PDC ENERGY, INC.
Form 10-Q
November 06, 2014
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2014

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 000-07246
PDC ENERGY, INC.
(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

Large accelerated filer x	Accelerated filer o

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

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 35,876,283 shares of the Company's Common Stock ($0.01 par value) were outstanding as of October 17, 2014.

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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") and Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") regarding our business, financial condition, results of operations and prospects. All statements other than statements of historical facts included in and incorporated by reference into this report are "forward-looking statements" within the meaning of the safe harbor provisions of the United States ("U.S.") Private Securities Litigation Reform Act of 1995. Words such as expects, anticipates, intends, plans, believes, seeks, estimates and similar expressions or variations of such words are intended to identify forward-looking statements herein. These statements relate to, among other things: use of expected proceeds from the PDC Mountaineer, LLC ("PDCM") divestiture; future crude oil, natural gas and natural gas liquids (“NGLs”) production (including the components of such production); future expenses, cash flows and liquidity; our evaluation method of our customers' and derivative counterparties' credit risk is appropriate; anticipated capital projects, expenditures and opportunities; future exploration, drilling and development activities; our drilling programs; impact of the Colorado task force on oil and gas regulation and potential future ballot initiatives and legislation; availability of sufficient funding for our capital program and sources of that funding; expected 2014 capital budget allocations; acquisitions of additional acreage and other future transactions; the impact of high line pressures and the timing, availability and effect of additional mid-stream facilities going forward; the expected NYMEX differential at our two primary sales hubs; compliance with debt covenants; expected funding sources for conversion of our 3.25% convertible senior notes due 2016 and expected impact on our financial position; impact of litigation on our results of operations and financial position; effectiveness of our derivative program in providing a degree of price stability; that we do not expect to pay dividends in the foreseeable future; electronic, cyber or physical security breaches; our expected receipt of a full acceptance notice from the Internal Revenue Service ("IRS") with respect to 2013 taxes and decrease in liability for uncertain tax positions; and our future strategies, plans and objectives.

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. Consequently, forward-looking statements are inherently subject to risks and uncertainties, including known and unknown risks and uncertainties incidental to the exploration for, and the acquisition, development, production and marketing of, crude oil, natural gas and NGLs, and actual outcomes may differ materially from the results and outcomes discussed in the forward-looking statements.

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

- changes in worldwide production volumes and demand, including economic conditions that might impact demand;
- volatility of commodity prices for crude oil, natural gas and NGLs;
- impact of governmental policies and/or regulations, including changes in environmental and other laws, the interpretation and enforcement related to those laws and regulations, liabilities arising thereunder and the costs to comply with those laws and regulations;
- potential 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;
- our ability to secure leases, drilling rigs, supplies and services at reasonable prices;
- 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;
- our future cash flows, liquidity and financial condition;
- competition within the oil and gas industry;
- availability and cost of capital;
- reductions in the borrowing base under our revolving credit facility;
- our success in marketing crude oil, natural gas and NGLs;
- effect of crude oil and natural gas derivatives activities;
- impact of environmental events, governmental and other third-party responses to such events, and our ability to insure adequately against such events;
- cost of pending or future litigation;
- effect that acquisitions we may pursue have on our capital expenditures;
- 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, 2013 ("2013 Form 10-K"), filed with the U.S. Securities and Exchange Commission ("SEC") on February 21, 2014, 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,

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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 and PDCM, a joint venture owned, until October 14, 2014, 50% each by PDC and Lime Rock Partners, LP. See Note 1, Nature of Operations and Basis of Presentation, elsewhere in this report for a description of our consolidated subsidiaries and Note 15, Subsequent Event, to the condensed consolidated financial statements for a discussion of the sale of our interest in PDCM.

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PART I - FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

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

	September 30, 2014	December 31, 2013
Assets		
Current assets:		
Cash and cash equivalents	$18,242	$192,642
Restricted cash	46	2,211
Accounts receivable, net	102,071	88,111
Accounts receivable affiliates	3,611	6,614
Fair value of derivatives	9,147	1,521
Deferred income taxes	13,388	22,374
Assets held for sale - current	5,375	7,661
Prepaid expenses and other current assets	5,329	4,679
Total current assets	157,209	325,813
Properties and equipment, net	1,783,797	1,484,638
Assets held for sale - non-current	176,694	178,484
Fair value of derivatives	18,039	4,503
Other assets	42,770	31,765
Total Assets	$2,178,509	$2,025,203
Liabilities and Shareholders' Equity		
Liabilities		
Current liabilities:		
Accounts payable	$106,728	$101,688
Accounts payable affiliates	—	41
Production tax liability	23,872	22,232
Fair value of derivatives	2,356	14,689
Funds held for distribution	37,413	31,040
Accrued interest payable	19,717	9,033
Liabilities held for sale - current	3,070	12,069
Other accrued expenses	53,222	22,628
Total current liabilities	246,378	213,420
Long-term debt	675,913	604,990
Deferred income taxes	124,762	118,767
Asset retirement obligation	39,564	37,638
Fair value of derivatives	2,241	2,842
Liabilities held for sale - non-current	61,543	55,915
Other liabilities	26,085	24,037
Total liabilities	1,176,486	1,057,609
Commitments and contingent liabilities		
Shareholders' equity		
	—	—

Preferred shares - par value $0.01 per share, 50,000,000 shares authorized, none issued		
Common shares - par value $0.01 per share, 150,000,000 authorized, 35,894,186 and 35,675,656 issued as of September 30, 2014 and December 31, 2013, respectively	359	357
Additional paid-in capital	686,045	674,211
Retained earnings	316,950	293,267
Treasury shares - at cost, 23,171 and 5,508 as of September 30, 2014 and December 31, 2013, respectively	(1,331)	(241)
Total shareholders' equity	1,002,023	967,594
Total Liabilities and Shareholders' Equity	$2,178,509	$2,025,203

See accompanying Notes to Condensed Consolidated Financial Statements

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Revenues				
Crude oil, natural gas and NGLs sales	$120,526	$77,340	$371,556	$226,985
Sales from natural gas marketing	13,297	16,946	62,649	48,695
Commodity price risk management gain (loss), net	90,213	(24,138)	12,661	(22,075)
Well operations, pipeline income and other	520	1,667	1,650	3,681
Total revenues	224,556	71,815	448,516	257,286
Costs, expenses and other				
Production costs	22,754	17,036	64,611	45,691
Cost of natural gas marketing	13,347	17,127	62,645	48,928
Exploration expense	190	1,841	773	4,647
Impairment of crude oil and natural gas properties	1,863	4,236	3,621	51,794
General and administrative expense	34,625	15,052	96,549	43,938
Depreciation, depletion and amortization	49,640	26,957	142,165	77,876
Accretion of asset retirement obligations	861	1,181	2,542	3,491
(Gain) loss on sale of properties and equipment	21	(100)	577	(131)
Total cost, expenses and other	123,301	83,330	373,483	276,234
Income (loss) from operations	101,255	(11,515)	75,033	(18,948)
Interest expense	(11,821)	(11,957)	(36,199)	(37,883)
Interest income	39	130	309	133
Income (loss) from continuing operations before income taxes	89,473	(23,342)	39,143	(56,698)
Provision for income taxes	(35,396)	9,435	(15,852)	20,789
Income (loss) from continuing operations	54,077	(13,907)	23,291	(35,909)
Income (loss) from discontinued operations, net of tax	(80)	(2,093)	392	409
Net income (loss)	$53,997	$(16,000)	$23,683	$(35,500)
Earnings per share:				
Basic				
Income (loss) from continuing operations	$1.51	$(0.42)	$0.65	$(1.14)
Income (loss) from discontinued operations, net of tax	—	(0.06)	0.01	0.01
Net income (loss)	$1.51	$(0.48)	$0.66	$(1.13)
Diluted				
Income (loss) from continuing operations	$1.47	$(0.42)	$0.63	$(1.14)
Income (loss) from discontinued operations, net of tax	—	(0.06)	0.01	0.01
Net income (loss)	$1.47	$(0.48)	$0.64	$(1.13)
Weighted-average common shares outstanding:				
Basic	35,834	33,413	35,763	31,350

Diluted	36,828	33,413	36,831	31,350

See accompanying Notes to Condensed Consolidated Financial Statements

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

	Nine Months Ended September 30, 2014	2013
Cash flows from operating activities:		
Net income (loss)	$23,683	$(35,500)
Adjustments to net loss to reconcile to net cash from operating activities:		
Net change in fair value of unsettled derivatives	(34,323)	32,057
Depreciation, depletion and amortization	151,293	88,877
Impairment of crude oil and natural gas properties	4,054	52,436
Accretion of asset retirement obligation	2,582	3,667
Stock-based compensation	13,111	9,991
Loss on sale of properties and equipment	384	1,571
Amortization of debt discount and issuance costs	5,206	5,093
Deferred income taxes	14,981	(21,714)
Other	(759)	(1,017)
Changes in assets and liabilities	21,753	(15,918)
Net cash from operating activities	201,965	119,543
Cash flows from investing activities:		
Capital expenditures	(451,081)	(256,096)
Proceeds from acquisition adjustments	—	7,579
Proceeds from sale of properties and equipment	1,587	178,987
Net cash from investing activities	(449,494)	(69,530)
Cash flows from financing activities:		
Proceeds from revolving credit facility	136,750	252,500
Repayment of revolving credit facility	(61,000)	(278,000)
Proceeds from sale of common stock, net of issuance costs	—	275,847
Other	(2,726)	(4,329)
Net cash from financing activities	73,024	246,018
Net change in cash and cash equivalents	(174,505)	296,031
Cash and cash equivalents, beginning of period	193,243	2,457
Cash and cash equivalents, end of period	$18,738	$298,488
Supplemental cash flow information:		
Cash payments for:		
Interest, net of capitalized interest	$24,933	$26,408
Income taxes	1,800	525
Non-cash investing activities:		
Change in accounts payable related to purchases of properties and equipment	$19,320	$24,308
Change in asset retirement obligation, with a corresponding change to crude oil and natural gas properties, net of disposals	500	337
Change in accounts payable related to disposition of properties and equipment	—	(231)

See accompanying Notes to Condensed Consolidated Financial Statements

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NOTE 1 - NATURE OF OPERATIONS AND BASIS OF PRESENTATION

PDC Energy, Inc. is a domestic independent exploration and production company that produces, develops, acquires and explores for crude oil, natural gas and NGLs with primary operations in the Wattenberg Field in Colorado, the Utica Shale in southeastern Ohio and, until the fourth quarter of 2014, the Marcellus Shale in northern West Virginia. Our operations in the Wattenberg Field are focused on the liquid-rich horizontal Niobrara and Codell plays and our Ohio operations are focused on the liquid-rich portion of the Utica Shale play. As of September 30, 2014, we owned an interest in approximately 2,900 gross wells. We are engaged in two business segments: Oil and Gas Exploration and Production and Gas Marketing. On October 14, 2014, we sold our entire 50% ownership interest in PDCM to an unrelated third-party. See Note 12, Assets Held for Sale, Divestitures and Discontinued Operations, and Note 15, Subsequent Event, for additional information.

The accompanying unaudited condensed consolidated financial statements include the accounts of PDC, our wholly-owned subsidiaries, and our proportionate share of PDCM and our affiliated partnerships. As of September 30, 2014, we had four remaining affiliated partnerships that continue to conduct crude oil and natural gas producing activities. 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 only normal recurring adjustments) necessary for a fair presentation 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 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 2013 Form 10-K. Our results of operations and cash flows for the three and nine months ended September 30, 2014 are not necessarily indicative of the results to be expected for the full year or any other future period.

Certain reclassifications have been made to prior period financial statements to conform to the current year presentation. The reclassifications are mainly attributable to reporting as discontinued operations the results of operations related to PDCM's Marcellus Shale assets, which have been classified as held for sale. These reclassifications had no impact on previously reported cash flows, net income, earnings per share or shareholders' equity.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Recently Adopted Accounting Standards

On January 1, 2014, we adopted changes issued by the Financial Accounting Standards Board ("FASB") regarding the accounting for income taxes. The change provides clarification on the presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss or a tax credit carryforward exists. Adoption of these changes had no impact on the condensed consolidated financial statements.

In April 2014, the FASB issued changes related to the criteria for determining which disposals can be presented as discontinued operations and modified related disclosure requirements. Under the new pronouncement, a discontinued operation is defined as a component of an entity that either has been disposed of or is classified as held for sale and represents a strategic shift that has a major effect on the entity's operations and financial results. These changes are to be applied prospectively for new disposals or components of an entity classified as held for sale during interim and annual periods beginning after December 15, 2014, with early adoption permitted. On July 1, 2014, we adopted the new pronouncement and as a result have reported as discontinued operations the results of operations related to PDCM's Marcellus Shale assets, which were classified as held for sale as of September 30, 2014. See Note 12, Assets Held for Sale, Divestitures and Discontinued Operations, and Note 15, Subsequent Event, for additional information.

Recently Issued Accounting Standards

In May 2014, the FASB and the International Accounting Standards Board ("IASB") issued their converged standard on revenue recognition that provides a single, comprehensive model that entities will apply to determine the measurement of revenue and timing of when it is recognized. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The standard outlines a five-step approach to apply the underlying principle: (a) identify the contract with the customer, (b) identify the separate performance obligations in the contract, (c) determine the transaction price, (d) allocate the transaction price to separate performance obligations and (e) recognize revenue when (or as) each performance obligation is satisfied. The revenue standard is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, and can be adopted under the full retrospective method or simplified transition method. Early adoption is not permitted. We plan to adopt the revenue standard beginning January 1, 2017 and are currently evaluating the impact these changes will have on our condensed consolidated financial statements.

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In August 2014, the FASB issued a new standard related to the disclosure of uncertainties about an entity's ability to continue as a going concern. The new standard will explicitly require management to assess an entity's ability to continue as a going concern every reporting period and to provide related footnote disclosures in certain circumstances. The new standard will be effective for all entities in the first annual period ending after December 15, 2016, with early adoption permitted. We are currently evaluating the impact these changes will have on our condensed consolidated financial statements.

NOTE 3 - FAIR VALUE OF FINANCIAL INSTRUMENTS

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

Our fixed-price swaps, basis swaps and physical purchases are included in Level 2 and our collars, calls and physical sales are included in 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:

	September 30, 2014			December 31, 2013		
	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)					
Assets:						
Commodity-based derivative contracts	$20,817	$6,369	$27,186	$3,852	$2,098	$5,950
Basis protection derivative contracts	—	—	—	74	—	74
Total assets	20,817	6,369	27,186	3,926	2,098	6,024
Liabilities:						
Commodity-based derivative contracts	4,079	437	4,516	16,539	987	17,526
Basis protection derivative contracts	81	—	81	5	—	5
Total liabilities	4,160	437	4,597	16,544	987	17,531
Net asset (liability)	$16,657	$5,932	$22,589	$(12,618)	$1,111	$(11,507)

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PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Fair value, net asset (liability), beginning of period	$(6,967)	$3,719	$1,111	$13,610
Changes in fair value included in statement of operations line item:				
Commodity price risk management gain (loss), net	12,758	(3,242)	3,961	(3,265)
Sales from natural gas marketing	2	10	(24)	16
Settlements included in statement of operations line items:				
Commodity price risk management gain (loss), net	142	(66)	882	(5,545)
Sales from natural gas marketing	(3)	(5)	2	(34)
Loss from discontinued operations, net of tax	—	—	—	(4,366)
Fair value, net asset end of period	$5,932	$416	$5,932	$416
Net change in fair value of unsettled derivatives included in statement of operations line item:				
Commodity price risk management gain (loss), net	$11,831	$(3,296)	$673	$(5,451)
Sales from natural gas marketing	1	(5)	(2)	4
Total	$11,832	$(3,301)	$671	$(5,447)

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.

Non-Derivative Financial Assets and Liabilities

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

The liability associated with our non-qualified deferred compensation plan for non-employee directors may be settled in cash or shares of our common stock. The carrying value of this obligation is based on the quoted market price of our common stock, which is a Level 1 input.

The portion of our long-term debt related to our revolving credit facility, as well as our proportionate share of PDCM's credit facility and second lien term loan, approximate 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, as of September 30, 2014, we estimate the fair value of the portion of our long-term debt related to our 3.25% convertible senior notes due 2016 to be $158.5 million, or 137.8% of par value, and the portion related to our 7.75% senior notes due 2022 to be $536.3 million, or 107.3% of par value. We determined these valuations based upon measurements of trading activity and broker and/or dealer quotes, respectively, which are published market prices, and therefore are Level 2 inputs.

Concentration of Risk

Derivative Counterparties. Our derivative 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 derivative contracts. To date, we have had no counterparty default losses relating to our derivative arrangements. 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 counterparties on the fair value of our derivative instruments was not significant at September 30, 2014, taking into account the estimated likelihood of nonperformance.

The following table presents the counterparties that expose us to credit risk as of September 30, 2014 with regard to our derivative assets:

Counterparty Name	Fair Value of Derivative Assets (in thousands)
Canadian Imperial Bank of Commerce (1)	$7,171
JP Morgan Chase Bank, N.A (1)	5,812
Wells Fargo Bank, N.A. (1)	5,343
Bank of Nova Scotia (1)	3,470
Key Bank N.A. (1)	2,540
Other lenders in our revolving credit facility	2,844
Various (2)	6
Total	$27,186

____
(1)Major lender in our revolving credit facility. See Note 7, Long-Term Debt.
(2)Represents a total of 26 counterparties.

NOTE 4 - 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 utilize the following economic hedging strategies for each of our business segments.

- For crude oil and natural gas sales, we enter into derivative contracts to protect against price declines in future periods. While we structure these derivatives to reduce our exposure to changes in price associated with the derivative commodity, they also limit the benefit we might otherwise have received from price increases in the physical market; and

- For natural gas marketing, we enter into fixed-price physical purchase and sale agreements that qualify as derivative contracts. In order to offset the fixed-price physical derivatives in our natural gas marketing, we enter into financial derivative instruments that have the effect of locking in the prices we will receive or pay for the same volumes and period, offsetting the physical derivative.

We believe our derivative instruments continue to be effective in achieving the risk management objectives for which they were intended. As of September 30, 2014, we had derivative instruments, which were comprised of collars, fixed-price swaps, basis protection swaps and physical sales and purchases, in place for a portion of our anticipated production through 2017 for a total of 46,913 BBtu of natural gas and 10,502 MBbls of crude oil. The majority of our derivative contracts are entered into at no cost to us as we hedge our anticipated production at the then-prevailing commodity market prices.

We have elected not to designate any of our derivative instruments as hedges, and therefore do not qualify for use of hedge accounting. Accordingly, changes in the fair value of our derivative instruments are recorded in the statements of operations. Changes in the fair value of derivative instruments related to our Oil and Gas Exploration and Production segment are recorded in commodity price risk management, net. Changes in the fair value of derivative instruments related to our Gas Marketing segment are recorded in sales from and cost of natural gas marketing.

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PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following table presents the balance sheet location and fair value amounts of our derivative instruments on the condensed consolidated balance sheets as of September 30, 2014 and December 31, 2013:

Derivative instruments:		Balance sheet line item	Fair Value September 30, 2014	December 31, 2013
			(in thousands)	
Derivative assets:	Current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	$8,761	$1,086
	Related to natural gas marketing	Fair value of derivatives	386	361
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	—	74
			9,147	1,521
	Non-current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	17,855	4,225
	Related to natural gas marketing	Fair value of derivatives	184	278
			18,039	4,503
Total derivative assets			$27,186	$6,024
Derivative liabilities:	Current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	$1,948	$14,437
	Related to natural gas marketing	Fair value of derivatives	334	247
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	74	—
	Related to natural gas marketing	Fair value of derivatives	—	5
			2,356	14,689
	Non-current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	2,077	2,609
	Related to natural gas marketing	Fair value of derivatives	157	233
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	7	—

	2,241	2,842
Total derivative liabilities	$4,597	$17,531

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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Commodity price risk management income (loss), net				
Net settlements	$(4,459)	$(2,051)	$(21,511)	$9,629
Net change in fair value of unsettled derivatives	94,672	(22,087)	34,172	(31,704)
Total commodity price risk management income (loss), net	$90,213	$(24,138)	$12,661	$(22,075)
Sales from natural gas marketing				
Net settlements	$210	$240	$(376)	$267
Net change in fair value of unsettled derivatives	170	(311)	123	340
Total sales from natural gas marketing	$380	$(71)	$(253)	$607
Cost of natural gas marketing				
Net settlements	$(182)	$(188)	$502	$(125)
Net change in fair value of unsettled derivatives	(191)	278	(199)	(281)
Total cost of natural gas marketing	$(373)	$90	$303	$(406)

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All of our financial derivative agreements contain master netting provisions that provide for the net settlement of all contracts through a single payment in the event of early termination. Our fixed-price physical purchase and sale agreements that qualify as derivative contracts are not subject to master netting provisions and are not significant. 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 September 30, 2014 and December 31, 2013:

As of September 30, 2014	Derivative instruments, recorded in condensed consolidated balance sheet, gross	Effect of master netting agreements	Derivative instruments, net
	(in thousands)		
Asset derivatives:			
Derivative instruments, at fair value	$27,186	$(4,106)	$23,080
Liability derivatives:			
Derivative instruments, at fair value	$4,597	$(4,106)	$491

As of December 31, 2013	Derivative instruments, recorded in condensed consolidated balance sheet, gross	Effect of master netting agreements	Derivative instruments, net
	(in thousands)		
Asset derivatives:			
Derivative instruments, at fair value	$6,024	$(4,637)	$1,387
Liability derivatives:			
Derivative instruments, at fair value	$17,531	$(4,637)	$12,894

Derivative activity related to PDCM is included in Note 12, Assets Held for Sale, Divestitures and Discontinued Operations.

NOTE 5 - PROPERTIES AND EQUIPMENT

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

	September 30, 2014	December 31, 2013
	(in thousands)	
Properties and equipment, net:		
Crude oil and natural gas properties		
Proved	$1,976,930	$1,677,271

Unproved	288,208	253,464
Total crude oil and natural gas properties	2,265,138	1,930,735
Equipment and other	30,428	28,832
Land and buildings	12,668	13,434
Construction in progress	146,324	41,180
Properties and equipment, at cost	2,454,558	2,014,181
Accumulated DD&A	(670,761)	(529,543)
Properties and equipment, net	$1,783,797	$1,484,638

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Continuing operations:				
Impairment of proved properties	$—	$3,750	$—	$48,750
Impairment of individually significant unproved properties	—	—	—	517
Amortization of individually insignificant unproved properties	1,085	486	2,843	2,527
Other	778	—	778	—
Total continuing operations	1,863	4,236	3,621	51,794
Discontinued operations:				
Impairment of individually significant unproved properties	—	154	—	462
Amortization of individually insignificant unproved properties	274	82	433	180
Total discontinued operations	274	236	433	642
Total impairment of crude oil and natural gas properties	$2,137	$4,472	$4,054	$52,436

During the first quarter of 2013, we recognized an impairment charge of approximately $45.0 million related to all of our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin producing properties located in West Virginia and Pennsylvania previously owned directly by us, as well as through our proportionate share of PDCM. The impairment charge represented the excess of the carrying value of the assets over the estimated fair value, less the cost to sell. The fair value of the assets was determined based upon estimated future cash flows from unrelated third-party bids, a Level 3 input. Pursuant to a purchase and sale agreement entered into in October 2013, we determined that the carrying value of the above-mentioned properties exceeded the transaction sales price, a Level 3 input, less costs to sell. As a result, we recognized an additional impairment charge of approximately $3.8 million in the third quarter of 2013 to reduce the carrying value of the net assets to reflect the current net sales price. The impairment charge was included in the condensed consolidated statement of operations line item impairment of crude oil and natural gas properties.

NOTE 6 - INCOME TAXES

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

The effective tax rate for continuing operations for the three and nine months ended September 30, 2014 was a 39.6% and 40.5%, respectively, provision on income compared to a 40.4% provision on income and 36.7% benefit on loss for the three and nine months ended September 30, 2013, respectively. The effective tax rates for the three and nine months ended September 30, 2014 include discrete tax expense of $0.6 million. This discrete tax expense arose based upon the final 2013 tax return expense exceeding the previous year’s tax provision amount. The effective rate for the three and nine months ended September 30, 2014 would have been 38.8% and 38.9%, respectively, without the inclusion of discrete items. This effective rate is based upon a full year forecasted tax provision on income and is greater than the statutory rate primarily due to nondeductible officers' compensation, partially offset by percentage depletion and domestic production deductions. There were no significant discrete items recorded during the three and nine months ended September 30, 2013. The effective tax rate for the three months ended September 30, 2013 differs from the statutory rate primarily due to net permanent additions, largely nondeductible officers' compensation, partially offset by percentage depletion deduction. For the nine months ended September 30, 2013, the nondeductible item for officers' compensation exceeded our deduction for percentage depletion, thereby reducing our tax benefit rate. Additionally, state statutory limits on the utilization of our net operating losses resulted in a reduced state tax benefit.

As of September 30, 2014, our gross liability for unrecognized tax benefits continues to be immaterial and was unchanged from the amount recorded at December 31, 2013. We expect our remaining liability for uncertain tax positions to decrease to zero in the current year due to the expiration of the statute of limitations.

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 examination. We continue voluntary participation in the Internal Revenue Service’s Compliance Assurance Program for the 2013 and 2014 tax years. We have received a partial acceptance “no change” notice from the IRS for our filed 2013 federal tax return and expect to receive a full acceptance notice after the IRS’s post filing review is completed.

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NOTE 7 - LONG-TERM DEBT

Long-term debt consists of the following:

	September 30, 2014	December 31, 2013
	(in thousands)	
Senior notes:		
3.25% Convertible senior notes due 2016:		
Principal amount	$115,000	$115,000
Unamortized discount	(7,087)	(10,010)
3.25% Convertible senior notes due 2016, net of discount	107,913	104,990
7.75% Senior notes due 2022	500,000	500,000
Total senior notes	607,913	604,990
Revolving credit facility	68,000	—
Long-term debt	675,913	604,990
PDCM credit facility	44,750	37,000
PDCM second lien term loan	15,000	15,000
PDCM long-term debt (included in liabilities held for sale - non-current)	59,750	52,000
Total debt	$735,663	$656,990

Senior Notes

3.25% Convertible Senior Notes Due 2016. In November 2010, we issued $115 million aggregate principal amount 3.25% convertible senior notes due May 15, 2016 (the "Convertible Notes") in a private placement to qualified institutional buyers. Interest is payable semi-annually in arrears on each May 15 and November 15. The indenture governing the Convertible Notes contains certain non-financial covenants. We allocated the gross proceeds of the Convertible Notes between the liability and equity components of the debt. The initial $94.3 million liability component was determined based upon the fair value of similar debt instruments with similar terms, excluding the conversion feature, and priced on the same day we issued the Convertible Notes. The original issue discount and capitalized debt issuance costs are being amortized to interest expense over the life of the Convertible Notes using an effective interest rate of 7.4%.

Upon conversion, the Convertible Notes may be settled, at our election, in shares of our common stock, cash or a combination of cash and shares of our common stock. We have initially elected a net-settlement method to satisfy our conversion obligation, which allows us to settle the principal amount of the Convertible Notes in cash and to settle the excess conversion value in shares, as well as cash in lieu of fractional shares. The Convertible Notes were not convertible at the option of holders as of September 30, 2014. Notwithstanding the inability to convert, the “if-converted” value of the Convertible Notes as of September 30, 2014 exceeded the principal amount by approximately $21.4 million.

7.75% Senior Notes Due 2022. In October 2012, we issued $500 million aggregate principal amount 7.75% senior notes due October 15, 2022 (the “2022 Senior Notes”) in a private placement to qualified institutional buyers. Interest on the 2022 Senior Notes is payable semi-annually in arrears on each April 15 and October 15. The indenture governing the 2022 Senior Notes contains customary restrictive incurrence covenants. Capitalized debt issuance costs are being amortized as interest expense over the life of the 2022 Senior Notes using the effective interest method.

As of September 30, 2014, we were in compliance with all covenants related to the Convertible Notes and the 2022 Senior Notes, and expect to remain in compliance throughout the next 12-month period.

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Credit Facility

Revolving Credit Facility. In May 2013, we entered into a Third Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A. as administrative agent and other lenders party thereto. This agreement amends and restates the credit agreement dated November 2010 and expires in May 2018. The revolving credit facility is available for working capital requirements, capital expenditures, acquisitions, general corporate purposes and to support letters of credit. The revolving credit facility provides for a maximum of $1 billion in allowable borrowing capacity, subject to the borrowing base. The borrowing base is based on, among other things, the loan value assigned to the proved reserves attributable to our and our subsidiaries' crude oil and natural gas interests, excluding proved reserves attributable to PDCM and our affiliated partnerships. The borrowing base is subject to a semi-annual size redetermination 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. On September 26, 2014, the semi-annual redetermination of our revolving credit facility's borrowing base was completed, resulting in an increase in the borrowing base from $450 million to $700 million. We have elected to maintain the aggregate commitment at $450 million. The revolving credit facility is secured by a pledge of the stock of certain of our subsidiaries, mortgages of certain producing crude oil and natural gas properties and substantially all of our and such subsidiaries' other assets. Neither PDCM nor our affiliated partnerships are guarantors of our obligations under the revolving credit facility.

We had an outstanding balance of $68.0 million on our revolving credit facility as of September 30, 2014 compared to no outstanding balance as of December 31, 2013. The weighted-average borrowing rate on our revolving credit facility, exclusive of the letter of credit noted below, was 4.1% per annum as of September 30, 2014.

As of September 30, 2014, Riley Natural Gas, a wholly-owned subsidiary of PDC, had an irrevocable standby letter of credit of approximately $11.7 million in favor of a third-party transportation service provider to secure firm transportation of the natural gas produced by third-party producers for whom we market production in the Appalachian Basin. The letter of credit expires in September 2015. The letter of credit reduces the amount of available funds under our revolving credit facility by an equal amount. As of September 30, 2014, the available funds under our revolving credit facility, including the reduction for the $11.7 million letter of credit, was $370.3 million. In addition to our currently elected commitment of $450 million, we have an additional $250 million of borrowing base availability under the revolving credit facility.

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 1.00 to 1.00 and (b) not exceed a maximum leverage ratio of 4.25 to 1.00. As of September 30, 2014, we were in compliance with all the revolving credit facility covenants and expect to remain in compliance throughout the next 12-month period.

PDCM

On October 14, 2014, we closed the sale of our entire 50% ownership interest in PDCM to an unrelated third-party. The transaction included the repayment of the PDCM credit facility and Second Lien Credit Agreement ("Term Loan Agreement") by the buyer. See Note 15, Subsequent Event, for additional information.

PDCM Credit Facility. As of September 30, 2014, PDCM had a credit facility dated April 2010, as amended in February 2014, with a borrowing base of $105 million, of which our proportionate share was approximately $53 million. As of September 30, 2014, our proportionate share of PDCM's outstanding credit facility balance was $44.8 million, included in liabilities held for sale - non-current on the condensed consolidated balance sheets, compared to

$37.0 million as of December 31, 2013. The weighted-average borrowing rate on PDCM's credit facility was 3.5% per annum as of September 30, 2014, compared to 3.7% as of December 31, 2013.

PDCM Second Lien Term Loan. In July 2013, PDCM entered into a Term Loan Agreement with Wells Fargo Energy Capital as administrative agent and a syndicate of other lenders party thereto. As of September 30, 2014, amounts borrowed and outstanding on the Term Loan Agreement were $30.0 million, of which our proportionate share was $15 million. This amount is included in liabilities held for sale - non-current on the condensed consolidated balance sheets. The weighted-average interest rate on the term loan was 8.5% per annum as of both September 30, 2014 and December 31, 2013.

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NOTE 8 - ASSET RETIREMENT OBLIGATIONS

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

	Amount (in thousands)
Balance at beginning of period, January 1, 2014	$41,030
Obligations incurred with development activities	501
Accretion expense	2,582
Revisions in estimated cash flows	(134)
Obligations discharged with divestitures of properties and asset retirements	(2,984)
Balance end of period, September 30, 2014	40,995
Less: Liabilities held for sale (1)	(273)
Less: Current portion	(1,158)
Long-term portion	$39,564

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(1) Represents asset retirement obligations related to our assets held for sale. See Note 12, Assets Held for Sale, Divestitures and Discontinued Operations, and Note 15, Subsequent Event, for additional information regarding the sale of our interest in PDCM.

NOTE 9 - COMMITMENTS AND CONTINGENCIES

Firm Transportation, Processing and Sales Agreements. We enter into contracts that provide firm transportation, sales and processing services 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 PDCM and other third-party working interest owners. We record in our financial statements only our share of costs based upon our working interest in the wells. These contracts require us to pay these transportation and processing charges whether or not the required volumes are delivered. With the exception of contracts entered into by PDCM, the costs of any volume shortfalls are borne by PDC.

The following table presents gross volume information, including our proportionate share of PDCM, related to our long-term firm transportation, sales and processing agreements for pipeline capacity as of September 30, 2014:

	For the Twelve Months Ending September 30,						
Area	2015	2016	2017	2018	2019 and Through Expiration	Total	Expiration Date
Natural gas (MMcf)							
Appalachian Basin	18,993	20,368	20,987	20,987	109,638	190,973	January 31, 2026
Utica Shale	2,737	2,745	2,737	2,737	13,239	24,195	July 22, 2023
Total	21,730	23,113	23,724	23,724	122,877	215,168	
Crude oil (MBbls)							
Wattenberg Field	1,210	2,420	2,414	2,414	3,616	12,074	March 31, 2020

Dollar commitment (in thousands)	$14,101	$20,678	$20,654	$19,508	$52,129	$127,070

In September 2014, we entered into a long-term agreement with White Cliffs Pipeline, LLC, to ship crude oil from southern Weld County, Colorado, to Cushing, Oklahoma. The primary term of the agreement is five years commencing on the first delivery of crude oil to the pipeline system. We currently expect crude oil delivery to the pipeline system to begin in April 2015. The agreement includes minimum volume commitments as shown in the table above, with certain fees assessed for any shortfall.

On October 14, 2014, we closed the sale of our entire 50% ownership interest in PDCM to an unrelated third-party. The transaction includes the buyer's assumption of approximately 134,875 MMcf and $30.4 million of our Appalachian Basin firm transportation obligation. See Note 15, Subsequent Event, for additional information.

Litigation. The Company is involved in various legal proceedings that it considers normal to its business. The Company reviews the status of these proceedings on an ongoing basis and, from time to time, may settle or otherwise resolve these matters on terms and conditions that management believes are in the best interests of the Company. There is no assurance that settlements can be reached on acceptable terms or that adverse judgments, if any, in the remaining litigation will not exceed the amounts reserved. 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.

Class Action Regarding 2010 and 2011 Partnership Purchases

In December 2011, the Company and its wholly-owned merger subsidiary were served with an alleged class action on behalf of unit holders of 12 former limited partnerships, related to its repurchase of the 12 partnerships, which were formed beginning in late 2002 through 2005. The mergers were completed in 2010 and 2011. The action was filed in U.S. District Court for the Central District of California and is titled Schulein v. Petroleum Development Corp. The complaint primarily alleges that the disclosures in the proxy statements issued in connection with the mergers were inadequate, and a state law breach of fiduciary duty. In January 2014, the plaintiffs were certified as a class by the court.

In October 2014, the Company and plaintiffs' counsel reached an oral settlement agreement, subject to the contingencies noted below. Under this agreement the plaintiffs would receive a cash payment of $37.5 million, of which PDC would pay $31.5 million and insurers would pay $6 million directly to the plaintiffs. This all-cash settlement agreement is a different structure than the initial agreement in principle, which was structured as part up-front cash and part interests in future wells. The proposed all-cash settlement remains subject to the satisfaction of various conditions, including but not limited to the following: execution of a written settlement agreement; preliminary approval by the court; payments to plaintiffs by the Company's insurance carriers; and final court approval following notice to members of the class. As a result, the Company accrued an additional $7.4 million of expense during the quarter ended September 30, 2014, which is included in general and administrative expense in the condensed consolidated statement of operations. As of September 30, 2014, the Company has accrued a total liability of $31.5 million related to this litigation, which is our best estimate of the amount required to settle the case. The liability is included in other accrued expenses in the condensed consolidated balance sheet.

Under this settlement agreement, the class action would be dismissed with prejudice and all claims would be released. If the matter proceeds to trial, the plaintiffs have indicated that they will seek damages of approximately $175 million, plus pre-judgment interest. In such event, we continue to believe we would have good defenses to both the asserted claims and plaintiffs' damage calculations.

Partnership Liquidation Lawsuit

In October 2014, PDC entered into a preliminary settlement agreement pursuant to which PDC will pay approximately $8.8 million in resolution of an adversary proceeding filed in June 2014 titled Eastern 1996D Limited Partnership, et al. v. PDC Energy, Inc. Adv. Pro. No. 14-03080 (the "Adversary Proceeding") related to bankruptcy Case No. 13-34773-HDH-11, currently pending in the United States Bankruptcy Court for the Northern District of Texas (the "Bankruptcy Court"). The bankruptcy case relates to 12 limited partnerships formed from1996 to 2002, for which PDC is the managing general partner. These partnerships filed bankruptcy in September 2013 to pursue an orderly liquidation of their assets and distribute the resulting proceeds to limited partners and the managing general partner. The Adversary Proceeding primarily alleges claims for breach of fiduciary duty and breach of contract against PDC as managing general partner of the partnerships. On October 28, 2014, the Bankruptcy Court approved the proposed disclosure statement in support of the debtors' joint liquidating plan and the manner of solicitation of votes on such plan. The plan incorporates and seeks approval of the above proposed settlement. The plan is expected to be mailed to the limited partners in November 2014, and the Bankruptcy Court is expected to hold a hearing in December 2014 regarding final approval of the plan and settlement agreement. During the quarter ended September 30, 2014, we recorded a litigation charge of $8.8 million related to this matter, included in general and administrative expense in the condensed consolidated statements of operations, of which an accrued liability of $7 million and a $1.8 million reduction in related-party accounts receivable are included in other accrued expenses and accounts receivable affiliates, respectively, at September 30, 2014 in the condensed consolidated balance sheet.

Environmental. Due to the nature of the natural gas and oil industry, we are exposed to environmental risks. We have various policies and procedures designed to mitigate the risks of environmental contamination and related liabilities. We conduct periodic reviews 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. As of September 30, 2014 and December 31, 2013, we had accrued environmental liabilities in the amount of $1.9 million and $5.4 million, respectively, included in other accrued expenses on the condensed consolidated balance sheets. We are not aware of any environmental claims existing as of September 30, 2014 which have not been provided for or would otherwise be expected to have a material impact on our financial statements. However, there can be no assurance that current regulatory requirements will not change or unknown past non-compliance with environmental laws will not be discovered on our properties.

In June 2014, we received an information request from the Environmental Protection Agency (the "EPA") pursuant to Sections 308 and 311 of the Clean Water Act (the "CWA") regarding a discharge of oil and related materials that occurred in May related to a mechanical failure during drilling at an Ohio location. The requested information relates to the facility from which the discharge occurred and details regarding the discharge. To date, the EPA has not issued any notice that a violation of the CWA occurred or sought to impose any fine or other relief in connection with the discharge. While the results cannot be predicted with certainty, we do not expect the ultimate resolution of this information request or any subsequent proceedings to have a material adverse effect on our financial condition or results of operation.

Employment Agreements with Executive Officers. Each of our senior executive officers, except the current Chief Executive Officer, may be entitled to a severance payment and certain other benefits upon the termination of the officer's employment pursuant to the officer's employment agreement and/or the Company's executive severance compensation plan. The nature and amount of such benefits would vary based upon, among other things, whether the termination followed a change of control of the Company. In June 2014, we announced a leadership

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transition and entered into a consulting agreement with our current Chief Executive Officer pursuant to which he will provide consulting services to the Company in 2015. Under the agreement, the current Chief Executive Officer ceased to be a participant in our executive severance plan.

NOTE 10 - COMMON STOCK

Stock-Based Compensation Plans

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Stock-based compensation expense	$4,232	$3,040	$13,111	$9,991
Income tax benefit	(1,482)	(1,161)	(4,856)	(3,816)
Net stock-based compensation expense	$2,750	$1,879	$8,255	$6,175

Stock Appreciation Rights ("SARs")

The SARs vest ratably over a three-year period and may be exercised at any point after vesting through 10 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.

In January 2014, the Compensation Committee awarded 88,248 SARs to our executive officers. The fair value of each SAR award was estimated on the date of grant using a Black-Scholes pricing model using the following assumptions:

	Nine Months Ended September 30,	
	2014	2013
Expected term of award	6 years	6 years
Risk-free interest rate	2.1%	1.0%
Expected volatility	65.6%	65.5%
Weighted-average grant date fair value per share	$29.96	$21.96

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

The following table presents the changes in our SARs:

	Nine Months Ended September 30,	
	2014	2013

	Number of SARs	Weighted-Average Exercise Price	Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)	Number of SARs	Weighted-Average Exercise Price	Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding beginning of year, January 1,	190,763	$ 33.77			118,832	$ 30.80		
Awarded	88,248	49.57			87,078	37.18		
Outstanding at September 30,	279,011	38.77	8.0	$ 3,215	205,910	33.50	8.4	$ 5,363
Vested and expected to vest at September 30,	270,589	38.56	8.0	3,173	198,163	33.41	8.4	5,178
Exercisable at September 30,	109,920	32.71	7.1	1,933	67,069	29.99	7.3	1,982

Total compensation cost related to SARs granted, net of estimated forfeitures, and not yet recognized in our condensed consolidated statement of operations as of September 30, 2014 was $3.0 million. The cost is expected to be recognized over a weighted-average period of 1.9 years.

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Restricted Stock Awards

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

In January 2014, the Compensation Committee awarded a total of 104,467 time-based restricted shares to our executive officers that vest ratably over a three-year period ending on January 16, 2017.

The following table presents the changes in non-vested time-based awards to all employees, including executive officers, for the nine months ended September 30, 2014:

	Shares	Weighted-Average Grant-Date Fair Value
Non-vested at December 31, 2013	651,781	$36.36
Granted	284,705	56.64
Vested	(269,725)	34.13
Forfeited	(30,536)	41.67
Non-vested at September 30, 2014	636,225	46.13

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

	As of/for the Nine Months Ended September 30,	
	2014	2013
	(in thousands, except per share data)	
Total intrinsic value of time-based awards vested	$15,840	$12,562
Total intrinsic value of time-based awards non-vested	31,996	38,774
Market price per common share as of September 30,	50.29	59.54
Weighted-average grant date fair value per share	56.64	44.56

Total compensation cost related to non-vested time-based awards, net of estimated forfeitures, and not yet recognized in our condensed consolidated statements of operations as of September 30, 2014 was $20.8 million. This cost is expected to be recognized over a weighted-average period of 2.0 years.

Market-Based Awards. The fair value of the market-based restricted shares is amortized ratably over the requisite service period, primarily three years. The market-based shares vest if the participant is continuously employed throughout the performance period and the market-based performance measure is achieved, with a maximum vesting period of five 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.

In January 2014, the Compensation Committee awarded a total of 42,151 market-based restricted shares to our executive officers. In addition to continuous employment, the vesting of these shares is contingent on the Company's total shareholder return ("TSR"), which is essentially the Company’s stock price change including any dividends, as compared to the TSR of a set group of 15 peer companies. The shares are measured over a three-year period ending on December 31, 2016 and can result in a payout between 0% and 200% of the total shares awarded. The weighted-average grant date fair value per market-based share for these awards granted was computed using the Monte Carlo pricing model using the following assumptions:

	Nine Months Ended September 30,	
	2014	2013
Expected term of award	3 years	3 years
Risk-free interest rate	0.8 %	0.4 %
Expected volatility	55.2 %	56.6 %
Weighted-average grant date fair value per share	$56.87	$49.04

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

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following table presents the change in non-vested market-based awards during nine months ended September 30, 2014:

	Shares	Weighted-Average Grant-Date Fair Value per Share
Non-vested at December 31, 2013	72,111	$43.75
Granted	42,151	56.87
Non-vested at September 30, 2014	114,262	48.59

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

	As of/for the Nine Months Ended September 30,	
	2014	2013
	(in thousands, except per share data)	
Total intrinsic value of market-based awards non-vested	$5,746	$4,898
Market price per common share as of September 30,	50.29	59.54
Weighted-average grant date fair value per share	56.87	49.04

Total compensation cost related to non-vested market-based awards, net of estimated forfeitures, and not yet recognized in our condensed consolidated statement of operations as of September 30, 2014 was $2.7 million. This cost is expected to be recognized over a weighted-average period of 1.9 years.

NOTE 11 - EARNINGS PER SHARE

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

The following table presents a reconciliation of the weighted-average diluted shares outstanding for the three and nine months ended September 30, 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Weighted-average common shares outstanding - basic	35,834	33,413	35,763	31,350
Dilutive effect of:				
Restricted stock	259	—	287	—
SARs	56	—	45	—

Stock options	1	—	1	—
Non-employee director deferred compensation	6	—	5	—
Convertible notes	672	—	730	—
Weighted-average common shares and equivalents outstanding - diluted	36,828	33,413	36,831	31,350

We reported a net loss for the three and nine months ended September 30, 2013. As a result, our basic and diluted weighted-average common shares outstanding were the same due to the fact that the effect of the common share equivalents was anti-dilutive.

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PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Weighted-average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:				
Restricted stock	4	805	—	857
SARs	11	83	30	65
Stock options	—	7	—	7
Non-employee director deferred compensation	—	4	—	4
Convertible notes	—	671	—	387
Total anti-dilutive common share equivalents	15	1,570	30	1,320

In November 2010, we issued the Convertible Notes, which give the holders the right to convert the aggregate principal amount into 2.7 million shares of our common stock at a conversion price of $42.40 per share. The Convertible Notes could be included in the dilutive earnings per share calculation using the treasury stock method if the average market share price exceeds the $42.40 conversion price during the period presented. Shares issuable upon conversion of the Convertible Notes were included in the diluted earnings per share calculation for the three and nine months ended September 30, 2014 as the average market price during the period exceeded the conversion price. Shares issuable upon conversion of the Convertible Notes were excluded from the diluted earnings per share calculation for the three and nine months ended September 30, 2013 as the effect would be anti-dilutive to our earnings per share.

NOTE 12 - ASSETS HELD FOR SALE, DIVESTITURES AND DISCONTINUED OPERATIONS

Appalachian Basin. In December 2013, we divested our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin crude oil and natural gas properties previously owned directly by us, as well as through our proportionate share of PDCM, for aggregate consideration of approximately $20.6 million, of which our share of the proceeds was approximately $5.1 million. We received our proportionate share of cash proceeds and a note receivable. Concurrent with the closing of the transaction, our $6.7 million irrevocable standby letter of credit and an agreement for firm transportation services was released and novated to the buyer.

In July 2014, we signed a definitive agreement pursuant to which we agreed to sell our entire 50% ownership interest in PDCM to an unrelated third-party for aggregate consideration of approximately $250 million, subject to certain purchase price adjustments. The transaction includes the buyer's assumption of our share of the firm transportation obligations related to the assets owned by PDCM as well as our share of certain of PDCM's natural gas hedging positions for the years 2014 through 2017 and the repayment of outstanding PDCM debt. Our proportionate share of PDCM's assets and liabilities have been classified as held for sale in the condensed consolidated balance sheets for all periods presented. In addition, because the divestiture represents a strategic shift that will have a major effect on our operations, our proportionate share of PDCM's Marcellus Shale results of operations have been separately reported as discontinued operations in the condensed consolidated statement of operations for all periods presented. In October 2014, this divestiture closed for total consideration, after our share of PDCM's debt repayment and other working capital adjustments, of approximately $190 million, comprised of approximately $150 million in cash and a promissory note due in 2020 of approximately $40 million, subject to customary post-closing adjustments. See Note 15, Subsequent Event, for additional information regarding the closing of this divestiture.

Piceance Basin and NECO. In June 2013, we divested our Piceance Basin, NECO and certain other non-core Colorado oil and gas properties, leasehold mineral interests and related assets for total consideration of approximately $177.6 million, with an additional $17.0 million paid to our non-affiliated investor partners in our affiliated partnerships. Following the sale, we do not have significant continuing involvement in the operations of, or cash flows from, the Piceance Basin and NECO oil and gas properties. Accordingly, the results of operations related to these assets have been separately reported as discontinued operations in the condensed consolidated statement of operations for the nine months ended September 30, 2013.

Selected Financial Information Related to Divested and Discontinued Operations. The tables below set forth selected financial information related to net assets held for sale and operating results related to discontinued operations. Net assets held for sale represent the assets that were expected to be sold, net of liabilities that were expected to be assumed by the purchaser.

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The following table presents condensed consolidated balance sheet data related to net assets held for sale:

Condensed consolidated balance sheet	As of September 30, 2014	As of December 31, 2013
	(in thousands)	
Assets		
Current assets		
Cash and cash equivalents	$496	$601
Other current assets	4,879	7,060
Assets held for sale - current	5,375	7,661
Non-current assets		
Properties and equipment, net	169,672	171,592
Other assets	7,022	6,892
Assets held for sale - non-current	176,694	178,484
Liabilities		
Liabilities held for sale - current	3,070	12,069
Non-current liabilities		
Long-term debt	59,750	52,000
Asset retirement obligation	273	2,234
Other liabilities	1,520	1,681
Liabilities held for sale - non-current	61,543	55,915
Net Assets	$117,456	$118,161

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following table presents condensed consolidated statement of operations data related to our discontinued operations:

Condensed consolidated statements of operations - discontinued operations	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
	(in thousands)			
Revenues				
Crude oil, natural gas and NGLs sales	$5,411	$4,738	$24,149	$32,525
Sales from natural gas marketing	—	1,789	—	2,825
Commodity price risk management gain (loss), net	1,929	500	(1,085)	806
Well operations, pipeline income and other	—	36	48	918
Total revenues	7,340	7,063	23,112	37,074
Costs, expenses and other				
Production costs	1,020	2,039	7,120	13,375
Cost of natural gas marketing	—	1,679	—	2,673
Impairment of crude oil and natural gas properties	273	236	433	642
Depreciation, depletion and amortization	1,272	3,913	9,128	11,001
Other	1,061	1,299	3,445	6,092
(Gain) loss on sale of properties and equipment	(1)	642	(193)	1,702
Total costs, expenses and other	3,625	9,808	19,933	35,485
Interest expense	(709)	(552)	(2,222)	(1,072)
Interest income	62	—	194	—
Income (loss) from discontinued operations	3,068	(3,297)	1,151	517
Provision for income taxes	(3,148)	1,204	(759)	(108)
Income (loss) from discontinued operations, net of tax	$(80)	$(2,093)	$392	$409

The following table presents supplemental cash flows information related to our 50% ownership interest in PDCM, which is classified as discontinued operations:

Supplemental cash flows information - discontinued operations	Nine Months Ended September 30, 2014	2013
	(in thousands)	
Cash flows from investing activities:		
Capital expenditures	$(17,253)	$(29,793)
Significant non-cash investing items:		
Change in accounts payable related to purchases of properties and equipment	(5,727)	4,834

NOTE 13 - TRANSACTIONS WITH AFFILIATES

PDCM and Affiliated Partnerships. Our Gas Marketing segment markets the natural gas produced by PDCM and our affiliated partnerships in the Appalachian Basin. Our cost of natural gas marketing includes $7.1 million and $23.2 million for the three and nine months ended September 30, 2014, respectively, related to the marketing of natural gas on behalf of PDCM compared to $4.7 million and $12.5 million for the three and nine months ended September 30, 2013, respectively. Our cost of natural gas marketing includes $0.3 million and $0.9 million for the three and nine months ended September 30, 2013, respectively, related to the marketing of natural gas on behalf of our affiliated partnerships.

Amounts due from/to affiliates primarily relate to amounts billed for certain well operating and administrative services provided to PDCM and, to a lesser extent, costs resulting from audit and tax preparation services for our affiliated partnerships. Amounts billed to PDCM for these services were $1.6 million and $5.7 million in the three and nine months ended September 30, 2014, respectively, compared to $3.6 million and $10.4 million in the three and nine months ended September 30, 2013, respectively. Our proportionate share of these billings are included in income (loss) from discontinued operations, net of tax, in the condensed consolidated statements of operations.

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PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

On October 14, 2014, we sold our entire 50% ownership interest in PDCM to an unrelated third-party. See Note 15, Subsequent Event, for additional information.

NOTE 14 - BUSINESS SEGMENTS

We separate our operating activities into two segments: Oil and Gas Exploration and Production and Gas Marketing. All material inter-company accounts and transactions between segments have been eliminated.

Oil and Gas Exploration and Production. Our Oil and Gas Exploration and Production segment includes all of our crude oil and natural gas properties. The segment represents revenues and expenses from the production and sale of crude oil, natural gas and NGLs. Segment revenue includes crude oil, natural gas and NGLs sales, commodity price risk management, net and well operation and pipeline income. Segment income (loss) consists of segment revenue less production cost, exploration expense, impairment of crude oil and natural gas properties, direct general and administrative expense and depreciation, depletion and amortization expense.

Gas Marketing. Our Gas Marketing segment purchases, aggregates and resells natural gas produced by us and others. Segment income (loss) primarily represents sales from natural gas marketing and direct interest income, less costs of natural gas marketing and direct general and administrative expense.

Unallocated Amounts. Unallocated income includes unallocated other revenue, less corporate general and administrative expense, corporate DD&A expense, interest income and interest expense. Unallocated assets include assets utilized for corporate general and administrative purposes, as well as assets not specifically included in our two business segments.

The following tables present our segment information:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Segment revenues:				
Oil and gas exploration and production	$211,259	$54,869	$385,867	$208,591
Gas marketing	13,297	16,946	62,649	48,695
Total revenues	$224,556	$71,815	$448,516	$257,286
Segment income (loss) before income taxes:				
Oil and gas exploration and production	$136,886	$5,853	$174,612	$31,218
Gas marketing	(51)	(181)	3	(233)
Unallocated	(47,362)	(29,014)	(135,472)	(87,683)
Income (loss) before income taxes	$89,473	$(23,342)	$39,143	$(56,698)

	September 30, 2014	December 31, 2013
	(in thousands)	
Segment assets:		
Oil and gas exploration and production	$1,930,333	$1,755,263
Gas marketing	9,305	20,342

Unallocated	56,802	63,453
Assets held for sale	182,069	186,145
Total assets	$2,178,509	$2,025,203

Assets held for sale as of September 30, 2014 and December 31, 2013 relate to our oil and gas exploration and production segment.

NOTE 15 - SUBSEQUENT EVENT

PDCM Divestiture

In July 2014, we signed a definitive agreement pursuant to which we agreed to sell our entire 50% ownership interest in PDCM to an unrelated third-party for aggregate consideration of approximately $250 million, subject to certain purchase price adjustments. The transaction includes cash, a promissory note and the buyer's assumption of our share of the firm transportation obligations related to the assets owned by

PDCM, as well as our share of certain of PDCM's natural gas derivative instruments for the years 2014 through 2017. On October 14, 2014, we closed this divestiture for aggregate consideration, after our share of PDCM's debt repayment and other working capital adjustments, of approximately $190 million, comprised of approximately $150 million in cash and a promissory note due in 2020 of approximately $40 million, subject to customary post-closing adjustments. Proceeds from the sale were used to reduce outstanding borrowings on our revolving credit facility and are expected to provide liquidity to fund our remaining 2014 capital budget.

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

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

EXECUTIVE SUMMARY

Financial Overview

We recorded substantial increases in crude oil, natural gas and NGLs sales from continuing operations during the three and nine months ended September 30, 2014 as a result of our significant increase in production. Total crude oil, natural gas and NGLs sales increased $43.1 million, or 56%, and $144.6 million, or 64%, during the three and nine months ended September 30, 2014, respectively, compared to the three and nine months ended September 30, 2013. Our crude oil, natural gas and NGLs production from continuing operations averaged 25.6 Mboe per day and 24.6 Mboe per day during the three and nine months ended September 30, 2014, respectively, an increase of approximately 60% and 51% compared to the three and nine months ended September 30, 2013, respectively. The increase in production is primarily attributable to our successful horizontal Niobrara and Codell drilling program in the Wattenberg Field. Our liquids percentage of total production from continuing operations was 65% and 66% during the three and nine months ended September 30, 2014, respectively, compared to 58% and 60% during the same prior year periods. Higher crude oil index prices at derivatives settlement were the primary reason for negative net settlements on derivatives of $4.5 million and $21.5 million during the three and nine months ended September 30, 2014, respectively, compared to negative net settlements on derivatives of $2.1 million and net positive settlements of $9.6 million during the three and nine months ended September 30, 2013, respectively. Crude oil, natural gas and NGLs sales including the impact of net settlements on derivatives was $116.0 million and $350.1 million during the three and nine months ended September 30, 2014, respectively, compared to $75.3 million and $236.6 million during the three and nine months ended September 30, 2013, respectively. This represents increases of 54% and 48% during the three and nine months ended September 30, 2014, respectively, compared to the same prior year periods.

Three other areas showed significant changes during 2014 as compared to 2013. General and administrative expense increased to $34.6 million and $96.5 million during the three and nine months ended September 30, 2014, respectively, compared to $15.1 million and $43.9 million during the three and nine months ended September 30, 2013, respectively, primarily attributable to charges of $16.2 million and $40.3 million recorded during the 2014 periods in connection with former partnership-related class action litigation and, in the third quarter of 2014, estimates relating to litigation arising from bankruptcy proceedings of certain affiliated partnerships. In addition, the crude oil and natural gas forward curves shifted lower during the current year resulting in a positive net change in the fair value of unsettled derivatives of $94.7 million and $34.2 million during the three and nine months ended September 30, 2014, respectively, compared to a negative net change in the fair value of unsettled derivatives of $22.0 million and $31.7 million during the three and nine months ended September 30, 2013, respectively. Finally, depreciation, depletion and amortization expense increased to $49.6 million and $142.2 million during the three and nine months ended September 30, 2014, respectively, compared to $27.0 million and $77.9 million during the three and nine months ended September 30, 2013, respectively, due primarily to the increase in production.

Select financial metrics for the three months ended September 30, 2014 compared to the three months ended September 30, 2013 were as follows:

- Adjusted net loss of $5.7 million compared to an adjusted net loss of $2.3 million in the prior period. Excluding the after-tax impact of the litigation charge recorded in general and administrative expense, adjusted net income in the current period would have been $4.3 million;
- Adjusted cash flows from operations of $55.5 million compared to $36.7 million in the prior period. Excluding the after-tax impact of the litigation charge recorded in general and administrative expense, adjusted cash flows from operations in the current period would have been $71.7 million; and
- Adjusted EBITDA of $62.6 million compared to $44.4 million in the prior period. Excluding the impact of the litigation charge recorded in general and administrative expense, adjusted EBITDA in the current period would have been $78.8 million.

Select financial metrics for the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013 were as follows:

- Adjusted net income of $2.4 million compared to an adjusted net loss of $15.7 million in the prior period. Excluding the after-tax impact of the litigation charges recorded in general and administrative expense during the nine months ended September 30, 2014 and the impairment charge recorded during the nine months ended September 30, 2013 related to our shallow Upper Devonian Appalachian Basin assets, adjusted net income in the current period would have been $27.4 million compared to $14.4 million during the prior period;
- Adjusted cash flows from operations of $180.2 million compared to $135.4 million in the prior period. Excluding the after-tax impact of the litigation charges recorded in general and administrative expense, adjusted cash flows from operations in the current period would have been $220.5 million; and
- Adjusted EBITDA of $201.8 million compared to $159.7 million in the prior period. Excluding the impact of the litigation charges recorded in general and administrative expense, adjusted EBITDA in the current period would have been $242.1 million.

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Adjusted net income (loss), adjusted cash flows from operations and adjusted EBITDA are non-U.S. GAAP financial measures. See Non-U.S. GAAP Financial Measures and Reconciliation of Non-U.S. GAAP Financial Measures below, for a more detailed discussion of these non-U.S. GAAP financial measures.

Available liquidity as of September 30, 2014 was $396.7 million, including $8.2 million related to PDCM, compared to $647.0 million, including $16.1 million related to PDCM, as of December 31, 2013. Available liquidity is comprised of $18.7 million of cash and cash equivalents and $378.0 million available for borrowing under our revolving credit facilities as of September 30, 2014. In addition to our currently elected commitment of $450 million, we have an additional $250 million of borrowing base availability under our revolving credit facility. We believe we have sufficient liquidity to allow us to execute our expected drilling program through 2015.

In July 2014, we signed a definitive agreement pursuant to which we agreed to sell our entire 50% ownership interest in PDCM to an unrelated third-party for aggregate consideration of approximately $250 million, subject to certain purchase price adjustments. On October 14, 2014, we closed this divestiture for aggregate consideration, after our share of PDCM's debt repayment and other working capital adjustments, of approximately $190 million, comprised of approximately $150 million in cash and a promissory note due in 2020 of approximately $40 million, subject to customary post-closing adjustments. The transaction includes the buyer's assumption of our share of the firm transportation obligations related to the assets owned by PDCM as well as our share of certain of PDCM's natural gas hedging positions for the years 2014 through 2017. Proceeds from the sale were used to reduce outstanding borrowings on our revolving credit facility and are expected to provide liquidity to fund our remaining 2014 capital budget.

Considering the proceeds received from the sale of our ownership interest in PDCM and the additional $250 million of borrowing base availability under our revolving credit facility, our pro forma liquidity as of September 30, 2014 was $788.5 million.

Operational Overview

Drilling Activities. During the nine months ended September 30, 2014, we continued to execute our strategic plan of increasing our overall production and liquids mix by focusing our drilling operations primarily in the liquid-rich Wattenberg Field in Colorado and the emerging Utica Shale play in southeastern Ohio.

In the Wattenberg Field, we are currently running five drilling rigs. We spudded 86 horizontal wells and turned in line 49 horizontal wells in the Wattenberg Field during the nine months ended September 30, 2014. We also participated in 71 gross, 15.4 net, horizontal non-operated drilling projects and turned in line 41 gross, 9.7 net, horizontal non-operated wells. In the Utica Shale, we spudded eight horizontal wells and turned in line four horizontal wells during the nine months ended September 30, 2014.

2014 Operational Outlook

In August 2014, we raised our expectations with respect to 2014 production to between 10.4 MMBoe and 10.6 MMBoe, including 1.1 MMBoe associated with PDCM, the divestiture of which was completed in October 2014. Accordingly, the expected 2014 production from continuing operations is between 9.3 MMBoe and 9.5 MMBoe. Our 2014 capital spending is currently on pace for $647 million, consistent with our previously disclosed capital budget, including $555 million of development capital and $92 million for leasehold acquisitions and environmental and other equipment.

Wattenberg Field. We expect to invest approximately $443 million in the Wattenberg Field in 2014. We expect to spud 123 gross operated horizontal wells in the field, of which 90 are expected to be turned in line during 2014. Approximately $76 million of the total Wattenberg Field capital budget is expected to be allocated to non-operated projects. During the nine months ended September 30, 2014, we invested approximately $344 million, or 78%, of our 2014 capital budget in the Wattenberg Field.

Utica Shale. We expect to invest approximately $192 million in the Utica Shale in 2014 to spud 12 horizontal wells, of which eight are expected to be turned in line during 2014. A second spudder rig was deployed during the majority of the third quarter to top-hole our next two four-well pads. The Utica capital budget includes approximately $59 million to acquire additional acreage. During the nine months ended September 30, 2014, we invested approximately $115 million, or 60%, of our 2014 capital budget in the Utica Shale.

Non-U.S. GAAP Financial Measures

We use "adjusted cash flows from operations," "adjusted net income (loss)" and "adjusted EBITDA," 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. See Reconciliation of Non-U.S. GAAP Financial Measures for a detailed description of these measures, as well as a reconciliation of each to the most comparable U.S. GAAP measure.

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Results of Operations

Summary Operating Results

The following table presents selected information regarding our operating results from continuing operations:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2014	2013	Percentage Change	2014	2013	Percentage Change
	(dollars in millions, except per unit data)					
Production (1)						
Crude oil (MBbls)	1,072.3	601.5	78.3 %	3,192.3	1,887.5	69.1 %
Natural gas (MMcf)	4,910.1	3,739.6	31.3 %	13,611.1	10,749.2	26.6 %
NGLs (MBbls)	461.7	248.2	86.0 %	1,252.2	763.0	64.1 %
Crude oil equivalent (MBoe) (2)	2,352.3	1,472.9	59.7 %	6,713.0	4,442.1	51.1 %
Average MBoe per day	25.6	16.0	59.7 %	24.6	16.3	51.1 %
Crude Oil, Natural Gas and NGLs Sales						
Crude oil	$90.8	$59.0	53.9 %	$279.4	$171.1	63.3 %
Natural gas	17.2	11.5	49.6 %	55.0	35.3	55.8 %
NGLs	12.5	6.9	81.2 %	37.2	20.6	80.6 %
Total crude oil, natural gas and NGLs sales	$120.5	$77.4	55.7 %	$371.6	$227.0	63.7 %
Net Settlements on Derivatives (3)						
Natural gas	$0.3	$2.2	(86.4)%	$(3.9)	$12.7	*
Crude oil	(4.8)	(4.3)	(11.6)%	(17.6)	(3.1)	*
Total net settlements on derivatives	$(4.5)	$(2.1)	(114.3)%	$(21.5)	$9.6	*
Average Sales Price (excluding net settlements on derivatives)						
Crude oil (per Bbl)	$84.67	$98.11	(13.7)%	$87.51	$90.63	(3.4)%
Natural gas (per Mcf)	3.50	3.06	14.4 %	4.04	3.28	23.2 %
NGLs (per Bbl)	27.15	27.70	(2.0)%	29.73	27.07	9.8 %
Crude oil equivalent (per Boe)	51.24	52.51	(2.4)%	55.35	51.10	8.3 %
Average Lifting Cost (per Boe) (4)						
Wattenberg Field	$4.73	$5.28	(10.4)%	$4.67	$4.35	7.4 %
Utica Shale	2.68	3.65	(26.6)%	1.79	3.31	(45.9)%
Other	—	15.63	*	—	13.81	*
Weighted-average	4.56	5.93	(23.1)%	4.42	4.93	(10.3)%
Natural Gas Marketing Contribution Margin (5)	$—	$(0.2)	*	$—	$(0.2)	*
Other Costs and Expenses						
Exploration expense	$0.2	$1.8	(89.7)%	$0.8	$4.6	(83.4)%
Impairment of crude oil and natural gas properties	1.9	4.2	(56.0)%	3.6	51.8	*
General and administrative expense	34.6	15.1	130.0 %	96.5	43.9	119.7 %

Depreciation, depletion and amortization	49.6	27.0	84.1 %	142.2	77.9	82.6 %
Interest Expense	$11.8	$12.0	(1.1)%	$36.2	$37.9	(4.4)%

*Percentage change is not meaningful or equal to or greater than 300%.
Amounts may not recalculate due to rounding.

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(1) Production is net and determined by multiplying the gross production volume of properties in which we have an interest by our ownership percentage.
(2) One Bbl of crude oil or NGL equals six Mcf of natural gas.
(3) Represents net settlements on derivatives related to crude oil and natural gas sales, which do not include net settlements on derivatives related to natural gas marketing.
(4) Represents lease operating expenses, exclusive of production taxes, on a per unit basis.
(5) Represents sales from natural gas marketing, net of costs of natural gas marketing, including net settlements and net change in fair value of unsettled derivatives related to natural gas marketing activities.

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Crude Oil, Natural Gas and NGLs Sales

The following tables present crude oil, natural gas and NGLs production and weighted-average sales price from continuing operations:

Production by Operating Region	Three Months Ended September 30, 2014	2013	Percentage Change	Nine Months Ended September 30, 2014	2013	Percentage Change
Crude oil (MBbls)						
Wattenberg Field	1,012.0	580.6	74.3 %	2,973.1	1,836.8	61.9 %
Utica Shale	60.3	20.2	198.5 %	219.2	48.2	*
Other	—	0.7	*	—	2.5	*
Total	1,072.3	601.5	78.3 %	3,192.3	1,887.5	69.1 %
Natural gas (MMcf)						
Wattenberg Field	4,318.6	3,091.2	39.7 %	11,971.8	8,982.9	33.3 %
Utica Shale	591.5	67.4	*	1,639.3	111.3	*
Other	—	581.0	*	—	1,655.0	*
Total	4,910.1	3,739.6	31.3 %	13,611.1	10,749.2	26.6 %
NGLs (MBbls)						
Wattenberg Field	421.1	246.5	70.8 %	1,151.3	760.0	51.5 %
Utica Shale	40.6	1.7	*	100.9	3.0	*
Total	461.7	248.2	86.0 %	1,252.2	763.0	64.1 %
Crude oil equivalent (MBoe)						
Wattenberg Field	2,152.9	1,342.3	60.4 %	6,119.7	4,094.0	49.5 %
Utica Shale	199.4	33.1	*	593.3	69.8	*
Other	—	97.5	*	—	278.3	*
Total	2,352.3	1,472.9	59.7 %	6,713.0	4,442.1	51.1 %

*Percentage change is not meaningful or equal to or greater than 300%.
Amounts may not recalculate due to rounding.

Average Sales Price by Operating Region (excluding net settlements on derivatives)	Three Months Ended September 30, 2014	2013	Percentage Change	Nine Months Ended September 30, 2014	2013	Percentage Change
Crude oil (per Bbl)						
Wattenberg Field	$84.56	$97.98	(13.7)%	$87.41	$90.53	(3.4)%
Utica Shale	86.56	101.61	(14.8)%	88.87	94.29	(5.7)%
Other	—	99.03	*	—	91.00	*
Weighted-average price	84.67	98.11	(13.7)%	87.51	90.63	(3.4)%
Natural gas (per Mcf)						
Wattenberg Field	$3.65	$3.09	18.1%	$4.10	$3.27	25.4%
Utica Shale	2.45	2.59	(5.4)%	3.60	2.96	21.6%
Other	—	2.98	*	—	3.38	*
Weighted-average price	3.50	3.06	14.4%	4.04	3.28	23.2%
NGLs (per Bbl)						
Wattenberg Field	$25.89	$27.65	(6.4)%	$28.17	$27.02	4.3%
Utica Shale	40.13	35.92	11.7%	47.58	38.26	24.4%
Weighted-average price	27.15	27.70	(2.0)%	29.73	27.07	9.8%
Crude oil equivalent (per Boe)						

Wattenberg Field	$52.13	$54.57	(4.5)%	$55.78	$52.80	5.6%
Utica Shale	41.58	69.05	(39.8)%	51.17	71.50	(28.4)%
Other	—	18.44	*	—	20.93	*
Weighted-average price	51.24	52.51	(2.4)%	55.35	51.10	8.3%

*Percentage change is not meaningful or equal to or greater than 300%.
Amounts may not recalculate due to rounding.

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For the three and nine months ended September 30, 2014, crude oil, natural gas and NGLs sales revenue increased compared to the three and nine months ended September 30, 2013 due to the following (in millions):

	September 30, 2014	
	Three Months Ended	Nine Months Ended
Increase in production	$55.6	$140.9
Increase in average natural gas price	2.2	10.3
Decrease in average crude oil price	(14.4)	(9.9)
Increase (decrease) in average NGLs price	(0.3)	3.3
Total increase in crude oil, natural gas and NGLs sales revenue	$43.1	$144.6

As expected, we experienced increases in gathering system pressures in the Wattenberg Field by our primary third-party midstream provider through the third quarter of 2014 and we had previously factored these higher line pressures into our production estimates for 2014. Overall, the line pressures thus far in 2014 have been within our expectations and were lower than they were in the comparable periods of 2012 and 2013, primarily due to the commissioning of the O’Connor gas plant in the fall of 2013, the recent startup of an additional compressor station in 2014 and relatively mild summer temperatures in 2014. Ongoing industry drilling activity in the area has continued to increase volumes on the gathering system and pressures have remained at 2014 summer levels through the third quarter of 2014. We believe our midstream service provider will be challenged to keep pace with industry drilling activity with new midstream infrastructure until the new Lucerne II plant is completed in the Spring of 2015. This should address system pressure issues at least until 2016, when the next significant midstream infrastructure projects are projected to be completed. We and other operators in the field are working with the midstream service provider, who continues to implement a multi-year facility expansion program that will significantly increase the long-term gathering and processing capacity of the system. Like most producers, we rely on our third-party midstream service providers to construct compression, gathering and processing facilities to keep pace with our production growth. As a result, the timing and availability of additional facilities going forward is beyond our control.

Crude Oil, Natural Gas and NGLs Pricing. Our results of operations depend upon many factors, particularly the price of crude oil, natural gas and NGLs and our ability to market our production effectively. Crude oil, natural gas and NGLs prices are among the most volatile of all commodity prices. These price variations can have a material impact on our financial results and capital expenditures.

Crude oil pricing is predominately driven by the physical market, supply and demand, financial markets and national and international politics. In the Wattenberg Field, crude oil is sold under various purchase contracts with monthly pricing provisions based on NYMEX pricing, adjusted for differentials. We are currently pursuing various alternatives with respect to oil transportation, particularly in the Wattenberg Field, with a view toward improving pricing and takeaway capacity. We recently reached agreement to commit a significant portion of our Wattenberg Field crude oil production to White Cliffs Pipeline, LLC, which will transport our crude oil to the Cushing market starting in April of 2015. In the Utica Shale, crude oil and condensate is sold to local purchasers at each individual well site based on NYMEX pricing, adjusted for differentials. Natural gas prices vary by region and locality, depending upon the distance to markets, availability of pipeline capacity and supply and demand relationships in that region or locality. The price we receive for our natural gas produced in the Wattenberg Field is based on CIG prices, adjusted for certain deductions, while natural gas produced in the Utica Shale is based on TETCO M-2 and Dominion pricing, adjusted for certain deductions. The differentials at our two primary sales hubs for the Utica Shale have recently widened primarily due to current oversupply in the Appalachian region. We have been able to sell a portion of our Utica gas to a Midwest market which has helped to mitigate the impact of these differentials. We anticipate that these widened Appalachian differentials will continue at least through the remainder of 2014. Our price for NGLs produced in the Wattenberg Field is based on a combination of prices from the Conway hub in Kansas and Mt. Belvieu in Texas where this production is marketed. The NGLs produced in the Utica Shale are sold based on month-to-month pricing to various markets.

We currently use the "net-back" method of accounting for crude oil, natural gas and NGLs production from the Wattenberg Field and crude oil from the Utica Shale as the majority of the purchasers of these commodities also provide transportation, gathering and processing services. We sell our commodities at the wellhead and collect a price and recognize revenues based on the wellhead sales price as transportation and processing costs downstream of the wellhead are incurred by the purchaser and reflected in the wellhead price. The net-back method results in the recognition of a sales price that is below the indices for which the production is based. Natural gas and NGLs sales related to production from the Utica Shale are recognized based on gross prices as the purchasers do not provide transportation, gathering or processing services and we recognize expenses relating to those services as production costs.

Production Costs

Production costs include lease operating expenses, production taxes, transportation, gathering and processing costs and certain production and engineering staff-related overhead costs, as well as other costs to operate wells and pipelines as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Lease operating expenses	$10.7	$8.7	$29.7	$21.9
Production taxes	8.8	5.6	22.7	15.3
Transportation, gathering and processing expenses	1.2	1.1	3.3	3.6
Overhead and other production expenses	2.1	1.6	9.0	4.9
Total production costs	$22.8	$17.0	$64.7	$45.7
Total production costs per Boe	$9.67	$11.57	$9.62	$10.29

Lease operating expenses. The $2.0 million increase in lease operating expenses during the three months ended September 30, 2014 compared to the three months ended September 30, 2013 was primarily due to an increase of $0.7 million for the rental of additional compressors used to accommodate high line pressures in the Wattenberg Field, an increase of $0.3 million for environmental compliance and remediation projects, $0.3 million for lease operating expenses incurred on the increasing number of non-operated wells and $0.2 million for workover and maintenance related projects. The $7.8 million increase in lease operating expenses during the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013 was primarily due to an increase of $2.4 million for the rental of additional compressors used to accommodate high line pressures in the Wattenberg Field, $1.9 million for workover and maintenance related projects, $1.5 million for environmental compliance and remediation projects, $1.0 million for lease operating expenses incurred on the increasing number of non-operated wells and $0.7 million in additional wages and benefits.

Production taxes. Production taxes are directly related to crude oil, natural gas and NGLs sales. The $3.2 million, or 57%, increase in production taxes for the three months ended September 30, 2014 compared to the three months ended September 30, 2013, was primarily related to the 56% increase in crude oil, natural gas and NGLs sales. Similarly, the $7.4 million, or 48%, increase in production taxes for the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013, was primarily related to the 64% increase in crude oil, natural gas and NGLs sales.

Transportation, gathering and processing expenses. The $0.1 million, or 9%, increase in transportation, gathering and processing expenses for the three months ended September 30, 2014 compared to the three months ended September 30, 2013 was primarily attributable to an increase in Utica gas transportation and processing expenses offset in part by a reduction in our unutilized takeaway capacity costs resulting from the divestiture of our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin producing properties. The $0.3 million, or 8%, decrease in transportation, gathering and processing expenses for the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013 was primarily attributable to a $1.3 million reduction in our unutilized takeaway capacity costs resulting from the divestiture of our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin producing properties and a $0.8 million decrease in compressor and refrigeration unit rentals, offset by a $1.8 million increase in Utica gas transportation and processing expenses due to higher production levels.

Overhead and other production expenses. Overhead and other production expenses increased $0.5 million during the three months ended September 30, 2014 as compared to the three months ended September 30, 2013. The increase consisted of a $0.6 million increase in wages and employee benefits, mostly attributable to moving Utica Shale employee costs to production expense from exploration expense. Overhead and other production expenses increased $4.1 million during the nine months ended September 30, 2014 as compared to the nine months ended September 30, 2013. The increase consisted of a $3.1 million increase in wages and employee benefits, mostly attributable to moving Utica Shale employee costs to production expense from exploration expense, and an increase of $0.9 million for the write-off of costs due to changes in our drilling locations.

Commodity Price Risk Management, Net

Commodity price risk management, net, includes cash settlements upon maturity of our derivative instruments and the change in fair value of unsettled derivatives related to our crude oil and natural gas production. Commodity price risk management, net, does not include derivative transactions related to our natural gas marketing, which are included in sales from and cost of natural gas marketing. See Note 3, Fair Value of Financial Instruments, and Note 4, Derivative Financial Instruments, to our condensed consolidated financial statements included elsewhere in this report for additional details of our derivative financial instruments.

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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Commodity price risk management gain (loss), net:				
Net settlements	$(4.5)	$(2.1)	$(21.5)	$9.6
Net change in fair value of unsettled derivatives	94.7	(22.0)	34.2	(31.7)
Total commodity price risk management gain (loss), net	$90.2	$(24.1)	$12.7	$(22.1)

Net settlements for the three and nine months ended September 30, 2014 were primarily the result of higher crude oil and natural gas index prices at maturity of our derivative instruments compared to the respective strike prices. For the three and nine months ended September 30, 2014, negative settlements on our crude oil positions were $4.8 million and $17.6 million, respectively. Positive settlements for the three months ended September 30, 2014 on natural gas positions, exclusive of basis swaps, were $0.2 million compared to negative settlements of $4.3 million for the nine months ended September 30, 2014. The negative settlements were slightly offset by positive settlements on our basis swap positions of $0.1 million and $0.4 million for the three and nine months ended September 30, 2014, respectively. The net change in fair value of unsettled derivatives for the three and nine months ended September 30, 2014 includes a $12.9 million and $11.2 million net asset increase, respectively, in the beginning-of-period fair value of derivative instruments that settled during the period. The corresponding impact of settlement of these instruments is included in net settlements for the period as discussed above. The net change in fair value of unsettled derivatives for the three and nine months ended September 30, 2014 also includes a $81.8 million and $23.0 million increase, respectively, in the fair value of unsettled derivatives during the period, primarily related to the downward shift in the crude oil and natural gas forward curves.

During the three and nine months ended September 30, 2013, positive settlements on natural gas, exclusive of basis swaps, were $3.2 million and $20.5 million, respectively. The positive settlements were offset in part by negative settlements of $1 million and $7.8 million, respectively, on our basis swap positions. Negative settlements for the three and nine months ended September 30, 2013 on our crude oil positions were $4.3 million and $3.1 million, respectively. The net change in fair value of unsettled derivatives for the three and nine months ended September 30, 2013 includes a $2.9 million and $25.3 million net asset reduction, respectively, in the beginning-of-period fair value of derivative instruments that settled during the period and a $19.2 million and $6.8 million decrease, respectively, in the fair value of unsettled derivatives during the period, primarily related to the upward shift in the crude oil and natural gas forward curves.

We use various derivative instruments to manage fluctuations in crude oil and natural gas prices. We have in place a variety of collars, fixed-price swaps and basis swaps on a portion of our estimated crude oil and natural gas production. Because we sell all of our physical crude oil and natural gas at prices similar to the indexes inherent in our derivative instruments, adjusted for certain fees and surcharges stipulated in the applicable sales agreements, we ultimately realize a price related to our collars of no less than the floor and no more than the ceiling and, for our commodity swaps, we ultimately realize the strike price, adjusted for differentials.

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Natural Gas Marketing

Fluctuations in our natural gas marketing segment's income contribution are primarily due to fluctuations in commodity prices, cash settlements upon maturity of derivative instruments and the change in fair value of unsettled derivatives, and, to a lesser extent, volumes sold and purchased.

The following table presents the components of sales from and costs of natural gas marketing:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Natural gas sales revenue	$12.9	$17.0	$62.9	$48.1
Net settlements from derivatives	0.2	0.2	(0.4)	0.3
Net change in fair value of unsettled derivatives	0.2	(0.3)	0.1	0.3
Other	—	—	—	—
Total sales from natural gas marketing	13.3	16.9	62.6	48.7
Costs of natural gas purchases	12.6	16.5	61.8	46.5
Net settlements from derivatives	0.2	0.2	(0.5)	0.1
Net change in fair value of unsettled derivatives	0.2	(0.3)	0.2	0.3
Other	0.3	0.7	1.1	2.0
Total costs of natural gas marketing	13.3	17.1	62.6	48.9
Natural gas marketing contribution margin	$—	$(0.2)	$—	$(0.2)

Natural gas sales revenue and cost of natural gas purchases decreased in the three months ended September 30, 2014 compared to the three months ended September 30, 2013, mainly attributable to lower natural gas prices, offset in part by higher production volumes. Natural gas sales revenue and cost of natural gas purchases increased in the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013, mainly attributable to higher natural gas prices and production volumes.

Derivative instruments related to natural gas marketing include both physical and cash-settled derivatives. We offer fixed-price derivative contracts for the purchase or sale of physical natural gas and enter into cash-settled derivative positions with counterparties in order to offset those same physical positions.

Exploration Expense

The following table presents the major components of exploration expense:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions)			

Geological and geophysical costs	$—	$0.2	$—	$0.7
Operating, personnel and other	0.2	1.6	0.7	3.9
Total exploration expense	$0.2	$1.8	$0.7	$4.6

Geological and geophysical costs. Geological and geophysical costs during the three and nine months ended September 30, 2013 were primarily related to costs associated with reservoir studies in the Utica Shale.

Operating, personnel and other. The $1.4 million and $3.2 million decreases during the three and nine months ended September 30, 2014, respectively, compared to the same prior year periods was primarily related to a reduction in personnel costs in the Utica Shale resulting from the reassignment of former exploration department personnel to production departments and to general and administrative expense.

Impairment of Crude Oil and Natural Gas Properties

The following table sets forth the major components of our impairments of crude oil and natural gas properties expense:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Impairment of proved properties	$—	$3.7	$—	$48.8
Impairment of individually significant unproved properties	—	—	—	0.5
Amortization of individually insignificant unproved properties	1.1	0.5	2.8	2.5
Other	0.8	—	0.8	—
Total impairment of crude oil and natural gas properties	$1.9	$4.2	$3.6	$51.8

Impairment of proved properties. In the first quarter of 2013, we recognized an impairment charge of approximately $45 million related to all of our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin producing properties located in West Virginia and Pennsylvania owned directly by us, as well as through our proportionate share of PDCM. The impairment charge represented the excess of the carrying value of the assets over the estimated fair value, less the cost to sell. The fair value of the assets was determined based upon estimated future cash flows from unrelated third-party bids, a Level 3 input. Pursuant to a purchase and sale agreement entered into in October 2013, we determined that the carrying value of the above-mentioned properties exceeded the transaction sales price, a Level 3 input, less costs to sell. As a result, we recognized an additional impairment charge of approximately $3.8 million in the third quarter of 2013 to reduce the carrying value of the net assets to reflect the current net sales price.

General and Administrative Expense

General and administrative expense increased $19.6 million to $34.6 million for the three months ended September 30, 2014 compared to $15.1 million for the three months ended September 30, 2013. The increase was attributable to $16.2 million recorded during the three months ended September 30, 2014 in connection with certain former partnership-related class action litigation and estimates relating to litigation arising from bankruptcy proceedings of certain affiliated partnerships, a $1.5 million increase in payroll and employee benefits, of which $0.9 million was related to stock-based compensation, and a $1.4 million increase in costs for legal and other professional services.

General and administrative expense increased $52.6 million to $96.5 million for the nine months ended September 30, 2014 compared to $43.9 million for the nine months ended September 30, 2013. The increase was attributable to $40.3 million recorded during the nine months ended September 30, 2014 in connection with certain partnership-related class action litigation and, in the third quarter of 2014, estimates relating to litigation arising from bankruptcy proceedings of certain affiliated partnerships, a $6.3 million increase in payroll and employee benefits, of which $2.5 million was related to stock-based compensation, and a $3.8 million increase in legal and other professional services.

Depreciation, Depletion and Amortization Expense

Crude oil and natural gas properties. DD&A expense related to crude oil and natural gas properties is directly related to proved reserves and production volumes. DD&A expense related to crude oil and natural gas properties was $48.7 million and $139.1 million for the three and nine months ended September 30, 2014, respectively, compared to $25.9 million and $74.0 million for the three and nine months ended September 30, 2013, respectively. The increase in our production for the three and nine months ended September 30, 2014 contributed $18.7 million and $44.9 million to these increases, respectively, while higher weighted-average depreciation, depletion and amortization rates contributed $4.1 million and $20.2 million for the three and nine months ended September 30, 2014, respectively.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
Operating Region/Area	2014	2013	2014	2013
	(per Boe)			
Wattenberg Field	$19.56	$18.18	$19.78	$17.69
Utica Shale	32.98	46.16	30.75	21.91
Other	—	—	—	5.30
Total weighted-average	20.70	18.96	20.73	17.72

Non-crude oil and natural gas properties. Depreciation expense for non-crude oil and natural gas properties was $1.0 million and $3.1 million for the three and nine months ended September 30, 2014, respectively, compared to $1.0 million and $3.9 million for the three and nine months ended September 30, 2013, respectively.

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Interest Expense

Interest expense decreased $1.7 million to $36.2 million for the nine months ended September 30, 2014 compared to $37.9 million for the nine months ended September 30, 2013. The year-over-year decrease is primarily comprised of a $1.2 million decrease due to lower average borrowings on our revolving credit facilities and a $1 million decrease attributable to an increase in the interest expense capitalized during the nine months ended September 30, 2014.

Provision for Income Taxes

See Note 6, Income Taxes, to the accompanying condensed consolidated financial statements included elsewhere in this report for a discussion of the changes in our effective tax rate for the three and nine months ended September 30, 2014 compared to the three and nine months ended September 30, 2013. The effective tax rate of 39.6% and 40.5% provision on income for the three and nine months ended September 30, 2014, respectively, are based on forecasted pre-tax income for the year adjusted for permanent differences. The forecasted effective tax rate has been applied to the year-to-date pre-tax income resulting in a tax provision for the respective periods. In addition, discrete tax expense of $0.6 million was included in the amounts for the three and nine month periods in 2014. This discrete expense arose based upon the final tax expense per 2013 tax returns compared to the previous year’s tax provision amount. The tax rates without discrete items would have been 38.8% and 38.9% for the three and nine month periods, respectively, in 2014. Because the estimate of full-year income may change from quarter to quarter, the effective tax rate for any particular quarter may not have a meaningful relationship to pre-tax income or loss for the quarter or the actual annual effective tax rate that is determined at the end of the year.

Discontinued Operations

In July 2014, we signed a definitive agreement pursuant to which we agreed to sell our entire 50% ownership interest in PDCM to an unrelated third-party for aggregate consideration of approximately $250 million, subject to certain purchase price adjustments. On October 14, 2014, we closed on this divestiture for aggregate consideration, after our share of PDCM's debt repayment and other working capital adjustments, of approximately $190 million, comprised of approximately $150 million in cash and a promissory note due in 2020 of approximately $40 million, subject to customary post-closing adjustments. The divestiture represents a significant strategic shift in our operations. Accordingly, our proportionate share of PDCM's Marcellus Shale results of operations have been separately reported as discontinued operations in the condensed consolidated statement of operations for all periods presented.

In June 2013, we divested our Piceance Basin, NECO and certain other non-core Colorado oil and gas properties, leasehold mineral interests and related assets for total consideration of approximately $177.6 million, with an additional $17.0 million paid to our non-affiliated investor partners in our affiliated partnerships. Following the sale, we do not have significant continuing involvement in the operations of, or cash flows from, the Piceance Basin and NECO oil and gas properties. Accordingly, the results of operations related to these assets have been separately reported as discontinued operations in the condensed consolidated statement of operations for the nine months ended September 30, 2013.

See Note 12, Assets Held for Sale, Divestitures and Discontinued Operations, and Note 15, Subsequent Event, to the accompanying condensed consolidated financial statements included elsewhere in this report for additional information regarding the sale of our ownership interest in PDCM and our Piceance Basin, NECO and other non-core Colorado oil and gas properties.

The table below presents production data related to the assets that have been divested and that are classified as discontinued operations:

Discontinued Operations	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Production				
Crude oil (MBbls)	—	0.5	—	14.6
Natural gas (MMcf)	2,097.4	1,484.2	6,557.9	10,179.3
Crude oil equivalent (MBoe)	349.6	247.9	1,093.0	1,711.1

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

Net income for the three and nine months ended September 30, 2014 was $54.0 million and $23.7 million, respectively, compared to net losses of $16.0 million and $35.5 million for the three and nine months ended September 30, 2013, respectively. Adjusted net loss, a non-U.S. GAAP financial measure, was $5.7 million for the three months ended September 30, 2014 compared to adjusted net loss of $2.3 million for the same prior year period. Adjusted net income for the nine months ended September 30, 2014 was $2.4 million compared to adjusted net loss of $15.7 million for the nine months ended September 30, 2013. The quarter-over-quarter changes in net income (loss) are discussed above, with the most significant changes related to the increase in crude oil, natural gas and NGLs sales, income from commodity price risk management activities, DD&A expense and general and administrative expense. The year-over-year changes in net income (loss) are discussed above, with the most significant changes related to the increase in crude oil, natural gas and NGLs sales, income from commodity price risk management activities, DD&A expense, general and administrative expense, and the decrease in impairment of crude oil and natural gas properties. These same reasons for change similarly impacted adjusted net income (loss), with the exception of the net change in fair value of unsettled derivatives,

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adjusted for taxes, as this amount is not included in the total. See Reconciliation of Non-U.S. GAAP Financial Measures, below, for a more detailed discussion of this non-U.S. GAAP financial measure.

Financial Condition, Liquidity and Capital Resources

Historically, our primary sources of liquidity have been cash flows from operating activities, our revolving credit facility, proceeds raised in debt and equity market transactions and asset sales. For the nine months ended September 30, 2014, our primary sources of liquidity were net cash flows from operating activities of $202.0 million and the remaining cash from the August 2013 equity transaction noted below. In light of our current focus on the Wattenberg Field and the Utica Shale, on October 14, 2014 we closed the sale of our entire 50% ownership interest in PDCM to an unrelated third-party for aggregate consideration, after our share of PDCM's debt repayment and other working capital adjustments, of approximately $190 million, comprised of approximately $150 million in cash and a promissory note due in 2020 of approximately $40 million, subject to certain post-closing adjustments. See Note 12, Assets Held for Sale, Divestitures and Discontinued Operations, and Note 15, Subsequent Event, to our condensed consolidated financial statements included elsewhere in this report for additional information. Proceeds from the sale were used to reduce outstanding borrowings on our revolving credit facility and are expected to provide liquidity to fund our remaining 2014 capital budget.

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 substantially driven by commodity prices and changes in our production volumes. Commodity prices have historically been volatile and we manage this volatility through our use of derivatives. We enter into commodity derivative instruments with maturities of no greater than five years from the date of the instrument. For instruments that mature in three years or less, our debt covenants restrict us from entering into hedges that would exceed 85% of our expected future production from total proved reserves (proved developed producing, proved developed non-producing and proved undeveloped). For instruments that mature later than three years, but no more than our designated maximum maturity, our debt covenants limit our holdings to 85% of our expected future production from proved developed producing properties. Therefore, we may still have significant fluctuations in our cash flows from operating activities due to the remaining non-hedged portion of our future production.

Our working capital fluctuates for various reasons, including, but not limited to, changes in the fair value of our commodity derivative instruments and changes in our cash and cash equivalents due to our practice of utilizing excess cash to reduce the outstanding borrowings under our revolving credit facility. At September 30, 2014, we had a working capital deficit of $89.2 million compared to a surplus of $112.4 million at December 31, 2013. The working capital deficit as of September 30, 2014 is a direct result of the decrease in cash and cash equivalents.

We ended September 2014 with cash and cash equivalents of $18.7 million and availability under our revolving credit facility and our proportionate share of PDCM's credit facility of $378.0 million, for a total liquidity position of $396.7 million, compared to $647.0 million at December 31, 2013. The decrease in liquidity of $250.3 million, or 38.7%, was primarily attributable to capital expenditures of $451.1 million during the nine months ended September 30, 2014, offset in part by cash flows provided by operating activities of $202.0 million. Considering the proceeds received from the sale of our ownership interest in PDCM and the additional $250 million of borrowing base availability under our revolving credit facility, our pro forma liquidity as of September 30, 2014 was $788.5 million. With our current liquidity position and expected cash flows from operations, we believe that we have sufficient capital to fund our planned operations.

In recent periods, we have been able to access borrowings under our revolving credit facility and to obtain proceeds from the issuance of debt and equity securities. We cannot, however, assure this will continue to be the case in the future. We continue to monitor market conditions and circumstances and their potential impact on each of our revolving credit facility lenders. Our revolving credit facility borrowing base is subject to a redetermination each May and November, based upon a quantification of our proved reserves at each June 30 and December 31, respectively. On September 26, 2014, the semi-annual redetermination of our revolving credit facility's borrowing base was completed, resulting in an increase in the borrowing base from $450 million to $700 million. However, we have elected to maintain the aggregate commitment at $450 million. Our next scheduled redetermination is in May 2015. While we expect to continue to add producing reserves through our drilling operations, these reserve additions could be offset by other factors including, among other things, a significant decrease in commodity prices.

In January 2012, we filed an automatic shelf registration statement on Form S-3 with the SEC, which expires in January 2015. Effective upon filing, the shelf provides for the potential sale of an unspecified amount of debt securities, common stock or preferred stock, either separately or represented by depository shares, warrants or purchase contracts, as well as units that may include any of these securities or securities of other entities. The shelf registration statement is intended to allow us to be proactive in our ability to raise capital and to have the flexibility to raise such funds in one or more offerings should we perceive market conditions to be favorable. Pursuant to this shelf registration, we sold 5.2 million shares of our common stock in August 2013 in an underwritten public offering at a price to us of $53.37 per share.

Our revolving credit facility contains financial maintenance covenants. The covenants require that we maintain: (i) total debt of less than 4.25 times earnings before interest, taxes, depreciation, depletion and amortization, change in fair value of unsettled derivatives, exploration expense, gains (losses) on sales of assets and other non-cash, extraordinary or non-recurring gains (losses) ("EBITDAX") and (ii) an adjusted current ratio of at least 1.0 to 1.0. Our adjusted current ratio is adjusted by eliminating the impact on our current assets and liabilities of recording the fair value of crude oil and natural gas derivative instruments. Additionally, available borrowings under our revolving credit facility are added to the current asset calculation and the current portion of our revolving credit facility debt is eliminated from the current liabilities calculation. At September 30, 2014, we were in compliance with all debt covenants with a 2.1 times debt to EBITDAX ratio and a 2.4 to 1.0 current ratio. We expect to remain in compliance throughout the next year.

The indenture governing our 7.75% senior notes due 2022 contains customary restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (a) incur additional debt, (b) make certain investments or pay dividends or distributions on our capital stock or purchase, redeem or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) restrict the payment of dividends or other payments by restricted subsidiaries to us, (e) create liens that secure debt, (f) enter into transactions with affiliates and (g) merge or consolidate with another company. At September 30, 2014, we were in compliance with all covenants and expect to remain in compliance throughout the next year.

The conversion rights on our Convertible Notes could be triggered prior to the maturity date. We have initially elected a net-settlement method to satisfy our conversion obligation, which allows us to settle the principal amount of the Convertible Notes in cash and to settle the excess conversion value in shares, as well as cash in lieu of fractional shares. In the event that a holder elects to convert its note, we expect to fund the cash settlement of any such conversion from working capital and/or borrowings under our revolving credit facility. The conversion right is not expected to have a material impact on our financial position. The Convertible Notes were not convertible at the option of holders as of September 30, 2014.

See Part I, Item 3, Quantitative and Qualitative Disclosures about Market Risk, for our discussion of credit risk.

Cash Flows

Operating Activities. Our net cash flows from operating activities are primarily impacted by commodity prices, production volumes, net settlements from our derivative positions, operating costs and general and administrative expenses. Cash flows from operating activities increased by $82.4 million for the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013. The increase in cash provided by operating activities was primarily due to the increase in crude oil, natural gas and NGLs sales of $144.6 million and changes in assets and liabilities of $37.7 million related to the timing of cash payments and receipts. The increase was offset in part by the decrease in net settlements from our derivative positions of $33.7 million and increases in general and administrative expense of $52.6 million and production costs of $18.9 million. The key components for the changes in our cash flows provided by operating activities are described in more detail in Results of Operations above.

Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased $44.8 million during the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013. The increase was primarily due to the same factors mentioned above for changes in cash flows provided by operating activities, without regard to timing of cash payments and receipts of assets and liabilities. Adjusted EBITDA, a non-U.S. GAAP financial measure, increased by $42.1 million during the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013. The increase was primarily the result of the increase in crude oil, natural gas and NGLs sales of $144.6 million, offset in part by the decrease in net settlements on derivatives of $33.7 million and an increase in general and administrative expense of $52.6 million and production costs of $18.9 million. See Reconciliation of Non-U.S. GAAP Financial Measures, below, for a more detailed discussion of non-U.S. GAAP financial measures.

Investing Activities. Because crude oil and natural gas production from a well declines rapidly in the first few years of production, we need to continue to commit significant amounts of capital in order to maintain and grow our production and replace our reserves. If capital is not available or is constrained in the future, we will be limited to our cash flows from operations and liquidity under our revolving credit facility as the sources for funding our capital expenditures. We would not be able to maintain our current level of crude oil, natural gas and NGLs production and cash flows from operating activities if capital markets were unavailable, commodity prices were to become depressed and/or the borrowing base under our revolving credit facility was significantly reduced. The occurrence of such an event may result in our election to defer a substantial portion of our planned capital expenditures and could have a material negative impact on our operations in the future.

Cash flows from investing activities primarily consist of leasehold acquisitions and exploration and development of crude oil and natural gas properties, net of dispositions of crude oil and natural gas properties. During the nine months ended September 30, 2014, our drilling program consisted of five drilling rigs operating in the liquid-rich horizontal Niobrara and Codell plays in our Wattenberg Field and one drilling rig and a spudder rig in the Utica Shale play. Net cash used in investing activities of $449.5 million during the nine months ended September 30, 2014 was primarily related to cash utilized for our drilling operations of $451.1 million, offset in part by $1.6 million received from the sale of properties and equipment.

Financing Activities. Net cash from financing activities for the nine months ended September 30, 2014 decreased by approximately $173.0 million compared to the nine months ended September 30, 2013. Net cash from financing activities of $73.0 million for the nine months ended September 30, 2014 primarily relates to amounts borrowed under our revolving credit facility as well as our proportionate share of PDCM's draw on its credit facility.

Drilling Activity

The following table presents our net developmental and exploratory drilling activity for the periods shown. There is no necessary correlation between the number of productive wells completed during any period and the aggregate reserves attributable to those wells. Productive wells consist of wells spudded, turned-in-line and producing during the period. In-process wells represent wells that have been spudded, drilled or are waiting to be completed and/or for gas pipeline connection during the period.

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	Net Drilling Activity										
	Three Months Ended September 30,					Nine Months Ended September 30,					
	2014		2013			2014			2013		
Operating Region/Area	Productive	In-Process	Productive	In-Process	Dry	Productive	In-Process	Dry	Productive	In-Process	Dry
Development Wells											
Wattenberg Field	12.1	48.9	10.8	25.9	0.1	48.3	48.9	1.7 (1)	28.8	15.6	0.1
Utica Shale	2.0	3.7	—	3.0	—	4.0	3.7	1.0 (1)	—	—	—
Marcellus Shale (2)	—	—	3.5	2.0	—	2.0	—	—	3.5	3.5	—
Total net development wells	14.1	52.6	14.3	30.9	0.1	54.3	52.6	2.7	32.3	19.1	0.1
Exploratory Wells											
Utica Shale	—	—	1.5	2.8	—	—	—	—	3.0	4.3	—
Total net exploratory wells	—	—	1.5	2.8	—	—	—	—	3.0	4.3	—
Total drilling activity	14.1	52.6	15.8	33.7	0.1	54.3	52.6	2.7	35.3	23.4	0.1

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(1) Represents two mechanical failures in the Wattenberg Field and one mechanical failure in the Utica Shale that resulted in the plugging and abandonment of the respective wells.
(2) Represents PDCM's drilling activity. On October 14, 2014, we closed the sale of our entire 50% ownership interest in PDCM to an unrelated third-party. See Note 12, Assets Held for Sale, Divestitures and Discontinued Operations, and Note 15, Subsequent Event, to our condensed consolidated financial statements included elsewhere in this report for additional information.

Off-Balance Sheet Arrangements

At September 30, 2014, we had no off-balance sheet arrangements, as defined under SEC rules, that 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 expenditures or capital resources.

Commitments and Contingencies

See Note 9, Commitments and Contingencies, to the accompanying condensed consolidated financial statements included elsewhere in this report.

Recent Accounting Standards

See Note 2, 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 consolidated financial statements and accompanying notes contained in our 2013 Form 10-K filed with the SEC on February 21, 2014.

Reconciliation of Non-U.S. GAAP Financial Measures

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 been only 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. See the condensed consolidated statements of cash flows in the accompanying condensed consolidated financial statements included elsewhere in this report.

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 operational trends.

Adjusted EBITDA. We define adjusted EBITDA as net income (loss), plus loss on commodity derivatives, interest expense, net of interest income, income taxes, impairment of crude oil and natural gas properties, depreciation, depletion and amortization and accretion of asset retirement obligations, less gain on commodity derivatives and net settlements on commodity derivatives. Adjusted EBITDA 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 EBITDA includes certain non-cash costs incurred by the Company and does not take into account changes in operating assets and liabilities. Other companies in our industry may calculate adjusted EBITDA differently than we do, limiting its usefulness as a comparative measure. We believe adjusted EBITDA 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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Adjusted cash flows from operations:				
Adjusted cash flows from operations	$55.5	$36.7	$180.2	$135.4
Changes in assets and liabilities	14.9	40.8	21.8	(15.9)
Net cash from operating activities	$70.4	$77.5	$202.0	$119.5
Adjusted net income (loss):				
Adjusted net income (loss)	$(5.7)	$(2.3)	$2.4	$(15.7)
Gain (loss) on commodity derivative instruments	92.2	(23.5)	11.6	(21.1)
Net settlements on commodity derivative instruments	4.1	1.3	22.7	(11.0)
Tax effect of above adjustments	(36.6)	8.5	(13.0)	12.3
Net income (loss)	$54.0	$(16.0)	$23.7	$(35.5)
Adjusted EBITDA to net income (loss):				
Adjusted EBITDA	$62.6	$44.4	$201.8	$159.7
Gain (loss) on commodity derivative instruments	92.2	(23.5)	11.6	(21.1)
Net settlements on commodity derivative instruments	4.1	1.3	22.7	(11.0)

Interest expense, net	(12.4)	(12.4)	(37.9)	(38.8)
Income tax provision	(38.5)	10.7	(16.6)	20.7
Impairment of crude oil and natural gas properties	(2.2)	(4.4)	(4.0)	(52.4)
Depreciation, depletion and amortization	(50.9)	(30.9)	(151.3)	(88.9)
Accretion of asset retirement obligations	(0.9)	(1.2)	(2.6)	(3.7)
Net income (loss)	$54.0	$(16.0)	$23.7	$(35.5)
Adjusted EBITDA to net cash from operating activities:				
Adjusted EBITDA	$62.6	$44.4	$201.8	$159.7
Interest expense, net	(12.4)	(12.4)	(37.9)	(38.8)
Stock-based compensation	4.2	3.0	13.1	10.0
Amortization of debt discount and issuance costs	1.8	1.7	5.2	5.1
Loss on sale of properties and equipment	—	0.6	0.4	1.6
Other	(0.7)	(0.6)	(2.4)	(2.2)
Changes in assets and liabilities	14.9	40.8	21.8	(15.9)
Net cash from operating activities	$70.4	$77.5	$202.0	$119.5

Colorado Oil & Natural Gas Task Force

As discussed in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2014, Colorado Governor Hickenlooper has created a task force charged with crafting recommendations to help minimize land use conflicts relating to the location of oil and gas facilities. The task force was created pursuant to a compromise under which certain potential ballot initiatives that would have impacted the oil and natural gas industry in Colorado were withdrawn from the November 2014 ballot. The task force, which is called the Task Force on State and Local Regulation of Oil and Gas Operations, is comprised of 21 members representing various interests. Recommendations of the task force regarding new or amended legislation must be approved by a two-thirds vote of the members and will be submitted to the Governor by no later than February 27, 2015. We cannot predict the outcome of this process or the proposals to be formulated by the task force. In addition, depending on the outcome of the task force process and any related legislative activity, ballot initiatives affecting our operations may be proposed and adopted by the voters in future elections.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market-Sensitive Instruments and Risk Management

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

Interest Rate Risk

Changes in interest rates affect the amount of interest we earn on our interest bearing cash, cash equivalents and restricted cash accounts and the interest we pay on borrowings under our revolving credit facility. Our 7.75% senior notes due 2022 and our Convertible 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 September 30, 2014, our interest-bearing deposit accounts included money market accounts, certificates of deposit and checking and savings accounts with various banks. The amount of our interest-bearing cash, cash equivalents and restricted cash as of September 30, 2014 was $37.2 million with an average interest rate of 0.1%. Based on a sensitivity analysis of our interest bearing deposits as of September 30, 2014, it was estimated that if market interest rates would have increased by 1%, the impact on interest income for the nine months ended September 30, 2014 would result in a change of $0.3 million.

As of September 30, 2014, excluding the $11.7 million irrevocable standby letter of credit, we had $68 million outstanding on our revolving credit facility and, representing our proportionate share, $44.8 million on PDCM's revolving credit facility. We estimate that if market interest rates would have increased or decreased by 1%, the impact on interest expense for the nine months ended September 30, 2014 would result in a change of $0.8 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 and NGLs. Pursuant to established policies and procedures, we manage a portion of the risks associated with these market fluctuations using 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 derivative policies and procedures are effective in achieving our risk management objectives.

The following table presents our derivative positions related to crude oil and natural gas sales in effect as of September 30, 2014:

	Collars			Fixed-Price Swaps		Basis Protection Swaps		
Commodity/ Index/ Maturity Period	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted-Average Contract Price Floors	Ceilings	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted-Average Contract Price	Quantity (BBtu) (1)	Weighted-Average Contract Price	Fair Value September 30, 2014 (2) (in millions)
Natural Gas								
NYMEX								
2014	—	$ —	$ —	3,510.0	$ 4.10	3,502.0	$ (0.15)	$ —
2015	5,140.0	4.00	4.43	10,215.0	4.07	1,800.0	(0.14)	1.4

2016	4,220.0	4.00	4.42	14,880.0	4.00	—	—	(0.7)
2017	1,630.0	4.25	5.00	3,300.0	4.13	—	—	0.1
CIG								
2014	—	—	—	1,038.0	3.97	—	—	—
2015	—	—	—	2,730.0	4.01	—	—	0.6
Total Natural Gas	10,990.0			35,673.0		5,302.0		1.4
Crude Oil								
NYMEX								
2014	145.5	83.38	102.42	1,016.0	90.59	—	—	0.6
2015	686.0	85.63	96.86	4,514.0	89.12	—	—	8.3
2016	1,740.0	77.59	97.55	2,400.0	90.37	—	—	12.2
Total Crude Oil	2,571.5			7,930.0		—		21.1
Total Natural Gas and Crude Oil								$22.5

(1) A standard unit of measurement for natural gas (one BBtu equals one MMcf).

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(2) Approximately 23.9% of the fair value of our derivative assets and 10.6% of our derivative liabilities were measured using significant unobservable inputs (Level 3). See Note 3, Fair Value Measurements, to the condensed consolidated financial statements included elsewhere in this report.

The following table presents average NYMEX and CIG closing prices for crude oil and natural gas for the periods identified, as well as average sales prices we realized for our crude oil, natural gas and NGLs production:

	Three Months Ended	Nine Months Ended	Year Ended
	September 30, 2014	September 30, 2014	December 31, 2013
Average Index Closing Price:			
Crude oil (per Bbl)			
NYMEX	$97.25	$99.62	$97.97
Natural gas (per MMBtu)			
NYMEX	$4.06	$4.55	$3.65
CIG	3.86	4.30	3.45
TETCO M-2	2.45	3.64	3.50
Average Sales Price Realized:			
Excluding net settlements on derivatives			
Crude oil (per Bbl)	$84.67	$87.51	$89.92
Natural gas (per Mcf)	3.50	4.04	3.29
NGLs (per Bbl)	27.15	29.73	27.97

Based on a sensitivity analysis as of September 30, 2014, it was estimated that a 10% increase in natural gas and crude oil prices, inclusive of basis, over the entire period for which we have derivatives in place, would have resulted in a decrease in the fair value of our derivative positions of $99.5 million, whereas a 10% decrease in prices would have resulted in an increase in fair value of $99.4 million.

See Note 3, Fair Value of Financial Instruments, and Note 4, Derivative Financial Instruments, to our condensed consolidated financial statements included elsewhere in this report for a summary of our open derivative positions, as well as a discussion of how we determine the fair value of and account for our derivative contracts.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. We attempt to reduce credit risk by diversifying our counterparty exposure and entering into transactions with high-quality counterparties. When exposed to significant credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. 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 segment's crude oil, natural gas and NGLs sales are concentrated with a few predominately large customers. This concentrates our credit risk exposure with a small number of large customers. Amounts due to our Gas Marketing segment are from a diverse group of entities, including major upstream and midstream energy companies, financial institutions and end-users in various industries. We monitor their creditworthiness through our credit committee, which utilizes a number of qualitative and quantitative tools to assess credit risk and takes mitigative actions if deemed necessary. To date, we have had no material counterparty default losses in either segment.

Our derivative financial instruments may expose us to the risk of nonperformance by the instrument's contract counterparty. We primarily use financial institutions which are lenders in our revolving credit facility as counterparties for our derivative financial instruments. We monitor the creditworthiness of our 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 monitoring procedures are reasonable, no amount of analysis can assure performance by a financial institution. In addition, disruption in the credit markets may have a significant adverse impact on a number of financial institutions. To date, we have had no material counterparty default losses from our derivative financial instruments. See Note 4, Derivative Financial Instruments, to our consolidated financial statements included elsewhere in this report for more detail on our derivative financial instruments.

Disclosure of Limitations

Because the information above included only those exposures that existed at September 30, 2014, 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.

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ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of September 30, 2014, we carried out an evaluation under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rules 13a-15(e) and 15d-15(e).

Based on the results of this evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2014.

Changes in Internal Control over Financial Reporting

During the three months ended September 30, 2014, we made no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II
ITEM 1. LEGAL PROCEEDINGS

Information regarding our legal proceedings can be found in Note 9, Commitments and Contingencies – Litigation, 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 2013 Form 10-K. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share
July 1 - 31, 2014	18,210	$61.94
August 1 - 31, 2014	171	60.09
September 1 - 30, 2014	—	—
Total second quarter purchases	18,381	61.92

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

ITEM 3. DEFAULTS UPON SENIOR SECURITIES - None.

ITEM 4. MINE SAFETY DISCLOSURES - Not applicable.

ITEM 5. OTHER INFORMATION - None.

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ITEM 6. EXHIBITS

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
10.1	Purchase and Sale Agreement by and among the Company, LR-Mountaineer Holdings, L.P., PDC Mountaineer, LLC and PDC Mountaineer Holdings, LLC, dated July 29, 2014.	8-K	000-07246	2.1	8/1/2014	
31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1*	Certifications by Chief Executive Officer and Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.					
101.INS	XBRL Instance Document					X
101.SCH	XBRL Taxonomy Extension Schema Document					X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document					X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document					X
101.LAB	XBRL Taxonomy Extension Label Linkbase Document					X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document					X

* Furnished herewith.

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PDC ENERGY, INC.

SIGNATURES

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

PDC Energy, Inc.
(Registrant)

Date: November 6, 2014

/s/ James M. Trimble
James M. Trimble
Chief Executive Officer
(principal executive officer)

/s/ Gysle R. Shellum
Gysle R. Shellum
Chief Financial Officer
(principal financial officer)

/s/ R. Scott Meyers
R. Scott Meyers
Chief Accounting Officer
(principal accounting officer)