[Table of contents](#)

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

FORM 10-Q

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

For the quarterly period ended June 30, 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 ☒ No ☐

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 ☒ No ☐

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 ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐
	Emerging growth company ☐

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. ☐

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 66,073,231 shares of the Company's Common Stock ($0.01 par value) were outstanding as of July 20, 2018.

PDC ENERGY, INC.

TABLE OF CONTENTS

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act"), Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") and the United States ("U.S.") Private Securities Litigation Reform Act of 1995 regarding our business, financial condition, results of operations and prospects. All statements other than statements of historical fact included in and incorporated by reference into this report are "forward-looking statements." Words such as 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; management of lease expiration issues; financial ratios and compliance with covenants in our revolving credit facility; impacts of certain accounting and tax changes; midstream capacity and related curtailments; impacts of a potential ballot initiative and other Colorado political matters; ability to meet our volume commitments to midstream providers; ongoing compliance with our consent decree; timing and likelihood that the Denver Metro/North Front Range NAA ozone classification will be reclassified to serious; and 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 costs and 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 and procurement costs associated with future build out of midstream-related assets;
- future cash flows, liquidity and financial condition;
- competition within the oil and gas industry;
- availability and cost of capital;
- our success in marketing crude oil, natural gas and NGLs;
- effect of crude oil and natural gas derivatives activities;

- impact of environmental events, governmental and other third-party responses to such events and our ability to insure adequately against such events;
- 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 filed with the U.S. Securities and Exchange Commission ("SEC") on February 27, 2018 and as amended on May 1, 2018 (the "2017 Form 10-K"), 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.

PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	June 30, 2018	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$ 1,425	$ 180,675
Accounts receivable, net	195,317	197,598
Fair value of derivatives	14,817	14,338
Prepaid expenses and other current assets	6,744	8,613
Total current assets	218,303	401,224
Properties and equipment, net	4,192,608	3,933,467
Assets held-for-sale, net	—	40,084
Other assets	31,243	45,116
Total Assets	$ 4,442,154	$ 4,419,891
Liabilities and Stockholders' Equity		
Liabilities		
Current liabilities:		
Accounts payable	$ 215,150	$ 150,067
Production tax liability	56,766	37,654
Fair value of derivatives	186,605	79,302
Funds held for distribution	102,354	95,811
Accrued interest payable	12,561	11,815
Other accrued expenses	35,888	42,987
Total current liabilities	609,324	417,636
Long-term debt	1,179,117	1,151,932
Deferred income taxes	141,811	191,992
Asset retirement obligations	73,549	71,006
Fair value of derivatives	36,430	22,343
Other liabilities	61,617	57,333
Total liabilities	2,101,848	1,912,242
Commitments and contingent liabilities		
Stockholders' equity		
Common shares - par value $0.01 per share, 150,000,000 authorized, 66,133,025 and 65,955,080 issued as of June 30, 2018 and December 31, 2017, respectively	661	659
Additional paid-in capital	2,509,693	2,503,294
Retained earnings (deficit)	(166,692)	6,704
Treasury shares - at cost, 67,169 and 55,927 as of June 30, 2018 and December 31, 2017, respectively	(3,356)	(3,008)
Total stockholders' equity	2,340,306	2,507,649
Total Liabilities and Stockholders' Equity	$ 4,442,154	$ 4,419,891

See accompanying Notes to Condensed Consolidated Financial Statements

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenues				
Crude oil, natural gas and NGLs sales	$ 325,933	$ 213,602	$ 631,158	$ 403,294
Commodity price risk management gain (loss), net	(116,126)	57,932	(163,366)	138,636
Other income	2,724	3,624	5,339	6,935
Total revenues	212,531	275,158	473,131	548,865
Costs, expenses and other				
Lease operating expenses	32,260	20,028	61,896	39,817
Production taxes	22,604	15,042	42,773	27,441
Transportation, gathering and processing expenses	8,964	6,488	16,277	12,390
Exploration, geologic and geophysical expense	875	1,033	3,521	1,987
Impairment of properties and equipment	159,554	27,566	192,742	29,759
General and administrative expense	37,247	29,531	72,943	55,846
Depreciation, depletion and amortization	135,624	126,013	262,412	235,329
Accretion of asset retirement obligations	1,285	1,666	2,573	3,434
(Gain) loss on sale of properties and equipment	(351)	(532)	1,081	(692)
Provision for uncollectible note receivable	—	(40,203)	—	(40,203)
Other expenses	2,708	3,890	5,476	7,418
Total costs, expenses and other	400,770	190,522	661,694	372,526
Income (loss) from operations	(188,239)	84,636	(188,563)	176,339
Interest expense	(17,410)	(19,617)	(34,939)	(39,084)
Interest income	69	768	217	1,008
Income (loss) before income taxes	(205,580)	65,787	(223,285)	138,263
Income tax (expense) benefit	45,323	(24,537)	49,889	(50,867)
Net income (loss)	$ (160,257)	$ 41,250	$ (173,396)	$ 87,396
Earnings per share:				
Basic	$ (2.43)	$ 0.63	$ (2.63)	$ 1.33
Diluted	$ (2.43)	$ 0.62	$ (2.63)	$ 1.32
Weighted-average common shares outstanding:				
Basic	66,066	65,859	66,012	65,804
Diluted	66,066	66,019	66,012	66,066

See accompanying Notes to Condensed Consolidated Financial Statements

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

	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Cash flows from operating activities:		
Net income (loss)	$ (173,396)	$ 87,396
Adjustments to net income (loss) to reconcile to net cash from operating activities:		
Net change in fair value of unsettled commodity derivatives	120,920	(126,070)
Depreciation, depletion and amortization	262,412	235,329
Impairment of properties and equipment	192,742	29,759
Provision for uncollectible notes receivable	—	(40,203)
Accretion of asset retirement obligations	2,573	3,434
Non-cash stock-based compensation	10,779	9,826
(Gain) loss on sale of properties and equipment	1,081	(692)
Amortization of debt discount and issuance costs	6,372	6,399
Deferred income taxes	(50,181)	50,767
Other	974	670
Changes in assets and liabilities	6,581	15,832
Net cash from operating activities	380,857	272,447
Cash flows from investing activities:		
Capital expenditures for development of crude oil and natural gas properties	(432,635)	(334,406)
Capital expenditures for other properties and equipment	(2,450)	(2,299)
Acquisition of crude oil and natural gas properties, including settlement adjustments	(181,052)	5,372
Proceeds from sale of properties and equipment	1,782	1,293
Proceeds from divestiture	39,023	—
Sale of promissory note	—	40,203
Restricted cash	1,249	(9,250)
Sale of short-term investments	—	49,890
Purchase of short-term investments	—	(49,890)
Net cash from investing activities	(574,083)	(299,087)
Cash flows from financing activities:		
Proceeds from revolving credit facility	233,000	—
Repayment of revolving credit facility	(211,000)	—
Payment of debt issuance costs	(4,060)	—
Purchases of treasury stock	(4,494)	(5,274)
Other	(719)	(645)
Net cash from financing activities	12,727	(5,919)
Net change in cash, cash equivalents and restricted cash	(180,499)	(32,559)
Cash, cash equivalents and restricted cash, beginning of period	189,925	244,100
Cash, cash equivalents and restricted cash, end of period	$ 9,426	$ 211,541
Supplemental cash flow information:		
Cash payments (receipts) for:		
Interest, net of capitalized interest	$ 27,817	$ 32,647
Income taxes	393	(39)
Non-cash investing and financing activities:		
Change in accounts payable related to capital expenditures	$ 72,334	$ 81,891
Change in asset retirement obligations, with a corresponding change to crude oil and natural gas properties, net of disposals	6,248	2,415
Purchase of properties and equipment under capital leases	689	2,160

See accompanying Notes to Condensed Consolidated Financial Statements

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	—	—	—	—	—	(173,396)	(173,396)
Purchase of treasury shares	—	—	—	(87,063)	(4,494)	—	(4,494)
Issuance of treasury shares	—	—	(4,288)	78,395	4,288	—	—
Non-employee directors' deferred compensation plan	—	—	—	(2,574)	(142)	—	(142)
Issuance of stock awards, net of forfeitures	177,945	2	(2)	—	—	—	—
Stock-based compensation expense	—	—	10,779	—	—	—	10,779
Other	—	—	(90)	—	—	—	(90)
Balance, June 30, 2018	66,133,025	$ 661	$ 2,509,693	(67,169)	$ (3,356)	$ (166,692)	$ 2,340,306

See accompanying Notes to Condensed Consolidated Financial Statements

PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 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 primarily focused in the Wolfcamp zones. We previously operated properties in the Utica Shale in Southeastern Ohio; however, we divested these properties during the first quarter of 2018. As of June 30, 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 six months ended June 30, 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. See the footnote below titled *Revenue Recognition* for further details regarding the changes in our revenue recognition resulting from the adoption of this standard.

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 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 June 30, 2018 and 2017 and December 31, 2017, which sum to the total of cash, cash equivalents and restricted cash in the condensed consolidated statements of cash flows:

	June 30, 2018	December 31, 2017	June 30, 2017
		(in thousands)	
Cash and cash equivalents	$ 1,425	$ 180,675	$ 202,291
Restricted cash	8,001	9,250	9,250
Cash, cash equivalents and restricted cash shown in the condensed consolidated statements of cash flows	$ 9,426	$ 189,925	$ 211,541

Restricted cash is included in other assets on the condensed consolidated balance sheets at June 30, 2018 and December 31, 2017. We did not have any cash classified as restricted cash at 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 $202.0 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.

The estimated allocation of the assets acquired and the liabilities assumed in the acquisition are presented below and are subject to customary post-closing adjustments. Adjustments to the preliminary purchase price stem from final settlement of the proceeds from operating activities and additional information we obtained about facts and circumstances that existed at the acquisition date that impact the underlying value of certain assets acquired and current liabilities assumed. Such adjustments primarily relate to sales, operating expenses and capital costs from the effective date through closing.

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

	June 30, 2018
Acquisition costs:	
Cash	$ 170,560
Deposit made in prior period	21,000
Total cash consideration	191,560
Other purchase price adjustments	10,422
Total acquisition costs	$ 201,982
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Assets acquired:	
Current assets	$ 517
Crude oil and natural gas properties - proved	207,816
Other assets	2,796
Total assets acquired	211,129
Liabilities assumed:	
Current liabilities	(4,460)
Asset retirement obligations	(4,687)
Total liabilities assumed	(9,147)
Total identifiable net assets acquired	$ 201,982

This transaction 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. 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.

The results of operations for the Bayswater Acquisition for the three and six months ended June 30, 2018 have been included in our condensed consolidated financial statements, including approximately $14.5 million and $21.8 million, respectively, of total revenue, $8.3 million and $12.0 million, respectively, of income from operations and $0.12 and $0.18, respectively, of diluted earnings per share. 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 and six months ended June 30, 2017.

NOTE 4 - REVENUE RECOGNITION

On January 1, 2018, we adopted the new accounting standard that was issued by the FASB to provide a single, comprehensive model to determine the measurement of revenue and timing of when it is recognized and all related amendments (the “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 New Revenue Standard would have reduced our crude oil, natural gas and NGLs sales by approximately $2.8 million and $5.4 million in the three and six months ended June 30, 2017, respectively, 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 and six months ended June 30, 2018, we applied the new guidance to contracts that were not completed as of December 31, 2017. We do not expect adoption of the New Revenue 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 delivered and prices received. We receive payment for sales 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 and six months ended June 30, 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 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 index 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 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, for natural gas, the average NYMEX pricing is based upon first-of-the-month index prices, as in each case 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.

Disaggregated Revenue. The following table presents crude oil, natural gas and NGLs sales disaggregated by commodity and operating region for the three and six months ended June 30, 2018 and 2017 (in thousands):

	Three Months Ended June 30,			Six Months Ended June 30,		
Revenue by Commodity and Operating Region	**2018**	**2017 (1)**	**Percentage Change**	**2018**	**2017 (1)**	**Percentage Change**
Crude oil						
Wattenberg Field	$ 189,992	$ 129,258	47.0 %	$ 360,299	$ 234,446	53.7 %
Delaware Basin	62,599	16,327	283.4 %	116,016	29,865	288.5 %
Utica Shale (2)	—	3,216	(100.0)%	2,696	7,486	(64.0)%
Total	$ 252,591	$ 148,801	69.8 %	$ 479,011	$ 271,797	76.2 %
Natural gas						
Wattenberg Field	$ 22,640	$ 34,004	(33.4)%	$ 52,412	$ 66,617	(21.3)%
Delaware Basin	7,472	2,767	170.0 %	15,151	5,236	189.4 %
Utica Shale (2)	—	1,561	(100.0)%	1,109	3,421	(67.6)%
Total	$ 30,112	$ 38,332	(21.4)%	$ 68,672	$ 75,274	(8.8)%
NGLs						
Wattenberg Field	$ 30,271	$ 21,923	38.1 %	$ 59,041	$ 47,242	25.0 %
Delaware Basin	12,959	3,680	252.1 %	23,594	6,626	256.1 %
Utica Shale (2)	—	866	(100.0)%	840	2,355	(64.3)%
Total	$ 43,230	$ 26,469	63.3 %	$ 83,475	$ 56,223	48.5 %
Revenue by Operating Region						
Wattenberg Field	$ 242,903	$ 185,185	31.2 %	$ 471,752	$ 348,305	35.4 %
Delaware Basin	83,030	22,774	264.6 %	154,761	41,727	270.9 %
Utica Shale (2)	—	5,643	(100.0)%	4,645	13,262	(65.0)%
Total	$ 325,933	$ 213,602	52.6 %	$ 631,158	$ 403,294	56.5 %

(1) As we have elected the modified retrospective method of adoption for the New Revenue Standard, revenues for the three and six months ended June 30, 2017 have not been restated. Such changes would not have been material.

(2) In March 2018, we completed the disposition of our Utica Shale properties.

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 assets 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 and NGLs sales revenue during the periods in which 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 six months ended June 30, 2018:

	Amount
	(in thousands)
Beginning balance, January 1, 2018	$ 4,446
Additions	1,202
Amortized as a reduction to crude oil, natural gas and NGLs sales	(2,408)
Ending balance, June 30, 2018	$ 3,240

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 June 30, 2018 and December 31, 2017 was $159.1 million and $154.3 million, respectively. We did not record an allowance for doubtful accounts for these receivables at June 30, 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 of the hierarchy. Our collars and propane fixed-price swaps are included in Level 3 of the hierarchy. Our basis swaps are included in Level 2 and Level 3 of the hierarchy. The following table presents, for each applicable level within the fair value hierarchy, our derivative assets and liabilities, including both current and non-current portions, measured at fair value on a recurring basis:

	June 30, 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)					
Total assets	$ 10,412	$ 4,405	$ 14,817	$ 12,949	$ 1,389	$ 14,338
Total liabilities	(199,530)	(23,505)	(223,035)	(90,569)	(11,076)	(101,645)
Net liability	$ (189,118)	$ (19,100)	$ (208,218)	$ (77,620)	$ (9,687)	$ (87,307)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Fair value of Level 3 instruments, net asset (liability) beginning of period	$ (8,834)	$ 2,316	$ (9,687)	$ (9,574)
Changes in fair value included in condensed consolidated statement of operations line item:				
Commodity price risk management gain (loss), net	(4,701)	9,262	(6,854)	22,622
Settlements included in condensed consolidated statement of operations line items:				
Commodity price risk management gain (loss), net	(5,565)	(2,959)	(2,559)	(4,429)
Fair value of Level 3 instruments, net asset (liability) end of period	$ (19,100)	$ 8,619	$ (19,100)	$ 8,619
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	$ (15,582)	$ 8,161	$ (9,412)	$ 17,194

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.

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:

	As of June 30, 2018		As of December 31, 2017	
	Estimated Fair Value	Percent of Par	Estimated Fair Value	Percent of Par
	(in millions)		*(in millions)*	
Senior notes:				
2021 Convertible Notes	$ 209.2	104.6%	$ 195.6	97.8%
2024 Senior Notes	408.4	102.1%	416.0	104.0%
2026 Senior Notes	599.7	99.9%	616.5	102.8%

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. To date, we have had no derivative counterparty default losses. We have evaluated the credit risk of our derivative assets from our counterparties using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the potential impact of nonperformance of our current counterparties on the fair value of our derivative instruments is not significant at June 30, 2018, taking into account the estimated likelihood of nonperformance.

Note Receivable. In 2014, we sold our entire 50 percent ownership interest in PDC Mountaineer, LLC to an unrelated third-party. As part of the consideration, we received a promissory note (the "Promissory Note") for a principal sum of $39.0 million, bearing variable interest rates. We regularly analyzed the Promissory Note for evidence of collectibility, evaluating factors such as the creditworthiness of the issuer of the Promissory Note and the value of the issuer's assets. Based upon this analysis, during the quarter ended March 31, 2016, we recognized a provision and recorded an allowance for uncollectible notes receivable for the $44.0 million accumulated outstanding balance, including interest. In April 2017, we sold the Promissory Note to an unrelated third-party buyer for approximately $40.2 million in cash. Accordingly, we reversed $40.2 million of the provision for uncollectible notes receivable during the second quarter of 2017.

Cash and Cash Equivalents. We consider all highly liquid instruments purchased with an original maturity of three months or less to be cash equivalents. Cash and cash equivalents potentially subject us to a concentration of credit risk as substantially all of our deposits held in financial institutions were in excess of the FDIC insurance limits at June 30, 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 June 30, 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, 2019 and 2020 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 June 30, 2018, we had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

	Collars			Fixed-Price Swaps		
	Quantity *(Crude oil - MBls Natural Gas - BBtu)*	Weighted-Average Contract Price		Quantity *(Crude Oil - MBbls Gas and Basis-BBtu Propane - MBbls)*	Weighted-Average Contract Price	Fair Value June 30, 2018 (1) *(in thousands)*
Commodity/ Index/ Maturity Period		**Floors**	**Ceilings**			
Crude Oil						
NYMEX						
2018	1,106.0	$ 46.01	$ 57.11	5,636.0	$ 52.34	$ (117,210)
2019	1,400.0	53.57	65.55	8,400.0	53.86	(99,002)
2020	—	—	—	600.0	62.50	343
Total Crude Oil	2,506.0			14,636.0		$ (215,869)
Natural Gas						
NYMEX						
2018	240.0	$ 3.00	$ 3.90	27,715.0	$ 2.94	$ (541)
2019	—	—	—	8,004.0	2.78	(218)
Dominion South						
2018	—	—	—	399.0	2.12	12
2019	—	—	—	256.6	2.13	7
Total Natural Gas	240.0			36,396.2		$ (740)
Basis Protection - Crude Oil						
Midland Cushing						
2018	—	$ —	$ —	343.9	$ (0.10)	$ 4,374
Total Basis Protection - Crude Oil	—			343.9		$ 4,374
Basis Protection - Natural Gas						
CIG						
2018	—	$ —	$ —	19,612.0	$ (0.42)	$ 6,440
2019	—	—	—	7,924.0	(0.88)	(369)
Waha						
2018	—	—	—	3,425.0	(0.50)	2,842
Total Basis Protection - Natural Gas	—			30,961.0		$ 8,913
Propane						
Mont Belvieu						
2018	—	$ —	$ —	333.4	$ 33.97	$ (1,882)
Total Propane	—			333.4		$ (1,882)
Rollfactor (2)						
Crude Oil CMA						
2018	—	$ —	$ —	2,934.3	$ 0.13	$ (3,014)
Total Rollfactor	—			2,934.3		$ (3,014)
Commodity Derivatives Fair Value						$ (208,218)

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(1) Approximately 29.9 percent of the fair value of our commodity derivative assets and 10.5 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.

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

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

Derivative Instruments:		Condensed Consolidated Balance Sheet Line Item	Fair Value June 30, 2018	Fair Value December 31, 2017
			(in thousands)	
Derivative assets:	Current			
	Commodity derivative contracts	Fair value of derivatives	$ 1,161	$ 7,340
	Basis protection derivative contracts	Fair value of derivatives	13,656	6,998
			14,817	14,338
	Non-current	Fair value of derivatives	—	—
Total derivative assets			$ 14,817	$ 14,338
Derivative liabilities:	Current			
	Commodity derivative contracts	Fair value of derivatives	$ 183,369	$ 77,999
	Basis protection derivative contracts	Fair value of derivatives	222	234
	Rollfactor derivative contracts	Fair value of derivatives	3,014	1,069
			186,605	79,302
	Non-current			
	Commodity derivative contracts	Fair value of derivatives	36,283	22,343
	Basis protection derivative contracts	Fair value of derivatives	147	—
			36,430	22,343
Total derivative liabilities			$ 223,035	$ 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 June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
	(in thousands)			
Commodity price risk management gain (loss), net				
Net settlements	$ (16,408)	$ 12,015	$ (42,446)	$ 12,566
Net change in fair value of unsettled derivatives	(99,718)	45,917	(120,920)	126,070
Total commodity price risk management gain (loss), net	$ (116,126)	$ 57,932	$ (163,366)	$ 138,636

Net settlements of commodity derivatives and net change in fair value of unsettled derivatives decreased for the three and six months ended June 30, 2018 as compared to the three and six months ended June 30, 2017 as a result of the increase in future commodity prices during the first half of 2018 compared to a decrease during the first half of 2017. Our decrease in net settlements for the three months ended June 30, 2018 was partially offset by an $11.3 million realized gain on the early settlement of certain commodity derivative basis protection positions, including $10.3 million for the early settlement of crude oil basis protection instruments and $1.0 million for the early settlement of natural gas basis protection instruments, both for our Delaware Basin operations. The volumes associated with these instruments were impacted by certain marketing agreements entered into during the three months ended June 30, 2018 which eliminated the underlying sale price variability, and therefore there was no longer a variable to hedge.

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

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

As of June 30, 2018	Derivative Instruments, Gross	Effect of Master Netting Agreements	Derivative Instruments, Net
		(in thousands)	
Asset derivatives:			
Derivative instruments, at fair value	$ 14,817	$ (14,752)	$ 65
Liability derivatives:			
Derivative instruments, at fair value	$ 223,035	$ (14,752)	$ 208,283

As of December 31, 2017	Derivative Instruments, 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"):

	June 30, 2018	December 31, 2017
	(in thousands)	
Properties and equipment, net:		
Crude oil and natural gas properties		
Proved	$ 4,944,476	$ 4,356,922
Unproved	908,271	1,097,317
Total crude oil and natural gas properties	5,852,747	5,454,239
Infrastructure, pipeline and other	127,799	109,359
Land and buildings	12,724	10,960
Construction in progress	294,669	196,024
Properties and equipment, at cost	6,287,939	5,770,582
Accumulated DD&A	(2,095,331)	(1,837,115)
Properties and equipment, net	$ 4,192,608	$ 3,933,467

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Impairment of proved and unproved properties	$ 159,528	$ 27,463	$ 192,658	$ 29,565
Amortization of individually insignificant unproved properties	26	103	84	194
Impairment of crude oil and natural gas properties	$ 159,554	$ 27,566	$ 192,742	$ 29,759

During the six months ended June 30, 2018, we recorded impairment charges totaling $192.7 million, including $159.5 million during the three months ended June 30, 2018. During the three months ended June 30, 2018, we identified current and anticipated near-term leasehold expirations within our non-focus areas of the Delaware Basin and made the determination that we would no longer pursue plans to develop these properties. The impaired non-focus leasehold typically has a higher gas to oil ratio and a greater degree of geologic complexity than our other Delaware Basin properties and is further impacted by widening natural gas differentials and increased well development costs. We intend to focus our future Delaware Basin development in our oilier core areas where we have identified approximately 450 mid-length lateral equivalent Wolfcamp drilling locations. We continue to explore options for our non-focus areas and monitor them for possible future impairment based on similar analyses. We determined the fair value of the properties 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.

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 on our previously-issued financial statements or those of the period of correction.

Utica Shale Divestiture. In March 2018, we completed the disposition of our Utica Shale properties (the "Utica Shale Divestiture") for net cash proceeds of approximately $39.0 million. We recorded a loss on sale of properties and equipment of $1.4 million for the six months ended June 30, 2018, which included post-closing adjustments. 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.

Suspended Well Costs. We have spud one well in the Delaware Basin for which we are unable to make a final determination regarding whether proved reserves can be associated with the well as of June 30, 2018 as the well had not been completed as of that date. Therefore, we have classified the capitalized costs of the well as suspended well costs as of June 30, 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:

	Six Months Ended June 30, 2018	Year Ended 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	23,443	51,776
Reclassifications to proved properties	(29,883)	(36,328)
Capitalized exploratory well costs charged to expense	—	—
Ending balance	$ 9,008	$ 15,448
Number of wells pending determination at period end	1	3

NOTE 8 - OTHER ACCRUED EXPENSES AND OTHER LIABILITIES

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

	June 30, 2018	December 31, 2017
	(in thousands)	
Employee benefits	$ 14,609	$ 22,383
Asset retirement obligations	15,959	15,801
Environmental expenses	2,355	1,374
Other	2,965	3,429
Other accrued expenses	$ 35,888	$ 42,987

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

	June 30, 2018	December 31, 2017
	(in thousands)	
Production taxes	$ 28,537	$ 50,476
Deferred oil gathering credit	23,115	—
Other	9,965	6,857
Other liabilities	$ 61,617	$ 57,333

Deferred Oil Gathering Credit. 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. The payment will be amortized using the straight-line method over the life of the amendment. Amortization charges totaling approximately $0.4 million and $0.7 million for the three and six months ended June 30, 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.

NOTE 9 - LONG-TERM DEBT

Long-term debt consisted of the following as of:

	June 30, 2018	December 31, 2017
	(in thousands)	
Senior notes:		
1.125% Convertible Notes due September 2021:		
Principal amount	$ 200,000	$ 200,000
Unamortized discount	(26,600)	(30,328)
Unamortized debt issuance costs	(3,128)	(3,615)
Net of unamortized discount and debt issuance costs	170,272	166,057
6.125% Senior Notes due September 2024:		
Principal amount	400,000	400,000
Unamortized debt issuance costs	(6,080)	(6,570)
Net of unamortized debt issuance costs	393,920	393,430
5.75% Senior Notes due May 2026:		
Principal amount	600,000	600,000
Unamortized debt issuance costs	(7,075)	(7,555)
Net of unamortized debt issuance costs	592,925	592,445
Total senior notes	1,157,117	1,151,932
Revolving credit facility due May 2023	22,000	—
Total long-term debt, net of unamortized discount and debt issuance costs	$ 1,179,117	$ 1,151,932

Senior Notes

2021 Convertible Notes. In September 2016, we issued $200 million of 1.125% convertible notes due September 15, 2021 (the "2021 Convertible Notes") in a public offering. Interest is payable in cash semiannually on each March 15 and September 15. The conversion 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 were capitalized as debt issuance costs. As of June 30, 2018, the unamortized debt discount will be amortized over the remaining contractual term to maturity of the 2021 Convertible Notes using the effective interest method.

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 on March 15 and September 15. Approximately $7.8 million in costs associated with the issuance of the 2024 Senior Notes were 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. In June 2018, 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 July 2018. The 2026 Senior Notes accrue interest from the date of issuance and interest is payable semi-annually on May 15 and November 15. The first interest payment occurred on May 15, 2018. Approximately $7.6 million in costs associated with the issuance of the 2026 Senior Notes were 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 June 30, 2018, we were in compliance with all covenants related to the Notes.

Revolving Credit Facility

In May 2018, we entered into a Fourth Amended and Restated Credit Agreement (the “Restated Credit Agreement”) with certain banks and other lenders, including JPMorgan Chase Bank, N.A. as administrative agent. The Restated Credit Agreement amends and restates our Third Amended and Restated Credit Agreement dated as of May 21, 2013, as amended. Among other things, the Restated Credit Agreement provides for a maximum credit amount of $2.5 billion, an initial borrowing base of $1.3 billion, an initial elected commitment amount of $700 million and is subject to certain limitations under our Notes. In addition, the Restated Credit Agreement extends the maturity date of the facility from May 2020 to May 2023, reflects improved covenant flexibility and certain reductions in interest rates applicable to borrowings under the facility and includes a $25.0 million swingline facility.

The revolving credit facility is available for working capital requirements, capital investments, acquisitions, to support letters of credit and for general corporate purposes. 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 outstanding principal amount under the revolving credit facility accrues interest at a varying interest rate that fluctuates with an alternate base rate (equal to the greatest of JPMorgan Chase Bank, N.A.'s prime rate, the federal funds rate plus a premium and the rate for dollar deposits in the London interbank market (“LIBOR”) for one month plus a premium) or, at our election, a rate equal to LIBOR for certain time periods. Additionally, commitment fees, interest margin and other bank fees, charged as a component of interest, vary with our utilization of the facility. As of June 30, 2018, the applicable interest margin is 0.25 percent for the alternate base rate option or 1.25 percent for the LIBOR option, and the unused commitment fee is 0.375 percent. Principal payments are generally not required until the revolving credit facility expires in May 2023, 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 June 30, 2018, we were in compliance with all the revolving credit facility covenants.

As of June 30, 2018 and December 31, 2017, debt issuance costs related to our revolving credit facility were $9.0 million and $6.2 million, respectively, and are included in other assets on the condensed consolidated balance sheets. As of June 30, 2018, the weighted-average interest rate on the outstanding balance on our revolving credit facility, exclusive of fees on the unused commitment, was 5.4 percent.

NOTE 10 - CAPITAL LEASES

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

The following table presents vehicles under capital lease as of:

	June 30, 2018	December 31, 2017
	(in thousands)	
Vehicles	$ 6,842	$ 6,249
Accumulated depreciation	(2,654)	(1,882)
	$ 4,188	$ 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 June 30,	Amount
	(in thousands)
2019	$ 2,036
2020	2,160
2021	966
	5,162
Executory cost	(267)
Amount representing interest	(582)
Present value of minimum lease payments	$ 4,313
Short-term capital lease obligations	$ 1,746
Long-term capital lease obligations	2,567
	$ 4,313

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 rates for the three and six months ended June 30, 2018 and June 30, 2017 are based upon a full year forecasted tax benefit on loss and a full year forecasted tax expense on income, respectively. The effective income tax rates differs from the statutory federal tax rate, primarily due to state taxes, stock-based compensation, nondeductible officers' compensation and nondeductible lobbying expenses. In addition, federal tax credits impacted the effective income tax rate for the three and six months ended June 30, 2018. 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 income tax rates for the three and six months ended June 30, 2018 were 22.0 percent and 22.3 percent benefit on loss, respectively, compared to 37.3 percent and 36.8 percent expense on income for the three and six months ended June 30, 2017, respectively. 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").

As of June 30, 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	1,517
Obligations incurred with acquisition	4,687
Accretion expense	2,573
Revisions in estimated cash flows	42
Obligations discharged with asset retirements and divestiture	(6,617)
Balance at June 30, 2018	89,508
Current portion	(15,959)
Long-term portion	$ 73,549

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. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligations liability, a corresponding adjustment is made to the properties and equipment balance. Changes in the liability due to the passage of time are recognized as an increase in the carrying amount of the liability and as corresponding accretion expense. 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 June 30,						
Area	2019	2020	2021	2022	2023 and Through Expiration	Total	Expiration Date
Natural gas (MMcf)							
Wattenberg Field	13,124	29,820	31,025	31,025	106,537	211,531	April 30, 2026
Delaware Basin	41,637	21,960	7,360	—	—	70,957	December 31, 2020
Gas Marketing	7,117	7,136	7,117	6,875	1,147	29,392	August 31, 2022
Total	61,878	58,916	45,502	37,900	107,684	311,880	
Crude oil (MBbls)							
Wattenberg Field	4,238	4,860	5,475	5,475	4,560	24,608	April 30, 2023
Delaware Basin	5,822	8,740	8,398	8,030	12,078	43,068	December 31, 2023
Total	10,060	13,600	13,873	13,505	16,638	67,676	
Dollar commitment (in thousands)	$ 80,377	$ 92,045	$ 71,309	$ 70,248	$ 150,493	$ 464,472	

Wattenberg Field. 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 completed and turned on line the first of the two 200 MMcfd cryogenic plants in August 2018. The second plant is currently scheduled to be completed in the second quarter of 2019. We are bound to the volume requirements in these agreements on the first day of the calendar month following the actual in-service date of the relevant 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 with minimal payment from us, if any.

In April 2018, we entered into two five-year firm transportation agreements, effective May 1, 2018, with a third-party crude oil pipeline company to transport 15,000 barrels of crude oil per day from our Wattenberg Field via pipeline to Cushing, Oklahoma, and other area refineries.

Delaware Basin. In May 2018, we entered into two firm sales agreements 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 an integrated marketing company for our crude oil production in the Delaware Basin. These agreements are expected to provide price diversification through realization of export market pricing via a Corpus Christi terminal and exposure to Brent-weighted prices.

Commodity Sales. For the three and six months ended June 30, 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 $5.2

million, respectively, and in accordance with the guidance in the New Revenue Standard, were netted against our crude oil and natural gas sales in our condensed consolidated statements of operations. For the three and six months ended June 30, 2017, commitments for long-term transportation volumes for Wattenberg Field crude oil and Utica Shale natural gas were $2.6 million and $4.8 million, respectively, and were recorded in transportation, gathering and processing expense in our condensed consolidated statements of operations. The commitments for the three and six months ended June 30, 2017 would have been netted against our crude oil and natural gas sales in accordance with the New Revenue Standard.

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 whom are currently independent members of our Board of Directors. We moved to dismiss the claims against the individuals named as defendants and in response, the plaintiffs filed a second amended complaint on July 10, 2018. We filed a motion to dismiss this second amended complaint and the claims against the individuals named as defendants on July 31, 2018. We are currently unable to estimate any potential damages resulting from 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 June 30, 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 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 and the above referenced Compliance Advisory. 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 June 30, 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.

We are in the process of implementing a program to comply with the consent decree. In July 2018, we identified certain immaterial deficiencies in our implementation of the program. We have reported these immaterial deficiencies to the appropriate authorities and are in the process of remediating them. We do not believe that any sanctions associated with these deficiencies will have a material effect on our financial condition or results of operations, but they may exceed $100,000.

NOTE 14 - COMMON STOCK

Stock-Based Compensation Plans

2018 Equity Incentive Plan. In May 2018, our stockholders approved a long-term equity compensation plan for our employees and non-employee directors (the “2018 Plan”). The 2018 Plan provides for a reserve of 1,800,000 shares of our common stock that may be issued pursuant to awards under the 2018 Plan and a term that expires in March 2028. Shares issued may be either authorized but unissued shares, treasury shares or any combination. Additionally, the 2018 Plan permits the reuse or reissuance of shares of common stock which were canceled, expired, forfeited, or paid out in the form of cash. Shares tendered or withheld to satisfy the exercise price of options or tax withholding obligations, and shares covering the portion of exercised stock-settled stock appreciation rights ("SARs") (regardless of the number of shares actually delivered), count against the share limit. Awards may be issued in the form of options, SARs, restricted stock, restricted stock units ("RSUs"), performance stock units ("PSUs") and other stock-based awards. Awards may vest over periods set at the discretion of the Compensation Committee of our Board of Directors (the "Compensation Committee") with certain minimum vesting periods. With regard to SARs, awards have a maximum exercisable period of ten years.

2010 Long-Term Equity Compensation Plan. Our Amended and Restated 2010 Long-Term Equity Compensation Plan, which was most recently approved by stockholders in 2013 (as the same has been amended and restated from time to time, the "2010 Plan"), will remain outstanding and we may use the 2010 Plan to grant awards. However, the share reserve of the 2010 Plan is nearly depleted. As of June 30, 2018, there were 256,059 shares available for grant under the 2010 Plan.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Stock-based compensation expense	$ 5,518	$ 5,372	$ 10,779	$ 9,826
Income tax benefit	(1,323)	(2,010)	(2,584)	(3,676)
Net stock-based compensation expense	$ 4,195	$ 3,362	$ 8,195	$ 6,150

Stock Appreciation Rights

The 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 and six months ended June 30, 2018.

Total compensation cost related to non-vested SARs granted and not yet recognized in our condensed consolidated statement of operations as of June 30, 2018 was $1.2 million. The cost is expected to be recognized over a weighted-average period of 1.3 years.

Restricted Stock Awards

Time-Based Awards. The fair value of the time-based RSUs 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.

The following table presents the changes in non-vested time-based RSUs to all employees, including executive officers, for the six months ended June 30, 2018:

	Shares	Weighted-Average Grant Date Fair Value per Share
Non-vested at December 31, 2017	472,132	$ 60.23
Granted	373,788	49.73
Vested	(208,060)	58.49
Forfeited	(26,878)	58.12
Non-vested at June 30, 2018	610,982	54.49

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

	Six Months Ended June 30,	
	2018	2017
	(in thousands, except per share data)	
Total intrinsic value of time-based awards vested	$ 10,482	$ 13,103
Total intrinsic value of time-based awards non-vested	36,934	22,454
Market price per share as of June 30,	60.45	43.11
Weighted-average grant date fair value per share	49.73	67.02

Total compensation cost related to non-vested time-based awards and not yet recognized in our condensed consolidated statements of operations as of June 30, 2018 was $26.8 million. This cost is expected to be recognized over a weighted-average period of 2.1 years.

Market-Based Awards. The fair value of the market-based PSUs 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 awarded a total of 90,778 market-based PSUs to our executive officers during the six months ended June 30, 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 target PSUs awarded. The weighted-average grant date fair value per PSU granted was computed using the Monte Carlo pricing model using the following assumptions:

	Six Months Ended June 30,	
	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.

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

	Six Months Ended June 30,	
	2018	2017
	(in thousands, except per share data)	
Total intrinsic value of market-based awards non-vested	$ 8,402	$ 3,297
Market price per common share as of June 30,	60.45	43.11
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 June 30, 2018 was $7.0 million. This cost is expected to be recognized over a weighted-average period of 2.3 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 June 30, 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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Weighted-average common shares outstanding - basic	66,066	65,859	66,012	65,804
Dilutive effect of:				
Restricted stock	—	94	—	176
Other equity-based awards	—	66	—	86
Weighted-average common shares and equivalents outstanding - diluted	66,066	66,019	66,012	66,066

We reported a net loss for the three and six months ended June 30, 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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Weighted-average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:				
Restricted stock	624	376	558	119
Other equity-based awards	272	1	225	10
Total anti-dilutive common share equivalents	896	377	783	129

In September 2016, we issued the 2021 Convertible Notes, which give the holders, at our election, the right to convert the aggregate principal amount into 2.3 million shares of our common stock at a conversion price of $85.39 per share. The 2021 Convertible Notes could be included in the diluted earnings per share calculation using the treasury stock method if the average market share price exceeds the $85.39 conversion price during the periods presented. During the three and six months ended June 30, 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.

PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2018
(unaudited)

	Condensed Consolidating Balance Sheets			
	June 30, 2018			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Current assets:				
Cash and cash equivalents	$ 1,425	$ —	$ —	$ 1,425
Accounts receivable, net	149,120	46,197	—	195,317
Fair value of derivatives	14,817	—	—	14,817
Prepaid expenses and other current assets	5,379	1,365	—	6,744
Total current assets	170,741	47,562	—	218,303
Properties and equipment, net	2,191,985	2,000,623	—	4,192,608
Intercompany receivable	352,436	—	(352,436)	—
Investment in subsidiaries	1,493,829	—	(1,493,829)	—
Other assets	27,069	4,174	—	31,243
Total Assets	$ 4,236,060	$ 2,052,359	$ (1,846,265)	$ 4,442,154
Liabilities and Stockholders' Equity				
Liabilities				
Current liabilities:				
Accounts payable	$ 135,677	$ 79,473	$ —	$ 215,150
Production tax liability	52,768	3,998	—	56,766
Fair value of derivatives	186,605	—	—	186,605
Funds held for distribution	80,439	21,915	—	102,354
Accrued interest payable	12,556	5	—	12,561
Other accrued expenses	35,143	745	—	35,888
Total current liabilities	503,188	106,136	—	609,324
Intercompany payable	—	352,436	(352,436)	—
Long-term debt	1,179,117	—	—	1,179,117
Deferred income taxes	48,740	93,071	—	141,811
Asset retirement obligations	67,142	6,407	—	73,549
Fair value of derivatives	36,430	—	—	36,430
Other liabilities	61,137	480	—	61,617
Total liabilities	1,895,754	558,530	(352,436)	2,101,848
Commitments and contingent liabilities				
Stockholders' Equity				
Stockholders' equity				
Common shares	661	—	—	661
Additional paid-in capital	2,509,693	1,766,775	(1,766,775)	2,509,693
Retained earnings	(166,692)	(272,946)	272,946	(166,692)
Treasury shares	(3,356)	—	—	(3,356)
Total stockholders' equity	2,340,306	1,493,829	(1,493,829)	2,340,306
Total Liabilities and Stockholders' Equity	$ 4,236,060	$ 2,052,359	$ (1,846,265)	$ 4,442,154

	Condensed Consolidating Balance Sheets December 31, 2017			
	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

	Condensed Consolidating Statements of Operations Three Months Ended June 30, 2018			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Revenues				
Crude oil, natural gas and NGLs sales	$ 242,903	$ 83,030	$ —	$ 325,933
Commodity price risk management loss, net	(116,126)	—	—	(116,126)
Other income	2,479	245	—	2,724
Total revenues	129,256	83,275	—	212,531
Costs, expenses and other				
Lease operating expenses	23,432	8,828	—	32,260
Production taxes	16,189	6,415	—	22,604
Transportation, gathering and processing expenses	3,610	5,354	—	8,964
Exploration, geologic and geophysical expense	296	579	—	875
Impairment of properties and equipment	86	159,468	—	159,554
General and administrative expense	33,152	4,095	—	37,247
Depreciation, depletion and amortization	93,217	42,407	—	135,624
Accretion of asset retirement obligations	1,177	108	—	1,285
Gain on sale of properties and equipment	(351)	—	—	(351)
Other expenses	2,708	—	—	2,708
Total costs, expenses and other	173,516	227,254	—	400,770
Loss from operations	(44,260)	(143,979)	—	(188,239)
Interest expense	(17,915)	505	—	(17,410)
Interest income	69	—	—	69
Loss before income taxes	(62,106)	(143,474)	—	(205,580)
Income tax benefit	13,348	31,975	—	45,323
Equity in loss of subsidiary	(111,499)	—	111,499	—
Net loss	$ (160,257)	$ (111,499)	$ 111,499	$ (160,257)

PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2018
(unaudited)

	Condensed Consolidating Statements of Operations			
	Three Months Ended June 30, 2017			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Revenues				
Crude oil, natural gas and NGLs sales	$ 190,828	$ 22,774	$ —	$ 213,602
Commodity price risk management gain, net	57,932	—	—	57,932
Other income	3,586	38	—	3,624
Total revenues	252,346	22,812	—	275,158
Costs, expenses and other				
Lease operating expenses	15,557	4,471	—	20,028
Production taxes	13,388	1,654	—	15,042
Transportation, gathering and processing expenses	5,767	721	—	6,488
Exploration, geologic and geophysical expense	256	777	—	1,033
Impairment of properties and equipment	531	27,035	—	27,566
General and administrative expense	26,617	2,914	—	29,531
Depreciation, depletion and amortization	108,727	17,286	—	126,013
Accretion of asset retirement obligations	1,589	77	—	1,666
Gain on sale of properties and equipment	(532)	—	—	(532)
Provision for uncollectible notes receivable	(40,203)	—	—	(40,203)
Other expenses	3,890	—	—	3,890
Total costs, expenses and other	135,587	54,935	—	190,522
Income (loss) from operations	116,759	(32,123)	—	84,636
Interest expense	(19,800)	183	—	(19,617)
Interest income	768	—	—	768
Income (loss) before income taxes	97,727	(31,940)	—	65,787
Income tax (expense) benefit	(36,285)	11,748	—	(24,537)
Equity in loss of subsidiary	(20,192)	—	20,192	—
Net income (loss)	$ 41,250	$ (20,192)	$ 20,192	$ 41,250

	Condensed Consolidating Statements of Operations Six Months Ended June 30, 2018			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Revenues				
Crude oil, natural gas and NGLs sales	$ 476,397	$ 154,761	$ —	$ 631,158
Commodity price risk management loss, net	(163,366)	—	—	(163,366)
Other income	4,995	344	—	5,339
Total revenues	318,026	155,105	—	473,131
Costs, expenses and other				
Lease operating expenses	44,794	17,102	—	61,896
Production taxes	32,270	10,503	—	42,773
Transportation, gathering and processing expenses	6,841	9,436	—	16,277
Exploration, geologic and geophysical expense	609	2,912	—	3,521
Impairment of properties and equipment	92	192,650	—	192,742
General and administrative expense	64,711	8,232	—	72,943
Depreciation, depletion and amortization	187,593	74,819	—	262,412
Accretion of asset retirement obligations	2,377	196	—	2,573
Loss on sale of properties and equipment	1,081	—	—	1,081
Other expenses	5,476	—	—	5,476
Total costs, expenses and other	345,844	315,850	—	661,694
Loss from operations	(27,818)	(160,745)	—	(188,563)
Interest expense	(36,012)	1,073	—	(34,939)
Interest income	217	—	—	217
Loss before income taxes	(63,613)	(159,672)	—	(223,285)
Income tax benefit	13,925	35,964	—	49,889
Equity in loss of subsidiary	(123,708)	—	123,708	—
Net loss	$ (173,396)	$ (123,708)	$ 123,708	$ (173,396)

PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2018
(unaudited)

	Condensed Consolidating Statements of Operations Six Months Ended June 30, 2017			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Revenues				
Crude oil, natural gas and NGLs sales	$ 361,567	$ 41,727	$ —	$ 403,294
Commodity price risk management gain, net	138,636	—	—	138,636
Other income	6,884	51	—	6,935
Total revenues	507,087	41,778	—	548,865
Costs, expenses and other				
Lease operating expenses	31,374	8,443	—	39,817
Production taxes	24,532	2,909	—	27,441
Transportation, gathering and processing expenses	10,982	1,408	—	12,390
Exploration, geologic and geophysical expense	527	1,460	—	1,987
Impairment of properties and equipment	1,134	28,625	—	29,759
General and administrative expense	50,146	5,700	—	55,846
Depreciation, depletion and amortization	210,465	24,864	—	235,329
Accretion of asset retirement obligations	3,274	160	—	3,434
Gain on sale of properties and equipment	(692)	—	—	(692)
Provision for uncollectible notes receivable	(40,203)	—	—	(40,203)
Other expenses	7,418	—	—	7,418
Total costs, expenses and other	298,957	73,569	—	372,526
Income (loss) from operations	208,130	(31,791)	—	176,339
Interest expense	(39,397)	313	—	(39,084)
Interest income	1,008	—	—	1,008
Income (loss) before income taxes	169,741	(31,478)	—	138,263
Income tax (expense) benefit	(62,448)	11,581	—	(50,867)
Equity in loss of subsidiary	(19,897)	—	19,897	—
Net income (loss)	$ 87,396	$ (19,897)	$ 19,897	$ 87,396

PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2018
(unaudited)

	Condensed Consolidating Statements of Cash Flows			
	Six Months Ended June 30, 2018			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Cash flows from operating activities	$ 267,551	$ 113,306		$ 380,857
Cash flows from investing activities:				
Capital expenditures for development of crude oil and natural gas properties	(218,614)	(214,021)	—	(432,635)
Capital expenditures for other properties and equipment	(1,898)	(552)	—	(2,450)
Acquisition of crude oil and natural gas properties, including settlement adjustments	(180,981)	(71)	—	(181,052)
Proceeds from sale of properties and equipment	1,782	—	—	1,782
Proceeds from divestiture	39,023	—	—	39,023
Restricted cash	1,249	—	—	1,249
Intercompany transfers	(101,398)	—	101,398	—
Net cash from investing activities	(460,837)	(214,644)	101,398	(574,083)
Cash flows from financing activities:				
Proceeds from revolving credit facility	233,000	—	—	233,000
Repayment of revolving credit facility	(211,000)	—	—	(211,000)
Payment of debt issuance costs	(4,060)	—	—	(4,060)
Purchases of treasury stock	(4,494)	—	—	(4,494)
Other	(659)	(60)	—	(719)
Intercompany transfers	—	101,398	(101,398)	—
Net cash from financing activities	12,787	101,338	(101,398)	12,727
Net change in cash, cash equivalents and restricted cash	(180,499)	—	—	(180,499)
Cash, cash equivalents and restricted cash, beginning of period	189,925	—	—	189,925
Cash, cash equivalents and restricted cash, end of period	$ 9,426	$ —	$ —	$ 9,426

PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2018
(unaudited)

	Condensed Consolidating Statements of Cash Flows			
	Six Months Ended June 30, 2017			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Cash flows from operating activities	$ 255,378	$ 17,069	$ —	$ 272,447
Cash flows from investing activities:				
Capital expenditures for development of crude oil and natural gas properties	(198,954)	(135,452)	—	(334,406)
Capital expenditures for other properties and equipment	(1,792)	(507)	—	(2,299)
Acquisition of crude oil and natural gas properties, including settlement adjustments	—	5,372	—	5,372
Proceeds from sale of properties and equipment	1,293	—	—	1,293
Sale of promissory note	40,203	—	—	40,203
Restricted cash	(9,250)	—	—	(9,250)
Sale of short-term investments	49,890	—	—	49,890
Purchase of short-term investments	(49,890)	—	—	(49,890)
Intercompany transfers	(109,923)	—	109,923	—
Net cash from investing activities	(278,423)	(130,587)	109,923	(299,087)
Cash flows from financing activities:				
Purchases of treasury stock	(5,274)	—	—	(5,274)
Other	(627)	(18)	—	(645)
Intercompany transfers	—	109,923	(109,923)	—
Net cash from financing activities	(5,901)	109,905	(109,923)	(5,919)
Net change in cash, cash equivalents and restricted cash	(28,946)	(3,613)	—	(32,559)
Cash, cash equivalents and restricted cash, beginning of period	240,487	3,613	—	244,100
Cash, cash equivalents and restricted cash, end of period	$ 211,541	$ —	$ —	$ 211,541

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 9.4 MMboe and 18.3 MMboe for the three and six months ended June 30, 2018, respectively, representing increases of 17 percent and 25 percent as compared to the three and six months ended June 30, 2017, respectively. Crude oil production increased 22 percent and 35 percent for the three and six months ended June 30, 2018, respectively, compared to the three and six months ended June 30, 2017. Crude oil production comprised approximately 42 percent and 39 percent of total production for the six months ended June 30, 2018 and 2017, respectively. NGLs production increased 10 percent and 14 percent for the three and six months ended June 30, 2018, respectively, compared to the three and six months ended June 30, 2017. Natural gas production increased 16 percent and 21 percent for the three and six months ended June 30, 2018, respectively, compared to the three and six months ended June 30, 2017. For the month ended June 30, 2018, we maintained an average daily production rate of approximately 102,000 Boe per day, up from approximately 87,000 Boe per day for the month ended June 30, 2017.

On a sequential quarterly basis, total production and crude oil production volumes for the three months ended June 30, 2018 as compared to the three months ended March 31, 2018 increased by five percent and four percent, respectively. In the Wattenberg Field, continued high line pressures, which have been greater than anticipated, and unplanned gathering system facility downtime hampered our production growth in the field during the three and six months ended June 30, 2018. These operating challenges are reflected in our expected full year 2018 production outlook as discussed under *2018 Operational and Financial Outlook.* We expect significant production growth in the Wattenberg Field during the second half of 2018 as an additional processing facility was completed by our primary third-party midstream provider and turned on line in August 2018. We continue to see successful development of our Delaware Basin properties. However, crude oil and natural gas takeaway capacity constraints and widening differentials could hinder production growth and result in further widening of price differentials for our future production in the basin. In an effort to address these issues, we entered into separate agreements during the second quarter of 2018 for pipeline capacity for significant portions of our Delaware Basin crude oil and natural gas production. See *Results of Operations - Crude Oil, Natural Gas and NGLs Production* for further details of these agreements.

Crude oil, natural gas and NGLs sales revenue increased to $325.9 million and $631.2 million for the three and six months ended June 30, 2018, respectively, compared to $213.6 million and $403.3 million for the three and six months ended June 30, 2017, respectively. The 53 percent and 57 percent increases in sales revenues were driven by the 17 percent and 25 percent increases in production and the 30 percent and 25 percent increases in average realized commodity prices. The adoption of the New Revenue Standard at January 1, 2018 did not significantly impact the change in our crude oil, natural gas and NGLs sales revenue for the three and six months ended June 30, 2018 as compared to the comparable periods of 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 Standard.

We had negative net settlements from our commodity derivative contracts of $16.4 million and $42.4 million for the three and six months ended June 30, 2018, respectively, as compared to positive net settlements of $12.0 million and $12.6 million for the three and six months ended June 30, 2017, respectively. The 2018 negative net settlements include an $11.3 million realized gain on the early settlement of certain commodity derivative basis protection positions. See *Results of Operations - Commodity Price Risk Management, Net* for further details of our settlements of derivatives and changes in the fair value of unsettled derivatives.

The combined revenue from crude oil, natural gas and NGLs sales and net settlements received on our commodity derivative instruments increased 37 percent to $309.5 million for the three months ended June 30, 2018 from $225.6 million for the three months ended June 30, 2017, and increased 42 percent to $588.7 million for the six months ended June 30, 2018 from $415.9 million for the six months ended June 30, 2017.

During the six months ended June 30, 2018, we recorded impairment charges totaling $192.7 million, including $159.5 million during the three months ended June 30, 2018. During the three months ended June 30, 2018, we identified current and anticipated near-term leasehold expirations within our non-focus areas of the Delaware Basin and made the determination that we would no longer pursue plans to develop these properties. The impaired non-focus leasehold typically has a higher gas to oil ratio and a greater degree of geologic complexity than our other Delaware Basin properties and is further impacted by widening natural gas differentials and increased well development costs. We intend to focus our future Delaware Basin development in our oilier core areas where we have identified approximately 450 mid-length lateral equivalent Wolfcamp drilling locations. We continue to explore options for our non-focus areas and monitor them for possible future impairment based on similar analyses. We determined the fair value of the properties 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.

For the three and six months ended June 30, 2018, we generated net losses of $160.3 million and $173.4 million, respectively, or $2.43 and $2.63 per diluted share. Our net loss was most negatively impacted by the commodity price risk management loss and Delaware Basin leasehold impairments, partially offset by the increase in crude oil, natural gas and NGLs sales. During the same periods, our adjusted EBITDAX, a non-U.S. GAAP financial measure, was $214.3 million and $404.4 million, respectively. For the three and six months ended June 30, 2017, we generated net income of $41.3 million and $87.4 million, respectively, or $0.62 and $1.32 per diluted share, and our adjusted EBITDAX was $200.4 million and $330.6 million, respectively. The seven percent increase in our adjusted EBITDAX for the three months ended June 30, 2018 as compared to the three months ended June 30, 2017 was primarily due to the increase in crude oil, natural gas and NGLs sales of $112.3 million. This increase was partially offset by the reversal of a provision for uncollectible notes receivable of $40.2 million in the three months ended June 30, 2017, an increase in operating costs of $30.0 million and a decrease in commodity derivative settlements of $28.4 million. The 22 percent increase in our adjusted EBITDAX for the six months ended June 30, 2018 as compared to the six months ended June 30, 2017 was primarily due to the increase in crude oil, natural gas and NGLs sales of $227.9 million. This increase was partially offset by an increase in operating costs of $58.4 million, a decrease in commodity derivative settlements of $55.0 million and the reversal of a provision for uncollectible notes receivable of $40.2 million in the six months ended June 30, 2017. Our cash flows from operations were $380.9 million and our adjusted cash flow from operations, a non-U.S. GAAP financial measure, was $374.3 million for the six months ended June 30, 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 June 30, 2018 was $679.4 million, which was comprised of $1.4 million of cash and cash equivalents and $678.0 million available for borrowing under our revolving credit facility at our current commitment level. In May 2018, we entered into the Restated Credit Agreement. See the footnote titled *Long-Term Debt* to our condensed consolidated financial statements included elsewhere in this report for further details. Based on our current production forecast for the remainder of 2018 and assuming average NYMEX prices for the remainder of the year of $65.00 per barrel of crude oil and $2.75 per Mcf of natural gas, less the anticipated differentials, we expect our 2018 capital investments to exceed our 2018 cash flows from operations by between $75 million and $100 million, of which we anticipate approximately $65 million will be covered by an amendment to a midstream dedication agreement and the divestiture of our Utica Shale properties. We experienced this outspend during the first half of 2018 and expect cash flows from operations to exceed capital investment during the second half of the year. 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 $202.0 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.

Utica Shale Divestiture. In March 2018, we completed the Utica Shale Divestiture for net cash proceeds of approximately $39 million. 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.

Operational Overview

During the six months ended June 30, 2018, we continued to execute our strategic plan to grow production while preserving our financial strength and liquidity. During the six months ended June 30, 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 pace 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 six months ended June 30, 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	78	72.3	14	12.7	92	85.0
Acquired DUCs (1)	12	11.0	—	—	12	11.0
Wells turned-in-line	(77)	(70.8)	(12)	(11.1)	(89)	(81.9)
In-process as of June 30, 2018	100	92.6	15	13.8	115	106.4

	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	21	2.6	3	0.1	24	2.7
Acquired DUCs (operated at June 30, 2018) (1)	(3)	(1.5)	—	—	(3)	(1.5)
Wells turned-in-line	(16)	(1.8)	(2)	(0.7)	(18)	(2.5)
In-process as of June 30, 2018	16	1.9	9	0.4	25	2.3

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(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 within three to nine months of drilling.

2018 Operational and Financial Outlook

We have updated our expected production guidance range for 2018 to 40 MMBoe to 42 MMBoe, or approximately 110,000 Boe per day to 115,000 Boe per day. The update assumes an adequate allocation of system capacity from our primary midstream service provider in the Wattenberg Field. 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. We are currently experiencing and expect to continue to experience fewer days between the spudding of wells resulting in an approximate 15 percent efficiency gain in the Wattenberg Field, which has led to an increase in the number of wells planned to be spud this year. We are also experiencing increased service costs in both the Wattenberg Field and Delaware Basin. Additionally, we have increased lateral lengths and the number of frac stages per well in the Kersey area of the Wattenberg Field. Accordingly, we have increased our 2018 capital investment forecast to between $950 million and $985 million.

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 experienced some service cost increases in the first half of 2018, drilling efficiencies are partially offsetting 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 if necessary in order to stay within 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 approximately 150 to 165 wells and turning-in-line approximately 145 to 160 operated wells in 2018, which is an increase over our previously-reported guidance for 2018. Our 2018 capital investment program is estimated to be approximately $525 million to $540 million in the Wattenberg Field, with over 90 percent 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 $425 million to $445 million, of which approximately 80 percent is allocated to both spud and turn-in-line approximately 25 to 30 operated wells, primarily targeting the Wolfcamp formation. Based on the timing of our operations and requirements to meet our drilling obligations, 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 five 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 financial guidance for the year ended December 31, 2018 for certain expenses and price differentials:

	Low	High
Operating Expenses		
Lease operating expenses ($/Boe)	$ 3.00	$ 3.15
Transportation, gathering and processing expenses ("TGP") ($/Boe)	$ 0.80	$ 0.90
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%

Regulatory Update

Proposed Statutory Ballot Initiative. As previously disclosed, certain interest groups in Colorado opposed to oil and natural gas development generally, and hydraulic fracturing in particular, have advanced a ballot initiative that would result in oil and natural gas development in the state being essentially eliminated. Proponents of the initiative have submitted signatures in an effort to qualify the initiative to appear on the ballot in November 2018. The signatures are subject to a verification process to be conducted by the Colorado Secretary of State. This process could take up to 30 days. We do not know what the outcome of this process will be. If approved by the voters of Colorado, the proposal would take effect by the end of 2018.

The initiative would require all new oil and gas development facilities to be located at least 2,500 feet away from any occupied structure or “vulnerable areas,” broadly defined to include playgrounds, permanent sports fields, amphitheaters, public parks, public open space, public and community drinking water sources, irrigation canals, reservoirs, lakes, rivers, perennial or intermittent streams and creeks and any additional vulnerable areas designated by the state or a local government. The current minimum required setback between oil and gas wells and occupied structures is generally 500 feet. Federal lands would be excluded from the effect of the initiative.

The Colorado Oil and Gas Conservation Commission has estimated that implementation of the proposed initiative would make drilling unlawful on approximately 85 percent of the non-federal surface area of the state of Colorado, and approximately 85 percent of the non-federal surface area of Weld County. If passed, this proposal would effectively prohibit the vast majority of our planned future drilling activities in Colorado, and would therefore make it impossible to continue to pursue our current development plans. This would have a highly material and adverse effect on our results of operations, financial condition and reserves.

Ozone Classification. In 2016, the EPA increased the state of Colorado’s non-attainment ozone classification for the Denver Metro North Front Range Ozone Eight-Hour Non-Attainment ("Denver Metro/North Front Range NAA") area from “marginal” to “moderate” under the 2008 national ambient air quality standard (“NAAQS”). This increase in non-attainment status triggered significant additional obligations for the state under the Clean Air Act ("CAA") and resulted in Colorado adopting new and more stringent air quality control requirements in November 2017 that are applicable to our operations. The Denver Metro/North Front Range NAA is at risk of being reclassified again to “serious” if it does not meet the 2008 NAAQS by 2018. The Colorado Department of Public Health and Environment ("CDPHE") has requested that the EPA extend this deadline to 2019. Based on recent air quality monitoring data, however, it appears likely that the Denver Metro/North Front Range NAA will not be able to meet the 2008 NAAQS even by 2019 and will be reclassified as “serious,” likely in 2020 or soon thereafter. A “serious” classification would trigger significant additional obligations for the state under the CAA and could result in new and more stringent air quality control requirements applicable to our operations and significant costs and delays in obtaining necessary permits.

2018 Colorado General Election. A general election will be held in November 2018, with high-profile races on the federal, state and local levels. Newly-elected officials may take a different approach than their predecessors to regulatory and legislative issues affecting the oil and gas industry. Because a substantial portion of our current operations and reserves are located in Colorado, the risks we face with respect to the outcome of the November 2018 Colorado political elections are greater than those of our competitors with more geographically diverse operations. We cannot predict the outcome of the election.

Results of Operations

Summary Operating Results

The following table presents selected information regarding our operating results:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	**2017**	**Percentage Change**	**2018**	**2017**	**Percentage Change**
	(dollars in millions, except per unit data)					
Production						
Crude oil (MBbls)	3,948	3,237	22.0 %	7,745	5,745	34.8 %
Natural gas (MMcf)	20,687	17,783	16.3 %	40,274	33,367	20.7 %
NGLs (MBbls)	1,987	1,814	9.5 %	3,833	3,357	14.2 %
Crude oil equivalent (MBoe)	9,382	8,015	17.1 %	18,290	14,663	24.7 %
Average Boe per day (Boe)	103,099	88,078	17.1 %	101,049	81,011	24.7 %
Crude Oil, Natural Gas and NGLs Sales						
Crude oil	$ 252.6	$ 148.8	69.8 %	$ 479.0	$ 271.8	76.2 %
Natural gas	30.0	38.3	(21.7)%	68.7	75.3	(8.8)%
NGLs	43.3	26.5	63.4 %	83.5	56.2	48.6 %
Total crude oil, natural gas and NGLs sales	$ 325.9	$ 213.6	52.6 %	$ 631.2	$ 403.3	56.5 %
Net Settlements on Commodity Derivatives						
Crude oil	$ (25.5)	$ 5.1	*	$ (52.5)	$ 1.9	*
Natural gas	11.2	6.8	64.7 %	13.9	10.6	31.1 %
NGLs (propane portion)	(2.1)	0.1	*	(3.8)	0.1	*
Total net settlements on derivatives	$ (16.4)	$ 12.0	*	$ (42.4)	$ 12.6	*
Average Sales Price (excluding net settlements on derivatives)						
Crude oil (per Bbl)	$ 63.99	$ 45.97	39.2 %	$ 61.85	$ 47.31	30.7 %
Natural gas (per Mcf)	1.46	2.16	(32.4)%	1.71	2.26	(24.3)%
NGLs (per Bbl)	21.76	14.59	49.1 %	21.78	16.75	30.0 %
Crude oil equivalent (per Boe)	34.74	26.65	30.4 %	34.51	27.50	25.5 %
Average Costs and Expenses (per Boe)						
Lease operating expenses	$ 3.44	$ 2.50	37.6 %	$ 3.38	$ 2.72	24.3 %
Production taxes	2.41	1.88	28.2 %	2.34	1.87	25.1 %
Transportation, gathering and processing expenses	0.96	0.81	18.5 %	0.89	0.84	6.0 %
General and administrative expense	3.97	3.68	7.9 %	3.99	3.81	4.7 %
Depreciation, depletion and amortization	14.46	15.72	(8.0)%	14.35	16.05	(10.6)%
Lease Operating Expenses by Operating Region (per Boe)						
Wattenberg Field	$ 3.29	$ 2.22	48.2 %	$ 3.16	$ 2.42	30.6 %
Delaware Basin	3.92	4.88	(19.7)%	4.16	5.53	(24.8)%
Utica Shale (1)	—	1.34	(100.0)%	3.46	1.48	133.8 %

* Percentage change is not meaningful.

Amounts may not recalculate due to rounding.

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

Crude Oil, Natural Gas and NGLs Sales

For the three and six months ended June 30, 2018, crude oil, natural gas and NGLs sales revenue increased compared to the three and six months ended June 30, 2017 due to the following (in millions):

	June 30, 2018	
	Three Months Ended	Six Months Ended
	(in millions)	
Increase in production	$ 41.4	$ 118.2
Increase in average crude oil price	71.2	112.6
Decrease in average natural gas price	(14.5)	(22.2)
Increase in average NGLs price	14.2	19.3
Total increase in crude oil, natural gas and NGLs sales revenue	$ 112.3	$ 227.9

Crude Oil, Natural Gas and NGLs Production

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

	Three Months Ended June 30,			Six Months Ended June 30,		
Production by Operating Region	**2018**	**2017**	**Percentage Change**	**2018**	**2017**	**Percentage Change**
Crude oil (MBbls)						
Wattenberg Field	2,943	2,798	5.2 %	5,823	4,940	17.9 %
Delaware Basin	1,005	364	176.1 %	1,876	639	193.6 %
Utica Shale (1)	—	75	(100.0)%	46	166	(72.3)%
Total	3,948	3,237	22.0 %	7,745	5,745	34.8 %
Natural gas (MMcf)						
Wattenberg Field	15,836	15,192	4.2 %	31,360	28,906	8.5 %
Delaware Basin	4,851	2,025	139.6 %	8,500	3,271	159.9 %
Utica Shale (1)	—	566	(100.0)%	414	1,190	(65.2)%
Total	20,687	17,783	16.3 %	40,274	33,367	20.7 %
NGLs (MBbls)						
Wattenberg Field	1,544	1,551	(0.5)%	2,973	2,909	2.2 %
Delaware Basin	443	212	109.0 %	826	343	140.8 %
Utica Shale (1)	—	51	(100.0)%	34	105	(67.6)%
Total	1,987	1,814	9.5 %	3,833	3,357	14.2 %
Crude oil equivalent (MBoe)						
Wattenberg Field	7,126	6,882	3.5 %	14,023	12,667	10.7 %
Delaware Basin	2,256	914	147.0 %	4,118	1,527	169.6 %
Utica Shale (1)	—	219	(100.0)%	149	469	(68.2)%
Total	9,382	8,015	17.1 %	18,290	14,663	24.7 %
Average crude oil equivalent per day (Boe)						
Wattenberg Field	78,308	75,621	3.6 %	77,475	69,984	10.7 %
Delaware Basin	24,791	10,047	146.8 %	22,751	8,437	169.7 %
Utica Shale (1)	—	2,410	(100.0)%	823	2,590	(68.2)%
Total	103,099	88,078	17.1 %	101,049	81,011	24.7 %

Amounts may not recalculate due to rounding.

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

The following table presents our crude oil, natural gas and NGLs production ratio by operating region:

Three Months Ended June 30, 2018	Crude Oil	Natural Gas	NGLs	Total
Wattenberg Field	41%	37%	22%	100%
Delaware Basin	45%	36%	20%	100%

Three Months Ended June 30, 2017	Crude Oil	Natural Gas	NGLs	Total
Wattenberg Field	41%	37%	23%	100%
Delaware Basin	40%	37%	23%	100%

Six Months Ended June 30, 2018	Crude Oil	Natural Gas	NGLs	Total
Wattenberg Field	42%	37%	21%	100%
Delaware Basin	46%	34%	20%	100%

Six Months Ended June 30, 2017	Crude Oil	Natural Gas	NGLs	Total
Wattenberg Field	39%	38%	23%	100%
Delaware Basin	42%	36%	22%	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 and six months ended June 30, 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 and six months ended June 30, 2017. During the six months ended June 30, 2018 and 2017, 97 percent and 92 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, currently all of our wells in the field are experiencing some adverse impact. We have continued to operate in a constrained environment into the third quarter of 2018. Additional processing capacity was brought into operation by DCP Midstream, LP ("DCP") in August 2018, with further processing capacity scheduled to be brought into operation during the second quarter of 2019.

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 to DCP to support its construction of two additional processing facilities, including a plant that was completed and turned on line in August 2018, 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 date of the relevant plant. The second plant is scheduled to be completed and turned on line in the second quarter of 2019. These 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 with minimal, if any, 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 these agreements. In addition, we have begun early discussions with DCP with respect to further increasing its processing capacity 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 elevated gathering line pressures for extended periods of time 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 facilities is operating near capacity. We are dependent upon third parties to construct downstream takeaway infrastructure, including crude oil, natural gas and NGL pipelines. This has the potential to lead to near term production constraints until new capacity is added. We expect additional infrastructure to be built starting in the second half of 2019. Until the additional infrastructure is turned on line, our production may be negatively impacted by midstream capacity issues 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 the second quarter of 2018, we entered into separate agreements for pipeline capacity for portions of our Delaware Basin crude oil and natural gas production. The crude oil agreement runs through December 2023 and provides for firm physical takeaway for approximately 85 percent of our forecasted 2018 and 2019 Delaware Basin crude oil volumes. The agreement provides us with price diversification through realization of export market pricing via a Corpus Christi terminal and exposure to Brent-weighted prices. As a result of this agreement, we expect to realize between 88 and 92 percent of West Texas Intermediate ("WTI") crude oil pricing for our total Delaware Basin production through 2018 and 2019, after deducting transportation and other related marketing expenses. Our actual realization for all Delaware Basin production for the second quarter of 2018 was 92 percent of WTI crude oil pricing. Our Delaware Basin natural gas sales agreements run through December 2019 and provide for firm physical takeaway capacity, which varies from approximately between 40,000 MMbtu and 75,000 MMbtu per day of our Delaware Basin natural gas volumes during the period of the agreements. Our Delaware Basin natural gas sales were partially curtailed during the second quarter of 2018 as a result of a shortage of our midstream compression capacity in our Central area of the basin. We plan to install additional compression in this area during the third quarter of 2018, which we expect will provide sufficient capacity to move our Central area natural gas volumes.

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 and six months ended June 30, 2018 compared to the three and six months ended June 30, 2017. NYMEX average daily crude oil prices increased 41 percent and 30 percent and NYMEX first-of-the-month natural gas prices decreased 12 percent and 11 percent for the three and six months ended June 30, 2018 as compared to the three and six months ended June 30, 2017.

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

Weighted-Average Realized Sales Price by Operating Region *(excluding net settlements on derivatives)*	**Three Months Ended June 30,**			**Six Months Ended June 30,**		
	2018	**2017**	**Percentage Change**	**2018**	**2017**	**Percentage Change**
Crude oil (per Bbl)						
Wattenberg Field	$ 64.57	$ 46.19	39.8 %	$ 61.88	$ 47.46	30.4 %
Delaware Basin	62.31	44.81	39.1 %	61.86	46.73	32.4 %
Utica Shale (1)	—	43.19	(100.0)%	58.10	45.05	29.0 %
Weighted-average price	63.99	45.97	39.2 %	61.85	47.31	30.7 %
Natural gas (per Mcf)						
Wattenberg Field	$ 1.43	$ 2.24	(36.2)%	$ 1.67	$ 2.30	(27.4)%
Delaware Basin	1.54	1.37	12.4 %	1.78	1.60	11.3 %
Utica Shale (1)	—	2.76	(100.0)%	2.68	2.88	(6.9)%
Weighted-average price	1.46	2.16	(32.4)%	1.71	2.26	(24.3)%
NGLs (per Bbl)						
Wattenberg Field	$ 19.60	$ 14.13	38.7 %	$ 19.86	$ 16.24	22.3 %
Delaware Basin	29.26	17.33	68.8 %	28.56	19.33	47.7 %
Utica Shale (1)	—	17.10	(100.0)%	24.29	22.58	7.6 %
Weighted-average price	21.76	14.59	49.1 %	21.78	16.75	30.0 %
Crude oil equivalent (per Boe)						
Wattenberg Field	$ 34.09	$ 26.91	26.7 %	$ 33.64	$ 27.50	22.3 %
Delaware Basin	36.80	24.91	47.7 %	37.58	27.32	37.6 %
Utica Shale (1)	—	25.72	(100.0)%	30.98	28.29	9.5 %
Weighted-average price	34.74	26.65	30.4 %	34.51	27.50	25.5 %

Amounts may not recalculate due to rounding.

(1) In March 2018, we completed the disposition 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 the New Revenue Standard effective January 1, 2018. Under the New Revenue 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 are 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 are recognized using the net-back method. If we had adopted the New Revenue Standard on January 1, 2017, we estimate that the average realization percentage before transportation, gathering and processing expenses for the three months ended June 30, 2017 would have been 94 percent, 67 percent and 30 percent for crude oil, natural gas and NGLs, respectively, as $2.8 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. For the six months ended June 30, 2017, the realization percentage before transportation, gathering and processing expense would have been 93 percent, 69 percent and 33 percent for crude oil, natural gas and NGLs, respectively, as $5.4 million in expenses currently recorded in transportation, gathering and processing expense on our condensed consolidated statements of operations for that period would have been reflected as a reduction to the sales price. However, the net realized price after transportation, gathering and processing would not have changed.

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, for natural gas, the average NYMEX pricing is based upon first-of-the-month index prices, as in each case this is the method used to sell the majority 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 June 30, 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)	$ 67.88	$ 63.99	94%	$ 0.92	$ 63.07	93%
Natural gas (per MMBtu)	2.80	1.46	52%	0.24	1.22	44%
NGLs (per Bbl)	67.88	21.76	32%	0.18	21.58	32%
Crude oil equivalent (per Boe)	49.11	34.74	71%	0.96	33.78	69%

For the Three Months Ended June 30, 2017	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)	$ 48.28	$ 45.97	95%	$ 1.38	$ 44.59	92%
Natural gas (per MMBtu)	3.18	2.16	68%	0.08	2.08	65%
NGLs (per Bbl)	48.28	14.59	30%	0.31	14.28	30%
Crude oil equivalent (per Boe)	37.48	26.65	71%	0.81	25.84	69%

For the Six Months Ended June 30, 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)	$ 65.37	$ 61.85	95%	$ 0.80	$ 61.05	93%
Natural gas (per MMBtu)	2.90	1.71	59%	0.23	1.48	51%
NGLs (per Bbl)	65.37	21.78	33%	0.21	21.57	33%
Crude oil equivalent (per Boe)	47.77	34.51	72%	0.89	33.62	70%

For the Six Months Ended June 30, 2017	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)	$ 50.10	$ 47.31	94%	$ 1.44	$ 45.87	92%
Natural gas (per MMBtu)	3.25	2.26	70%	0.09	2.17	67%
NGLs (per Bbl)	50.10	16.75	33%	0.35	16.40	33%
Crude oil equivalent (per Boe)	38.50	27.50	71%	0.84	26.66	69%

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 June 30, 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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Commodity price risk management gain (loss), net:				
Net settlements of commodity derivative instruments:				
Crude oil fixed price swaps, collars and rollfactors	$ (37.2)	$ 5.1	$ (63.9)	$ 1.9
Crude oil basis protection swaps	11.7	—	11.4	—
Natural gas fixed price swaps and collars	2.5	4.8	2.6	8.5
Natural gas basis protection swaps	8.7	2.0	11.2	2.0
NGLs (propane portion) fixed price swaps	(2.1)	0.1	(3.8)	0.1
Total net settlements of commodity derivative instruments	(16.4)	12.0	(42.5)	12.5
Change in fair value of unsettled commodity derivative instruments:				
Reclassification of settlements included in prior period changes in fair value of commodity derivative instruments	18.1	(5.1)	32.0	18.4
Crude oil fixed price swaps, collars and rollfactors	(111.4)	43.1	(152.9)	88.7
Natural gas fixed price swaps and collars	(2.3)	8.3	(3.2)	16.7
Natural gas basis protection swaps	(1.7)	(0.2)	5.0	2.3
NGLs (propane portion) fixed price swaps	(2.4)	(0.2)	(1.8)	—
Net change in fair value of unsettled commodity derivative instruments	(99.7)	45.9	(120.9)	126.1
Total commodity price risk management gain (loss), net	$ (116.1)	$ 57.9	$ (163.4)	$ 138.6

Net settlements of commodity derivatives and net change in fair value of unsettled derivatives decreased for the three and six months ended June 30, 2018 as compared to the three and six months ended June 30, 2017 as a result of the increase in future commodity prices during the first half of 2018 compared to a decrease during the first half of 2017. Our decrease in net settlements for the three months ended June 30, 2018 was partially offset by an $11.3 million realized gain on the early settlement of certain commodity derivative basis protection positions, including $10.3 million for the early settlement of crude oil basis protection instruments and $1.0 million for the early settlement of natural gas basis protection instruments, both for our Delaware Basin operations. The volumes associated with these instruments were impacted by certain marketing agreements entered into during the three months ended June 30, 2018 which eliminated the underlying sale price variability, and therefore there was no longer a variable to hedge.

Lease Operating Expenses

Lease operating expenses increased 61 percent to $32.3 million in the three months ended June 30, 2018 compared to $20.0 million in the three months ended June 30, 2017. The increase was primarily due to increases of $4.4 million for increased workover projects, $1.6 million related to additional compressor and equipment rentals, $1.2 million for payroll and employee benefits related to increases in headcount, $1.2 million for environmental remediation expenses, $0.8 million related to midstream expense in the Delaware Basin and $0.8 million for produced water disposal. Lease operating expense per Boe increased by 38 percent to $3.44 for the three months ended June 30, 2018 from $2.50 for the three months ended June 30, 2017.

Lease operating expenses increased 55 percent to $61.9 million in the six months ended June 30, 2018 compared to $39.8 million in the six months ended June 30, 2017. The increase was primarily due to increases of $4.6 million for increased workover projects, $3.1 million for payroll and employee benefits related to increases in headcount, $2.9 million related to additional compressor and equipment rentals, $2.5 million related to midstream expense in the Delaware Basin, $2.1 million for environmental remediation expenses, $1.3 million for produced water disposal and $1.1 million related to chemical treatment programs. Lease operating expense per Boe increased by 24 percent to $3.38 for the six months ended June 30, 2018 from $2.72 for the six months ended June 30, 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.

Production taxes increased 50 percent to $22.6 million in the three months ended June 30, 2018 compared to $15.0 million in the three months ended June 30, 2017, primarily due to the 53 percent increase in crude oil, natural gas and NGLs sales for the three months ended June 30, 2018 compared to the three months ended June 30, 2017, as well as an increase in the ad valorem tax rate in the Delaware Basin related to an increase in assessed property values.

Production taxes increased 56 percent to $42.8 million in the six months ended June 30, 2018 compared to $27.4 million in the six months ended June 30, 2017, primarily due to the 57 percent increase in crude oil, natural gas and NGLs sales for the six months ended June 30, 2018 compared to the six months ended June 30, 2017, as well as an increase in the ad valorem tax rate in the Delaware Basin related to an increase in assessed property values.

Transportation, Gathering and Processing Expenses

Transportation, gathering and processing expenses increased 38 percent to $9.0 million in the three months ended June 30, 2018 compared to $6.5 million in the three months ended June 30, 2017. The increase was primarily due to an increase of $5.2 million related to natural gas gathering and transportation operations in the Delaware Basin and a $1.2 million increase in oil transportation costs due to additional volumes delivered through pipelines in the Wattenberg Field, 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 and a $1.1 million decrease due to the disposition of the Utica Shale properties. Transportation, gathering and processing expenses per Boe increased to $0.96 for the three months ended June 30, 2018 compared to $0.81 for the three months ended June 30, 2017.

Transportation, gathering and processing expenses increased 31 percent to $16.3 million in the six months ended June 30, 2018 compared to $12.4 million in the six months ended June 30, 2017. The increase was primarily due to an increase of $8.6 million related to natural gas gathering and transportation operations in the Delaware Basin and a $2.0 million increase in oil transportation costs due to additional volumes delivered through pipelines in the Wattenberg Field, partially offset by a $5.0 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 and a $1.8 million decrease due to the disposition of the Utica Shale properties. Transportation, gathering and processing expenses per Boe increased to $0.89 for the six months ended June 30, 2018 compared to $0.84 for the six months ended June 30, 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.

Impairment of Properties and Equipment

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Impairment of proved and unproved properties	$ 159.5	$ 27.5	$ 192.6	$ 29.6
Amortization of individually insignificant unproved properties	—	0.1	0.1	0.2
Impairment of crude oil and natural gas properties	$ 159.5	$ 27.6	$ 192.7	$ 29.8

During the six months ended June 30, 2018, we recorded impairment charges totaling $192.7 million, including $159.5 million during the three months ended June 30, 2018. During the three months ended June 30, 2018, we identified current and anticipated near-term leasehold expirations within our non-focus areas of the Delaware Basin and made the determination that we would no longer pursue plans to develop these properties. The impaired non-focus leasehold typically has a higher gas to oil ratio and a greater degree of geologic complexity than our other Delaware Basin properties and is further impacted by widening natural gas differentials and increased well development costs. We intend to focus our future Delaware Basin development in our oilier core areas where we have identified approximately 450 mid-length lateral equivalent

Wolfcamp drilling locations. We continue to explore options for our non-focus areas and monitor them for possible future impairment based on similar analyses. We determined the fair value of the properties 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.

General and Administrative Expense

General and administrative expense increased 26 percent to $37.2 million in the three months ended June 30, 2018 compared to $29.5 million in the three months ended June 30, 2017. The increase was primarily attributable to a $4.1 million increase in payroll and employee benefits, a $1.9 million increase related to professional services and a $1.0 million increase related to government relations.

General and administrative expense increased 31 percent to $72.9 million in the six months ended June 30, 2018 compared to $55.8 million in the six months ended June 30, 2017. The increase was primarily attributable to a $10.3 million increase in payroll and employee benefits, a $4.0 million increase related to professional services and a $1.9 million increase in government relations expenses.

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 $133.6 million and $258.4 million for the three and six months ended June 30, 2018, respectively, compared to $124.4 million and $232.2 million for the three and six months ended June 30, 2017, respectively.

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

	June 30, 2018	
	Three Months Ended	**Six Months Ended**
	(in thousands)	
Increase in production	$ 25.6	$ 58.2
Decrease in weighted-average depreciation, depletion and amortization rates	(16.4)	(32.0)
Total increase in DD&A expense related to crude oil and natural gas properties	$ 9.2	$ 26.2

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

	Three Months Ended June 30,		Six Months Ended June 30,	
Operating Region/Area	**2018**	**2017**	**2018**	**2017**
		(per Boe)		
Wattenberg Field	$ 12.94	$ 15.30	$ 13.23	$ 16.05
Delaware Basin	18.34	18.14	17.69	15.46
Utica Shale (1)	—	11.27	—	11.26
Total weighted-average	$ 14.24	$ 15.51	$ 14.13	$ 15.83

(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 in 2018. In March 2018, we completed the disposition of the properties.

Non-crude oil and natural gas properties. Depreciation expense for non-crude oil and natural gas properties was $2.0 million and $4.0 million for the three and six months ended June 30, 2018, respectively, compared to $1.7 million and $3.2 million for the three and six months ended June 30, 2017, respectively.

Provision for Uncollectible Notes Receivable

In the first quarter of 2016, we recorded a provision for uncollectible notes receivable of $44.7 million to impair two third-party notes receivable whose collection was not reasonably assured. As described in the footnote titled *Fair Value of Financial Instruments*, in April 2017, we sold one of the associated notes receivable to an unrelated third-party. Accordingly, we reversed $40.2 million of the provision for uncollectible notes receivable during the three months ended June 30, 2017.

Interest Expense

Interest expense decreased $2.2 million to $17.4 million for the three months ended June 30, 2018 compared to $19.6 million for the three months ended June 30, 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 $1.1 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.

Interest expense decreased $4.1 million to $34.9 million for the six months ended June 30, 2018 compared to $39.1 million for the six months ended June 30, 2017. The decrease was primarily related to a $19.9 million decrease in interest expense relating to the net settlement of $500 million 7.75% senior notes in December 2017 and a $2.0 million increase in capitalized interest. The decreases were partially offset by a $17.6 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 rates for the three and six months ended June 30, 2018 were a 22.0 percent and 22.3 percent benefit on loss, respectively, compared to 37.3 percent and 36.8 percent expense on income, respectively, for the three and six months ended June 30, 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 pursuant to the 2017 Tax Act.

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

The factors resulting in changes in net loss in the three and six months ended June 30, 2018 of $160.3 million and $173.4 million, respectively, and net income in the three and six months ended June 30, 2017 of $41.2 million and $87.4 million, respectively, are discussed above. Adjusted net loss, a non-U.S. GAAP financial measure, was $84.5 million and $81.4 million for the three and six months ended June 30, 2018, respectively, and adjusted net income, a non-U.S. GAAP financial measure, was $12.5 million and $8.5 million for the three and six months ended June 30, 2017, respectively. With the exception of the tax affected net change in fair value of unsettled derivatives of $75.8 million and $92.0 million for the three and six months ended June 30, 2018, respectively, and $28.7 million and $78.9 million for the three and six months ended June 30, 2017, respectively, 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 six months ended June 30, 2018, our net cash flows from operating activities were $380.9 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. Due to a decreasing leverage ratio that we have recently experienced, the percentage of our expected future production that we currently have hedged is lower than we have historically maintained and we anticipate that this may remain the case in the near term. Based upon our current hedge position and assuming forward strip pricing as of June 30, 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 $391.0 million and $16.4 million at June 30, 2018 and December 31, 2017, respectively. The increase in working capital deficit as of June 30, 2018 of $374.6 million is primarily the result of a decrease in cash and cash equivalents of $179.3 million related to the Bayswater Acquisition, partially offset by the proceeds received from the Utica Shale Divestiture and an amendment to a midstream dedication agreement, a decrease in the net fair value of our unsettled commodity derivative instruments of $106.8 million, an increase in accounts payable of $65.1 million related to increased development and exploration activity, and an increase in production tax liability of $19.1 million.

Our cash and cash equivalents were $1.4 million at June 30, 2018 and availability under our revolving credit facility was $678.0 million, providing for a total liquidity position of $679.4 million as of June 30, 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 between $75 million and $100 million, of which we anticipate approximately $65 million will be covered by an amendment to a midstream dedication agreement and the divestiture of our Utica Shale properties. We experienced this outspend during the first half of 2018 and expect cash flows from operations to exceed capital investment during the second half of the year. 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 2023.

In May 2018, we entered into the Restated Credit Agreement with certain banks and other lenders, including JPMorgan Chase Bank, N.A. as administrative agent. The Restated Credit Agreement amends and restates our Third Amended and Restated Credit Agreement dated as of May 21, 2013. See the footnote titled *Long-Term Debt* to our condensed consolidated financial statements included elsewhere in this report for additional information regarding the Restated Credit Agreement.

Amounts borrowed under the revolving credit facility bear interest at either an alternate base rate option or a LIBOR option as defined in the revolving credit facility plus an applicable margin, depending on the percentage of the commitment that has been utilized. As of June 30, 2018, the applicable margin is 0.25 percent for the alternate base rate option or 1.25 percent for the LIBOR option, and the unused commitment fee is 0.375 percent.

We had a $22.0 million outstanding balance on our revolving credit facility as of June 30, 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 June 30, 2018 and December 31, 2017, we had $8.0 million and $9.3 million in restricted cash, respectively.

Our revolving credit facility contains financial maintenance covenants. The covenants require that we maintain (i) a leverage ratio defined as total debt of less than 4.0 times the trailing 12 months earnings before interest, taxes, depreciation, depletion and amortization, change in fair value of unsettled commodity derivatives, exploration expense, gains (losses) on sales of assets and other non-cash gains (losses) and (ii) an adjusted current ratio of at least 1.0:1.0. Our adjusted current ratio is adjusted by eliminating the impact on our current assets and liabilities of recording the fair value of crude oil and natural gas commodity derivative instruments. Additionally, available borrowings under our revolving credit facility are added to the current asset calculation and the current portion of our revolving credit facility debt is eliminated from the current liabilities calculation. At June 30, 2018, we were in compliance with all debt covenants with a leverage ratio of 1.6:1.0 and a current ratio of 2.1:1.0. 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 June 30, 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 $108.4 million to $380.9 million for the six months ended June 30, 2018 compared to the six months ended June 30, 2017, primarily due to increases in crude oil, natural gas and NGLs sales of $227.9 million. This increase was offset in part by a decrease in commodity derivative settlements of $55.0 million and increases in lease operating expenses of $22.1 million, general and administrative expenses of $17.1 million and production taxes of $15.3 million.

Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased by $117.7 million to $374.3 million during the six months ended June 30, 2018 compared to the six months ended June 30, 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 $73.8 million during the six months ended June 30, 2018, compared to the six months ended June 30, 2017. The increase was primarily the result of an increase in crude oil, natural gas and NGLs sales of $227.9 million. This increase was partially offset by a decrease in commodity derivative settlements of $55.0 million, the reversal of a provision for uncollectible notes receivable of $40.2 million in the six months ended June 30, 2017, and increases in lease operating expenses of $22.1 million, general and administrative expenses of $17.1 million and production taxes of $15.3 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 $574.1 million during the six months ended June 30, 2018 was primarily related to cash utilized toward the purchase price of the Bayswater Acquisition of $181.1 million and our drilling and completion activities of $432.6 million. Partially offsetting these investments was the receipt of approximately $39.0 million related to the Utica Shale Divestiture.

Financing Activities. Net cash received from financing activities of $12.7 million during the six months ended June 30, 2018 was primarily comprised of net borrowings from our credit facility of $22.0 million, which was partially offset by $4.5 million related to purchases of our stock and $4.1 million of debt issuance costs, primarily related to our Restated Credit Agreement.

Off-Balance Sheet Arrangements

At June 30, 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.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Adjusted cash flows from operations:				
Net cash from operating activities	$ 175.7	$ 132.9	$ 380.9	$ 272.4
Changes in assets and liabilities	23.6	10.0	(6.6)	(15.8)
Adjusted cash flows from operations	$ 199.3	$ 142.9	$ 374.3	$ 256.6
Adjusted net income (loss):				
Net income (loss)	$ (160.3)	$ 41.2	$ (173.4)	$ 87.4
(Gain) loss on commodity derivative instruments	116.1	(57.9)	163.4	(138.6)
Net settlements on commodity derivative instruments	(16.4)	12.0	(42.4)	12.5
Tax effect of above adjustments	(23.9)	17.2	(29.0)	47.2
Adjusted net income (loss)	$ (84.5)	$ 12.5	$ (81.4)	$ 8.5
Net income (loss) to adjusted EBITDAX:				
Net income (loss)	$ (160.3)	$ 41.2	$ (173.4)	$ 87.4
(Gain) loss on commodity derivative instruments	116.1	(57.9)	163.4	(138.6)
Net settlements on commodity derivative instruments	(16.4)	12.0	(42.4)	12.5
Non-cash stock-based compensation	5.5	5.4	10.8	9.8
Interest expense, net	17.3	18.9	34.7	38.1
Income tax expense (benefit)	(45.3)	24.5	(49.9)	50.9
Impairment of properties and equipment	159.5	27.6	192.7	29.8
Exploration, geologic and geophysical expense	0.9	1.0	3.5	2.0
Depreciation, depletion and amortization	135.6	126.0	262.4	235.3
Accretion of asset retirement obligations	1.4	1.7	2.6	3.4
Adjusted EBITDAX	$ 214.3	$ 200.4	$ 404.4	$ 330.6
Cash from operating activities to adjusted EBITDAX:				
Net cash from operating activities	$ 175.7	$ 132.9	$ 380.9	$ 272.4
Interest expense, net	17.3	18.9	34.7	38.1
Amortization of debt discount and issuance costs	(3.1)	(3.2)	(6.4)	(6.4)
Gain (loss) on sale of properties and equipment	0.4	0.5	(1.1)	0.7
Exploration, geologic and geophysical expense	0.9	1.0	3.5	2.0
Other	(0.5)	40.3	(0.6)	39.6
Changes in assets and liabilities	23.6	10.0	(6.6)	(15.8)
Adjusted EBITDAX	$ 214.3	$ 200.4	$ 404.4	$ 330.6

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 June 30, 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 June 30, 2018 was $0.6 million with a weighted-average interest rate of 1.3 percent. Based on a sensitivity analysis of our interest-bearing deposits as of June 30, 2018 and assuming we had $0.6 million outstanding throughout the period, we estimate that a one percent increase in interest rates would not have had a material impact on interest income for the six months ended June 30, 2018.

As of June 30, 2018, we had $22.0 million 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 June 30, 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 June 30, 2018	Six Months Ended June 30, 2018	Year Ended December 31, 2017
Average NYMEX Index Price:			
Crude oil (per Bbl)	$ 67.88	$ 65.37	$ 50.95
Natural gas (per MMBtu)	2.80	2.90	3.11
Average Sales Price Realized:			
Excluding net settlements on commodity derivatives			
Crude oil (per Bbl)	$ 63.99	$ 61.85	$ 48.45
Natural gas (per Mcf)	1.46	1.71	2.21
NGLs (per Bbl)	21.76	21.78	18.59

Based on a sensitivity analysis as of June 30, 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 $92.4 million, whereas a ten percent decrease in prices would have resulted in an increase in fair value of $91.7 million.

Credit Risk

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

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

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

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

Disclosure of Limitations

Because the information above included only those exposures that existed at June 30, 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 June 30, 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 June 30, 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 six months ended June 30, 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.

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
April 1 - 30, 2018	45,706	$ 48.99
May 1 - 31, 2018	—	—
June 1 - 30, 2018	—	—
Total second quarter 2018 purchases	45,706	$ 48.99

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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.

ITEM 6. EXHIBITS

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

* Furnished herewith.

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: August 8, 2018

/s/ Barton Brookman
Barton 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)

Exhibit 31.1

CERTIFICATIONS

I, Barton Brookman, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PDC Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 8, 2018

/s/ Barton Brookman

Barton Brookman
President and Chief Executive Officer

(principal executive officer)

Exhibit 31.2

CERTIFICATIONS

I, R. Scott Meyers, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PDC Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 8, 2018

/s/ R. Scott Meyers

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

Exhibit 32.1

CERTIFICATION

In connection with the Quarterly Report of PDC Energy, Inc. (the "Company") on Form 10-Q for the period ended June 30, 2018, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned certify pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Barton Brookman	August 8, 2018
Barton Brookman President and Chief Executive Officer (principal executive officer)	
/s/ R. Scott Meyers	August 8, 2018
R. Scott Meyers Senior Vice President and Chief Financial Officer (principal financial officer)	