	(7,298)	(7,555)
5.75% Senior Notes due 2026, net of unamortized debt issuance costs	592,702	592,445
6.125% Senior Notes due 2024:		
Principal amount	400,000	400,000
Unamortized debt issuance costs	(6,325)	(6,570)
6.125% Senior Notes due 2024, net of unamortized debt issuance costs	393,675	393,430
Total senior notes	1,154,528	1,151,932
Revolving credit facility	—	—
Total long-term debt, net of unamortized discount and debt issuance costs	$1,154,528	$1,151,932

Senior Notes

2021 Convertible Notes. In September 2016, we issued $200 million of 1.125% convertible 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 Notes have been capitalized as debt issuance costs. As of March 31, 2018, 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, with cash paid in lieu of fractional shares.

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, and we completed the exchange offer in September 2017. 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.

2026 Senior Notes. In November 2017, we issued $600 million aggregate principal amount of 5.75% senior notes due May 15, 2026, in a private placement to qualified institutional buyers. The 2026 Senior Notes are governed by an indenture dated November 29, 2017 between us and the U.S. Bank National Association, as trustee. The maturity for the payment of principal is May 15, 2026. Interest at the rate of 5.75% per year is payable in cash semiannually in arrears on each May 15 and November 15, commencing on May 15, 2018. Approximately $7.6 million in costs associated with the issuance of the 2026 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.

Our wholly-owned subsidiary PDC Permian, Inc. guarantees our obligations under the 2021 Convertible Notes, the 2026 Senior Notes, and the 2024 Senior Notes (collectively, the "Notes"). Accordingly, condensed consolidating financial information for PDC and PDC Permian, Inc. is presented in the footnote titled Subsidiary Guarantor.

As of March 31, 2018, 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

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 $1.0 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.

In May and October 2017, we entered into the Fifth and Sixth Amendments, respectively, to the Third Amended and Restated Credit Agreement to amend the revolving credit facility to reflect increases in the borrowing base. The Fifth amendment reflected an increase of the borrowing base from $700 million to $950 million and the Sixth Amendment amended the revolving credit facility to allow the borrowing base to increase above the borrowing capacity of $1.0 billion. In addition, the Fifth Amendment made changes to certain of the covenants in the existing agreement as well as other administrative changes. We elected to increase the borrowing base to $1.1 billion for our November 2017 borrowing base redetermination and have elected to maintain a $700 million commitment level as of the date of this report.

In April 2018, we began negotiations with our bank group to enter into the Fourth Amended and Restated Credit Agreement, and we anticipate closing to occur by the end of May 2018. This agreement is expected to replace the Third Amended and Restated Credit Agreement. Following the amendment and restatement, the facility is expected to mature in May 2023.

As of March 31, 2018 and December 31, 2017, debt issuance costs related to our revolving credit facility were $5.5 million and $6.2 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 March 31, 2018 or December 31, 2017. 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 March 31, 2018, 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 0.5 percent. Principal payments are generally not required until the revolving credit facility expires in May 2020 unless 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 March 31, 2018, 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 leverage ratio was 1.7 and our current ratio was 2.5 as of March 31, 2018.

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:

	March 31, 2018	December 31, 2017
	(in thousands)	
Vehicles	$6,500	$ 6,249
Accumulated depreciation	(2,271)	(1,882)
	$4,229	$ 4,367

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 March 31,	Amount (in thousands)
2019	$ 1,952
2020	2,061
2021	1,247
	5,260
Less executory cost	(400)
Less amount representing interest	(501)
Present value of minimum lease payments	$ 4,359
Short-term capital lease obligations	$ 1,789
Long-term capital lease obligations	2,570
	$ 4,359

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 - 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 rate for the three months ended March 31, 2018 was a 25.8 percent benefit on loss compared to a 36.3 percent expense on income for the three months ended March 31, 2017. The effective income tax rate for the three months ended March 31, 2018, is based upon a full year forecasted tax expense on income. The effective income tax rate for the three months ended March 31, 2018 includes discrete income tax benefits of $0.2 million relating to the excess tax benefit recognized with the vesting of stock awards during the three months ended March 31, 2018, which resulted in a 1.2 percent increase to our effective tax rate. The federal corporate statutory income tax rate decreased from 35 percent in 2017 to 21 percent in 2018 resulting from the 2017 Tax Cuts and Jobs Act (the "2017 Tax Act").

The effective income tax rate for the three months ended March 31, 2018 is based upon a full year forecasted tax expense on income and is greater than the statutory federal tax rate, primarily due to state 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 tax rates from the impact of stock-based compensation tax deductions as they are treated as discrete tax items. The effective tax rate for the three months ended March 31, 2017 is based upon a full year forecasted tax expense on income and is greater than the statutory federal tax rate, primarily due to state taxes, nondeductible officers' compensation and nondeductible lobbying expenses, partially offset by stock-based compensation tax deductions.

As of March 31, 2018, 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 ("IRS") Compliance Assurance Program for the 2017 and 2018 tax years. We have received final acceptance of our 2016 federal income tax return from the IRS; however, this return is going through the Joint Tax Committee review process due to tax refunds requested.

NOTE 12 - 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, 2017	$ 87,306
Obligations incurred with development activities	620
Obligations incurred with acquisition	4,687

Accretion expense	1,288
Revisions in estimated cash flows	50
Obligations discharged with asset retirements and divestiture	(4,102)
Balance at March 31, 2018	89,849
Less current portion	(15,944)
Long-term portion	$ 73,905

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 March 31, 2018, the credit-adjusted risk-free rates used to discount our plugging and abandonment liabilities ranged from 6.5 percent to 7.5 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 13 - 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 March 31,						
Area	2019	2020	2021	2022	2023 and Through Expiration	Total	Expiration Date
Natural gas (MMcf)							
Wattenberg Field	7,416	27,794	31,025	31,025	114,272	211,532	April 30, 2026
Delaware Basin	25,520	25,600	11,000	—	—	62,120	December 31, 2020
Gas Marketing	7,117	7,136	7,117	6,965	2,830	31,165	August 31, 2022
Total	40,053	60,530	49,142	37,990	117,102	304,817	
Crude oil (MBbls)							
Wattenberg Field	7,438	8,062	5,085	4,563	4,937	30,085	April 30, 2023
Delaware Basin	4,493	8,227	8,580	7,392	14,080	42,772	December 31, 2023
Total	11,931	16,289	13,665	11,955	19,017	72,857	
Dollar commitment (in thousands)	$64,690	$99,560	$69,434	$65,060	$160,183	$458,927	

In March 2018, we completed the sale of our Utica Shale properties. Upon closing, the related commitment was assumed by the purchaser of the Utica Shale properties.

In anticipation of our future drilling activities in the Wattenberg Field, we have entered into two facilities expansion agreements with our primary midstream provider to expand and improve its natural gas gathering pipelines and processing facilities. The midstream provider is expected to construct two new 200 MMcfd cryogenic plants. We will be bound to the volume requirements in these agreements on the first day of the calendar month following the actual in-service dates of the plants, which, as reflected in the above table, are currently scheduled to be in the third quarter of 2018 for the first plant and the second quarter of 2019 for the second plant. Both agreements require baseline volume commitments, consisting of our gross wellhead volume delivered in November 2016, to this midstream provider, and incremental wellhead volume commitments of 51.5 MMcfd and 33.5 MMcfd for the first and second agreements, respectively, for seven years. We may be required to pay shortfall fees for any volumes under the 51.5 MMcfd and 33.5 MMcfd incremental commitments. Any shortfall in these volume commitments may be offset by other 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 contracts to guarantee a certain target profit margin to the midstream provider on these incremental volumes. We currently expect that our future development plans will meet both the baseline and incremental volumes, and we believe that the contractual target profit margin will be achieved without additional payment from us.

In April 2018, we entered into a five-year firm transportation agreement, effective May 1, 2018, with a third-party crude oil pipeline company to transport 12,500 barrels of crude oil per day from our Wattenberg Field via pipeline to Cushing, Oklahoma and other area refineries. This agreement is reflected in the pipeline capacity commitment table above.

In May 2018, we entered into a firm sales agreement that is effective from June 1, 2018 through December 31, 2023 for an initial 11,400 barrels of crude oil per day and incrementally increasing to 26,400 barrels of crude oil per day with a large integrated marketing company for our crude oil production in the Delaware Basin. This agreement is expected to provide price diversification through realization of export market pricing via a Corpus Christi terminal and exposure to Brent-weighted prices. The fixed transportation charge associated with this agreement is reflected in the pipeline capacity commitment table above.

For the three months ended March 31, 2018, commitments for long-term transportation volumes, net to our interest, for Wattenberg Field crude oil and Delaware Basin natural gas were $2.6 million, and in accordance with the guidance in the new revenue recognition standard, were netted against our crude oil and natural gas sales in our condensed consolidated statements of operations. For the three months ended March 31, 2017, commitments for long-term transportation volumes for Wattenberg Field crude oil and Utica Shale natural gas were $2.2 million and were recorded in transportation, gathering, and processing expense in our condensed consolidated statements of operations.

Litigation and Legal Items. We are involved in various legal proceedings. We review 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 our best interests. We have 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. Although the results cannot be known with certainty, we currently believe that the ultimate results of such proceedings will not have a material adverse effect on our financial position, results of operations, or liquidity.

Action Regarding Partnerships. In December 2017, we received an action entitled Dufresne, et al. v. PDC Energy, et al., filed in the United States District Court for the District of Colorado. The complaint states that it is a derivative action brought by a number of limited partner investors seeking to assert claims on behalf of our two affiliated partnerships, Rockies Region 2006 LP and Rockies Region 2007 LP, against PDC and includes claims for breach of fiduciary duty and breach of contract. The plaintiffs also included claims against two of our senior officers for alleged breach of fiduciary duty. The lawsuit accuses PDC, as the managing general partner of the two partnerships, of, among other things, failing to maximize the productivity of the partnerships’ crude oil and natural gas wells. We filed a motion to dismiss the lawsuit on February 1, 2018, on the grounds that the complaint is deficient, including because the plaintiffs failed to allege that PDC refused a demand to take action on their claims. On March 14, 2018, the motion was denied as moot by the court because the plaintiffs requested leave to amend their complaint. In late April 2018, the plaintiffs filed an amendment to their complaint. Such amendment primarily alleges additional facts to support the plaintiffs’ claims and purports to add direct class action claims in addition to the original derivative claims. The amendment also adds three new individual defendants, all of which are independent members of our Board of Directors. We are currently unable to estimate any potential damages as a result of this lawsuit.

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 material environmental claims existing as of March 31, 2018 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 potential past non-compliance with environmental laws or other environmental liabilities will not be discovered on our properties.

Accrued environmental liabilities are recorded in other accrued expenses on the condensed consolidated balance sheets. The liability ultimately incurred with respect to a matter may exceed the related accrual.

Clean Air Act Tentative Agreement and Related Consent Decree. 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 ("DJ Basin"). The Information Request focused on historical operation and design information for 46 of our production facilities and requested 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.

In June 2017, the U.S. Department of Justice, on behalf of the EPA and the state of Colorado, filed a complaint against us in the U.S. District Court for the District of Colorado, claiming that we failed to operate and maintain certain condensate collection facilities at 65 facilities so as to minimize leakage of volatile organic compounds in compliance with applicable law. In October 2017, we entered into a consent decree to resolve the lawsuit. Pursuant to the consent decree, we agreed to implement a variety of operational enhancements and mitigation and similar projects, including vapor control system modifications and verification, increased inspection and monitoring, and installation of tank pressure monitors. The three primary elements of the consent decree are: (i) fine/supplemental environmental projects ($1.5 million cash fine, plus $1 million in supplemental environmental projects) of which the cash fines were paid in the first quarter of 2018 and the environmental projects have been accrued in other accrued expenses on our consolidated balance sheet as of March 31, 2018 (ii) injunctive relief with an estimated cost of approximately $18 million, primarily representing capital enhancements to our operations; and (iii) mitigation with an estimated cost of $1.7 million. We continue to incur costs associated with these activities. If we fail to comply fully with the requirements of the consent decree with respect to those matters, we could be subject to additional liability. In addition, we could be the subject of other enforcement actions by regulatory authorities in the future relating to our past, present or future operations. We do not believe that the expenditures resulting from the settlement will have a material adverse effect on our consolidated financial statements.

Since our entry into the consent decree we have implemented a comprehensive program to comply with all of its requirements. As of the date of the filing of this report, all aspects of the consent decree compliance program are on or ahead of schedule.

NOTE 14 - COMMON STOCK

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 March 31,	
	2018	2017
	(in thousands)	
Stock-based compensation expense	$5,261	$4,453
Income tax benefit	(1,261)	(1,666)
Net stock-based compensation expense	$4,000	$2,787

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. No SARs were awarded or expired during the three months ended March 31, 2018.

Total compensation cost related to non-vested SARs granted and not yet recognized in our condensed consolidated statement of operations as of March 31, 2018 was $1.4 million. The cost is expected to be recognized over a weighted-average period of 1.52 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.

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The following table presents the changes in non-vested time-based awards to all employees, including executive officers, for the three months ended March 31, 2018:

	Shares	Weighted-Average Grant Date Fair Value per Share
Non-vested at December 31, 2017	472,132	$ 60.23
Granted	136,256	50.94
Vested	(66,253)	58.16
Forfeited	(5,800)	68.18
Non-vested at March 31, 2018	536,335	58.04

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

	As of/Three Months Ended March 31,	
	2018	2017
	(in thousands, except per share data)	
Total intrinsic value of time-based awards vested	$3,530	$3,602
Total intrinsic value of time-based awards non-vested	26,297	33,366
Market price per share as of March 31,	49.03	62.35
Weighted-average grant date fair value per share	50.94	73.28

Total compensation cost related to non-vested time-based awards and not yet recognized in our condensed consolidated statements of operations as of March 31, 2018 was $20.6 million. This cost is expected to be recognized over a weighted-average period of 2.0 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 90,778 market-based restricted shares to our executive officers during the three months ended March 31, 2018. 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, 2020, 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:

	Three Months Ended March 31,	
	2018	2017
Expected term of award (in years)	3	3
Risk-free interest rate	2.4 %	1.4 %
Expected volatility	42.3 %	51.4 %
Weighted-average grant date fair value per share	$69.98	$94.02

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.

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The following table presents the change in non-vested market-based awards during the three months ended March 31, 2018:

	Shares	Weighted-Average Grant Date Fair Value per Share
Non-vested at December 31, 2017	52,349	$ 84.06
Granted	90,778	69.98
Forfeited	(4,128)	94.02
Non-vested at March 31, 2018	138,999	74.57

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

	As of Three Months Ended March 31,	
	2018	2017
	(in thousands, except per share data)	
Total intrinsic value of market-based awards non-vested	$6,815	$4,769
Market price per common share as of March 31,	49.03	62.35
Weighted-average grant date fair value per share	69.98	94.02

Total compensation cost related to non-vested market-based awards not yet recognized in our condensed consolidated statements of operations as of March 31, 2018 was $7.9 million. This cost is expected to be recognized over a weighted-average period of 2.5 years.

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 of Directors from time to time. Through March 31, 2018, no preferred shares have been issued.

NOTE 15 - 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 March 31,	
	2018	2017
	(in thousands)	
Weighted-average common shares outstanding - basic	65,957	65,749
Dilutive effect of:		
Restricted stock	—	211
Convertible notes	—	157
Weighted-average common shares and equivalents outstanding - diluted	65,957	66,117

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We reported a net loss for the three months ended March 31, 2018. 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 March 31,	
	2018	2017
	(in thousands)	
Weighted-average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:		
Restricted stock	491	76
Convertible notes	—	—
Other equity-based awards	198	18
Total anti-dilutive common share equivalents	689	94

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 months ended March 31, 2018 and 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.

NOTE 16 - SUBSIDIARY GUARANTOR

PDC Permian, Inc., our wholly-owned subsidiary, guarantees our obligations under our publicly-registered senior 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 senior 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; and
(iv) Parent and subsidiaries on a consolidated basis ("Consolidated").

The Guarantor is 100 percent owned by the Parent. The senior 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.

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	Condensed Consolidating Balance Sheets			
	March 31, 2018			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Current assets:				
Cash and cash equivalents	$45,923	$—	$—	$45,923
Accounts receivable, net	143,250	37,775	—	181,025
Fair value of derivatives	28,610	—	—	28,610
Prepaid expenses and other current assets	7,116	1,781	—	8,897
Total current assets	224,899	39,556	—	264,455
Properties and equipment, net	2,139,471	2,091,786	—	4,231,257
Assets held-for-sale, net	1,647	—	—	1,647
Intercompany receivable	294,476	—	(294,476)	—
Investment in subsidiaries	1,605,330	—	(1,605,330)	—
Other assets	23,339	1,459	—	24,798
Total Assets	$4,289,162	$2,132,801	$(1,899,806)	$4,522,157
Liabilities and Stockholders' Equity				
Liabilities				
Current liabilities:				
Accounts payable	$113,529	$82,174	$—	$195,703
Production tax liability	35,309	1,341	—	36,650
Fair value of derivatives	110,683	—	—	110,683
Funds held for distribution	80,203	17,408	—	97,611
Accrued interest payable	13,756	4	—	13,760
Other accrued expenses	33,136	641	—	33,777
Total current liabilities	386,616	101,568	—	488,184
Intercompany payable	—	294,476	(294,476)	—
Long-term debt	1,154,528	—	—	1,154,528
Deferred income taxes	62,088	125,095	—	187,183
Asset retirement obligations	67,922	5,983	—	73,905
Fair value of derivatives	26,426	—	—	26,426
Other liabilities	94,208	349	—	94,557
Total liabilities	1,791,788	527,471	(294,476)	2,024,783
Commitments and contingent liabilities				
Stockholders' Equity				
Stockholders' equity				
Common shares	660	—	—	660
Additional paid-in capital	2,504,663	1,766,777	(1,766,777)	2,504,663
Retained earnings	(6,435)	(161,447)	161,447	(6,435)
Treasury shares	(1,514)	—	—	(1,514)

Total stockholders' equity	2,497,374	1,605,330	(1,605,330)	2,497,374
Total Liabilities and Stockholders' Equity	$4,289,162	$2,132,801	$(1,899,806)	$4,522,157

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Condensed Consolidating Balance Sheets
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	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Current assets:				
Cash and cash equivalents	$180,675	$—	$—	$180,675
Accounts receivable, net	160,490	37,108	—	197,598
Fair value of derivatives	14,338	—	—	14,338
Prepaid expenses and other current assets	8,284	329	—	8,613
Total current assets	363,787	37,437	—	401,224
Properties and equipment, net	1,891,314	2,042,153	—	3,933,467
Assets held-for-sale, net	40,084	—	—	40,084
Intercompany receivable	250,279	—	(250,279)	—
Investment in subsidiaries	1,617,537	—	(1,617,537)	—
Other assets	42,547	2,569	—	45,116
Total Assets	$4,205,548	$2,082,159	$(1,867,816)	$4,419,891
Liabilities and Stockholders' Equity				
Liabilities				
Current liabilities:				
Accounts payable	$85,000	$65,067	$—	$150,067
Production tax liability	35,902	1,752	—	37,654
Fair value of derivatives	79,302	—	—	79,302
Funds held for distribution	83,898	11,913	—	95,811
Accrued interest payable	11,812	3	—	11,815
Other accrued expenses	42,543	444	—	42,987
Total current liabilities	338,457	79,179	—	417,636
Intercompany payable	—	250,279	(250,279)	—
Long-term debt	1,151,932	—	—	1,151,932
Deferred income taxes	62,857	129,135	—	191,992
Asset retirement obligations	65,301	5,705	—	71,006
Fair value of derivatives	22,343	—	—	22,343
Other liabilities	57,009	324	—	57,333
Total liabilities	1,697,899	464,622	(250,279)	1,912,242
Commitments and contingent liabilities				
Stockholders' Equity				
Stockholders' equity				
Common shares	659	—	—	659
Additional paid-in capital	2,503,294	1,766,775	(1,766,775)	2,503,294
Retained earnings	6,704	(149,238)	149,238	6,704
Treasury shares	(3,008)	—	—	(3,008)

Total stockholders' equity	2,507,649	1,617,537	(1,617,537)	2,507,649
Total Liabilities and Stockholders' Equity	$4,205,548	$2,082,159	$(1,867,816)	$4,419,891

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PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
March 31, 2018
(unaudited)

	Condensed Consolidating Statements of Operations			
	Three Months Ended March 31, 2018			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Revenues				
Crude oil, natural gas, and NGLs sales	$233,494	$71,731	$ —	$ 305,225
Commodity price risk management loss, net	(47,240)	—	—	(47,240)
Other income	2,516	99	—	2,615
Total revenues	188,770	71,830	—	260,600
Costs, expenses and other				
Lease operating expenses	21,362	8,274	—	29,636
Production taxes	16,081	4,088	—	20,169
Transportation, gathering, and processing expenses	3,231	4,082	—	7,313
Exploration, geologic, and geophysical expense	313	2,333	—	2,646
Impairment of properties and equipment	6	33,182	—	33,188
General and administrative expense	31,559	4,137	—	35,696
Depreciation, depletion and amortization	94,376	32,412	—	126,788
Accretion of asset retirement obligations	1,200	88	—	1,288
Loss on sale of properties and equipment	1,432	—	—	1,432
Other expenses	2,768	—	—	2,768
Total costs, expenses and other	172,328	88,596	—	260,924
Income (loss) from operations	16,442	(16,766)	—	(324)
Interest expense	(18,097)	568	—	(17,529)
Interest income	148	—	—	148
Loss before income taxes	(1,507)	(16,198)	—	(17,705)
Income tax benefit	577	3,989	—	4,566
Equity in loss of subsidiary	(12,209)	—	12,209	—
Net loss	$(13,139)	$(12,209)	$ 12,209	$ (13,139)

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PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
March 31, 2018
(unaudited)

	Condensed Consolidating Statements of Operations			
	Three Months Ended March 31, 2017			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Revenues				
Crude oil, natural gas, and NGLs sales	$170,739	$18,953	$ —	$ 189,692
Commodity price risk management gain, net	80,704	—	—	80,704
Other income	3,297	14	—	3,311
Total revenues	254,740	18,967	—	273,707
Costs, expenses and other				
Lease operating expenses	15,816	3,973	—	19,789
Production taxes	11,144	1,255	—	12,399
Transportation, gathering, and processing expenses	5,215	687	—	5,902
Exploration, geologic, and geophysical expense	271	683	—	954
Impairment of properties and equipment	604	1,589	—	2,193
General and administrative expense	23,529	2,786	—	26,315
Depreciation, depletion and amortization	101,738	7,578	—	109,316
Accretion of asset retirement obligations	1,685	83	—	1,768
Gain on sale of properties and equipment	(160)	—	—	(160)
Other expenses	3,528	—	—	3,528
Total costs, expenses and other	163,370	18,634	—	182,004
Income from operations	91,370	333	—	91,703
Interest expense	(19,597)	130	—	(19,467)
Interest income	240	—	—	240
Income before income taxes	72,013	463	—	72,476
Income tax expense	(26,162)	(168)	—	(26,330)
Equity in income of subsidiary	295	—	(295)	—
Net income	$46,146	$295	$ (295)	$ 46,146

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	Condensed Consolidating Statements of Cash Flows Three Months Ended March 31, 2018			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Cash flows from operating activities	$149,009	$56,140	$ —	$205,149
Cash flows from investing activities:				
Capital expenditures for development of crude oil and natural gas properties	(97,286)	(99,631)	—	(196,917)
Capital expenditures for other properties and equipment	(701)	(365)	—	(1,066)
Acquisition of crude oil and natural gas properties, including settlement adjustments	(180,825)	—	—	(180,825)
Proceeds from sale of properties and equipment	20	—	—	20
Proceeds from divestiture	39,023	—	—	39,023
Restricted cash	1,249	—	—	1,249
Intercompany transfers	(43,891)	—	43,891	—
Net cash from investing activities	(282,411)	(99,996)	43,891	(338,516)
Cash flows from financing activities:				
Proceeds from revolving credit facility	35,000	—	—	35,000
Repayment of revolving credit facility	(35,000)	—	—	(35,000)
Purchase of treasury stock	(2,255)	—	—	(2,255)
Other	(344)	(35)	—	(379)
Intercompany transfers	—	43,891	(43,891)	—
Net cash from financing activities	(2,599)	43,856	(43,891)	(2,634)
Net change in cash, cash equivalents, and restricted cash	(136,001)	—	—	(136,001)
Cash, cash equivalents, and restricted cash, beginning of period	189,925	—	—	189,925
Cash, cash equivalents, and restricted cash, end of period	$53,924	$—	$ —	$53,924

	Condensed Consolidating Statements of Cash Flows Three Months Ended March 31, 2017			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Cash flows from operating activities	$131,661	$7,839	$ —	$139,500
Cash flows from investing activities:				
Capital expenditures for development of crude oil and natural gas properties	(82,489)	(47,337)	—	(129,826)
Capital expenditures for other properties and equipment	(890)	69	—	(821)
Acquisition of crude oil and natural gas properties, including settlement adjustments	—	6,181	—	6,181
Proceeds from sale of properties and equipment	737	—	—	737
Purchase of short-term investments	(49,890)	—	—	(49,890)

Intercompany transfers	(33,795)	—	33,795	—
Net cash from investing activities	(166,327)	(41,087)	33,795	(173,619)
Cash flows from financing activities:				
Purchase of treasury stock	(2,017)	—	—	(2,017)
Other	(330)	(10)	—	(340)
Intercompany transfers	—	33,795	(33,795)	—
Net cash from financing activities	(2,347)	33,785	(33,795)	(2,357)
Net change in cash, cash equivalents, and restricted cash	(37,013)	537	—	(36,476)
Cash, cash equivalents, and restricted cash, beginning of period	240,487	3,613	—	244,100
Cash, cash equivalents, and restricted cash, end of period	$ 203,474	$ 4,150	$ —	$ 207,624

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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

Production and Financial Overview

Production volumes increased to 8.9 MMboe for the three months ended March 31, 2018, representing an increase of 34 percent as compared to the three months ended March 31, 2017. Crude oil production increased 51 percent for the three months ended March 31, 2018 compared to the three months ended March 31, 2017. Crude oil production comprised approximately 43 percent and 38 percent of total production for the three months ended March 31, 2018 and 2017, respectively. NGLs production increased 20 percent for the three months ended March 31, 2018 compared to the three months ended March 31, 2017. Natural gas production increased 26 percent for the three months ended March 31, 2018 compared to the three months ended March 31, 2017. On a combined basis, total liquids production comprised 63 percent of our total production during the three months ended March 31, 2018 and 61 percent of total production during the three months ended March 31, 2017.

On a sequential quarterly basis, total production and crude oil production volumes for the three months ended March 31, 2018 as compared to the three months ended December 31, 2017 increased slightly by three percent and two percent, respectively. Continued high line pressures, fewer production days, gathering line freezing issues, and unexpected gathering system facility downtime in the Wattenberg Field have temporarily tempered the growth rate in the field. These operating challenges do not impact our expected full year 2018 production outlook as discussed under 2018 Operational and Financial Outlook. High line pressures in the Wattenberg Field are expected to remain a concern until our primary third-party midstream provider completes the construction of additional processing facilities. We expect significant production growth in the Wattenberg Field during the second half of 2018 once an additional facility is completed and on line, which is expected to occur in the third quarter of 2018. We expect our company-wide production to increase modestly in the second quarter of 2018, led by the continued successful development of our Delaware Basin properties. However, our production and realized prices in the Delaware Basin may be negatively impacted by ongoing increased crude oil and natural gas takeaway capacity constraints and widening differentials. Such constraints could hinder production growth and result in further widening of price differentials for our commodities in the basin; however, we are currently investigating various options to mitigate this risk. In an effort to address these issues, in May 2018, we entered into an agreement for pipeline capacity for a portion of our Delaware Basin crude oil production. See Results of Operations - Crude Oil, Natural Gas, and NGLs Production for further details of this agreement.

Crude oil, natural gas, and NGLs sales revenue increased to $305.2 million for the three months ended March 31, 2018 compared to $189.7 million for the three months ended March 31, 2017. The 61 percent increase in sales revenues was driven by a 34 percent increase in production and a 20 percent increase in average realized commodity prices. The adoption of the new revenue recognition standard at January 1, 2018 did not significantly impact the change in our crude oil, natural gas, and NGLs sales revenue for the three months ended March 31, 2018 as compared to the same period in 2017. See the footnote titled Revenue Recognition to our condensed consolidated financial statements included elsewhere in this report for additional information regarding the new revenue recognition standard.

We had negative net settlements from our commodity derivative contracts of $26.0 million for the three months ended March 31, 2018 as compared to positive net settlements of $0.5 million for the three months ended March 31, 2017. 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 47 percent to $279.2 million for the three months ended March 31, 2018 from $190.2 million for the three months ended March 31, 2017.

During the three months ended March 31, 2018, we recorded impairment charges totaling $33.2 million, primarily related to certain unproved Delaware Basin leasehold positions that expired during the three months ended March 31, 2018.

For the three months ended March 31, 2018, we generated a net loss of $13.1 million or $0.20 per diluted share. Our net loss was most negatively impacted by the commodity price risk management loss and the aforementioned Delaware Basin leasehold impairments. During the same period, our adjusted EBITDAX, a non-U.S. GAAP financial measure, was $190.1 million, up 46 percent from the three months ended March 31, 2017. For the three months ended March 31, 2017, our net income per diluted share was $0.70 and our adjusted EBITDAX was $130.2 million. The increase in our adjusted EBITDAX for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017 was primarily due to the increase in crude oil, natural gas, and NGLs sales of $115.5 million. These increases were partially offset by an increase in operating costs of $28.4 million and a decrease in commodity derivative settlements of $26.6 million. Our cash flows from operations were $205.1 million and our adjusted cash flow from operations, a non-U.S. GAAP financial measure, was $174.9 million for the three months ended March 31, 2018. 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.

Liquidity

Available liquidity as of March 31, 2018, was $745.9 million, which was comprised of $45.9 million of cash and cash equivalents and $700 million available for borrowing under our revolving credit facility at our current commitment level. Based on our current production forecast for the remainder of 2018 and assuming averages of approximately $62.00 NYMEX crude oil price for the year and a $2.85 NYMEX natural gas price, less the associated differential, we expect 2018 capital investments to exceed our 2018 cash flows from operations by approximately $65 million. We anticipate that the proceeds received from the sale of our Utica Shale assets and an amendment to a midstream dedication agreement will fund this outspend. We expect this outspend to occur during the first half of 2018, with cash flows exceeding capital investment during the second half of the year. As a result, we expect to be undrawn on our credit facility at December 31, 2018.

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, utilization of our borrowing capacity under our revolving credit facility, and if warranted, capital markets transactions from time to time.

Acquisitions and Divestitures

Bayswater Acquisition. In January 2018, we closed the Bayswater Acquisition for $201.8 million, subject to certain customary post-closing adjustments. See the footnote titled Business Combination to our condensed consolidated financial statements included elsewhere in this report for further details regarding the Bayswater Acquisition.

Utica Shale Divestiture. In March 2018, we completed the Utica Shale Divestiture for net cash proceeds of approximately $39 million, subject to certain customary post-closing adjustments. We do not believe the divestiture of these assets will have a material impact on our results of operations or reserves. See the footnote titled Properties and Equipment to our condensed consolidated financial statements included elsewhere in this report for further details regarding the Utica Shale Divestiture.

Operational Overview

During the three months ended March 31, 2018, we continued to execute our strategic plan to grow production while preserving our financial strength and liquidity. During the three months ended March 31, 2018, we ran three drilling rigs in the Wattenberg Field and briefly ran four drilling rigs in the Delaware Basin while we swapped out a rig to focus on improved drill times before returning to three rigs. We expect to maintain a three rig count in both the Wattenberg Field and the Delaware Basin during the remainder of 2018.

The following tables summarizes our drilling and completion activity for the three months ended March 31, 2018:

	Wells Operated by PDC					
	Wattenberg Field		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
In-process as of December 31, 2017	87	80.1	13	12.2	100	92.3
Wells spud	35	32.7	8	6.8	43	39.5
Acquired DUCs (1)	12	11.0	—	—	12	11.0
Wells turned-in-line	(29)	(26.8)	(7)	(6.5)	(36)	(33.3)
In-process as of March 31, 2018	105	97.0	14	12.5	119	109.5

	Wells Operated by Others					
	Wattenberg Field		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
In-process as of December 31, 2017	14	2.6	8	1.0	22	3.6
Wells spud	22	3.7	3	0.1	25	3.8
Acquired DUCs (operated at March 31, 2018) (1)	(3)	(1.5)	—	—	(3)	(1.5)
Wells turned-in-line	(4)	(0.3)	(2)	(0.7)	(6)	(1.0)
In-process as of March 31, 2018	29	4.5	9	0.4	38	4.9

(1) Represents DUCs that we acquired with the Bayswater Acquisition in January 2018.

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 DUCs are generally completed and turned in-line to sales within three to nine months of drilling.

2018 Operational and Financial Outlook

As previously disclosed, we expect our production for 2018 to range between 38 MMBoe and 42 MMBoe, or approximately 104,000 Boe to 115,000 Boe per day. We currently expect that approximately 42 to 45 percent of our 2018 production will be crude oil and approximately 19 to 22 percent will be NGLs, for total liquids of approximately 61 to 67 percent. Our 2018 capital forecast of between $850 million and $920 million is focused on continued execution in the Wattenberg Field and Delaware Basin with three drilling rigs and one completion crew in each basin throughout the year.

We believe that we maintain significant operational flexibility to control the pace of our capital spending. As we execute our capital investment program, we continually monitor, among other things, commodity prices, development costs, midstream capacity, and offset and continuous drilling obligations. While we have started to experience service cost increases, certain drilling efficiencies are helping to offset these increases. Should commodity pricing or the operating environment deteriorate, we may determine that an adjustment to our development plan is appropriate. We believe we have ample opportunities to reduce capital spending in order to stay within the range of our capital investment plan, including but not limited to reducing the number of rigs being utilized in our drilling program and/or managing our completion schedule. This flexibility is more limited in the Delaware Basin given leasehold maintenance requirements.

Wattenberg Field. We are drilling in the Niobrara and Codell plays within the field and anticipate spudding and turning-in-line approximately 135 to 150 operated wells in 2018. Our 2018 capital investment program is estimated to be approximately $470 million to $500 million in the Wattenberg Field, of which approximately 90 percent is anticipated to be invested in operated drilling and completion activity. The remainder of the Wattenberg Field capital investment program is expected to be used for non-operated wells and miscellaneous workover and capital projects.

Delaware Basin. Total capital investment in the Delaware Basin in 2018 is estimated to be approximately $380 million to $420 million, of which approximately 75 percent is allocated to both spud and turn-in-line approximately 25 to 30 operated wells targeting the Wolfcamp formation. Based on the timing of our operations and requirements to hold acreage, we may adapt our capital investment program to drill wells different from or in addition to those currently anticipated, as we are continuing to analyze the terms of the relevant leases. We plan to invest approximately 10 percent of our capital for leasing, non-operated capital, seismic, and technical studies, with an additional approximately 15 percent for midstream-related projects, including oil and gas gathering systems and water supply and disposal systems. In addition, we are in the process of evaluating our strategic alternatives with respect to our midstream assets in the Delaware Basin.

Financial Guidance.

The following table provides projected financial guidance for the year ended December 31, 2018:

	Low	High
Operating Expenses		
Lease operating expenses ($/Boe)	$2.75	$3.00
Transportation, gathering, and processing expenses ("TGP") ($/Boe)	$0.60	$0.80
Production taxes (% of crude oil, natural gas, and NGLs sales)	6 %	8 %
General and administrative expense ($/Boe)	$3.40	$3.70
Estimated Price Realizations (% of NYMEX, excludes TGP)		
Crude oil	91%	95%
Natural gas	55%	60%
NGLs	30%	35%

Colorado Ballot Initiative Update

As previously disclosed, certain interest groups opposed to oil and natural gas development generally, and hydraulic fracturing in particular, from time to time advance various ballot initiatives in Colorado that, if implemented, would significantly limit or prevent oil and natural gas development in the state. See “Item 1A. Risk Factors - Risks Relating to Our Business and the Industry-Changes in laws and regulations applicable to us could increase our costs, impose additional operating restrictions or have other adverse effects on us” in our Annual Report on Form 10-K for the year ended December 31, 2017. In particular, we are aware of a potential “setback” initiative that would require all new oil and gas development facilities, including wells, to be located at least 2,500 feet away from any occupied structures or other designated areas. Another initiative would increase severance taxes on oil and natural gas production in Colorado. We do not know whether either initiative will meet the signature requirements to be included on the November ballot.

Results of Operations

Summary Operating Results

The following table presents selected information regarding our operating results:

	Three Months Ended March 31,		
	2018	2017	Percentage Change
	(dollars in millions, except per unit data)		
Production			
Crude oil (MBbls)	3,798	2,508	51.4 %
Natural gas (MMcf)	19,587	15,584	25.7 %
NGLs (MBbls)	1,846	1,543	19.6 %
Crude oil equivalent (MBoe)	8,908	6,648	34.0 %
Average Boe per day (Boe)	98,980	73,866	20.1 %
Crude Oil, Natural Gas and NGLs Sales			
Crude oil	$226.4	$123.0	84.1 %
Natural gas	38.6	36.9	4.6 %
NGLs	40.2	29.8	34.9 %
Total crude oil, natural gas, and NGLs sales	$305.2	$189.7	60.9 %
Net Settlements on Commodity Derivatives			
Crude oil	$(27.0)	$(3.2)	*
Natural gas	2.7	3.7	(27.0)%
NGLs (propane portion)	(1.7)	—	*
Total net settlements on derivatives	$(26.0)	$0.5	*
Average Sales Price (excluding net settlements on derivatives)			
Crude oil (per Bbl)	$59.62	$49.04	21.6 %
Natural gas (per Mcf)	1.97	2.37	(16.9)%
NGLs (per Bbl)	21.80	19.29	13.0 %
Crude oil equivalent (per Boe)	34.26	28.53	20.1 %
Average Costs and Expenses (per Boe)			
Lease operating expenses	$3.33	$2.98	11.7 %
Production taxes	2.26	1.87	20.9 %
Transportation, gathering, and processing expenses	0.82	0.89	(7.9)%
General and administrative expense	4.01	3.96	1.3 %
Depreciation, depletion, and amortization	14.23	16.44	(13.4)%
Lease Operating Expenses by Operating Region (per Boe)			
Wattenberg Field	$3.02	$2.66	13.5 %
Delaware Basin	4.44	6.48	(31.5)%
Utica Shale (1)	3.46	1.60	116.3 %

* Percentage change is not meaningful.

Amounts may not recalculate due to rounding.

(1) In March 2018, we completed the sale of our Utica Shale properties.

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Crude Oil, Natural Gas, and NGLs Sales

For the three months ended March 31, 2018, crude oil, natural gas, and NGLs sales revenue increased compared to the three months ended March 31, 2017 due to the following (in millions):

	Three Months Ended March 31, 2018 (in millions)
Increase in production	$ 78.6
Increase in average crude oil price	40.2
Decrease in average natural gas price	(7.9)
Increase in average NGLs price	4.6
Total increase in crude oil, natural gas and NGLs sales revenue	$ 115.5

Crude Oil, Natural Gas, and NGLs Production

The following table presents crude oil, natural gas, and NGLs production.

Production by Operating Region	Three Months Ended March 31, 2018	2017	Percentage Change
Crude oil (MBbls)			
Wattenberg Field	2,881	2,142	34.5 %
Delaware Basin	871	275	*
Utica Shale (1)	46	91	(49.5)%
Total	3,798	2,508	51.4 %
Natural gas (MMcf)			
Wattenberg Field	15,524	13,714	13.2 %
Delaware Basin	3,649	1,246	*
Utica Shale (1)	414	624	(33.7)%
Total	19,587	15,584	25.7 %
NGLs (MBbls)			
Wattenberg Field	1,428	1,358	5.2 %
Delaware Basin	383	131	*
Utica Shale (1)	35	54	(35.2)%
Total	1,846	1,543	19.6 %
Crude oil equivalent (MBoe)			
Wattenberg Field	6,896	5,786	19.2 %
Delaware Basin	1,862	613	*
Utica Shale (1)	150	249	(39.8)%
Total	8,908	6,648	34.0 %
Average crude oil equivalent per day (Boe)			
Wattenberg Field	76,623	64,288	19.2 %
Delaware Basin	20,690	6,811	*

Utica Shale (1)	1,667	2,767	(39.8)%
Total	98,980	73,866	34.0 %

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

(1) In March 2018, we completed the sale of our Utica Shale properties.

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The following table presents our crude oil, natural gas, and NGLs production ratio by operating region:
Three Months Ended March 31, 2018

	Crude Oil	Natural Gas	NGLs	Total
Wattenberg Field	42%	37%	21%	100%
Delaware Basin	47%	32%	21%	100%

Three Months Ended March 31, 2017

	Crude Oil	Natural Gas	NGLs	Total
Wattenberg Field	37%	40%	23%	100%
Delaware Basin	45%	34%	21%	100%

Wattenberg Field. 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. During the three months ended March 31, 2018, our production was adversely impacted by high line pressures on gas gathering facilities, primarily due to increases in field-wide production volumes, gathering line freezes that occur more often at higher line pressures, and unexpected facility downtime. Line pressures did not materially affect our production during the three months ended March 31, 2017. During the three months ended March 31, 2018 and 2017, 97 percent and 91 percent, respectively, of our production in the Wattenberg Field was delivered from horizontal wells, with the remaining production coming from vertical wells. The horizontal wells are less prone to curtailments than the vertical wells because they are newer and have greater producing capacity and higher formation pressures and therefore tend to be more resilient to gas system pressure issues; however, all of our wells in the field are currently experiencing some impact. We expect to continue to operate in a constrained environment into the third quarter of 2018, at which time additional processing capacity is scheduled to be brought into operation by DCP Midstream, LP ("DCP").

We continue to work closely with our third-party midstream providers in an effort to ensure that adequate midstream system capacity is available going forward in the Wattenberg Field. We, along with other operators, have made a commitment with DCP to support its construction of two additional processing facilities with associated gathering and compression in the field. These expansions are 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 these agreements for a period of seven years beginning on the first day of the calendar month after the actual in-service dates of the plants, which are currently scheduled to occur in the third quarter of 2018 and in the second quarter of 2019, respectively. The agreements impose a baseline volume commitment and guarantee a certain target profit margin to DCP on those volumes during the initial three years of the contracts. Under our current drilling plans and in the current commodity pricing environment, we expect to meet both the baseline and incremental volume commitments, and we believe that the contractual target profit margin will be achieved without additional payment from us. See the footnote titled Commitments and Contingencies to our condensed consolidated financial statements included elsewhere in this report for additional details regarding the agreements. In addition, we have begun early discussions with DCP with respect to further increasing its processing facilities in the Wattenberg Field. We also continue to work with our other midstream service providers in the field in an effort to ensure all of the existing infrastructure is fully utilized and that all options for system expansions are evaluated and implemented, where possible. The ultimate timing and availability of adequate infrastructure is not within our control and if our midstream service providers' construction projects are delayed, we could experience higher gathering line pressures that would negatively impact our ability to meet our production targets.

Delaware Basin. Due to prolific development and the resulting increased production in the Delaware Basin, product takeaway infrastructure downstream of in-field gathering and processing is nearing capacity. We are dependent upon third parties to construct additional facilities. This has the potential to lead to near term production constraints until new capacity is added, which we expect to occur in the second half of 2019. As a result, our production may be negatively impacted from time to time. We have the option to transport a portion of our crude oil production via truck or rail; however, doing so would decrease the realized prices we receive. A current trucking shortage in the basin could result in increased differentials. In May 2018, we executed a firm sales agreement for a significant portion of our Delaware Basin crude oil production with the marketing division of a large international energy company. The agreement is effective June 1, 2018 and runs through December 31, 2023 and provides for firm physical takeaway for approximately 85 percent of our forecasted 2018 and 2019 Delaware Basin crude oil volumes. The agreement is expected to provide us with price diversification through realization of export market pricing via a Corpus Christi terminal and exposure to Brent-weighted prices. Taking the effect of this agreement into account, we currently expect to realize between 88 and 92 percent of NYMEX pricing for our Delaware Basin production through 2018 and 2019, after including transportation, gathering, and processing expenses.

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PDC ENERGY, INC.

Crude Oil, Natural Gas, and NGLs Pricing

Our results of operations depend upon many factors. Key factors include the price of crude oil, natural gas, and NGLs and our ability to market our production effectively. Crude oil, natural gas, and NGLs prices have a high degree of volatility and our realizations can change substantially. Our sales prices for crude oil and NGLs increased during the three months ended March 31, 2018 compared to the three months ended March 31, 2017. NYMEX average daily crude oil prices increased 21 percent and NYMEX first-of-the-month natural gas prices decreased 12 percent as compared to the three months ended March 31, 2017.

The following tables present weighted-average sales prices of crude oil, natural gas, and NGLs for the periods presented.

	Three Months Ended March 31,		
Weighted-Average Realized Sales Price by Operating Region (excluding net settlements on derivatives)	2018	2017	Percentage Change
Crude oil (per Bbl)			
Wattenberg Field	$59.13	$49.12	20.4 %
Delaware Basin	61.34	49.28	24.5 %
Utica Shale (1)	58.10	46.55	24.8 %
Weighted-average price	59.62	49.04	21.6 %
Natural gas (per Mcf)			
Wattenberg Field	$1.92	$2.38	(19.3)%
Delaware Basin	2.10	1.98	6.1 %
Utica Shale (1)	2.68	2.98	(10.1)%
Weighted-average price	1.97	2.37	(16.9)%
NGLs (per Bbl)			
Wattenberg Field	$20.14	$18.64	8.0 %
Delaware Basin	27.76	22.58	22.9 %
Utica Shale (1)	24.29	27.75	(12.5)%
Weighted-average price	21.80	19.29	13.0 %
Crude oil equivalent (per Boe)			
Wattenberg Field	$33.18	$28.19	17.7 %
Delaware Basin	38.52	30.93	24.5 %
Utica Shale (1)	30.98	30.55	1.4 %
Weighted-average price	34.26	28.53	20.1 %

Amounts may not recalculate due to rounding.

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(1) In March 2018, we completed the sale of our Utica Shale properties.

Crude oil, natural gas, and NGLs revenues are recognized when we have transferred control of crude oil, natural gas, or NGLs production to the purchaser. We consider the transfer of control to have occurred when the purchaser has the ability to direct the use of, and obtain substantially all of the remaining benefits, from the crude oil, natural gas, or NGLs production. We record sales revenue based on an estimate of the volumes delivered at estimated prices as determined by the applicable sales agreement. We estimate our sales volumes based on company-measured volume readings. We then adjust our crude oil, natural gas, and NGLs sales in subsequent periods based on the data received from our purchasers that reflects actual volumes and prices received.

Our crude oil, natural gas, and NGLs sales are recorded using either the “net-back” or "gross" method of accounting, depending upon the related purchase agreement. We use the net-back method when control of the crude oil, natural gas, or NGLs has been transferred to the purchasers of these commodities that are providing transportation, gathering, or 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. 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 are paid.

We use the gross method of accounting when control of the crude oil, natural gas, or NGLs is not transferred to the purchasers and the purchaser does not provide transportation, gathering, or processing services as a function of the price we receive. Rather, we contract separately with midstream providers for the applicable transport and processing on a per unit basis. Under this method, we recognize revenues based on the gross selling price and recognize transportation, gathering, and processing expenses.

We adopted a new revenue recognition accounting standard effective January 1, 2018. Under the guidance of the new revenue recognition standard, certain crude oil sales in the Wattenberg Field that were recognized using the gross method prior to the adoption of the new revenue standard will be recognized using the net-back method. In the Delaware Basin, certain crude oil and natural gas sales that were recognized using the gross method prior to the adoption of the new revenue standard will be recognized using the net-back method. If we had adopted the standard on January 1, 2017, we estimate that the average realization percentage before transportation, gathering, and processing expenses for the three months ended March 31, 2017 would have been 93 percent, 71 percent, and 37 percent for crude oil, natural gas, and NGLs, respectively, as $2.5 million in expenses currently recorded in transportation, gathering, and processing expense on our condensed consolidated statements of operations for that period would, in that case, have been reflected as a reduction to the sales price. However, the net realized price would remain unchanged.

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 both before and after transportation, gathering, and processing expenses shown in the table below represents our approximate composite per barrel price for NGLs.

For the three months ended March 31, 2018	Average NYMEX Price	Average Realized Price Before Transportation, Gathering and Processing Expenses	Average Realization Percentage Before Transportation, Gathering and Processing Expenses	Average Transportation, Gathering and Processing Expenses	Average Realized Price After Transportation, Gathering and Processing Expenses	Average Realization Percentage After Transportation, Gathering, and Processing Expenses
Crude oil (per Bbl)	$ 62.87	$ 59.62	95 %	$ 0.67	$ 58.95	94 %
Natural gas (per MMBtu)	3.00	1.97	66 %	0.22	1.75	58 %
NGLs (per Bbl)	62.87	21.80	35 %	0.24	21.56	34 %
Crude oil equivalent (per Boe)	46.43	34.26	74 %	0.82	33.44	72 %

For the three months ended March 31, 2017	Average NYMEX Price	Average Realized Price Before Transportation, Gathering and	Average Realization Percentage Before Transportation, Gathering	Average Transportation, Gathering and Processing Expenses	Average Realized Price After Transportation, Gathering and	Average Realization Percentage After Transportation, Gathering,

		Processing Expenses	and Processing Expenses			Processing Expenses	and Processing Expenses	
Crude oil (per Bbl)	$ 51.92	$ 49.04	94	%	$ 1.58	$ 47.46	91	%
Natural gas (per MMBtu)	3.32	2.37	71	%	0.06	2.31	70	%
NGLs (per Bbl)	51.92	19.29	37	%	0.22	19.07	37	%
Crude oil equivalent (per Boe)	39.42	28.53	72	%	0.89	27.64	70	%

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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. For our commodity swaps, we ultimately realize the fixed price value related to the swaps. See the footnote titled Commodity Derivative Financial Instruments to our condensed consolidated financial statements included elsewhere in this report for a detailed presentation of our derivative positions as of March 31, 2018.

Commodity price risk management, net, includes cash settlements upon maturity of our derivative instruments, as well as 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 March 31,	
	2018	2017
	(in millions)	
Commodity price risk management gain (loss), net:		
Net settlements of commodity derivative instruments:		
Crude oil fixed price swaps and collars	$(26.8)	$(3.2)
Crude oil basis protection swaps	(0.2)	—
Natural gas fixed price swaps and collars	0.1	3.6
Natural gas basis protection swaps	2.6	0.1
NGLs (propane portion) fixed price swaps	(1.7)	—
Total net settlements of commodity derivative instruments	(26.0)	0.5
Change in fair value of unsettled commodity derivative instruments:		
Reclassification of settlements included in prior period changes in fair value of commodity derivative instruments	20.3	9.1
Crude oil fixed price swaps, collars, and rollfactors	(52.6)	56.2
Natural gas fixed price swaps and collars	(0.8)	11.2
Natural gas basis protection swaps	10.6	3.3
NGLs (propane portion) fixed price swaps	1.3	0.4
Net change in fair value of unsettled commodity derivative instruments	(21.2)	80.2

Total commodity price risk management gain (loss), net	$(47.2)	$80.7

Net settlements of commodity derivatives decreased for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017.

Lease Operating Expenses

Lease operating expenses were $29.6 million in the three months ended March 31, 2018 compared to $19.8 million in the three months ended March 31, 2017. Aggregate lease operating expenses during the three months ended March 31, 2018 increased $9.8 million due to increases of $1.9 million for payroll and employee benefits related to increases in headcount, $1.7

million related to midstream expense in the Delaware Basin, $1.1 million related to additional compressor rentals, $0.9 million for environmental remediation expenses, $0.8 million related to chemical treatment programs, $0.6 million for expenses related to non-operated wells, $0.6 million related to oil inventory valuation, $0.5 million for produced water disposal, and $0.3 million for increased workover projects. Lease operating expense per Boe increased by 12 percent to $3.33 for the three months ended March 31, 2018 from $2.98 for the three months ended March 31, 2017.

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. From time to time, there are 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 $7.8 million increase in production taxes during the three months ended March 31, 2018 compared to the three months ended March 31, 2017 were primarily related to the 61 percent increase in crude oil, natural gas, and NGLs sales.

Transportation, Gathering, and Processing Expenses

Transportation, gathering, and processing expenses increased $1.4 million during the three months ended March 31, 2018 compared to the three months ended March 31, 2017. The increase was mainly attributable to a $1.3 million increase in oil transportation costs due to additional volumes delivered through pipelines in the Wattenberg Field and an increase of $2.8 million related to natural gas gathering and transportation operations in the Delaware Basin, partially offset by a $2.8 million decrease resulting from the adoption of the new revenue standard on January 1, 2018 whereby we record certain portions of our current transportation, gathering, and processing expense as a reduction to the sales price. Transportation, gathering, and processing expenses per Boe decreased to $0.82 for the three months ended March 31, 2018 compared to $0.89 for the three months ended March 31, 2017. As discussed in Crude Oil, Natural Gas, and NGLs Pricing, whether transportation, gathering, and processing costs are presented separately or are reflected as a reduction to net revenue is a function of the terms of the relevant marketing contract.

Exploration, Geologic, and Geophysical Expense

Exploration, geological and geophysical expense increased $1.7 million to $2.7 million during the three months ended March 31, 2018 compared to $1.0 million for the three months ended March 31, 2017. The increase in the three months ended March 31, 2018 was primarily related to the purchase of seismic data related to unproved acreage and lease costs associated with certain delayed drilling in the Delaware Basin, which was partially offset by a decrease in costs related to drilling pilot holes in the Delaware Basin during the three months ended March 31, 2017.

Impairment of Properties and Equipment

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

	Three Months Ended March 31,	
	2018	2017
	(in millions)	

Impairment of proved and unproved properties	$33.1	$2.1
Amortization of individually insignificant unproved properties	0.1	0.1
Impairment of crude oil and natural gas properties	$33.2	$2.2

During the three months ended March 31, 2018, we recorded impairment charges primarily related to certain unproved Delaware Basin leasehold positions that expired during the three months ended March 31, 2018.

General and Administrative Expense

General and administrative expense increased $9.4 million for the three months ended March 31, 2018, as compared to the three months ended March 31, 2017. The increase of $9.4 million was primarily attributable to a $6.1 million increase in payroll and employee benefits and a $2.1 million increase related to professional services.

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 $124.8 million for the three months ended March 31, 2018 compared to $107.8 million for the three months ended March 31, 2017.

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

	Three Months Ended March 31, 2018
	(in thousands)
Increase in production	$ 32,005
Decrease in weighted-average depreciation, depletion, and amortization rates	(15,035)
Total increase in DD&A expense related to crude oil and natural gas properties	$ 16,970

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

Operating Region/Area	Three Months Ended March 31, 2018	2017
	(per Boe)	
Wattenberg Field	$ 13.53	$ 16.94
Delaware Basin	16.91	11.46
Utica Shale (1)	—	11.24
Total weighted-average	$ 14.01	$ 16.22

(1) The Utica Shale properties were classified as held-for-sale during the third quarter of 2017; therefore, we did not record DD&A expense on these properties for the three months ended March 31, 2018.

Non-crude oil and natural gas properties. Depreciation expense for non-crude oil and natural gas properties was $2.0 million for the three months ended March 31, 2018 compared to $1.5 million for the three months ended March 31, 2017.

Interest Expense

Interest expense decreased $2.0 million to $17.5 million for the three months ended March 31, 2018 compared to $19.5 million for the three months ended March 31, 2017. The decrease was primarily related to a $10.0 million decrease in interest expense relating to the net settlement of $500 million 7.75% senior notes in December 2017 and a $0.9 million increase in capitalized interest. The decreases were partially offset by an $8.8 million increase in interest expense related to the issuance of our 2026 Senior Notes in November 2017.

Provision for Income Taxes

The effective income tax rate for the three months ended March 31, 2018 was a 25.8 percent benefit on loss compared to a 36.3 percent expense on income for the three months ended March 31, 2017. The effective income tax rates are based upon a full year forecasted pre-tax income for the year adjusted for permanent differences. The federal corporate statutory income tax rate decreased from 35 percent in 2017 to 21 percent in 2018 resulting from the 2017 Tax Act. The forecasted full year effective income tax rate has been applied to the quarter-to-date pre-tax loss, resulting in an income tax benefit 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 rate for the three months ended March 31, 2018 includes discrete income tax benefits of $0.2 million related to the excess tax benefit recognized with the vesting of stock awards, which resulted in a 1.2 percent increase to our effective tax rate. The excess tax benefit recognized with the vesting of stock awards was the only discrete tax item reported for the three months ended March 31, 2017 and resulted in a 2.2 percent reduction to our effective tax rate.

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

The factors resulting in changes in net loss in the three months ended March 31, 2018 of $13.1 million and net income in the three months ended March 31, 2017 of $46.1 million are discussed above. Adjusted net income, a non-U.S. GAAP financial measure, was $3.0 million for the three months ended March 31, 2018 and adjusted net loss, a non-U.S. GAAP financial measure, was $4.1 million for the three months ended March 31, 2017. With the exception of the tax affected net change in fair value of unsettled derivatives of $16.1 million for the three months ended March 31, 2018 and $50.2 million for the three months ended March 31, 2017, these same factors impacted adjusted net income (loss), a non-U.S. GAAP financial measure. 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.

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 three months ended March 31, 2018, our net cash flows from operating activities were $205.1 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 a portion of 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 facility 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 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 March 31, 2018, our derivatives are expected to be a source of net cash outflow 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. We had working capital deficits of $223.7 million and $16.4 million at March 31, 2018 and December 31, 2017, respectively. The increase in working capital deficit as of March 31, 2018 of $207.3 million is primarily the result of a decrease in cash and cash equivalents of $134.8 million related to the Bayswater Acquisition which was partially offset by the proceeds received from the Utica Divestiture and an amendment to a midstream dedication agreement, an increase in accounts payable of $45.6 million related to increased development and exploration activity, a decrease in the net fair value of our unsettled commodity derivative instruments of $17.1 million, and a decrease in accounts receivable of $16.6 million.

Our cash and cash equivalents were $45.9 million at March 31, 2018 and availability under our revolving credit facility was $700.0 million, providing for a total liquidity position of $745.9 million as of March 31, 2018. Based on the pricing assumptions described in Executive Summary - Liquidity, we expect our 2018 capital investments to exceed our 2018 cash flows from operations by approximately $65 million. We anticipate that the proceeds received from the Utica Shale Divestiture and an amendment to a midstream dedication agreement will fund this outspend. We expect this capital investment outspend to occur during the first half of 2018, with cash flows exceeding capital investment during the second half of the year. As a result, we expect to be undrawn on our credit facility at December 31, 2018.

Based on our expected cash flows from operations, our cash and cash equivalents, and availability under our revolving credit facility, we believe that we will have sufficient capital available to fund our planned activities through the 12-month period following the filing of this report.

Our revolving credit facility is a borrowing base facility and availability under the facility is subject to redetermination, generally each May and November, based upon a quantification of our proved reserves at each December 31 and June 30, respectively. The maturity date of our revolving credit facility is May 2020.

In May and October 2017, we entered into the Fifth and Sixth Amendments, respectively, to the Third Amended and Restated Credit Agreement to amend the revolving credit facility to reflect increases in the borrowing base. The Fifth Amendment reflected an increase of the borrowing base from $700 million to $950 million and the Sixth Amendment amended the revolving credit facility to allow the borrowing base to increase above the borrowing capacity of $1.0 billion. In addition, the Fifth Amendment made changes to certain of the covenants in the existing agreement as well as other administrative changes. We elected to increase the borrowing base to $1.1 billion for our November 2017 borrowing base redetermination and have elected to maintain a $700 million commitment level as of the date of this report.

In April 2018, we began negotiations with our bank group to enter into the Fourth Amended and Restated Credit Agreement, and we anticipate closing to occur by the end of May 2018. This agreement is expected to replace the Third Amended and Restated Credit Agreement. Following the amendment and restatement, the facility is expected to mature in May 2023.

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 March 31, 2018, 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 0.5 percent.

We had no balance outstanding on our revolving credit facility as of March 31, 2018. 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 cash deposit, which is classified as restricted cash and is included in other assets on the condensed consolidated balance sheet. As of March 31, 2018 and December 31, 2017, we had $8.0 million and $9.3 million in restricted cash, respectively. As of March 31, 2018, the available funds under our revolving credit facility were $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 March 31, 2018, we were in compliance with all debt covenants with a leverage ratio of 1.7 and a current ratio of 2.5. We expect to remain in compliance throughout the 12-month period following the filing of this report.

The indentures governing our 2024 Senior Notes and 2026 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 March 31, 2018, 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 and the 2024 Senior Notes, our subsidiary PDC Permian, Inc. became a guarantor of the notes. PDC Permian, Inc. is also the guarantor of our 2026 Senior Notes issued in November 2017.

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 $65.6 million to $205.1 million for the three months ended March 31, 2018 compared to the three months ended March 31, 2017, primarily due to increases in crude oil, natural gas and NGLs sales of $115.5 million. This increase was offset in part by a decrease in commodity derivative settlements of $26.6 million and increases in lease operating expenses of $9.8 million, general and administrative expenses of $9.4 million, and production taxes of $7.8 million.

Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased by $61.2 million to $174.9 million during the three months ended March 31, 2018 compared to the three months ended March 31, 2017. 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 $59.9 million during the three months ended March 31, 2018, compared to the three months ended March 31, 2017. The increase was primarily the result of an increase in crude oil, natural gas and NGLs sales of $115.5 million. This increase was partially offset by a decrease in commodity derivative settlements of $26.6 million and increases in lease operating expenses of $9.8 million, general and administrative expenses of $9.4 million, and production taxes of $7.8 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 $338.5 million during the three months ended March 31, 2018 was primarily related to cash utilized toward the purchase price of the Bayswater Acquisition of $180.8 million and our drilling and completion activities of $196.9 million. Partially offsetting these investments was the receipt of approximately $39.0 million related to Utica Shale Divestiture.

Financing Activities. Net cash used in financing activities of $2.6 million during the three months ended March 31, 2018 was primarily related to purchases of our treasury stock.

Off-Balance Sheet Arrangements

At March 31, 2018, 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.

Recent Accounting Standards

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

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 2017 Form 10-K filed with the SEC on

February 27, 2018 and amended on May 1, 2018.

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. 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.

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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 March 31,	
	2018	2017
	(in millions)	
Adjusted cash flows from operations:		
Net cash from operating activities	$205.1	$139.5
Changes in assets and liabilities	(30.2)	(25.8)
Adjusted cash flows from operations	$174.9	$113.7
Adjusted net income (loss):		
Net income (loss)	$(13.1)	$46.1
(Gain) loss on commodity derivative instruments	47.2	(80.7)
Net settlements on commodity derivative instruments	(26.0)	0.5
Tax effect of above adjustments	(5.1)	30.0
Adjusted net income (loss)	$3.0	$(4.1)
Net income (loss) to adjusted EBITDAX:		
Net income (loss)	$(13.1)	$46.1
(Gain) loss on commodity derivative instruments	47.2	(80.7)
Net settlements on commodity derivative instruments	(26.0)	0.5
Non-cash stock-based compensation	5.3	4.5
Interest expense, net	17.4	19.2
Income tax expense (benefit)	(4.6)	26.3
Impairment of properties and equipment	33.2	2.2
Exploration, geologic, and geophysical expense	2.6	1.0
Depreciation, depletion, and amortization	126.8	109.3
Accretion of asset retirement obligations	1.3	1.8
Adjusted EBITDAX	$190.1	$130.2
Cash from operating activities to adjusted EBITDAX:		
Net cash from operating activities	$205.1	$139.5
Interest expense, net	17.4	19.2
Amortization of debt discount and issuance costs	(3.2)	(3.2)
Gain (loss) on sale of properties and equipment	(1.4)	0.2
Exploration, geologic, and geophysical expense	2.6	1.0
Other	(0.2)	(0.7)
Changes in assets and liabilities	(30.2)	(25.8)
Adjusted EBITDAX	$190.1	$130.2

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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 2026 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 March 31, 2018, our interest-bearing deposit accounts included money market accounts and checking accounts with various banks. The amount of our interest-bearing cash, cash equivalents, and restricted cash as of March 31, 2018 was $12.8 million with a weighted-average interest rate of 1.4 percent. Based on a sensitivity analysis of our interest-bearing deposits as of March 31, 2018 and assuming we had $12.8 million outstanding throughout the period, we estimate that a one percent increase in interest rates would have increased interest income for the three months ended March 31, 2018 by approximately $0.1 million.

As of March 31, 2018, 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, 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. See the footnote titled Commodity Derivative Financial Instruments to our condensed consolidated financial statements included elsewhere in this report for a description of our open commodity derivative positions at March 31, 2018.

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 March 31, 2018	Year Ended December 31, 2017
Average NYMEX Index Price:		
Crude oil (per Bbl)	$ 62.87	$ 50.95
Natural gas (per MMBtu)	3.00	3.11
Average Sales Price Realized:		

Excluding net settlements on commodity derivatives		
Crude oil (per Bbl)	$ 59.62	$ 48.45
Natural gas (per Mcf)	1.97	2.21
NGLs (per Bbl)	21.80	18.59

Based on a sensitivity analysis as of March 31, 2018, 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 $113.0 million, whereas a ten percent decrease in prices would have resulted in an increase in fair value of $111.6 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 March 31, 2018, 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 March 31, 2018, we carried out an evaluation under the supervision and with the participation of management, including the Chief Executive Officer and the Chief 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 Chief Financial Officer concluded that our disclosure controls and procedures were not effective as of March 31, 2018 because of the material weaknesses in our internal control over financial reporting described below.

Management is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Internal control over financial reporting is a process designed by, or under the supervision of, our Chief Executive Officer and Chief Financial Officer, or persons performing similar functions, and effected by our board of directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

During 2017, we did not maintain a sufficient complement of personnel within the Land Department as a result of increased volume of leases, which contributed to the ineffective design and maintenance of controls to verify the completeness and accuracy of land administrative records associated with unproved leases, which are used in verifying the completeness, accuracy, valuation, rights and obligations over the accounting of properties and equipment, sales and accounts receivable, and costs and expenses. These control deficiencies resulted in immaterial adjustments of our unproved properties, impairment of unproved properties, sales, accounts receivable, and depletion expense accounts and related disclosures during 2017.

Additionally, these control deficiencies could result in misstatements of substantially all accounts and disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, our management has determined that these control deficiencies constitute material weaknesses.

Remediation Plan for Material Weaknesses

In response to the identified material weaknesses, our management, with the oversight of the Audit Committee of our Board of Directors, has begun the process of assessing a number of different remediation initiatives to improve our internal control over financial reporting for the year ended December 31, 2018. We are currently in the process of evaluating the material weaknesses and are developing a plan of remediation to strengthen our overall controls over the sufficient complement of personnel within the Land Department and the completeness and accuracy of land administration records. We are committed to continuing to improve our internal control processes and will continue to review, optimize, and enhance our internal control environment. These material weaknesses will not be considered remediated until the applicable remedial controls operate for a sufficient period of time and management has concluded, through testing, that these controls are operating effectively.

Changes in Internal Control over Financial Reporting

During the three months ended March 31, 2018, 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

Information regarding our legal proceedings can found in the footnote titled Commitments and Contingencies - Litigation and Legal Items to our condensed consolidated financial statements included elsewhere in this report.

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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 2017 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 2017 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
January 1 - 31, 2018	34,846	$ 55.37
February 1 - 28, 2018	6,511	50.04
March 1 - 31, 2018	—	—
Total first quarter 2018 purchases	41,357	$ 54.53

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(1) Purchases 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.

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ITEM 6. EXHIBITS

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
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.					
99.1	Form of 2018 Performance Share Agreement.					X
99.2	Form of 2018 Restricted Stock Unit Agreement (Executives).					X
99.3	Form of 2018 Restricted Stock Unit Agreement (Directors).					X
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.

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PDC ENERGY, INC.

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: May 2, 2018 /s/ Barton R. Brookman
Barton R. Brookman
President and Chief Executive Officer
(principal executive officer)

/s/ R. Scott Meyers
R. Scott Meyers
Senior Vice President and Chief Financial Officer
(principal financial officer)