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

FORM 10-Q

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

For the quarterly period ended June 30, 2019
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

Securities registered pursuant to Section 12(b) of the Act.

Title of each class	Ticker Symbol	Name of each exchange on which registered
Common stock, par value $0.01 per share	PDCE	Nasdaq Global Select Market

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 every Interactive Data File required to be submitted 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 such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth 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	☐	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: 62,597,588 shares of the Company's Common Stock ($0.01 par value) were outstanding as of July 22, 2019.

PDC ENERGY, INC.

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act"), Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") and the United States ("U.S.") Private Securities Litigation Reform Act of 1995 regarding our business, financial condition, results of operations and prospects. All statements other than statements of historical fact included in and incorporated by reference into this report are "forward-looking statements." Words such as expect, anticipate, intend, plan, believe, seek, estimate, schedule 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, zones and growth opportunities; commodity prices and differentials; capital expenditures and projects, including the number of rigs employed, and that cash flows from operations will exceed expected capital investments in crude oil and natural gas properties for 2019 and 2020; our stock repurchase program, which may be modified or discontinued at any time; potential additional payments from the sale of our midstream assets; financial ratios and compliance with covenants in our revolving credit facility and other debt instruments; impacts of certain accounting and tax changes; timing and adequacy of infrastructure projects of our midstream providers and the related impact on our midstream capacity and related curtailments; fractionation capacity; impacts of Colorado political matters and expected timing of rulemakings; ability to meet our volume commitments to midstream providers; ongoing compliance with our consent decree and expected timing of certain litigation; and reclassification of the Denver Metro/North Front Range NAA ozone classification to serious.

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 global 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 or 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 changes in costs and expenses;
- 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 derivative activities;
- impact to our operations, personnel retention, strategy, stock price and expenses caused by the actions of activist shareholders;
- 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, 2018 filed with the U.S. Securities and Exchange Commission ("SEC") on February 28, 2019 (the "2018 Form 10-K"), our Quarterly Report on Form 10-Q for the quarter ended March 31, 2019 filed with the SEC on May 2, 2019 (the "2019 Q1 Form 10-Q") 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, 2019	December 31, 2018
Assets		
Current assets:		
Cash and cash equivalents	$ 1,474	$ 1,398
Accounts receivable, net	277,321	181,434
Fair value of derivatives	41,425	84,492
Prepaid expenses and other current assets	5,607	7,136
Total current assets	325,827	274,460
Properties and equipment, net	4,196,335	4,002,862
Assets held-for-sale, net	—	140,705
Fair value of derivatives	31,655	93,722
Other assets	41,087	32,396
Total Assets	$ 4,594,904	$ 4,544,145
Liabilities and Stockholders' Equity		
Liabilities		
Current liabilities:		
Accounts payable	$ 219,158	$ 181,864
Production tax liability	69,951	60,719
Fair value of derivatives	19,775	3,364
Funds held for distribution	88,879	105,784
Accrued interest payable	14,273	14,150
Other accrued expenses	86,523	75,133
Total current liabilities	498,559	441,014
Long-term debt	1,197,744	1,194,876
Deferred income taxes	183,120	198,096
Asset retirement obligations	78,909	85,312
Liabilities held-for-sale	—	4,111
Fair value of derivatives	927	1,364
Other liabilities	257,239	92,664
Total liabilities	2,216,498	2,017,437
Commitments and contingent liabilities		
Stockholders' equity		
Common shares - par value $0.01 per share, 150,000,000 authorized, 63,520,462 and 66,148,609 issued as of June 30, 2019 and December 31, 2018, respectively	635	661
Additional paid-in capital	2,433,974	2,519,423
Retained earnings (deficit)	(42,901)	8,727
Treasury shares - at cost, 364,780 and 45,220 as of June 30, 2019 and December 31, 2018, respectively	(13,302)	(2,103)
Total stockholders' equity	2,378,406	2,526,708
Total Liabilities and Stockholders' Equity	$ 4,594,904	$ 4,544,145

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,	
	2019	2018	2019	2018
Revenues				
Crude oil, natural gas and NGLs sales	$ 338,956	$ 325,933	$ 660,055	$ 631,158
Commodity price risk management gain (loss), net	47,349	(116,126)	(142,725)	(163,366)
Other income	4,353	2,724	7,828	5,339
Total revenues	390,658	212,531	525,158	473,131
Costs, expenses and other				
Lease operating expenses	34,328	32,260	69,549	61,896
Production taxes	22,642	22,604	44,810	42,773
Transportation, gathering and processing expenses	12,208	8,964	23,632	16,277
Exploration, geologic and geophysical expense	640	875	3,283	3,521
Impairment of properties and equipment	28,979	159,554	36,854	192,742
General and administrative expense	42,808	37,247	82,406	72,943
Depreciation, depletion and amortization	168,523	135,624	319,945	262,412
Accretion of asset retirement obligations	1,563	1,285	3,147	2,573
(Gain) loss on sale of properties and equipment	(33,904)	(351)	(34,273)	1,081
Other expenses	2,836	2,708	6,390	5,476
Total costs, expenses and other	280,623	400,770	555,743	661,694
Income (loss) from operations	110,035	(188,239)	(30,585)	(188,563)
Interest expense	(18,905)	(17,410)	(35,883)	(34,939)
Interest income	5	69	15	217
Income (loss) before income taxes	91,135	(205,580)	(66,453)	(223,285)
Income tax (expense) benefit	(22,587)	45,323	14,825	49,889
Net income (loss)	$ 68,548	$ (160,257)	$ (51,628)	$ (173,396)
Earnings per share:				
Basic	$ 1.04	$ (2.43)	$ (0.78)	$ (2.63)
Diluted	$ 1.04	$ (2.43)	$ (0.78)	$ (2.63)
Weighted-average common shares outstanding:				
Basic	65,815	66,066	65,998	66,012
Diluted	65,926	66,066	65,998	66,012

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, 2019	Six Months Ended June 30, 2018
Cash flows from operating activities:		
Net loss	$ (51,628)	$ (173,396)
Adjustments to net loss to reconcile to net cash from operating activities:		
Net change in fair value of unsettled commodity derivatives	121,080	120,920
Depreciation, depletion and amortization	319,945	262,412
Impairment of properties and equipment	36,854	192,742
Accretion of asset retirement obligations	3,147	2,573
Non-cash stock-based compensation	12,258	10,779
(Gain) loss on sale of properties and equipment	(34,273)	1,081
Amortization of debt discount and issuance costs	6,731	6,372
Deferred income taxes	(14,975)	(50,181)
Other	395	974
Changes in assets and liabilities	42,702	6,581
Net cash from operating activities	442,236	380,857
Cash flows from investing activities:		
Capital expenditures for development of crude oil and natural gas properties	(542,791)	(432,635)
Capital expenditures for other properties and equipment	(10,453)	(2,450)
Acquisition of crude oil and natural gas properties	(4,146)	(181,052)
Proceeds from sale of properties and equipment	1,154	1,782
Proceeds from divestitures	199,430	39,023
Restricted cash	8,001	1,249
Net cash from investing activities	(348,805)	(574,083)
Cash flows from financing activities:		
Proceeds from revolving credit facility	890,000	233,000
Repayment of revolving credit facility	(892,500)	(211,000)
Payment of debt issuance costs	(36)	(4,060)
Purchase of treasury shares	(94,113)	—
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	(3,717)	(4,494)
Other	(990)	(719)
Net cash from financing activities	(101,356)	12,727
Net change in cash, cash equivalents and restricted cash	(7,925)	(180,499)
Cash, cash equivalents and restricted cash, beginning of period	9,399	189,925
Cash, cash equivalents and restricted cash, end of period	$ 1,474	$ 9,426

See accompanying Notes to Condensed Consolidated Financial Statements

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

	Three Months Ended June 30, 2019						
	Common Stock		Additional Paid-in Capital	Treasury Stock		Retained Earnings (Deficit)	Total Stockholders' Equity
	Shares	Amount		Shares	Amount		
Balance, March 31, 2019	66,196,863	$ 662	$ 2,521,558	(22,635)	$ (1,016)	$ (111,449)	$ 2,409,755
Net income	—	—	—	—	—	68,548	68,548
Stock-based compensation	148,040	1	7,574	—	—	—	7,575
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(54,784)	(2,257)	—	(2,257)
Retirement of treasury shares for employee stock-based compensation tax withholding obligations	(2,182)	—	(78)	2,182	78	—	—
Purchase of treasury shares	—	—	—	(3,136,406)	(105,215)	—	(105,215)
Retirement of treasury shares	(2,822,259)	(28)	(94,085)	2,822,259	94,113	—	—
Issuance of treasury shares	—	—	(995)	24,604	995	—	—
Balance, June 30, 2019	63,520,462	$ 635	$ 2,433,974	(364,780)	$ (13,302)	$ (42,901)	$ 2,378,406

	Three Months Ended June 30, 2018						
	Common Stock		Additional Paid-in Capital	Treasury Stock		Retained Earnings (Deficit)	Total Stockholders' Equity
	Shares	Amount		Shares	Amount		
Balance, March 31, 2018	65,999,010	$ 660	$ 2,504,663	(29,255)	$ (1,514)	$ (6,435)	$ 2,497,374
Net loss	—	—	—	—	—	(160,257)	(160,257)
Stock-based compensation	134,015	1	5,517	—	—	—	5,518
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(45,706)	(2,239)	—	(2,239)
Issuance of treasury shares	—	—	(397)	7,792	397	—	—
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.
Condensed Consolidated Statements of Equity
(unaudited; in thousands, except share data)

	Six Months Ended June 30, 2019						
	Common Stock		Additional Paid-in Capital	Treasury Stock		Retained Earnings (Deficit)	Total Stockholders' Equity
	Shares	Amount		Shares	Amount		
Balance, December 31, 2018	66,148,609	$ 661	$ 2,519,423	(45,220)	$ (2,103)	$ 8,727	$ 2,526,708
Net loss	—	—	—	—	—	(51,628)	(51,628)
Stock-based compensation	196,294	2	12,256	—	—	—	12,258
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(96,571)	(3,717)	—	(3,717)
Retirement of treasury shares for employee stock-based compensation tax withholding obligations	(2,182)	—	(78)	2,182	78	—	—
Purchase of treasury shares	—	—	—	(3,136,406)	(105,215)	—	(105,215)
Retirement of treasury shares	(2,822,259)	(28)	(94,085)	2,822,259	94,113	—	—
Issuance of treasury shares	—	—	(3,542)	88,976	3,542	—	—
Balance, June 30, 2019	63,520,462	$ 635	$ 2,433,974	(364,780)	$ (13,302)	$ (42,901)	$ 2,378,406

	Six Months Ended June 30, 2018						
	Common Stock		Additional Paid-in Capital	Treasury Stock		Retained Earnings (Deficit)	Total Stockholders' Equity
	Shares	Amount		Shares	Amount		
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)
Stock-based compensation	177,945	2	10,777	—	—	—	10,779
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(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)
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, 2019
(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, 2019, we owned an interest in approximately 2,800 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, 2018 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 2018 Form 10-K. Our results of operations and cash flows for the six months ended June 30, 2019 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 Standards

In February 2016, the Financial Accounting Standards Board ("FASB") issued an accounting update and subsequent amendments 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 “New Lease Standard”). For leases with terms of more than 12 months, the accounting update requires lessees to recognize a right-of-use ("ROU") asset and lease liability for its right to use the underlying asset and the corresponding lease obligation. As provided by practical expedients, we made accounting policy elections to not recognize ROU assets and lease liabilities that arise from short-term leases and to not separate lease and non-lease components for any class of underlying asset. The FASB issued an accounting update which provides an optional transition practical expedient for the adoption of the New Lease Standard that, if elected, permits an organization to not evaluate the accounting for existing land easements that are not accounted for under the previous lease accounting standard. We elected this practical expedient, and accordingly, existing land easements at December 31, 2018 were not assessed. All new or modified land easements entered into after January 1, 2019 are evaluated under the New Lease Standard. The New Lease Standard does not apply to leases of mineral rights to explore for or use crude oil and natural gas. Adoption of the New Lease Standard resulted in increases to other assets of $20.1 million, other accrued expenses of $4.6 million and other liabilities of $15.5 million at January 1, 2019, with no adjustment to the opening balance of retained earnings.

Recently Issued Accounting Standards

In June 2016, the FASB issued an accounting update and subsequent amendments on the impairment of financial instruments. The update adds a new impairment model, known as the current expected credit loss ("CECL") model, which is based upon expected credit losses rather than incurred losses. Under the new guidance, an allowance will be recognized based upon the entity's estimate of lifetime expected credit losses. The update is effective for fiscal years beginning after December

15, 2019, including interim periods within those fiscal years and early adoption is permitted. We are currently evaluating the impact these changes may have on our condensed consolidated financial statements.

NOTE 3 - REVENUE RECOGNITION

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.

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, 2019 and 2018 (in thousands):

Revenue by Commodity and Operating Region	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Percent Change	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018	Percentage Change
Crude oil						
Wattenberg Field	$ 203,548	$ 189,992	7.1 %	$ 383,974	$ 360,299	6.6 %
Delaware Basin	70,620	62,599	12.8 %	121,277	116,016	4.5 %
Utica Shale (1)	—	—	*	—	2,696	*
Total	$ 274,168	$ 252,591	8.5 %	$ 505,251	$ 479,011	5.5 %
Natural gas						
Wattenberg Field	$ 30,129	$ 22,640	33.1 %	$ 76,831	$ 52,412	46.6 %
Delaware Basin	910	7,472	(87.8)%	6,680	15,151	(55.9)%
Utica Shale (1)	—	—	*	—	1,109	*
Total	$ 31,039	$ 30,112	3.1 %	$ 83,511	$ 68,672	21.6 %
NGLs						
Wattenberg Field	$ 22,677	$ 30,271	(25.1)%	$ 50,399	$ 59,041	(14.6)%
Delaware Basin	11,072	12,959	(14.6)%	20,894	23,594	(11.4)%
Utica Shale (1)	—	—	*	—	840	*
Total	$ 33,749	$ 43,230	(21.9)%	$ 71,293	$ 83,475	(14.6)%
Revenue by Operating Region						
Wattenberg Field	$ 256,354	$ 242,903	5.5 %	$ 511,204	$ 471,752	8.4 %
Delaware Basin	82,602	83,030	(0.5)%	148,851	154,761	(3.8)%
Utica Shale (1)	—	—	*	—	4,645	*
Total	$ 338,956	$ 325,933	4.0 %	$ 660,055	$ 631,158	4.6 %

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

NOTE 4 - 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.

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

	June 30, 2019			December 31, 2018		
	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	$ 48,200	$ 24,880	$ 73,080	$ 118,521	$ 59,693	$ 178,214
Total liabilities	(18,326)	(2,376)	(20,702)	(3,364)	(1,364)	(4,728)
Net asset	$ 29,874	$ 22,504	$ 52,378	$ 115,157	$ 58,329	$ 173,486

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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,	
	2019	2018	2019	2018
	(in thousands)			
Fair value of Level 3 instruments, net asset (liability) beginning of period	$ 12,990	$ (8,834)	$ 58,329	$ (9,687)
Changes in fair value included in condensed consolidated statement of operations line item:				
Commodity price risk management gain (loss), net	10,597	(4,701)	(32,923)	(6,854)
Settlements included in condensed consolidated statement of operations line items:				
Commodity price risk management gain (loss), net	(1,083)	(5,565)	(2,902)	(2,559)
Fair value of Level 3 instruments, net asset (liability) end of period	$ 22,504	$ (19,100)	$ 22,504	$ (19,100)
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	$ 6,200	$ (15,582)	$ (26,641)	$ (9,412)

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 the financial statements.

Non-Derivative Financial Assets and Liabilities

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:

	June 30, 2019		December 31, 2018	
	Estimated Fair Value	Percent of Par	Estimated Fair Value	Percent of Par
	(in millions)			
Senior notes:				
2021 Convertible Notes	$ 188.8	94.4%	$ 175.4	87.7%
2024 Senior Notes	400.4	100.1%	370.2	92.5%
2026 Senior Notes	598.2	99.7%	532.4	88.7%

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.

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 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, 2019.

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, 2019 and December 31, 2018. 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 lenders under our revolving credit facility.

NOTE 5 - COMMODITY DERIVATIVE FINANCIAL INSTRUMENTS

Our results of operations and operating cash flows are affected by changes in market prices for crude oil, natural gas and NGLs. To manage a portion of our exposure to price volatility from producing crude oil and natural gas 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, 2019, we had derivative instruments, which were comprised of collars, fixed-price swaps and basis protection swaps, in place for a portion of our anticipated 2019, 2020 and 2021 production. Our commodity derivative contracts have been entered into at no upfront 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, 2019, we had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted-average contract price is disclosed.

	Collars			Fixed-Price Swaps		
Commodity/ Index/ Maturity Period	**Quantity** *(Crude oil - MBls Natural Gas - BBtu)*	**Weighted-Average Contract Price Floors**	**Weighted-Average Contract Price Ceilings**	**Quantity** *(Crude Oil - MBbls Gas and Basis- BBtu)*	**Weighted-Average Contract Price**	**Fair Value June 30, 2019 (1)** *(in thousands)*
Crude Oil						
NYMEX						
2019	2,500	$ 57.40	$ 67.26	3,900	$ 55.08	$ (5,583)
2020	3,600	55.00	71.68	6,200	61.28	48,856
2021	—	—	—	1,200	57.99	4,262
Total Crude Oil	6,100			11,300		$ 47,535
Natural Gas						
NYMEX						
2019	—	$ —	$ —	15,164	$ 2.91	$ 8,228
Dominion South						
2019	—	—	—	42	2.54	2
2020	—	—	—	14	2.54	—
Total Natural Gas	—			15,220		$ 8,230
Basis Protection - Natural Gas						
CIG						
2019	—	$ —	$ —	22,322	$ (0.68)	$ (3,102)
2020	—	—	—	10,500	(0.64)	(285)
Total Basis Protection - Natural Gas	—			32,822		$ (3,387)
Commodity Derivatives Fair Value						$ 52,378

(1) *Approximately 34.0 percent of the fair value of our commodity derivative assets and 11.5 percent of the fair value of our commodity derivative liabilities were measured using significant unobservable inputs (Level 3).*

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, 2019	Fair Value December 31, 2018
			(in thousands)	
Derivative assets:	Current			
	Commodity derivative contracts	Fair value of derivatives	$ 41,214	$ 84,492
	Basis protection derivative contracts	Fair value of derivatives	211	—
			41,425	84,492
	Non-current			
	Commodity derivative contracts	Fair value of derivatives	31,655	93,722
Total derivative assets			$ 73,080	$ 178,214
Derivative liabilities:	Current			
	Commodity derivative contracts	Fair value of derivatives	$ 16,410	$ 748
	Basis protection derivative contracts	Fair value of derivatives	3,365	2,616
			19,775	3,364
	Non-current			
	Commodity derivative contracts	Fair value of derivatives	694	1,364
	Basis protection derivative contracts	Fair value of derivatives	233	—
			927	1,364
Total derivative liabilities			$ 20,702	$ 4,728

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, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
	(in thousands)			
Commodity price risk management gain (loss), net				
Net settlements	$ (13,193)	$ (16,408)	$ (21,645)	$ (42,446)
Net change in fair value of unsettled derivatives	60,542	(99,718)	(121,080)	(120,920)
Total commodity price risk management gain (loss), net	$ 47,349	$ (116,126)	$ (142,725)	$ (163,366)

Our financial derivative agreements contain master netting provisions that provide for the net settlement of 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, 2019	Derivative Instruments, Gross	Effect of Master Netting Agreements	Derivative Instruments, Net
		(in thousands)	
Asset derivatives:			
Derivative instruments, at fair value	$ 73,080	$ (15,731)	$ 57,349
Liability derivatives:			
Derivative instruments, at fair value	$ 20,702	$ (15,731)	$ 4,971

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As of December 31, 2018	Derivative Instruments, Gross	Effect of Master Netting Agreements	Derivative Instruments, Net
		(in thousands)	
Asset derivatives:			
Derivative instruments, at fair value	$ 178,214	$ (3,985)	$ 174,229
Liability derivatives:			
Derivative instruments, at fair value	$ 4,728	$ (3,985)	$ 743

NOTE 6 - PROPERTIES AND EQUIPMENT

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

	June 30, 2019	December 31, 2018
	(in thousands)	
Properties and equipment, net:		
Crude oil and natural gas properties		
Proved	$ 5,920,714	$ 5,452,613
Unproved	480,316	492,594
Total crude oil and natural gas properties	6,401,030	5,945,207
Equipment and other	40,716	60,612
Land and buildings	12,547	11,243
Construction in progress	429,542	356,095
Properties and equipment, at cost	6,883,835	6,373,157
Accumulated DD&A	(2,687,500)	(2,370,295)
Properties and equipment, net	$ 4,196,335	$ 4,002,862

Midstream Asset Divestitures. During the second quarter of 2019, we completed the sales of our Delaware Basin produced water gathering and disposal, crude oil gathering and natural gas gathering assets (the "Midstream Asset Divestitures") for aggregate proceeds of $345.6 million. Concurrent with the Midstream Asset Divestitures, we entered into agreements with the purchasers which provide us with certain gathering, processing, transportation and water disposal services. Proceeds were allocated first to the assets sold based upon the fair values of the tangible assets sold, with the remainder of $179.6 million allocated to the acreage dedication agreements. See footnote titled *Other Accrued Expenses and Other Liabilities* for further details regarding these agreements.

In May 2019, we completed the sale of our produced water gathering and disposal midstream assets in the Delaware Basin for $126.3 million, subject to certain customary post-closing adjustments, plus potential future payments of up to $75.0 million. We recorded a gain on the sale of $25.7 million based on the fair value of the tangible assets sold.

In May 2019, we also completed the sale of our crude oil gathering midstream assets in the Delaware Basin for $37.3 million, subject to certain customary post-closing adjustments, plus potential future payments of up to $15.2 million. We recorded a loss on the sale of $0.2 million based on the fair value of the tangible assets sold.

In June 2019, we completed the sale of our natural gas gathering midstream assets in the Delaware Basin for $182.0 million ($100.0 million of which was paid upon closing with the remaining $82.0 million paid one year post-closing), subject to certain customary post-closing adjustments, plus potential future payments of up to $60.5 million. The $82.0 million receivable is included in accounts receivable, net on our condensed consolidated balance sheet at June 30, 2019. We recorded a gain on the sale of $8.5 million based on the fair value of the tangible assets sold.

The Midstream Asset Divestitures 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 the divested assets as discontinued operations.

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Classification of Assets and Liabilities as Held-for-Sale. Assets held-for-sale at December 31, 2018 included assets sold in the Midstream Asset Divestitures, and certain non-core Delaware Basin crude oil and natural gas properties. The following table presents balance sheet data related to assets and liabilities held-for-sale:

	December 31, 2018
	(in thousands)
Assets	
Properties and equipment, net	$ 137,448
Other assets	3,257
Total assets	$ 140,705
Liabilities	
Asset retirement obligation	$ 4,111
Total liabilities	$ 4,111

During the three months ended June 30, 2019, we sold certain Delaware Basin crude oil and natural gas properties for net cash proceeds of $33.4 million, which approximated the net book value, resulting in no gain or loss on the sale.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(in thousands)			
Impairment of proved and unproved properties	$ 2,229	$ 159,528	$ 10,104	$ 192,658
Amortization of individually insignificant unproved properties	—	26	—	84
Impairment of infrastructure and other	26,750	—	26,750	—
Impairment of properties and equipment	$ 28,979	$ 159,554	$ 36,854	$ 192,742

During the six months ended June 30, 2019 and 2018, we recorded impairment charges totaling $10.1 million and $192.7 million respectively, including $2.2 million and $159.5 million during the three months ended June 30, 2019 and 2018, respectively, related to the divestiture of leaseholds and then-current and anticipated near-term leasehold expirations within our non-focus areas of the Delaware Basin that we determined not to develop. 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. During the three and six months ended June 30, 2019, we also recorded impairments of $26.8 million related to certain midstream facility infrastructure in the Delaware Basin. Upon closing of the Midstream Asset Divestitures, it was determined that the net book value of these assets was not recoverable.

During the six months ended June 30, 2018, we also 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 Accounting Standards Codification 250, *Accounting Changes and Error Corrections* ("ASC 250"). Based on the guidance in ASC 250, we determined that the error did not have a material impact on our previously-issued financial statements or those of the period of correction.

Suspended Well Costs. 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,	Year Ended December 31, 2018
	(in thousands, except for number of wells)	
Beginning balance	$ 12,188	$ 15,448
Additions to capitalized exploratory well costs pending the determination of proved reserves	22,270	35,127
Reclassifications to proved properties	(13,213)	(38,387)
Ending balance	$ 21,245	$ 12,188
Number of wells pending determination at period-end	3	2

During the six months ended June 30, 2019, one well classified as exploratory at December 31, 2018 was reclassified as productive and two new wells drilled were classified as exploratory.

NOTE 7 - OTHER ACCRUED EXPENSES AND OTHER LIABILITIES

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

	June 30, 2019	December 31, 2018
	(in thousands)	
Employee benefits	$ 16,229	$ 25,811
Asset retirement obligations	29,853	25,598
Purchases of treasury shares	11,102	—
Environmental expenses	2,424	3,038
Operating and finance leases	5,870	—
Other	21,045	20,686
Other accrued expenses	$ 86,523	$ 75,133

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

	June 30, 2019	December 31, 2018
	(in thousands)	
Production taxes	$ 34,608	$ 61,310
Deferred oil gathering credits	21,705	22,710
Deferred midstream gathering credits	178,918	—
Operating and finance leases	18,292	—
Other	3,716	8,644
Other liabilities	$ 257,239	$ 92,664

Deferred Oil Gathering Credits. In January 2018, we entered into an agreement that dedicates crude oil from the majority of our Wattenberg Field acreage to the midstream provider's gathering lines and extends the term of the agreement through December 2029. The payment is being amortized over the life of the agreement. Amortization charges totaling approximately $0.5 million and $0.4 million for the three months ended June 30, 2019 and 2018, respectively, and $1.0 million and $0.7 million for the six months ended June 30, 2019 and 2018, respectively, related to this deferred oil gathering credit are included as a reduction to transportation, gathering and processing expenses in our condensed consolidated statements of operations.

Deferred Midstream Gathering Credits. In May 2019, concurrent with the sale of our Delaware Basin crude oil gathering midstream assets, we entered into an agreement with the purchaser which provides us with gathering and transport for crude oil from dedicated acreage within an area of mutual interest for a term of 15 years. We recorded a long-term deferred credit of $28.9 million attributable to the value of the dedication, which is being amortized on a units-of-production basis. Amortization charges for the three and six months ended June 30, 2019 related to the deferred oil gathering credit were not material. Future amortization charges will be included as crude oil sales in our condensed consolidated statements of operations.

Also in May 2019, concurrent with the sale of our Delaware Basin produced water gathering and disposal midstream assets, we entered into an agreement with the purchaser which dedicates all of our water gathering and disposal volumes in the Delaware Basin via pipeline for a term of 15 years. We recorded a long-term deferred credit of $40.5 million attributable to the value of the dedication, which is being amortized using the units-of-production basis. Amortization charges for the three and six months ended June 30, 2019 related to the deferred water gathering credit were not material. Future amortization charges will be included as a reduction to lease operating expenses and capital costs in our condensed consolidated statements of operations and on our condensed consolidated balance sheets, respectively.

In June 2019, concurrent with the sale of our Delaware Basin natural gas gathering midstream assets, we entered into an agreement with the purchaser which provides us with gathering, processing and transportation of our natural gas from certain dedicated leases for a term of 22 years. We recorded a long-term deferred credit of $110.2 million attributable to the value of the dedication, which is being amortized on a units-of-production basis. Amortization charges for the three and six months ended June 30, 2019 related to the deferred natural gas gathering credit were not material. Future amortization charges will be included as a reduction to transportation, gathering and processing expenses in our condensed consolidated statements of operations.

NOTE 8 - LONG-TERM DEBT

Long-term debt consisted of the following as of:

	June 30, 2019	December 31, 2018
	(in thousands)	
Senior Notes:		
1.125% Convertible Notes due September 2021:		
Principal amount	$ 200,000	$ 200,000
Unamortized discount	(18,821)	(22,766)
Unamortized debt issuance costs	(2,153)	(2,640)
Net of unamortized discount and debt issuance costs	179,026	174,594
6.125% Senior Notes due September 2024:		
Principal amount	400,000	400,000
Unamortized debt issuance costs	(5,101)	(5,590)
Net of unamortized debt issuance costs	394,899	394,410
5.75% Senior Notes due May 2026:		
Principal amount	600,000	600,000
Unamortized debt issuance costs	(6,181)	(6,628)
Net of unamortized debt issuance costs	593,819	593,372
Total senior notes	1,167,744	1,162,376
Revolving Credit Facility:		
Revolving credit facility due May 2023	30,000	32,500
Total long-term debt, net of unamortized discount and debt issuance costs	$ 1,197,744	$ 1,194,876

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"). Interest is payable in cash semi-annually on 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, 2019, 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"). 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 (the "2026 Senior Notes"). The 2026 Senior Notes accrue interest from the date of issuance and interest is payable semi-annually on May 15 and November 15. 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 2024 Senior Notes and the 2026 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, 2019, 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"). Among other things, the Restated Credit Agreement provides for a maximum credit amount of $2.5 billion. In May 2019, as part of our semi-annual redetermination, the borrowing base on our revolving credit facility was increased to $1.6 billion; however, we elected to retain our commitment amount at $1.3 billion. The amount we may borrow under the Restated Credit Agreement is subject to certain limitations under our Notes.

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. Substantially all of our crude oil and natural gas properties, excluding our share of properties held by the limited partnerships that we sponsor, have been mortgaged or pledged as security for our revolving credit facility.

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 the administrative agent'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, 2019, 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, 2019, we were in compliance with all the revolving credit facility covenants.

As of June 30, 2019 and December 31, 2018, debt issuance costs related to our revolving credit facility were $10.2 million and $11.5 million, respectively, and are included in other assets on the condensed consolidated balance sheets. As of June 30, 2019, the weighted-average interest rate on the outstanding balance on our revolving credit facility, exclusive of fees on the unused commitment, was 5.8 percent.

NOTE 9 - LEASES

On January 1, 2019, we adopted the New Lease Standard issued by the FASB. We determine if an arrangement is representative of a lease under the New Lease Standard at contract inception. ROU assets represent our right to use the underlying assets for the lease term and the corresponding lease liabilities represent our obligations to make lease payments arising from the leases. Operating and finance lease ROU assets and liabilities are recognized at the commencement date based on the present value of the expected lease payments over the lease term. As most of our leases do not provide an implicit interest rate, we utilize our incremental borrowing rate based on information available at the commencement date in determining the present value of lease payments. Subsequent measurement, as well as presentation of expenses and cash flows, will depend upon the classification of the lease as either a finance or operating lease. Terms of our leases include options to extend or terminate the lease only when we can ascertain that it is reasonably certain we will exercise that option.

We have operating leases for office space and compressors and finance leases for vehicles. Our leases have remaining lease terms ranging from one to five years. The vehicle leases include options to renew for up to four years. Lease payments associated with vehicle leases also include a contractually stated residual value guarantee.

The following table presents the components of lease costs:

Lease Costs	Three Months Ended June 30, 2019	Six Months Ended June 30, 2019
	(in thousands)	
Operating lease costs	$ 1,384	$ 2,731
Finance lease costs:		
Amortization of ROU assets	$ 497	$ 987
Interest on lease liabilities	67	129
Total finance lease costs	564	1,116
Short-term lease costs	51,074	112,105
Total lease costs	$ 53,022	$ 115,952

Our operating lease costs are recorded in lease operating expenses or general and administrative expense and our finance lease costs are recorded in DD&A expense and interest expense on our condensed consolidated statements of operations. Our short-term lease costs include amounts that are capitalized as part of the cost of another asset and are recorded as properties and equipment in our condensed consolidated balance sheets or amounts recognized as expense in our condensed consolidated statements of operations.

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The following table presents leases and the balance sheet classification as of:

Leases	**Condensed Consolidated Balance Sheet Line Item**		**June 30, 2019**
			(in thousands)
Operating Leases:			
Operating lease ROU assets	Other assets	$	16,665
Operating lease obligation - short-term	Other accrued expense	$	4,028
Operating lease obligation - long-term	Other liabilities		15,016
Total operating lease liabilities		$	19,044
Finance Leases:			
Finance lease ROU assets	Properties and equipment, net	$	5,161
Finance lease obligation - short-term	Other accrued expense	$	1,842
Finance lease obligation - long-term	Other liabilities		3,276
Total finance lease liabilities		$	5,118
Weighted-average remaining lease term (years)			
Operating leases			4.71
Finance leases			3.27
Weighted-average discount rate			
Operating leases			5.0%
Finance leases			5.0%

Maturity of lease liabilities by year and in the aggregate, under operating and financing leases with terms of one year or more, as of June 30, 2019 consist of the following:

		Operating Leases		**Finance Leases**		**Total**
				(in thousands)		
2019	$	2,387	$	1,044	$	3,431
2020		4,847		1,956		6,803
2021		4,923		1,313		6,236
2022		5,016		711		5,727
2023		1,559		496		2,055
Thereafter		2,648		29		2,677
Total lease payments		21,380		5,549		26,929
Less interest and discount		(2,336)		(431)		(2,767)
Present value of lease liabilities	$	19,044	$	5,118	$	24,162

NOTE 10 - 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, 2018	$ 115,021
Obligations incurred with development activities	4,066
Accretion expense	3,147
Revisions in estimated cash flows	3,556
Obligations discharged with asset retirements	(11,687)
Obligations discharged with divestitures	(5,341)
Balance at June 30, 2019	108,762
Current portion	(29,853)
Long-term portion	$ 78,909

Our estimated asset retirement obligations liability is based on historical experience in plugging and abandoning wells, estimated economic lives and estimated plugging, abandonment and surface reclamation costs considering federal and state regulatory requirements in effect at that time. 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 accretion expense. Short-term asset retirement obligations are included in other accrued expenses on the condensed consolidated balance sheets.

NOTE 11 - 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, sales and processing agreements for pipeline capacity and water delivery and disposal commitments:

	For the Twelve Months Ending June 30,						
Area	**2020**	**2021**	**2022**	**2023**	**2024 and Through Expiration**	**Total**	**Expiration Date**
Natural gas (MMcf)							
Wattenberg Field	29,820	31,025	31,025	31,025	77,556	200,451	June 30, 2026
Delaware Basin	44,907	29,326	10,770	—	—	85,003	December 31, 2021
Gas Marketing	7,137	7,116	6,875	1,147	—	22,275	August 31, 2022
Total	81,864	67,467	48,670	32,172	77,556	307,729	
Crude oil (MBbls)							
Wattenberg Field	11,713	12,389	14,965	14,050	36,926	90,043	December 31, 2027
Delaware Basin	8,740	8,398	8,030	8,030	4,048	37,246	December 31, 2023
Total	20,453	20,787	22,995	22,080	40,974	127,289	
Water (MBbls)							
Wattenberg Field	4,659	6,207	6,207	6,207	9,352	32,632	December 31, 2024
Dollar commitment (in thousands)	$ 104,184	$ 92,260	$ 98,773	$ 92,994	$ 202,488	$ 590,699	

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 and the second plant is expected to be completed in the third 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. We are currently satisfying the volume commitment.

Delaware Basin. In May 2018, we entered into a firm sales agreement that is effective from June 2018 through December 2023 with an integrated marketing company for our crude oil production in the Delaware Basin. Contracted volumes are currently 21,000 barrels of crude oil per day and increase over time to 26,400 barrels of crude oil per day. This agreement is expected to provide price diversification through realization of export market pricing via a Corpus Christi terminal and exposure to Brent-weighted prices.

Crude Oil, Natural Gas and NGLs Sales. For the three months ended June 30, 2019 and 2018, amounts related to long-term transportation volumes in the table above were $12.2 million and $2.6 million, respectively, and were netted against our crude oil and natural gas sales in our condensed consolidated statements of operations. For the six months ended June 30, 2019 and 2018, amounts related to long-term transportation volumes in the table above were $23.1 million and $5.2 million, respectively, and were netted against our crude oil and natural gas sales in our condensed consolidated statements of operations.

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

Action Regarding Partnerships. In December 2017, we received an action entitled Dufresne, et al. v. PDC Energy, et al. (the "Dufresne Case"), filed in the United States District Court for the District of Colorado (the "District Court"). The original complaint stated that it was 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 (collectively, the "Partnerships"), 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 and three independent members of our Board of Directors for allegedly aiding and abetting PDC's breach of fiduciary duty. We filed a motion to dismiss on July 31, 2018. On February 19, 2019, the District Court granted the motion to dismiss, in part. It dismissed all claims against the individuals named as defendants. It also held that that the plaintiffs were time-barred from using the failure to assign acreage to support their claims for breach of fiduciary duty against PDC. On June 4, 2019, the District Court entered an order holding its opinion on the motion to dismiss in abeyance pending resolution of the Partnerships' bankruptcy cases and staying the litigation. As discussed in more detail below, we have reached a settlement, subject to approval by the bankruptcy court, that would resolve the remaining claims in the Dufresne Case.

Partnership Bankruptcy Filings. On October 30, 2018, the Partnerships filed petitions under Chapter 11 of the Bankruptcy Code (the "Chapter 11 Proceedings") in the United States Bankruptcy Court for the Northern District of Texas, Dallas Division (the "Bankruptcy Court"). Prior to the bankruptcy filings, PDC designated a third-party (the "Responsible Party") to analyze strategic options for the Partnerships. After designation of the Responsible Party and before filing the Chapter 11 Proceedings, PDC and the Partnerships agreed to enter into a transaction pursuant to which PDC would acquire substantially all of the Partnerships' assets through a Chapter 11 plan of liquidation (the "Original Plan"). The Original Plan also provided a release of claims asserted against PDC, including, but not limited to, the claims asserted in the Dufresne Case. In June 2019, the Responsible Party and the Plaintiffs in the Dufresne Case reached a settlement of the matters raised in the Dufresne Case and the Chapter 11 Proceedings. The settlement will be incorporated into an Amended Chapter 11 Plan (the "Amended Chapter 11 Plan"), which will be subject to approval by the Bankruptcy Court. The Amended Chapter 11 Plan, if approved by the Bankruptcy Court, will settle claims asserted against PDC, whether direct or derivative, including, but not limited to, the claims asserted in the Dufresne Case. It is anticipated that a hearing to approve the disclosure statement accompanying the Amended Chapter 11 Plan will be scheduled for early September 2019, after which the Amended Chapter 11 Plan and disclosure statement will be mailed to the Partnerships' unit holders for review and to provide them with an opportunity to contest the Amended Chapter 11 Plan or opt out of the settlement. We do not believe that the Partnership's Chapter 11 Proceedings will have a material adverse effect on our financial position, results of operations or liquidity, but we cannot predict with certainty the outcome of such proceedings.

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, 2019 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 June 2017, following our receipt of a 2015 Clean Air Act information request from the Environmental Protection Agency ("EPA") and a 2015 compliance advisory from the Colorado Department of Public Health and Environment's ("CDPHE") Air Pollution Control Division, 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 compliance advisory. 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. 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 the consent decree program. Over the course of its execution, we have identified certain immaterial deficiencies in our implementation of the program. We report these immaterial deficiencies to the appropriate authorities and remediate them promptly. We do not believe that the penalties and expenditures associated with the consent decree, including 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.

In addition, in December 2018, we were named as a nominal defendant in a derivative action filed in the Delaware chancery court. The complaint, which seeks unspecified monetary damages and various forms of equitable relief, alleges that certain current and former members of our Board of Directors violated their fiduciary duties, committed waste and were unjustly enriched by, among other things, failing to implement adequate environmental safeguards in connection with the issues that gave rise to the Department of Justice lawsuit and consent decree. We believe that this lawsuit is without merit but cannot predict its outcome.

Further, we could be the subject of other enforcement actions by regulatory authorities in the future relating to our past, present or future operations.

NOTE 12 - 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. However, 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 of continued service or the satisfaction of performance conditions set at the discretion of the Compensation Committee of our Board of Directors (the "Compensation Committee"), with a minimum one-year vesting period applicable to most awards. With regard to SARs and options, awards have a maximum exercisable period of ten years. We began issuing shares from the 2018 Plan during the six months ended June 30, 2019. As of June 30, 2019, there were 1,425,570 shares available for grant under the 2018 Plan.

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"), remains outstanding and we may continue to use the 2010 Plan to grant awards. As of June 30, 2019, there were 111,317 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,	
	2019	2018	2019	2018
	(in thousands)			
Stock-based compensation expense	$ 7,575	$ 5,518	$ 12,258	$ 10,779
Income tax benefit	(1,812)	(1,323)	(2,932)	(2,584)
Stock-based compensation expense, net of tax	$ 5,763	$ 4,195	$ 9,326	$ 8,195

Restricted Stock Units

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 RSUs 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, 2019:

	Shares	Weighted-Average Grant Date Fair Value per Share
Non-vested at December 31, 2018	618,407	$ 54.16
Granted	576,776	40.47
Vested	(266,329)	54.00
Forfeited	(74,319)	46.40
Non-vested at June 30, 2019	854,535	45.64

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,	
	2019	2018
	(in thousands, except per share data)	
Total intrinsic value of time-based awards vested	$ 10,424	$ 10,482
Total intrinsic value of time-based awards non-vested	30,815	36,934
Market price per share as of June 30	36.06	60.45
Weighted-average grant date fair value per share	40.47	49.73

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, 2019 was $30.9 million. This cost is expected to be recognized over a weighted-average period of 2.2 years.

Performance Stock Units

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 139,197 market-based PSUs to our executive officers during the six months ended June 30, 2019. In addition to continuous employment, the vesting of these PSUs is contingent on our total stockholder return ("TSR"), which is essentially our stock price change including any dividends over a three-year period ending on December 31, 2021, as compared to the TSR of a group of peer companies over the same period. The PSUs will result in a payout between zero 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,	
	2019	2018
Expected term of award (in years)	3	3
Risk-free interest rate	2.5%	2.4%
Expected volatility	41.4%	42.3%

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, 2019:

	Shares	Weighted-Average Grant Date Fair Value per Share
Non-vested at December 31, 2018	102,914	$ 74.88
Granted	139,197	56.68
Non-vested at June 30, 2019	242,111	64.42

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,	
	2019	2018
	(in thousands, except per share data)	
Total intrinsic value of market-based awards non-vested	$ 8,731	$ 8,402
Market price per common share as of June 30,	36.06	60.45
Weighted-average grant date fair value per share	56.68	69.98

Total compensation cost related to non-vested market-based awards not yet recognized in our condensed consolidated statements of operations as of June 30, 2019 was $10.3 million. This cost is expected to be recognized over a weighted-average period of 2.0 years.

Stock Appreciation Rights

The SARs vest ratably over a three-year period and may generally 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, 2019.

Total compensation cost related to non-vested SARs granted and not yet recognized in our condensed consolidated statements of operations as of June 30, 2019 was $0.3 million. The cost is expected to be recognized over a weighted-average period of 0.6 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, 2019, no shares of preferred stock have been issued.

Stock Repurchase Program

In April 2019, our Board of Directors approved a stock repurchase program (the "Stock Repurchase Program") to acquire up to $200.0 million of our outstanding common stock, depending on market conditions. Repurchases under the Stock Repurchase Program can be made in open markets at our discretion and in compliance with safe harbor provisions, or in privately negotiated transactions. The Stock Repurchase Program does not require any specific number of shares to be acquired, and can be modified or discontinued by the Board of Directors at any time. Our target completion date for the Stock Repurchase Program is December 31, 2020.

During the three months ended June 30, 2019, we repurchased 3,136,406 shares of our outstanding common stock at a cost of $105.2 million pursuant to the Stock Repurchase Program. We settled $94.1 million of the repurchases prior to June 30, 2019 and accrued $11.1 million for settlements that occurred subsequent to period-end. During July 2019, we repurchased

569,733 additional shares of our outstanding common stock at a cost of $19.8 million. Approximately $75.0 million remains available for repurchases under the Stock Repurchase Program.

NOTE 13 - INCOME TAXES

We compute our quarterly tax provision using the effective tax rate method by applying the anticipated annual effective rate to our year-to-date income or loss, except for discrete items. Income tax on discrete items is computed and recorded in the period in which the specific transaction occurs. 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 effective income tax rates differ from the statutory federal tax rate, primarily due to state taxes, stock-based compensation, nondeductible officers' compensation and nondeductible lobbying expenses. The effective income tax rates for the three and six months ended June 30, 2019 includes discrete income tax provision items of $2.5 million and $3.0 million, respectively, relating to the tax detriment on stock-based compensation and change in estimated federal tax credits, which resulted in a 2.7 percent increase and a 4.5 percent decrease to our effective income tax rate for the three and six months ended June 30, 2019, respectively. 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 rate for the three months ended June 30, 2019 was a 24.8 percent provision on income and the effective income tax rate for the six months ended June 30, 2019 was a 22.3 percent benefit on loss, compared to a 22.0 percent and 22.3 percent benefit on loss for the three and six months ended June 30, 2018.

As of June 30, 2019, 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. The IRS partially accepted our 2017 tax return. The 2017 tax return is in the IRS CAP Program post-filing review process, with no significant tax adjustments currently proposed. We are currently participating in the CAP Program for the review of our 2018 and 2019 tax years. Participation in the CAP Program has enabled us to have minimal uncertain tax benefits associated with our federal tax return filings.

NOTE 14 - EARNINGS PER SHARE

Basic earnings per share is computed by dividing net earnings by the weighted-average number of common shares outstanding for the period. Diluted earnings per share is similarly computed, except that the denominator includes the effect, using the treasury stock method, of unvested restricted stock, outstanding SARs, 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 our weighted-average basic and diluted shares outstanding:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(in thousands)			
Weighted-average common shares outstanding - basic	65,815	66,066	65,998	66,012
Dilutive effect of:				
Restricted stock and PSU	85	—	—	—
Other equity-based awards	26	—	—	—
Weighted-average common shares and equivalents outstanding - diluted	65,926	66,066	65,998	66,012

We reported a net loss for the six months ended June 30, 2019 and 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 those periods 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,	
	2019	2018	2019	2018
	(in thousands)			
Weighted-average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:				
RSUs and PSUs	770	803	1,048	698
Other equity-based awards	208	93	302	85
Total anti-dilutive common share equivalents	978	896	1,350	783

The 2021 Convertible Notes 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, 2019 and 2018, 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 15 - SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION

	Six Months Ended June 30,	
	2019	2018 (1)
	(in thousands)	
Supplemental cash flow information:		
Cash payments for:		
Interest, net of capitalized interest	$ 29,034	$ 27,817
Income taxes	200	393
Non-cash investing and financing activities:		
Change in accounts payable related to capital expenditures	$ 16,520	$ 72,334
Change in asset retirement obligations, with a corresponding change to crude oil and natural gas properties, net of disposals	(1,139)	6,248
Change in accounts payable related to the purchase and retirement of treasury shares	11,102	—
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 2,914	$ —
Operating cash flows from finance leases	127	—
Financing cash flows from finance leases	988	—
ROU assets obtained in exchange for lease obligations:		
Operating leases	$ 1,428	$ —
Finance leases	1,593	—

(1) As we have elected the modified retrospective method of adoption for the New Lease Standard, cash flows related to lease liabilities have not been restated for the six months ended June 30, 2019.

NOTE 16 - SUBSIDIARY GUARANTOR

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

(i) PDC Energy, Inc. ("Parent"), the issuer of the guaranteed obligations, including non-material subsidiaries;

(ii) PDC Permian, Inc., the guarantor subsidiary ("Guarantor"), as specified in the indentures related to our senior notes;

(iii) Eliminations representing adjustments to (a) eliminate intercompany transactions between or among Parent, Guarantor and our other subsidiaries and (b) eliminate the investments in our subsidiaries; and

(iv) Parent and subsidiaries on a consolidated basis ("Consolidated").

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

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

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	Condensed Consolidating Balance Sheets			
	June 30, 2019			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Current assets:				
Cash and cash equivalents	$ 1,474	$ —	$ —	$ 1,474
Accounts receivable, net	157,661	119,660	—	277,321
Fair value of derivatives	41,425	—	—	41,425
Prepaid expenses and other current assets	5,200	407	—	5,607
Total current assets	205,760	120,067	—	325,827
Properties and equipment, net	2,345,072	1,851,263	—	4,196,335
Intercompany receivable	327,983	—	(327,983)	—
Investment in subsidiaries	1,317,269	—	(1,317,269)	—
Fair value of derivatives	31,655	—	—	31,655
Other assets	36,031	5,056	—	41,087
Total Assets	$ 4,263,770	$ 1,976,386	$ (1,645,252)	$ 4,594,904
Liabilities and Stockholders' Equity				
Liabilities				
Current liabilities:				
Accounts payable	$ 133,024	$ 86,134	$ —	$ 219,158
Production tax liability	64,933	5,018	—	69,951
Fair value of derivatives	19,775	—	—	19,775
Funds held for distribution	76,424	12,455	—	88,879
Accrued interest payable	14,269	4	—	14,273
Other accrued expenses	83,624	2,899	—	86,523
Total current liabilities	392,049	106,510	—	498,559
Intercompany payable	—	327,983	(327,983)	—
Long-term debt	1,197,744	—	—	1,197,744
Deferred income taxes	147,444	35,676	—	183,120
Asset retirement obligations	71,906	7,003	—	78,909
Fair value of derivatives	927	—	—	927
Other liabilities	75,294	181,945	—	257,239
Total liabilities	1,885,364	659,117	(327,983)	2,216,498
Commitments and contingent liabilities				
Stockholders' Equity				
Common shares	635	—	—	635
Additional paid-in capital	2,433,974	1,766,775	(1,766,775)	2,433,974
Retained deficit	(42,901)	(449,506)	449,506	(42,901)
Treasury shares	(13,302)	—	—	(13,302)
Total stockholders' equity	2,378,406	1,317,269	(1,317,269)	2,378,406
Total Liabilities and Stockholders' Equity	$ 4,263,770	$ 1,976,386	$ (1,645,252)	$ 4,594,904

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	Condensed Consolidating Balance Sheets			
	December 31, 2018			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Current assets:				
Cash and cash equivalents	$ 1,398	$ —	$ —	$ 1,398
Accounts receivable, net	146,529	34,905	—	181,434
Fair value of derivatives	84,492	—	—	84,492
Prepaid expenses and other current assets	6,725	411	—	7,136
Total current assets	239,144	35,316	—	274,460
Properties and equipment, net	2,270,711	1,732,151	—	4,002,862
Assets held-for-sale	—	140,705	—	140,705
Intercompany receivable	451,601	—	(451,601)	—
Investment in subsidiaries	1,316,945	—	(1,316,945)	—
Fair value of derivatives	93,722	—	—	93,722
Other assets	30,084	2,312	—	32,396
Total Assets	$ 4,402,207	$ 1,910,484	$ (1,768,546)	$ 4,544,145
Liabilities and Stockholders' Equity				
Liabilities				
Current liabilities:				
Accounts payable	$ 110,847	$ 71,017	$ —	$ 181,864
Production tax liability	53,309	7,410	—	60,719
Fair value of derivatives	3,364	—	—	3,364
Funds held for distribution	90,183	15,601	—	105,784
Accrued interest payable	14,143	7	—	14,150
Other accrued expenses	73,689	1,444	—	75,133
Total current liabilities	345,535	95,479	—	441,014
Intercompany payable	—	451,601	(451,601)	—
Long-term debt	1,194,876	—	—	1,194,876
Deferred income taxes	162,368	35,728	—	198,096
Asset retirement obligations	79,904	5,408	—	85,312
Liabilities held-for-sale	—	4,111	—	4,111
Fair value of derivatives	1,364	—	—	1,364
Other liabilities	91,452	1,212	—	92,664
Total liabilities	1,875,499	593,539	(451,601)	2,017,437
Commitments and contingent liabilities				
Stockholders' Equity				
Common shares	661	—	—	661
Additional paid-in capital	2,519,423	1,766,775	(1,766,775)	2,519,423
Retained earnings	8,727	(449,830)	449,830	8,727
Treasury shares	(2,103)	—	—	(2,103)
Total stockholders' equity	2,526,708	1,316,945	(1,316,945)	2,526,708
Total Liabilities and Stockholders' Equity	$ 4,402,207	$ 1,910,484	$ (1,768,546)	$ 4,544,145

PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2019
(unaudited)

Condensed Consolidating Statements of Operations
Three Months Ended June 30, 2019

	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Revenues				
Crude oil, natural gas and NGLs sales	$ 256,355	$ 82,601	$ —	$ 338,956
Commodity price risk management gain, net	47,349	—	—	47,349
Other income	2,555	1,798	—	4,353
Total revenues	306,259	84,399	—	390,658
Costs, expenses and other				
Lease operating expenses	23,554	10,774	—	34,328
Production taxes	17,928	4,714	—	22,642
Transportation, gathering and processing expenses	5,869	6,339	—	12,208
Exploration, geologic and geophysical expense	259	381	—	640
Impairment of properties and equipment	—	28,979	—	28,979
General and administrative expense	37,285	5,523	—	42,808
Depreciation, depletion and amortization	116,964	51,559	—	168,523
Accretion of asset retirement obligations	1,351	212	—	1,563
Gain on sale of properties and equipment	(66)	(33,838)	—	(33,904)
Other expenses	2,836	—	—	2,836
Total costs, expenses and other	205,980	74,643	—	280,623
Income from operations	100,279	9,756	—	110,035
Interest expense	(19,750)	845	—	(18,905)
Interest income	5	—	—	5
Income before income taxes	80,534	10,601	—	91,135
Income tax expense	(20,068)	(2,519)	—	(22,587)
Equity in income of subsidiary	8,082	—	(8,082)	—
Net income	$ 68,548	$ 8,082	$ (8,082)	$ 68,548

PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2019
(unaudited)

	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, 2019
(unaudited)

	Condensed Consolidating Statements of Operations			
	Six Months Ended June 30, 2019			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Revenues				
Crude oil, natural gas and NGLs sales	$ 511,204	$ 148,851	$ —	$ 660,055
Commodity price risk management loss, net	(142,725)	—	—	(142,725)
Other income	5,188	2,640	—	7,828
Total revenues	373,667	151,491	—	525,158
Costs, expenses and other				
Lease operating expenses	47,188	22,361	—	69,549
Production taxes	33,813	10,997	—	44,810
Transportation, gathering and processing expenses	11,309	12,323	—	23,632
Exploration, geologic and geophysical expense	576	2,707	—	3,283
Impairment of properties and equipment	—	36,854	—	36,854
General and administrative expense	71,719	10,687	—	82,406
Depreciation, depletion and amortization	229,595	90,350	—	319,945
Accretion of asset retirement obligations	2,729	418	—	3,147
Gain on sale of properties and equipment	(448)	(33,825)	—	(34,273)
Other expenses	6,390	—	—	6,390
Total costs, expenses and other	402,871	152,872	—	555,743
Loss from operations	(29,204)	(1,381)	—	(30,585)
Interest expense	(37,685)	1,802	—	(35,883)
Interest income	15	—	—	15
Income (loss) before income taxes	(66,874)	421	—	(66,453)
Income tax (expense) benefit	14,923	(98)	—	14,825
Equity in income of subsidiary	323	—	(323)	—
Net income (loss)	$ (51,628)	$ 323	$ (323)	$ (51,628)

PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2019
(unaudited)

	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, 2019
(unaudited)

	Condensed Consolidating Statements of Cash Flows			
	Six Months Ended June 30, 2019			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Cash flows from operating activities	$ 263,339	$ 178,897	$ —	$ 442,236
Cash flows from investing activities:				
Capital expenditures for development of crude oil and natural gas properties	(292,743)	(250,048)	—	(542,791)
Capital expenditures for other properties and equipment	(10,235)	(218)	—	(10,453)
Acquisition of crude oil and natural gas properties	(83)	(4,063)	—	(4,146)
Proceeds from sale of properties and equipment	154	1,000	—	1,154
Proceeds from divestitures	—	199,430	—	199,430
Restricted cash	8,001	—	—	8,001
Intercompany transfers	124,848	—	(124,848)	—
Net cash from investing activities	(170,058)	(53,899)	(124,848)	(348,805)
Cash flows from financing activities:				
Proceeds from revolving credit facility	890,000	—	—	890,000
Repayment of revolving credit facility	(892,500)	—	—	(892,500)
Payment of debt issuance costs	(36)	—	—	(36)
Purchase of treasury shares	(94,113)	—	—	(94,113)
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	(3,717)	—	—	(3,717)
Other	(840)	(150)	—	(990)
Intercompany transfers	—	(124,848)	124,848	—
Net cash from financing activities	(101,206)	(124,998)	124,848	(101,356)
Net change in cash, cash equivalents and restricted cash	(7,925)	—	—	(7,925)
Cash, cash equivalents and restricted cash, beginning of period	9,399	—	—	9,399
Cash, cash equivalents and restricted cash, end of period	$ 1,474	$ —	$ —	$ 1,474

	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 divestitures	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)
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	(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

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

The following discussion and analysis 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 12.4 MMboe and 23.6 MMboe for the three and six months ended June 30, 2019, respectively, representing increases of 32 percent and 29 percent as compared to the three and six months ended June 30, 2018, respectively. Crude oil production increased 24 percent and 22 percent for the three and six months ended June 30, 2019, respectively, compared to the three and six months ended June 30, 2018. Natural gas production increased 40 percent and 36 percent for the three and six months ended June 30, 2019 and 2018, respectively. NGLs production increased 36 percent and 33 percent for the three and six months ended June 30, 2019 and 2018, respectively. For the month ended June 30, 2019, we maintained an average daily production rate of approximately 138,000 Boe per day, up from approximately 102,000 Boe per day for the month ended June 30, 2018.

On a sequential quarterly basis, total production and crude oil production volumes for the three months ended June 30, 2019 as compared to the three months ended March 31, 2019 increased by 11 percent and eight percent, respectively. The increase in these production volumes was primarily related to an increase in wells turned in-line in both the Wattenberg Field and the Delaware Basin.

Crude oil, natural gas and NGLs sales revenue increased to $339.0 million and $660.1 million for the three and six months ended June 30, 2019, respectively, compared to $325.9 million and $631.2 million for the three and six months ended June 30, 2018, respectively. The four percent and five percent increases in sales revenues were driven by the 32 percent and 29 percent increases in production, partially offset by the 22 percent and 19 percent decreases in weighted-average realized commodity prices, as compared to the prior periods.

We had negative net settlements from our commodity derivative contracts of $13.2 million and $21.6 million for the three and six months ended June 30, 2019, respectively, as compared to negative net settlements of $16.4 million and $42.4 million for the three and six months ended June 30, 2018.

The combined revenue from crude oil, natural gas and NGLs sales and net settlements from our commodity derivative instruments increased five percent to $325.8 million for the three months ended June 30, 2019 from $309.5 million for the three months ended June 30, 2018 and increased eight percent to $638.4 million for the six months ended June 30, 2019 from $588.8 million for the six months ended June 30, 2018.

For the three months ended June 30, 2019, we generated net income of $68.5 million and for the six months ended June 30, 2019 we generated net losses of $51.6 million, or $1.04 and $0.78 per diluted share, respectively, compared to net losses of $160.3 million and $173.4 million, respectively, or $2.43 and $2.63 per diluted share, for the comparable periods in 2018. Our net income for the three months ended June 30, 2019 as compared to the net loss for the three months ended June 30, 2018 was increased by the net change in fair value of unsettled commodity derivatives, the decrease in impairments of properties and equipment and the gain from the Midstream Asset Divestitures during the three months ended June 30, 2019. Our net loss for the six months ended June 30, 2019 as compared to the six months ended June 30, 2018 was most positively impacted by the decrease in impairments of properties and equipment and the gain from the Midstream Asset Divestitures.

During the three and six months ended June 30, 2019, our adjusted EBITDAX, a non-U.S. GAAP financial measure, was $256.8 million and $466.1 million, respectively, compared to $214.3 million and $404.4 million, respectively, for the comparable periods in 2018. The increases were primarily due to the increases in crude oil, natural gas and NGLs sales of $13.0 million and $28.9 million, respectively, the gains on the sale of properties and equipment of $33.9 million and $34.3 million, respectively, and decreases in the loss on commodity derivative settlements of $3.2 million and $20.8 million, respectively. The increases were partially offset by increases in operating costs of $10.9 million and $26.5 million, respectively. 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.

Our cash flows from operations were $442.2 million and $380.9 million and our adjusted cash flows from operations, a non-U.S. GAAP financial measure, were $399.5 million and $374.3 million for the six months ended June 30, 2019 and June 30, 2018, respectively.

Liquidity

Available liquidity as of June 30, 2019 was $1.3 billion, which was comprised of $1.5 million of cash and cash equivalents and $1.3 billion available for borrowing under our revolving credit facility. In May 2019, as part of our semi-annual redetermination, the borrowing base on our revolving credit facility was increased to $1.6 billion; however, we elected to retain our commitment amount at $1.3 billion. Based on our current production forecast for 2019 and assuming a NYMEX crude oil price of $55.00, we expect cash flows from operations to slightly exceed our capital investments in crude oil and natural gas properties. Although capital investments exceeded cash flows from operations during the first half of 2019, we expect cash flows from operations to exceed capital investments during the remainder of the year and are taking active steps to ensure that our capital investments remain within our guidance range.

In the second quarter of 2019, we completed the Midstream Asset Divestitures for an aggregate cash purchase price of $345.6 million ($263.6 million of which was paid upon closing and $82.0 million will be paid one year post-closing), subject to certain customary post-closing adjustments, plus aggregate conditional payments of up to $150.7 million. We allocated $179.6 million of the proceeds to deferred midstream gathering credits for future gathering, processing, transportation and water disposal services. We have and expect to continue to use the proceeds from these divestitures for our capital investment program.

In April 2019, our Board of Directors approved the acquisition of up to $200.0 million of our outstanding common stock, depending on market conditions. During the three months ended June 30, 2019, we repurchased 3.1 million shares of our outstanding common stock for a total cost of $105.2 million pursuant to the Stock Repurchase Program. During July 2019, we repurchased 0.6 million shares of outstanding common stock at a cost of $19.8 million. Approximately $75.0 million remains available for repurchases under the Stock Repurchase Program.

Operational Overview

We ran three drilling rigs in the Wattenberg Field through June 2019. We expect to maintain a three-rig pace in the Wattenberg Field through late in the third quarter of 2019 and then drop to a two-rig pace for the remainder of the year. In the Delaware Basin, we ran three rigs through May 2019 and then dropped to a two-rig pace in June 2019 and expect to continue to operate at a two-rig pace throughout the remainder of the year. We were able to reduce the number of rigs in each area primarily due to operational efficiencies, our disciplined approach in allocating our planned expenditures and our inventory of drilled uncompleted wells in each basin.

The following tables summarize our drilling and completion activity for the six months ended June 30, 2019:

	Operated Wells					
	Wattenberg Field		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
In-process as of December 31, 2018	133	122.4	18	17.4	151	139.8
Spud	81	77.4	20	18.9	101	96.3
Turned-in-line	(59)	(54.4)	(17)	(16.5)	(76)	(70.9)
In-process as of June 30, 2019	155	145.4	21	19.8	176	165.2

	Non-Operated Wells					
	Wattenberg Field		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
In-process as of December 31, 2018	5	2.0	6	0.9	11	2.9
Spud	28	3.5	2	0.4	30	3.9
Turned-in-line	(17)	(1.1)	(8)	(1.3)	(25)	(2.4)
In-process as of June 30, 2019	16	4.4	—	—	16	4.4

Our in-process wells represent wells that are in the process of being drilled and/or have been drilled and are waiting to be fractured and/or for gas pipeline connection. Our drilled uncompleted wells are generally completed and turned-in-line within a year of drilling.

2019 Operational and Financial Outlook

We have updated our expected production guidance range for 2019 to range between 48 MMBoe to 50 MMBoe, or approximately 132,000 Boe to 137,000 Boe per day. We currently expect that approximately 40 percent of our 2019 production will be comprised of crude oil and approximately 22 percent will be NGLs, for total liquids of approximately 62 percent. Our planned 2019 capital investments in crude oil and natural gas properties, which we now expect to be between $810 million and $840 million, are focused on continued execution of our development plans in the Wattenberg Field and Delaware Basin.

In 2019, we also expect to spend approximately $20 million for corporate capital, the majority of which is related to the implementation of an ERP system to replace our existing operating and financial systems. This long-planned investment is being made to enhance maintenance of our financial records, improve operational functionality and provide timely information to our management team related to the operation of the business.

We believe that our disciplined approach in allocating our planned expenditures allows us to maintain a degree of operational flexibility to control the pace of our capital spending. As we execute our capital investment program, we continually monitor, among other things, cost efficiencies, expected rates of return, the political environment and our remaining inventory in order to best meet our short- and long-term corporate strategy. Should commodity pricing or the operating environment deteriorate, we may determine that an adjustment to our development plan is appropriate.

Wattenberg Field. We are drilling in the horizontal Niobrara and Codell plays in the core Wattenberg Field, which we have further delineated between the Kersey, Prairie and Plains development areas. Our 2019 capital investment program for the Wattenberg Field is approximately 60 percent of our total capital investments in crude oil and natural gas properties, of which approximately 90 percent is expected to be invested in operated drilling and completion activity. We plan to drill standard-reach lateral (“SRL”), mid-reach lateral (“MRL”) and extended-reach lateral (“XRL”) wells in 2019, the majority of which will be in the Kersey area of the field. In 2019, we anticipate spudding approximately 120 to 130 operated wells and turning-in-line approximately 110 to 125 operated wells. We expect an average development cost of between $3 million and $5 million per well, depending upon the lateral length of the well. The remainder of the Wattenberg Field capital investment program is expected to be used for non-operated drilling, land, capital workovers and facilities projects.

Delaware Basin. Total capital investments in crude oil and natural gas properties in the Delaware Basin for 2019 are expected to be approximately 40 percent of our total capital investments in crude oil and natural gas properties, of which approximately 85 percent is allocated to spud approximately 25 to 30 operated wells and turn-in-line approximately 21 operated wells. We plan to drill MRL and XRL wells in 2019 with an expected average development cost of between $11.5 million and

$13 million per well, depending upon the lateral length of the well. We do not plan to drill any SRL wells in the Delaware Basin in 2019. Based on the timing of our operations and requirements to hold acreage, we may elect 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 use approximately 15 percent of our budgeted Delaware Basin capital for leasing, non-operated capital, seismic and technical studies and facilities.

Financial Guidance.

The following table sets forth our current financial guidance for the year ended December 31, 2019 for certain expenses and the impact of price differentials:

	Low	High
Operating Expenses		
Lease operating expenses ($/Boe)	$ 2.85	$ 3.00
Transportation, gathering and processing expenses ("TGP") ($/Boe)	$ 0.90	$ 1.00
Production taxes (% of crude oil, natural gas and NGLs sales)	6%	7%
General and administrative expense ("G&A") ($/Boe)	$ 3.00	$ 3.20
Estimated Price Realizations (% of NYMEX, excludes TGP)		
Crude oil	90%	95%
Natural gas	40%	45%
NGLs	20%	25%

In June 2019, in response to current market conditions and reductions in development activity in the Wattenberg Field and Delaware Basin, we instituted measures we believe were necessary to reduce our general and administrative expenses. As a result, we reduced corporate headcount by approximately 15 percent to more closely align with our updated operational plans. We estimate these measures will result in general and administrative expense of $2.60 to $2.80 per Boe for the second half of 2019.

Regulatory Update

Senate Bill 19-181. In April 2019, Colorado Senate Bill 19-181 was signed into law and made a number of changes to oil and gas regulation in Colorado. The bill gives local governments the option to regulate facility siting and surface impacts and increases air quality monitoring and environmental protection. It also changes the mission and makeup of the Colorado Oil and Gas Conservation Commission ("COGCC"), among other things. Rulemakings contemplated by the bill may create new application and operating requirements; however, the rulemaking process is expected to take years to finalize. Although we have been experiencing a slowdown in the permitting process as the new operating requirements are being finalized, we have been successful in obtaining new permits. The COGCC has finalized all required operator guidance related to permit applications and has publicly stated with this guidance in place, it now plans to increase permit approvals. We primarily operate in the core Wattenberg Field in Weld County and have approved permits for development through a significant portion of 2020; however, significant delays in the issuance of permits could impact the timing of our future development plans in the Wattenberg Field.

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. Ozone measurements in the Denver Metro/North Front Range NAA exceeded the NAAQS during 2018, subjecting it to a further reclassification to “serious.” In 2018, the Colorado Department of Public Health and Environment (“CDPHE”) requested an extension to the “serious” ozone classification as a result of a year of compliant ozone monitoring in 2017. This extension request was withdrawn by Governor Polis in March 2019. The EPA and CDPHE are currently determining the process for a “serious” designation, which is expected to occur later this year. A “serious” classification will trigger significant additional obligations for the state under the CAA and could result in new and more stringent air quality control requirements, which may in turn result in significant costs, and delays in obtaining necessary permits applicable to our operations.

Shareholder Activism

In March 2019, Kimmeridge Energy Management Company, LLC and its affiliates (collectively, "Kimmeridge"), which at that time was a beneficial holder of approximately 5.1 percent of the outstanding shares of our common stock, nominated for election three candidates for our Board of Directors at our 2019 Annual Meeting of Stockholders (the "Annual Meeting"). If elected, this slate would have replaced the Board of Directors' three nominees, our Chief Executive Officer, Barton R. Brookman, and independent directors Mark E. Ellis and Larry F. Mazza on our eight-member board. The Annual Meeting was held on May 29, 2019. Based on final results of the election, as certified by the independent inspector of elections for the meeting, PDC shareholders voted to re-elect Messrs. Brookman, Ellis and Mazza.

We incurred approximately $5.7 million in costs and devoted significant management attention to the contested solicitation for the Annual Meeting, and future contested solicitations or other forms of shareholder activism could have similar effects. Activist campaigns can also create perceived uncertainties as to our future direction, strategy and leadership and may result in the loss of potential business opportunities, harm our ability to pursue certain transactions and cause our stock price to experience periods of volatility.

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,		
	2019	2018	Percent Change	2019	2018	Percent Change
	(dollars in millions, except per unit data)					
Production						
Crude oil (MBbls)	4,899	3,948	24.1 %	9,425	7,745	21.7 %
Natural gas (MMcf)	28,992	20,687	40.1 %	54,643	40,274	35.7 %
NGLs (MBbls)	2,693	1,987	35.5 %	5,108	3,833	33.3 %
Crude oil equivalent (MBoe)	12,425	9,382	32.4 %	23,640	18,290	29.3 %
Average Boe per day (Boe)	136,539	103,099	32.4 %	130,608	101,049	29.3 %
Crude Oil, Natural Gas and NGLs Sales						
Crude oil	$ 274.2	$ 252.6	8.6 %	$ 505.3	$ 479.0	5.5 %
Natural gas	31.0	30.0	3.3 %	83.5	68.7	21.5 %
NGLs	33.8	43.3	(21.9)%	71.3	83.5	(14.6)%
Total crude oil, natural gas and NGLs sales	$ 339.0	$ 325.9	4.0 %	$ 660.1	$ 631.2	4.6 %
Net Settlements on Commodity Derivatives						
Crude oil	$ (14.7)	$ (25.5)	(42.4)%	$ (17.6)	$ (52.5)	(66.5)%
Natural gas	1.5	11.2	(86.6)%	(4.0)	13.9	*
NGLs	—	(2.1)	*	—	(3.8)	*
Total net settlements on derivatives	$ (13.2)	$ (16.4)	(19.5)%	$ (21.6)	$ (42.4)	(49.1)%
Average Sales Price (excluding net settlements on derivatives)						
Crude oil (per Bbl)	$ 55.96	$ 63.99	(12.5)%	$ 53.61	$ 61.85	(13.3)%
Natural gas (per Mcf)	1.07	1.46	(26.7)%	1.53	1.71	(10.5)%
NGLs (per Bbl)	12.53	21.76	(42.4)%	13.96	21.78	(35.9)%
Crude oil equivalent (per Boe)	27.28	34.74	(21.5)%	27.92	34.51	(19.1)%
Average Costs and Expenses (per Boe)						
Lease operating expenses	$ 2.76	$ 3.44	(19.8)%	$ 2.94	$ 3.38	(13.0)%
Production taxes	1.82	2.41	(24.5)%	1.90	2.34	(18.8)%
Transportation, gathering and processing expenses	0.99	0.96	3.1 %	1.00	0.89	12.4 %
General and administrative expense	3.45	3.97	(13.1)%	3.49	3.99	(12.5)%
Depreciation, depletion and amortization	13.56	14.46	(6.2)%	13.53	14.35	(5.7)%
Lease Operating Expenses by Operating Region (per Boe)						
Wattenberg Field	$ 2.46	$ 3.29	(25.2)%	$ 2.55	$ 3.16	(19.3)%
Delaware Basin	3.76	3.92	(4.1)%	4.37	4.16	5.0 %
Utica Shale (1)	—	—	*	—	3.46	*

* Percent 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, 2019, crude oil, natural gas and NGLs sales revenue increased compared to the three and six months ended June 30, 2018 due to the following:

	Three Months Ended June 30, 2019	Six Months Ended June 30, 2019
	(in millions)	
Increase in production	$ 88.4	$ 156.2
Decrease in average crude oil price	(39.4)	(39.9)
Decrease in average natural gas price	(11.2)	(9.7)
Decrease in average NGLs price	(24.8)	(77.7)
Total increase in crude oil, natural gas and NGLs sales revenue	$ 13.0	$ 28.9

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	**2019**	**2018**	**Percent Change**	**2019**	**2018**	**Percent Change**
Crude oil (MBbls)						
Wattenberg Field	3,681	2,943	25.1%	7,253	5,823	24.6%
Delaware Basin	1,218	1,005	21.2%	2,172	1,876	15.8%
Utica Shale (1)	—	—	*	—	46	*
Total	4,899	3,948	24.1%	9,425	7,745	21.7%
Natural gas (MMcf)						
Wattenberg Field	23,233	15,836	46.7%	44,193	31,360	40.9%
Delaware Basin	5,759	4,851	18.7%	10,450	8,500	22.9%
Utica Shale (1)	—	—	*	—	414	*
Total	28,992	20,687	40.1%	54,643	40,274	35.7%
NGLs (MBbls)						
Wattenberg Field	2,007	1,544	30.0%	3,908	2,973	31.4%
Delaware Basin	686	443	54.9%	1,200	826	45.3%
Utica Shale (1)	—	—	*	—	34	*
Total	2,693	1,987	35.5%	5,108	3,833	33.3%
Crude oil equivalent (MBoe)						
Wattenberg Field	9,561	7,126	34.2%	18,526	14,023	32.1%
Delaware Basin	2,864	2,256	27.0%	5,114	4,118	24.2%
Utica Shale (1)	—	—	*	—	149	*
Total	12,425	9,382	32.4%	23,640	18,290	29.3%
Average crude oil equivalent per day (Boe)						
Wattenberg Field	105,066	78,308	34.2%	102,354	77,475	32.1%
Delaware Basin	31,473	24,791	27.0%	28,254	22,751	24.2%
Utica Shale (1)	—	—	*	—	823	*
Total	136,539	103,099	32.4%	130,608	101,049	29.3%

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:

	Crude Oil	Natural Gas	NGLs	Total
Three Months Ended June 30, 2019				
Wattenberg Field	39%	40%	21%	100%
Delaware Basin	42%	34%	24%	100%
Three Months Ended June 30, 2018				
Wattenberg Field	41%	37%	22%	100%
Delaware Basin	44%	36%	20%	100%
Six Months Ended June 30, 2019				
Wattenberg Field	39%	40%	21%	100%
Delaware Basin	43%	34%	23%	100%
Six Months Ended June 30, 2018				
Wattenberg Field	42%	37%	21%	100%
Delaware Basin	46%	34%	20%	100%

Midstream Capacity

Our ability to market our production depends substantially on the availability, proximity and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. If adequate midstream facilities and services are not available to us on a timely basis and at acceptable costs, our production and results of operations could be adversely affected. In recent years, there has been substantial development in our current areas of operation, and this has made it more challenging for providers of midstream infrastructure and services to keep pace with the corresponding increases in field-wide production. The ultimate timing and availability of adequate infrastructure is not within our control and we could experience capacity constraints for extended periods of time that could negatively impact our ability to meet our production targets. Weather, regulatory developments and other factors also affect the adequacy of midstream infrastructure. Like other producers, we from time to time enter into volume commitments with midstream providers in order to induce them to provide increased capacity. If our production falls below the level required under these agreements, we could be subject to transportation charges for commitment shortfalls.

Wattenberg Field. From time to time, elevated line pressures on gas gathering facilities have adversely affected production from the Wattenberg Field. While system pressures declined in early 2019 as a result of system expansions completed by DCP Midstream, LP ("DCP") in late 2018, they have remained at relatively elevated levels and have recently increased to historical highs. DCP is working to complete construction of its O'Connor II plant, which is currently scheduled for mechanical completion in August 2019. After commissioning of the plant, we currently expect NGL takeaway to continue to be constrained into the fourth quarter of 2019, when additional NGL pipeline capacity is expected. Until the capacity becomes available, we expect that DCP's incremental system capacity will be limited to approximately 50 percent of the nameplate capacity of the plant. DCP has acquired additional firm residue gas takeaway capacity through October 2019 to accommodate the incremental gas volumes associated with the O'Connor II Plant. DCP is also working to ensure it has sufficient residue gas capacity available beyond October to accommodate these incremental volumes into early 2020, when completion of the planned Cheyenne Connector pipeline is expected.

We have been engaged with DCP in planning for further incremental increases to the processing capacity in the field. DCP has recently executed a long-term agreement with another in-basin midstream provider for up to 225MMcfd of incremental processing capacity. This incremental processing capacity is expected to be constructed, commissioned and in service by mid-2020, and we expect will be well integrated with the NGL and residue gas takeaway expansion projects mentioned above. We also continue to work with our midstream service providers in an effort to ensure all of the existing

infrastructure is fully utilized and that all options for system expansion are evaluated and implemented to the extent possible to accommodate projected future volume growth from the field.

NGL fractionation on the Gulf Coast and Conway continues to operate at or near full capacity and this could potentially impact the operation of gas plants in the Wattenberg Field. While our Wattenberg Field operations are not currently being impacted by NGL fractionation capacity constraints, the limitation on NGL fractionation capacity did limit the throughput of some gas processing plants in the field for a portion of the first quarter of 2019. Limitations on downstream fractionation capacity could limit the ability of our service providers to adjust ethane and propane recoveries to optimize the plant product mix to maximize revenue. Additional fractionation capacity is scheduled to come online later in 2019 and in 2020.

Delaware Basin. In the second quarter of 2018, we entered into firm sales and pipeline agreements for portions of our Delaware Basin crude oil and natural gas production, respectively. The crude oil agreement runs through December 2023 and provides for firm physical takeaway for all of our forecasted 2019 Delaware Basin crude oil volumes. This agreement provides us with price diversification through realization of export market pricing that includes access to a Corpus Christi terminal and exposure to Brent-weighted prices. As a result of this agreement, we expect to realize approximately 94 percent of West Texas Intermediate ("WTI") crude oil pricing for our total Delaware Basin production in 2019, after deducting transportation and other related marketing expenses. Our actual realization for Delaware Basin production for the second quarter of 2019 was 97 percent of WTI crude oil pricing. While our current crude oil production is not sufficient to satisfy this commitment, we have been able to satisfy our obligation under the agreement by purchasing volumes from third parties. This may not continue to be the case in the future and we could incur unutilized transportation charges for any such shortfalls.

Our Delaware Basin natural gas sales agreements run through December 2021 and provide for firm physical takeaway of amounts varying between 60,000 MMbtu and 100,000 MMbtu per day of our natural gas volumes from the basin during the term of the agreements. In addition, concurrent with the sale of our natural gas gathering system in the Delaware Basin, we entered into an agreement with the purchaser which provides us with gathering, processing and transportation of our natural gas from certain dedicated leases through 2041.

Our production from the Delaware Basin was not materially affected by midstream or downstream capacity constraints during the first half of 2019. However, natural gas takeaway capacity downstream of in-field gathering and processing facilities in the basin is operating close to capacity and near-term production constraints are possible.

As discussed above, NGL fractionation on the Gulf Coast and at Conway is running at or near full capacity, and this could potentially impact the operation of gas plants in the Delaware Basin. In addition, residue pipeline and downstream crude oil pipelines in the Delaware Basin are also operating at high utilization rates. We expect additional residue gas takeaway to be available in late 2019 and additional crude oil pipelines to be available in early 2020 with additional NGL fractionation infrastructure being available starting in mid-2019, with more projects scheduled to be completed in 2020.

Crude Oil, Natural Gas and NGLs Pricing

Our results of operations depend upon many factors. Key factors include market prices 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 realized sales prices for crude oil, natural gas and NGLs decreased during the three and six months ended June 30, 2019 compared to the three and six months ended June 30, 2018. Changes in market prices for crude oil, natural gas and NGLs negatively impacted these realized prices. The NYMEX average daily crude oil prices decreased 12 percent for the three and six months ended June 30, 2019 as compared to the respective periods in 2018 and the NYMEX average first-of-the-month natural gas price decreased six percent for the three months ended June 30, 2019 compared to the three months ended June 30, 2018. The NYMEX average first-of-the-month natural gas price for the six months ended June 30, 2019 was comparable to the average price for the same period in 2018.

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	**Three Months Ended June 30,**			**Six Months Ended June 30,**		
(excluding net settlements on derivatives)	**2019**	**2018**	**Percent Change**	**2019**	**2018**	**Percent Change**
Crude oil (per Bbl)						
Wattenberg Field	$ 55.30	$ 64.57	(14.4)%	$ 52.94	$ 61.88	(14.4)%
Delaware Basin	57.97	62.31	(7.0)%	55.83	61.86	(9.7)%
Utica Shale (1)	—	—	*	—	58.10	*
Weighted-average price	55.96	63.99	(12.5)%	53.61	61.85	(13.3)%
Natural gas (per Mcf)						
Wattenberg Field	$ 1.30	$ 1.43	(9.1)%	$ 1.74	$ 1.67	4.2 %
Delaware Basin	0.16	1.54	(89.6)%	0.64	1.78	(64.0)%
Utica Shale (1)	—	—	*	—	2.68	*
Weighted-average price	1.07	1.46	(26.7)%	1.53	1.71	(10.5)%
NGLs (per Bbl)						
Wattenberg Field	$ 11.30	$ 19.60	(42.3)%	$ 12.90	$ 19.86	(35.0)%
Delaware Basin	16.14	29.26	(44.8)%	17.41	28.56	(39.0)%
Utica Shale (1)	—	—	*	—	24.29	*
Weighted-average price	12.53	21.76	(42.4)%	13.96	21.78	(35.9)%
Crude oil equivalent (per Boe)						
Wattenberg Field	$ 26.81	$ 34.09	(21.4)%	$ 27.59	$ 33.64	(18.0)%
Delaware Basin	28.84	36.80	(21.6)%	29.11	37.58	(22.5)%
Utica Shale (1)	—	—	*	—	30.98	*
Weighted-average price	27.28	34.74	(21.5)%	27.92	34.51	(19.1)%

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 transfer control of crude oil, natural gas or NGLs production to the purchaser. We consider the transfer of control to occur 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.

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 based on a percent of proceeds or a sales price fixed 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 transportation 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.

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 on average daily prices throughout each month and, for natural gas, the average NYMEX pricing is based on 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 relevant 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, 2019	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)	$ 59.81	$ 55.96	94%	$ 1.20	$ 54.76	92%
Natural gas (per MMBtu)	2.64	1.07	41%	0.19	0.88	33%
NGLs (per Bbl)	59.81	12.53	21%	0.18	12.35	21%
Crude oil equivalent (per Boe)	42.78	27.28	64%	0.96	26.32	62%

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 Six Months Ended June 30, 2019	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)	$ 57.36	$ 53.61	93%	$ 1.21	$ 52.40	91%
Natural gas (per MMBtu)	2.89	1.53	53%	0.19	1.34	46%
NGLs (per Bbl)	57.36	13.96	24%	0.21	13.75	24%
Crude oil equivalent (per Boe)	41.93	27.92	67%	0.97	26.95	64%

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%

Our average realization percentages for crude oil sales for the three and six months ended June 30, 2019 are comparable to those for the corresponding periods of 2018. The realization percentages for our natural gas sales for the three and six months ended June 30, 2019 have decreased as compared to the same periods in 2018, primarily due to widening of the basis between NYMEX and the indices upon which we sell our natural gas production. This was especially true in the Delaware Basin, where we experienced some days during the three and six months ended June 30, 2019 when the transportation cost to deliver our natural gas to market exceeded the price we received. The realization percentages for our NGLs sales also decreased as compared to 2018, primarily due to decreases in prices for the individual NGLs components for the three and six months ended June 30, 2019 as compared to the same periods in 2018.

Commodity Price Risk Management

We use commodity derivative instruments to manage fluctuations in crude oil and natural gas prices, including collars, fixed-price swaps and basis swaps on a portion of our estimated crude oil and natural gas 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, 2019.

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 and natural gas production. Commodity price risk management, net, does not include gains or losses from derivative transactions related to our gas marketing segment, which are included in other income and other expenses.

Net settlements of commodity derivative instruments are based on the difference between the crude oil and natural gas 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 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 net change in fair value of unsettled commodity derivatives during the period is primarily related to shifts in the crude oil and natural gas 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,	
	2019	2018	2019	2018
		(in millions)		
Commodity price risk management gain (loss), net:				
Net settlements of commodity derivative instruments:				
Crude oil fixed price swaps, collars and rollfactors	$ (14.7)	$ (37.2)	$ (17.5)	$ (63.9)
Crude oil basis protection swaps	—	11.7	—	11.4
Natural gas fixed price swaps and collars	2.1	2.5	0.5	2.6
Natural gas basis protection swaps	(0.6)	8.7	(4.6)	11.2
NGLs fixed price swaps	—	(2.1)	—	(3.8)
Total net settlements of commodity derivative instruments	(13.2)	(16.4)	(21.6)	(42.5)
Change in fair value of unsettled commodity derivative instruments:				
Reclassification of settlements included in prior period changes in fair value of commodity derivative instruments	15.4	18.1	(39.7)	32.0
Crude oil fixed price swaps, collars and rollfactors	38.3	(111.4)	(85.6)	(152.9)
Natural gas fixed price swaps and collars	7.2	(2.3)	6.7	(3.2)
Natural gas basis protection swaps	(0.4)	(1.7)	(2.5)	5.0
NGLs fixed price swaps	—	(2.4)	—	(1.8)
Net change in fair value of unsettled commodity derivative instruments	60.5	(99.7)	(121.1)	(120.9)
Total commodity price risk management gain (loss), net	$ 47.3	$ (116.1)	$ (142.7)	$ (163.4)

Lease Operating Expenses

Lease operating expenses increased six percent to $34.3 million in the three months ended June 30, 2019 compared to $32.3 million in the three months ended June 30, 2018. Significant changes in lease operating expenses included increases of $1.7 million for produced water disposal, $1.5 million for non-operated wells, $1.4 million in additional compressor and equipment rentals and $0.9 million for payroll and employee benefits. The increases were partially offset by a $2.7 million decrease in workover expense and a $1.6 million decrease related to midstream expense resulting from the sale of Delaware Basin midstream assets during the second quarter of 2019. Lease operating expense per Boe decreased by 20 percent to $2.76 for the three months ended June 30, 2019 from $3.44 for the three months ended June 30, 2018, primarily due to a 32 percent increase in production volumes.

Lease operating expenses increased 12 percent to $69.5 million in the six months ended June 30, 2019 compared to $61.9 million in the six months ended June 30, 2018. Significant changes in lease operating expenses included increases of $3.1 million in additional compressor and equipment rentals, $3.1 million for produced water disposal, $1.5 million for payroll and employee benefits, $1.1 million for non-operated wells and $0.7 million in environmental remediation services. The increases were partially offset by a $3.1 million decrease in workover expense and a $0.7 million decrease related to midstream expense resulting from the sale of Delaware Basin midstream assets during the second quarter of 2019. Lease operating expense per Boe decreased by 13 percent to $2.94 for the six months ended June 30, 2019 from $3.38 for the six months ended June 30, 2018, primarily due to a 29 percent increase in production volumes.

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 were $22.6 million in each of the three months ended June 30, 2019 and 2018, despite a four percent increase in crude oil, natural gas and NGLs sales, primarily due to adjustments to appraised property values during the three months ended June 30, 2019.

Production taxes increased five percent to $44.8 million in the six months ended June 30, 2019 compared to $42.8 million in the six months ended June 30, 2018, primarily due to the five percent increase in crude oil, natural gas and NGLs sales for the six months ended June 30, 2019 compared to the six months ended June 30, 2018.

Transportation, Gathering and Processing Expenses

Transportation, gathering and processing expenses increased 36 percent to $12.2 million in the three months ended June 30, 2019 compared to $9.0 million in the three months ended June 30, 2018 and 45 percent to $23.6 million in the six months ended June 30, 2019 compared to $16.3 million in the six months ended June 30, 2018. Transportation, gathering and processing expenses are primarily impacted by variances in the volumes delivered through pipelines and for natural gas gathering and transportation operations. 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:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(in millions)			
Impairment of proved and unproved properties	$ 2.2	$ 159.5	$ 10.1	$ 192.6
Amortization of individually insignificant unproved properties	—	—	—	0.1
Impairment of infrastructure and other	26.8	—	26.8	—
Impairment of properties and equipment	$ 29.0	$ 159.5	$ 36.9	$ 192.7

During the three and six months ended June 30, 2019 and 2018, we recorded impairment charges primarily related to the divestiture of leaseholds and leasehold expirations within our non-focus areas of the Delaware Basin that we no longer plan to develop. During the three and six months ended June 30, 2019, we also recorded impairments of $26.8 million related to certain midstream facility infrastructure in the Delaware Basin. Upon closing of the Midstream Asset Divestitures, it was determined that the net book value of these assets was not recoverable.

General and Administrative Expense

General and administrative expense increased 15 percent to $42.8 million in the three months ended June 30, 2019 compared to $37.2 million in the three months ended June 30, 2018. The increase was primarily attributable to a $4.7 million increase related to shareholder activism and a $4.2 million increase in payroll and related benefits, which includes $1.6 million of costs related to a reduction in force in June 2019. The increases were partially offset by a $4.3 million decrease in legal-related fees related to an expected insurance reimbursement.

General and administrative expense increased 13 percent to $82.4 million in the six months ended June 30, 2019 compared to $72.9 million in the six months ended June 30, 2018. The increase was primarily attributable to a $5.7 million increase related to shareholder activism and a $4.3 million increase in payroll and related benefits, including $1.6 million of costs related to a reduction in force in June 2019. The increases were partially offset by a $2.1 million decrease in legal-related fees related to an expected insurance reimbursement.

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 $167.1 million and $317.0 million for the three and six months ended June 30, 2019, respectively, compared to $133.6 million and $258.4 million for the three and six months ended June 30, 2018, respectively.

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

	Three Months Ended June 30, 2019	Six Months Ended June 30, 2019
	(in millions)	
Increase in production	$ 42.6	$ 77.2
Decrease in weighted-average depreciation, depletion and amortization rates	(9.1)	(18.5)
Total increase in DD&A expense related to crude oil and natural gas properties	$ 33.5	$ 58.7

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	**2019**	**2018**	**2019**	**2018**
		(per Boe)		
Wattenberg Field	$ 12.12	$ 12.94	$ 12.27	$ 13.23
Delaware Basin	17.88	18.34	17.53	17.69
Total weighted-average	$ 13.45	$ 14.24	$ 13.41	$ 14.13

Non-crude oil and natural gas properties. Depreciation expense for non-crude oil and natural gas properties was $1.4 million and $2.9 million for the three and six months ended June 30, 2019, respectively, compared to $2.0 million and $4.0 million for the three and six months ended June 30, 2018, respectively.

Interest Expense

Interest expense increased $1.5 million to $18.9 million for the three months ended June 30, 2019 compared to $17.4 million for the three months ended June 30, 2018. The increase was primarily related to a $2.5 million increase in interest related to our revolving credit facility, partially offset by a $1.2 million increase in capitalized interest.

Interest expense increased $1.0 million to $35.9 million for the six months ended June 30, 2019 compared to $34.9 million for the six months ended June 30, 2018. The increase was primarily related to a $3.0 million increase in interest related to our revolving credit facility, partially offset by a $2.3 million increase in capitalized interest.

Provision for Income Taxes

The effective income tax rate for the three months ended June 30, 2019 was a 24.8 percent provision on income and the effective income tax rate for the six months ended June 30, 2019 was a 22.3 percent benefit on loss, compared to a 22.0 percent and 22.3 percent benefit on loss for the three and six months ended June 30, 2018, respectively. The effective income tax rates are based upon a full year forecasted pre-tax income for the year adjusted for permanent differences. The forecasted full year effective income tax rate has been applied to the quarterly pre-tax loss, resulting in an income tax benefit for the period. The quarterly rates are proportionately impacted by updates to previously-forecasted pre-tax earnings.

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

The factors resulting in net income for the three months ended June 30, 2019 of $68.5 million, a net loss in the six months ended June 30, 2019 of $51.6 million and a net loss in the three and six months ended June 30, 2018 of $160.3 million and $173.4 million, respectively, are discussed above, with the net change in the fair value of unsettled commodity derivatives and the decrease in impairments of properties and equipment during the three months ended June 30, 2019 and the decrease in impairments of properties and equipment during the six months ended June 30, 2019 having the most significant impact. Adjusted net income, a non-U.S. GAAP financial measure, was $22.5 million and $40.5 million for the three and six months ended June 30, 2019, respectively, and $84.5 million and $81.4 million for the three and six months ended June 30, 2018, respectively. With the exception of the tax-affected net change in fair value of unsettled derivatives of $46.0 million and $92.1 million for the three and six months ended June 30, 2019, respectively, and $75.8 million and $92.0 million for the three and six months ended June 30, 2018, 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, asset sales and proceeds raised in debt and equity capital market transactions. For the six months ended June 30, 2019, our net cash flows from operating activities were $442.2 million.

Our primary source of cash flows from operating activities is the sale of crude oil, natural gas and NGLs. Fluctuations in our operating cash flows are principally driven by commodity prices and changes in our production volumes. Commodity prices have historically been volatile and we manage 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 experienced over the past year, 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.

We may use our available liquidity for operating activities, capital investments, working capital requirements, acquisitions, support for letters of credit and for general corporate purposes. We maintain a significant capital investment program to execute our development plans, which requires capital expenditures to be made in periods prior to initial production from newly developed wells.

From time to time, these activities may result in a working capital deficit; however, we do not believe that our working capital deficit as of June 30, 2019 is an indication of a lack of liquidity. We had working capital deficits of $172.7 million and $166.6 million at June 30, 2019 and December 31, 2018, respectively. The increase in the working capital deficit as of June 30, 2019 of $6.2 million is primarily the result of a decrease in the net fair value of our unsettled commodity derivative instruments of $59.5 million, an increase in accounts payable of $37.3 million related to our increased development activities and an increase in other accrued expense of $11.4 million primarily related to our Stock Repurchase Program. The changes were partially offset by an increase in accounts receivable of $95.9 million related to our crude oil, natural gas and NGLs sales and the Midstream Asset Divestitures and a decrease in funds held for distribution of $16.9 million. 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 favorable 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 the borrowing capacity under our revolving credit facility and, if warranted, capital markets transactions from time to time.

Our cash and cash equivalents were $1.5 million at June 30, 2019 and availability under our revolving credit facility was $1.3 billion, providing for a total liquidity position of $1.3 billion as of June 30, 2019. Based on our current production forecast for 2019 and assuming a NYMEX crude oil price of $55.00, we expect cash flows from operations to slightly exceed our capital investments in crude oil and natural gas properties.

In the second quarter of 2019, we completed the Midstream Asset Divestitures for an aggregate cash purchase price of $345.6 million ($263.6 million of which was paid upon closing with the remaining $82.0 million paid one year post-closing), subject to certain customary post-closing adjustments, plus aggregate conditional payments of up to $150.7 million. We have and expect to continue to use the proceeds from these divestitures for our capital investment program.

In April 2019, our Board of Directors approved the acquisition of up to $200.0 million of our outstanding common stock, depending on market conditions. During the three months ended June 30, 2019, we repurchased 3.1 million shares of our outstanding common stock for a total cost of $105.2 million. During July 2019, we repurchased 0.6 million shares of outstanding common stock at a cost of $19.8 million. Approximately $75.0 million remains available for repurchases under the Stock Repurchase Program. We currently project that we will generate a sufficient level of free cash flows through December 2020 to fund the Stock Repurchase Program, while maintaining the ability to pursue additional future return of capital programs, depending on market conditions. Repurchases under the Stock Repurchase Program can be made in open markets at our discretion and in compliance with safe harbor provisions, or in privately negotiated transactions. The Stock Repurchase Program does not require any specific number of shares to be acquired, and can be modified or discontinued by the Board of Directors at any time.

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 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 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. At June 30, 2019, we were in compliance with all covenants in the revolving credit facility with a current ratio of 3.2:1.0 and a leverage ratio of 1.4:1.0. 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. See the footnote titled *Long-Term Debt* to the accompanying condensed consolidated financial statements included elsewhere in this report for more information regarding our revolving credit facility.

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 $61.4 million to $442.2 million for the six months ended June 30, 2019 compared to the six months ended June 30, 2018, due to an increase in changes in assets and liabilities of $36.1 million, primarily attributable to $97.7 million due to deferred midstream gathering credits related to our Midstream Asset Divestitures, as well as increases in general and administrative expenses of $9.5 million, lease operating expenses of $7.7 million, transportation, gathering and processing expense of $7.4 million and production taxes of $2.0 million. These changes were partially offset by increases in commodity derivative settlements of $20.8 million and crude oil, natural gas and NGLs sales of $28.9 million.

Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased by $25.2 million to $399.5 million during the six months ended June 30, 2019 compared to the six months ended June 30, 2018. 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. During the six months ended June 30, 2019, our adjusted EBITDAX, a non-U.S. GAAP financial measure, was $466.1 million compared to $404.4 million for the comparable period in 2018. The 15 percent increase in our adjusted EBITDAX for the six months ended June 30, 2019 as compared to the six months ended June 30, 2018 was primarily due to the increase in crude oil, natural gas and NGLs sales of $28.9 million, the gain from sale of properties and equipment of $34.3 million and a decrease in the loss on commodity derivative settlements of $20.8 million. The increase was partially offset by an increase in operating costs of $26.5 million. 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.

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 $348.8 million during the six months ended June 30, 2019 was primarily related to our drilling and completion activities of $542.8 million. Net cash received from the Midstream Asset Divestitures and certain Delaware Basin crude oil and natural gas properties was $199.4 million. 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 a property 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 sale of our Utica Shale assets in March 2018.

Financing Activities. Net cash used in financing activities of $101.4 million during the six months ended June 30, 2019 was primarily due to the repurchase and retirement of shares of our common stock totaling $94.1 million pursuant to the Stock Repurchase Program, partially offset by net borrowings from our credit facility of $2.5 million.

Off-Balance Sheet Arrangements

At June 30, 2019, 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 2018 Form 10-K filed with the SEC on February 28, 2019.

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,	
	2019	2018	2019	2018
	(in millions)			
Adjusted cash flows from operations:				
Net cash from operating activities	$ 260.4	$ 175.7	$ 442.2	$ 380.9
Changes in assets and liabilities	(53.4)	23.6	(42.7)	(6.6)
Adjusted cash flows from operations	$ 207.0	$ 199.3	$ 399.5	$ 374.3
Adjusted net income (loss):				
Net income (loss)	$ 68.5	$ (160.3)	$ (51.6)	$ (173.4)
(Gain) loss on commodity derivative instruments	(47.3)	116.1	142.7	163.4
Net settlements on commodity derivative instruments	(13.2)	(16.4)	(21.6)	(42.4)
Tax effect of above adjustments	14.5	(23.9)	(29.0)	(29.0)
Adjusted net income (loss)	$ 22.5	$ (84.5)	$ 40.5	$ (81.4)
Net income (loss) to adjusted EBITDAX:				
Net income (loss)	$ 68.5	$ (160.3)	$ (51.6)	$ (173.4)
(Gain) loss on commodity derivative instruments	(47.3)	116.1	142.7	163.4
Net settlements on commodity derivative instruments	(13.2)	(16.4)	(21.6)	(42.4)
Non-cash stock-based compensation	7.6	5.5	12.3	10.8
Interest expense, net	18.9	17.3	35.9	34.7
Income tax expense (benefit)	22.6	(45.3)	(14.8)	(49.9)
Impairment of properties and equipment	29.0	159.5	36.9	192.7
Exploration, geologic and geophysical expense	0.6	0.9	3.3	3.5
Depreciation, depletion and amortization	168.5	135.6	319.9	262.4
Accretion of asset retirement obligations	1.6	1.4	3.1	2.6
Adjusted EBITDAX	$ 256.8	$ 214.3	$ 466.1	$ 404.4
Cash from operating activities to adjusted EBITDAX:				
Net cash from operating activities	$ 260.4	$ 175.7	$ 442.2	$ 380.9
Interest expense, net	18.9	17.3	35.9	34.7
Amortization of debt discount and issuance costs	(3.4)	(3.1)	(6.7)	(6.4)
Gain (loss) on sale of properties and equipment	33.9	0.4	34.3	(1.1)
Exploration, geologic and geophysical expense	0.6	0.9	3.3	3.5
Other	(0.2)	(0.5)	(0.2)	(0.6)
Changes in assets and liabilities	(53.4)	23.6	(42.7)	(6.6)
Adjusted EBITDAX	$ 256.8	$ 214.3	$ 466.1	$ 404.4

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, 2019, 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, 2019 was $0.6 million with a weighted-average interest rate of 1.2 percent. Based on a sensitivity analysis of our interest-bearing deposits as of June 30, 2019 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, 2019.

As of June 30, 2019, we had a $30.0 million outstanding balance on our revolving credit facility. If market interest rates would have increased or decreased one percent, our interest expense for the six months ended June 30, 2019 would have changed by approximately $0.3 million.

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 and natural gas 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, 2019.

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, 2019	Six Months Ended June 30, 2019	Year Ended December 31, 2018
Average NYMEX Index Price:			
Crude oil (per Bbl)	$ 59.81	$ 57.36	$ 64.77
Natural gas (per MMBtu)	2.64	2.89	3.09
Average Sales Price Realized:			
Excluding net settlements on commodity derivatives			
Crude oil (per Bbl)	$ 55.96	$ 53.61	$ 61.19
Natural gas (per Mcf)	1.07	1.53	1.85
NGLs (per Bbl)	12.53	13.96	22.14

Based on a sensitivity analysis as of June 30, 2019, we estimate that a ten percent increase in natural gas and crude oil, 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 $62.1 million, whereas a ten percent decrease in prices would have resulted in an increase in fair value of $62.9 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. 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.

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, 2019, 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, 2019, 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 defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act. 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, 2019 because of the material weaknesses in our internal control over financial reporting described below.

Management's Report on Internal Control over Financial Reporting

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 CEO and CFO, 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.

Management has assessed the effectiveness of our internal control over financial reporting as of June 30, 2019, based upon the criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis.

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 to our unproved properties, impairment of unproved properties, sales, accounts receivable and depletion expense accounts and related disclosures in our consolidated financial statements for the years ended December 31, 2018 and 2017 and the six months ended June 30, 2019.

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

We are committed to continuing to review, optimize and enhance our internal control over financial reporting. In response to the identified material weaknesses, our management, with the oversight of the Audit Committee of our Board of Directors, has assessed a number of different remediation initiatives to improve our internal control over financial reporting. Building on our efforts during 2017, we continued throughout 2018 and the beginning of 2019 to dedicate significant resources and efforts to improve our internal control over financial reporting and to take steps to remediate the material weaknesses identified above. While certain remediation plans have been implemented, we continue to actively plan for and implement additional remediation measures.

During 2018 and 2019, we have taken steps to strengthen the control activities within the Land Department, which include new leadership, hiring additional personnel with relevant experience, increased layers of supervision, staff training and development and division of responsibilities within the Land Department. We have also designed and implemented control activities to verify the completeness and accuracy of land administrative records associated with unproved leases, including the

verification of the reliability of underlying data used in the execution of the control activities. As we continue to evaluate and work to improve our internal control over financial reporting, we may take additional measures to address these control deficiencies, or we may modify certain of the remediation measures described above to improve the operating effectiveness of those measures. These material weaknesses will not be considered remediated until the applicable remediated 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

There were no changes in our internal control over financial reporting during the quarter ended June 30, 2019 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 2018 Form 10-K and 2019 Q1 Form 10-Q. 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 2018 Form 10-K and 2019 Q1 Form 10-Q.

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) (2)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (2)	Approximate Dollar Value of Shares that may yet be Purchased Under the Plans or Programs (in millions) (3)
April 1 - 30, 2019	51,059	$ 41.67	—	$ 200.0
May 1 - 31, 2019	—	—	—	200.0
June 1 - 30, 2019	3,140,131	33.55	3,136,406	94.8
Total second quarter 2019 purchases	3,191,190	$ 33.68	3,136,406	$ 94.8

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(1) Certain purchases represent shares withheld from employees for the payment of their tax liabilities related to the vesting of securities issued pursuant to our stock-based compensation plans. The withheld shares are not issued or considered common stock repurchased under the Stock Repurchase Program described in the footnote titled Common Stock to our condensed consolidated financial statements included elsewhere in this report.

(2) In April 2019, our Board of Directors approved a program to acquire up to $200 million of our outstanding common stock. The Stock Repurchase Program does not require any specific number of shares to be acquired, and can be modified or discontinued by the Board of Directors at any time.

(3) In July 2019, we repurchased $19.8 million of our outstanding common stock as part of the Stock Repurchase Program. At July 31, 2019, $75.0 million of shares remained available for repurchase that may yet be purchased under the Stock Repurchase Program.

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 - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL 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 7, 2019

/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 7, 2019

/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 7, 2019

/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, 2019, 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 7, 2019

Barton Brookman
President and Chief Executive Officer

(principal executive officer)

/s/ R. Scott Meyers — August 7, 2019

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