PDC ENERGY, INC.
Form 10-Q
October 31, 2013
Table of contents

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

FORM 10-Q

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

For the quarterly period ended September 30, 2013

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: 35,653,050 shares of the Company's Common Stock ($0.01 par value) were outstanding as of October 18, 2013.

Table of contents

PDC ENERGY, INC.

TABLE OF CONTENTS

	PART I – FINANCIAL INFORMATION	Page
Item 1.	Financial Statements	
	Condensed Consolidated Balance Sheets (unaudited)	1
	Condensed Consolidated Statements of Operations (unaudited)	2
	Condensed Consolidated Statements of Cash Flows (unaudited)	3
	Notes to Condensed Consolidated Financial Statements	4
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	23
Item 3.	Quantitative and Qualitative Disclosures About Market Risk	37
Item 4.	Controls and Procedures	39
PART II – OTHER INFORMATION		
Item 1.	Legal Proceedings	39
Item 1A.	Risk Factors	39
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	40
Item 3.	Defaults Upon Senior Securities	40
Item 4.	Mine Safety Disclosures	40
Item 5.	Other Information	40
Item 6.	Exhibits	41
	SIGNATURES	42

Table of contents

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act") 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: estimated crude oil, natural gas and natural gas liquids (“NGLs”) reserves; future production (including the components of such production), sales, expenses, cash flows and liquidity; that our evaluation method is appropriate and consistent with those used by other market participants; anticipated capital projects, expenditures and opportunities; future exploration, drilling and development activities; our drilling programs; expected timing of additional rigs in the Wattenberg Field; availability of additional midstream facilities and services, timing of that availability and related benefits to us; impact of recent flooding in the Wattenberg Field; availability of sufficient funding for the remainder of our 2013 and 2014 capital program and sources of that funding, including our partnership repurchase obligation; expected use of the net proceeds from our August 2013 equity offering; expected use of proceeds from the potential sale of the upper Devonian assets; the impact of high line pressures and the expected impact of the O'Connor (formerly known as LaSalle) gas plant; our compliance with debt covenants; PDCM's compliance with its debt covenants and transactions to maintain compliance and/or reduce its indebtedness; potential future transactions; the borrowing base under our credit facility; our expected funding source for payments under our 3.25% Convertible Senior Notes due 2016; 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; 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 production volumes and worldwide demand, including economic conditions that might impact demand;
- volatility of commodity prices for crude oil, natural gas and NGLs;
- the 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 and natural gas 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 to be 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;
- timing of the connection of our Utica Basin wells to gathering, processing, fractionation and transportation infrastructure;

- 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;
- availability of sufficient pipeline, gathering and other transportation facilities and related infrastructure to process and transport our production, particularly in the Wattenberg Field and Utica Shale, and the impact of these facilities on the prices we receive for our production;
- 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;
- purchase price or other adjustments relating to asset acquisitions or dispositions that may be unfavorable to us;
- 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, 2012 ("2012

Table of contents

Form 10-K"), filed with the U.S. Securities and Exchange Commission ("SEC") on February 27, 2013, and in our Current Report on Form 8-K filed on June 28, 2013, 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 forward-looking statements, which speak only as of the date of this report. We undertake no obligation to update any forward-looking statements in order to reflect any event or circumstance occurring after the date of this report or currently unknown facts or conditions or the occurrence of unanticipated events. All forward-looking statements are qualified in their entirety by this cautionary statement.

REFERENCES

Unless the context otherwise requires, references in this report to "PDC Energy," "PDC," "the Company," "we," "us," "our" or "ours" refer to the registrant, PDC Energy, Inc. and all subsidiaries consolidated for the purposes of its financial statements, including our proportionate share of the financial position, results of operations, cash flows and operating activities of our affiliated partnerships and PDC Mountaineer, LLC ("PDCM"), a joint venture currently owned 50% each by PDC and Lime Rock Partners, LP, formed for the purpose of exploring and developing the Marcellus Shale formation in the Appalachian Basin. Unless the context otherwise requires, references in this report to "Appalachian Basin" refers to our operations in the Utica Shale in Ohio and Marcellus Shale in West Virginia and Pennsylvania, including PDC's proportionate share of our affiliated partnerships' and PDCM's assets, results of operations, cash flows and operating activities. See Note 1, Nature of Operations and Basis of Presentation, to our condensed consolidated financial statements included elsewhere in this report for a description of our consolidated subsidiaries.

Table of contents

PART I - FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

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

	September 30, 2013	December 31, 2012
Assets		
Current assets:		
Cash and cash equivalents	$298,488	$2,457
Restricted cash	3,950	3,942
Accounts receivable, net	56,181	64,880
Accounts receivable affiliates	4,784	4,842
Fair value of derivatives	9,660	52,042
Deferred income taxes	22,238	36,151
Prepaid expenses and other current assets	9,073	7,635
Total current assets	404,374	171,949
Properties and equipment, net	1,539,701	1,616,706
Assets held for sale	29,034	—
Fair value of derivatives	5,922	6,883
Other assets	31,932	31,310
Total Assets	$2,010,963	$1,826,848
Liabilities and Shareholders' Equity		
Liabilities		
Current liabilities:		
Accounts payable	$93,520	$82,716
Accounts payable affiliates	44	5,296
Production tax liability	23,867	25,899
Fair value of derivatives	14,623	18,439
Funds held for distribution	29,753	34,228
Current portion of long-term debt	104,050	—
Accrued interest payable	19,874	11,056
Other accrued expenses	25,720	25,715
Total current liabilities	311,451	203,349
Long-term debt	549,750	676,579
Deferred income taxes	112,800	148,427
Asset retirement obligation	35,654	61,563
Fair value of derivatives	6,573	10,137
Liabilities held for sale	22,788	—
Other liabilities	20,849	23,612
Total liabilities	1,059,865	1,123,667
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, 100,000,000 authorized, 35,657,872 and 30,294,224 issued as of September 30, 2013 and December 31, 2012, respectively	357	303
Additional paid-in capital	670,990	387,494
Retained earnings	280,068	315,568
Treasury shares - at cost, 7,114 and 5,059 as of September 30, 2013 and December 31, 2012, respectively	(317)	(184)
Total shareholders' equity	951,098	703,181
Total Liabilities and Shareholders' Equity	$2,010,963	$1,826,848

See accompanying Notes to Condensed Consolidated Financial Statements
1

Table of contents

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Revenues:				
Crude oil, natural gas and NGLs sales	$82,136	$52,291	$239,112	$170,588
Sales from natural gas marketing	16,946	11,178	48,695	31,172
Commodity price risk management gain (loss), net	(23,638)	(31,943)	(21,269)	18,287
Well operations, pipeline income and other	1,672	1,194	3,709	3,419
Total revenues	77,116	32,720	270,247	223,466
Costs, expenses and other:				
Production costs	19,057	15,797	51,091	41,106
Cost of natural gas marketing	17,127	11,260	48,928	30,841
Exploration expense	2,030	1,773	5,156	6,019
Impairment of crude oil and natural gas properties	4,472	388	52,433	1,332
General and administrative expense	16,080	13,710	46,978	42,796
Depreciation, depletion, and amortization	30,870	22,121	86,619	73,872
Accretion of asset retirement obligations	1,186	1,101	3,506	2,560
Gain on sale of properties and equipment	(712)	(1,508)	(759)	(3,908)
Total cost, expenses and other	90,110	64,642	293,952	194,618
Income (loss) from operations	(12,994)	(31,922)	(23,705)	28,848
Interest expense	(12,509)	(11,360)	(38,955)	(31,857)
Interest income	130	3	133	5
Loss from continuing operations before income taxes	(25,373)	(43,279)	(62,527)	(3,004)
Provision for income taxes	10,155	15,268	22,856	935
Loss from continuing operations	(15,218)	(28,011)	(39,671)	(2,069)
Income (loss) from discontinued operations, net of tax	(782)	(4,632)	4,171	(2,468)
Net loss	$(16,000)	$(32,643)	$(35,500)	$(4,537)
Earnings per share:				
Basic				
Loss from continuing operations	$(0.46)	$(0.93)	$(1.26)	$(0.08)
Income (loss) from discontinued operations	(0.02)	(0.15)	0.13	(0.09)
Net loss	$(0.48)	$(1.08)	$(1.13)	$(0.17)
Diluted				
Loss from continuing operations	$(0.46)	$(0.93)	$(1.26)	$(0.08)
Income (loss) from discontinued operations	(0.02)	(0.15)	0.13	(0.09)
Net loss	$(0.48)	$(1.08)	$(1.13)	$(0.17)
Weighted-average common shares outstanding:				
Basic	33,413	30,214	31,350	26,819
Diluted	33,413	30,214	31,350	26,819

See accompanying Notes to Condensed Consolidated Financial Statements

Table of contents

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

	Nine Months Ended September 30,	
	2013	2012
Cash flows from operating activities:		
Net loss	$(35,500)	$(4,537)
Adjustments to net loss to reconcile to net cash from operating activities:		
Unrealized loss on derivatives, net	32,057	20,917
Depreciation, depletion and amortization	88,877	106,745
Impairment of crude oil and natural gas properties	52,436	1,418
Exploratory dry hole costs	—	1,043
Accretion of asset retirement obligation	3,667	2,839
Stock-based compensation	9,991	6,126
(Gain) loss on sale of properties and equipment	1,571	(23,828)
Amortization of debt discount and issuance costs	5,093	5,082
Deferred income taxes	(21,714)	(7,090)
Other	(1,017)	4,674
Changes in assets and liabilities	(15,918)	13,786
Net cash from operating activities	119,543	127,175
Cash flows from investing activities:		
Capital expenditures	(256,096)	(271,769)
Acquisition of oil and gas properties	—	(309,285)
Proceeds from acquisition adjustments	7,579	11,969
Proceeds from sale of properties and equipment	178,987	192,040
Increase in restricted cash	—	(17,497)
Net cash from investing activities	(69,530)	(394,542)
Cash flows from financing activities:		
Proceeds from revolving credit facility	252,500	591,250
Repayment of revolving credit facility	(278,000)	(492,250)
Proceeds from sale of common stock, net of issuance costs	275,847	164,496
Other	(4,329)	(1,460)
Net cash from financing activities	246,018	262,036
Net change in cash and cash equivalents	296,031	(5,331)
Cash and cash equivalents, beginning of period	2,457	8,238
Cash and cash equivalents, end of period	$298,488	$2,907
Supplemental cash flow information:		
Cash payments for:		
Interest, net of capitalized interest	$26,408	$30,868
Income taxes	525	1,830
Non-cash investing activities:		
Change in accounts payable related to purchases of properties and equipment	$24,308	$(9,514)
Change in asset retirement obligation, with a corresponding change to crude oil and natural gas properties, net of disposals	337	11,871

See accompanying Notes to Condensed Consolidated Financial Statements

Table of Contents

PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
SEPTEMBER 30, 2013
(Unaudited)

NOTE 1 - NATURE OF OPERATIONS AND BASIS OF PRESENTATION

PDC Energy, Inc. ("PDC," "PDC Energy," "we," "us" or "the Company") is a domestic independent crude oil, natural gas and NGL company engaged in the exploration for and the acquisition, development, production and marketing of crude oil, natural gas and NGLs. PDC is focused operationally on the liquid-rich Wattenberg Field in the DJ Basin and, in the Appalachian Basin, on the liquid-rich Utica Shale and the dry-gas Marcellus Shale formations. As of September 30, 2013, we owned an interest in approximately 6,250 gross wells. We are engaged in two business segments: (1) Oil and Gas Exploration and Production and (2) Gas Marketing.

The accompanying unaudited condensed consolidated financial statements include the accounts of PDC, our wholly owned subsidiaries, and our proportionate share of PDC Mountaineer, LLC ("PDCM") and our 21 affiliated partnerships. Pursuant to the proportionate consolidation method, our accompanying condensed consolidated financial statements include our pro rata share of assets, liabilities, revenues and expenses of the entities which we proportionately consolidate. All material intercompany accounts and transactions have been eliminated in consolidation.

In our opinion, the accompanying condensed consolidated financial statements contain all adjustments (consisting of 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 2012 Form 10-K. Our results of operations and cash flows for the three and nine months ended September 30, 2013 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. 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 Standard

On January 1, 2013, we adopted changes issued by the Financial Accounting Standards Board ("FASB") regarding the disclosure of offsetting assets and liabilities. These changes require an entity to disclose both gross and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an enforceable master netting arrangement or similar agreement. The enhanced disclosures enable users of an entity’s financial statements to understand and evaluate the effect or potential effect of master netting arrangements on the entity’s financial position, including the effect or potential effect of rights of setoff associated with certain financial instruments and derivative instruments. Adoption of these changes had no impact on the condensed consolidated financial statements, except for additional disclosures.

Recently Issued Accounting Standard

Income Taxes. On July 18, 2013, the FASB issued an update to accounting for income taxes. The update 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. The update is effective for public entities for fiscal years, and interim periods within those years, beginning after December 15, 2013. Early adoption is permitted. We are currently evaluating the impact of adopting this update on our financial statements, but do not believe it will have a material impact.

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. In these cases, 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.

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 crude oil and natural gas collars, natural gas 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, 2013			December 31, 2012		
	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	$12,328	$3,060	$15,388	$42,788	$15,734	$58,522
Basis protection derivative contracts	182	12	194	387	16	403
Total assets	12,510	3,072	15,582	43,175	15,750	58,925
Liabilities:						
Commodity-based derivative contracts	17,293	2,340	19,633	9,839	2,081	11,920
Basis protection derivative contracts	1,563	—	1,563	16,656	—	16,656
Total liabilities	18,856	2,340	21,196	26,495	2,081	28,576
Net asset (liability)	$(6,346)	$732	$(5,614)	$16,680	$13,669	$30,349

5

Table of contents
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,	
	2013	2012	2013	2012
	(in thousands)			
Fair value, net asset, beginning of period	$3,904	$28,600	$13,669	$22,107
Changes in fair value included in statement of operations line item:				
Commodity price risk management gain (loss), net	(3,111)	(9,055)	(3,008)	6,098
Sales from natural gas marketing	11	(4)	16	35
Changes in fair value included in balance sheet line item:				
Accounts payable affiliates (1)	—	(93)	—	(240)
Settlements included in statement of operations line items:				
Commodity price risk management gain (loss), net	(66)	(3,900)	(5,545)	(12,357)
Sales from natural gas marketing	(6)	(10)	(34)	(105)
Income (loss) from discontinued operations, net of tax	—	—	(4,366)	—
Fair value, net asset end of period	$732	$15,538	$732	$15,538
Changes in unrealized gains (losses) relating to assets (liabilities) still held as of period-end, included in statement of operations line item:				
Commodity price risk management gain (loss), net	$(3,333)	$(8,169)	$(5,362)	$2,577
Sales from natural gas marketing	(5)	(13)	4	(1)
Total	$(3,338)	$(8,182)	$(5,358)	$2,576

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(1) Represents the change in fair value related to derivative instruments entered into by us and designated to our affiliated partnerships.

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

The portion of our debt related to our revolving credit facility, as well as our proportionate share of PDCM's credit facility and second lien term loan, approximates fair value due to the variable nature of related interest rates. We have not elected to account for the portion of our debt related to our senior notes under the fair value option; however, as of

September 30, 2013, we estimate the fair value of our 3.25% convertible senior notes due 2016 to be $176.4 million, or 153.4% of par value, and our 7.75% senior notes due 2022 to be $528.8 million, or 105.7% of par value. We determined these valuations based upon measurements of trading activity and broker and/or dealer quotes 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, 2013, taking into account the estimated likelihood of nonperformance.

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

The following table presents the counterparties that expose us to credit risk as of September 30, 2013 with regard to our derivative assets:

Counterparty Name	Fair Value of Derivative Assets As of September 30, 2013 (in thousands)
JPMorgan Chase Bank, N.A. (1)	$4,163
Wells Fargo Bank, N.A. (1)	3,830
Natixis (1)	1,637
Bank of Montreal (1)	1,885
BNP Paribas (1)	1,285
Other lenders in our revolving credit facility	2,624
Various (2)	158
Total	$15,582

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(1)Major lender in our revolving credit facility. See Note 7, Long-Term Debt.
(2)Represents a total of 20 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.

- 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, 2013, we had derivative instruments, which were comprised of commodity floors, collars and swaps, basis protection swaps and physical sales and purchases, in place for a portion of our anticipated production through 2017 for a total of 51,305 BBtu of natural gas and 7,735 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, with the exception of changes in fair value related to those derivatives we designated to our affiliated partnerships. 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. Changes in the fair value of the derivative instruments designated to our affiliated partnerships are recorded on the condensed consolidated balance sheets in accounts payable affiliates and accounts receivable affiliates. As positions designated to our affiliated partnerships settle, the realized gains and losses are netted for distribution. Net realized gains are paid to the partnerships and net realized losses are deducted from the partnerships' cash distributions from production. The affiliated partnerships bear their designated share of counterparty risk. As of September 30, 2013, our affiliated partnerships had no outstanding derivative instruments.

The following table presents the location and fair value amounts of our derivative instruments on the condensed consolidated balance sheets as of September 30, 2013 and December 31, 2012:

Derivatives instruments:		Balance sheet line item	Fair Value September 30, 2013 (in thousands)	December 31, 2012
Derivative assets:	Current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	$9,067	$47,016
	Related to affiliated partnerships (1)	Fair value of derivatives	—	4,707
	Related to natural gas marketing	Fair value of derivatives	444	302
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	133	—
	Related to natural gas marketing	Fair value of derivatives	16	17
			9,660	52,042
	Non Current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	5,792	6,671
	Related to natural gas marketing	Fair value of derivatives	85	203
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	44	—
	Related to natural gas marketing	Fair value of derivatives	1	9
			5,922	6,883
Total derivative assets			$15,582	$58,925
Derivative liabilities:	Current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	$12,880	$1,744
	Related to natural gas marketing	Fair value of derivatives	310	226
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	1,433	14,329
	Related to affiliated partnerships (2)	Fair value of derivatives	—	2,140
			14,623	18,439

	Non Current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	6,403	9,969
	Related to natural gas marketing	Fair value of derivatives	40	168
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	130	—
			6,573	10,137
Total derivative liabilities			$21,196	$28,576

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(1) Represents derivative positions designated to our affiliated partnerships. Accordingly, our accompanying December 31, 2012 condensed consolidated balance sheet includes a corresponding payable to our affiliated partnerships representing their proportionate share of the derivative assets.

(2) Represents derivative positions designated to our affiliated partnerships. Accordingly, our accompanying December 31, 2012 condensed consolidated balance sheet includes a corresponding receivable from our affiliated partnerships representing their proportionate share of the derivative liabilities.

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

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

Statement of operations line item	2013 Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	2013 Realized and Unrealized Gains (Losses) For the Current Period	2013 Total	2012 Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	2012 Realized and Unrealized Gains (Losses) For the Current Period	2012 Total
	(in thousands)					
Three Months Ended September 30,						
Commodity price risk management gain (loss), net						
Realized gains (losses)	$2,936	$(4,461)	$(1,525)	$15,010	$(1,915)	$13,095
Unrealized losses	(2,936)	(19,177)	(22,113)	(15,010)	(30,028)	(45,038)
Total commodity price risk management gain (loss), net	$—	$(23,638)	$(23,638)	$—	$(31,943)	$(31,943)
Sales from natural gas marketing						
Realized gains (losses)	$249	$(9)	$240	$386	$15	$401
Unrealized losses	(249)	(62)	(311)	(386)	(404)	(790)
Total sales from natural gas marketing	$—	$(71)	$(71)	$—	$(389)	$(389)
Cost of natural gas marketing						
Realized gains (losses)	$(196)	$8	$(188)	$(364)	$(20)	$(384)
Unrealized gains	196	82	278	364	467	831
Total cost of natural gas marketing	$—	$90	$90	$—	$447	$447
Nine Months Ended September 30,						
Commodity price risk management gain (loss), net						
Realized gains (losses)	$25,273	$(14,426)	$10,847	$22,813	$16,387	$39,200
Unrealized gains (losses)	(25,273)	(6,843)	(32,116)	(22,813)	1,900	(20,913)
Total commodity price risk management gain (loss), net	$—	$(21,269)	$(21,269)	$—	$18,287	$18,287
Sales from natural gas marketing						
Realized gains	$206	$61	$267	$1,358	$588	$1,946
Unrealized gains (losses)	(206)	546	340	(1,358)	(428)	(1,786)
Total sales from natural gas marketing	$—	$607	$607	$—	$160	$160
Cost of natural gas marketing						
Realized gains (losses)	$(133)	$8	$(125)	$(1,195)	$(652)	$(1,847)
Unrealized gains (losses)	133	(414)	(281)	1,195	587	1,782
Total cost of natural gas marketing	$—	$(406)	$(406)	$—	$(65)	$(65)

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, 2013 and December 31, 2012:

As of September 30, 2013	Derivatives instruments, recorded in condensed consolidated balance sheet, gross (in thousands)	Effect of master netting agreements	Derivative instruments, net
Asset derivatives:			
Derivative instruments, at fair value	$15,582	$(11,739)	$3,843
Liability derivatives:			
Derivative instruments, at fair value	$21,196	$(11,739)	$9,457

As of December 31, 2012	Derivatives instruments, recorded in condensed consolidated balance sheet, gross (in thousands)	Effect of master netting agreements	Derivative instruments, net
Asset derivatives:			
Derivative instruments, at fair value	$58,925	$(11,437)	$47,488
Liability derivatives:			
Derivative instruments, at fair value	$28,576	$(11,437)	$17,139

NOTE 5 - PROPERTIES AND EQUIPMENT

The following table presents the components of properties and equipment, net of accumulated depreciation, depletion and amortization:

	September 30, 2013	December 31, 2012
	(in thousands)	
Properties and equipment, net:		
Crude oil and natural gas properties		
Proved	$1,533,430	$2,075,924
Unproved	315,233	319,327
Total crude oil and natural gas properties	1,848,663	2,395,251
Pipelines and related facilities	15,749	47,786
Equipment and other	28,780	34,858
Land and buildings	13,612	14,935
Construction in progress	146,921	67,217
Gross properties and equipment	2,053,725	2,560,047
Accumulated depreciation, depletion and amortization	(514,024)	(943,341)
Properties and equipment, net	$1,539,701	$1,616,706

The above decrease in property and equipment, net, includes decreases in crude oil and natural gas properties, pipelines and related facilities and equipment and other in the amount of $780.0 million and accumulated depreciation, depletion and amortization in the amount of $566.4 million attributable to the divestiture of our Piceance Basin, NECO and certain other non-core Colorado properties in June 2013 and the classification of our shallow upper Devonian (non-Marcellus Shale) Appalachian Basin crude oil and natural gas properties as held for sale in the condensed consolidated balance sheet as of September 30, 2013. See Note 12, Assets Held for Sale, Divestitures and Discontinued Operations, for additional information regarding these properties.

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands)			
Continuing operations:				
Impairment of proved properties	$3,750	$—	$48,750	$—
Impairment of individually significant unproved properties	154	154	979	462
Amortization of individually insignificant unproved properties	568	234	2,704	870
Total continuing operations	4,472	388	52,433	1,332
Discontinued operations:				
Amortization of individually insignificant unproved properties	—	7	3	86
Total discontinued operations	—	7	3	86
Total impairment of crude oil and natural gas properties	$4,472	$395	$52,436	$1,418

In 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 owned directly by us, as well as through our proportionate share of PDCM and our affiliated partnerships. The impairment charge represented the excess of the carrying value of the assets over the estimated fair value, less 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 dated October 8, 2013 with an unrelated third-party, 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 statement of operations line item impairment of crude oil and natural gas properties. See Note 12, Assets Held for Sale, Divestitures and Discontinued Operations, and Note 15, Subsequent Events, for additional information regarding the potential sale of these properties. We expect this sale to close in the fourth quarter of 2013. However, there can be no assurance we will be successful in closing this divestiture.

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, 2013 was a 40.0% and 36.6%, respectively, benefit on loss compared to a 35.3% and 31.1% benefit on loss for the three and nine months ended September 30, 2012, respectively. The effective tax rates for the three and nine months ended September 30, 2013 differ from the statutory rate primarily due to net permanent additions, largely nondeductible officers' compensation, partially offset by percentage depletion deductions. The effective tax rates for the three and nine months ended September 30, 2012 differ from the statutory rate primarily due to net permanent deductions, largely percentage depletion, partially offset by nondeductible officer's compensation. There were no significant discrete items recorded during the three and nine months ended September 30, 2013 or 2012.

As of September 30, 2013, we had a gross liability for unrecognized tax benefits of $0.2 million, unchanged from the amount recorded at December 31, 2012. If recognized, this liability would affect our effective tax rate. This liability is reflected in other accrued expenses on our accompanying condensed consolidated balance sheets. We expect our remaining liability for uncertain tax positions to decrease in the next twelve months 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. We have received notice from the State of Colorado that our 2008 through current state income tax returns have been selected for audit.

NOTE 7 - LONG-TERM DEBT

Long-term debt consists of the following:

	September 30, 2013	December 31, 2012
	(in thousands)	
Senior notes:		
3.25% Convertible senior notes due 2016:		
Principal amount	$115,000	$115,000
Unamortized discount	(10,950)	(13,671)
3.25% Convertible senior notes due 2016, net of discount	104,050	101,329
7.75% Senior notes due 2022	500,000	500,000
Total senior notes	604,050	601,329
Credit facilities:		
Corporate	—	49,000
PDCM	34,750	26,250
Total credit facilities	34,750	75,250
PDCM second lien term loan	15,000	—
Total debt	653,800	676,579
Less: Current portion of long-term debt	104,050	—
Long-term debt	$549,750	$676,579

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 investors. Interest on the Convertible Notes is payable semi-annually in arrears on each May 15 and November 15. 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 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 became convertible at the option of holders beginning October 1, 2013. The conversion right was triggered on September 20, 2013, when the closing sale price of our common stock on the NASDAQ Global Select Market exceeded $55.12 (130% of the applicable conversion price) for the 20th trading day in the 30 consecutive trading days ending on September 30, 2013. In the event a holder elects to convert its note, we expect to fund any cash settlement of any such conversion from working capital and/or borrowings under our revolving credit facility. As a result of the Convertible Notes becoming convertible, we have included the carrying value of the Convertible Notes, net of discount, in the current portion of long-term debt on our condensed consolidated balance sheet as of September 30, 2013. We will reassess the convertibility of the Convertible Notes, and the related balance sheet classification, on a quarterly basis. In the event that a holder exercises the right to convert its note, we will write-off a ratable portion of the remaining debt issuance costs and unamortized discount to interest expense. Based on a September 30, 2013 stock price of $59.54, the "if-converted" value of the Convertible Notes exceeded the principal amount by approximately $46.5 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 investors. Interest on the 2022 Senior Notes is payable semi-annually in arrears on each April 15 and October 15. The indenture governing the notes contains customary restrictive incurrence covenants. Capitalized debt issuance costs are being amortized as interest expense over the life of the notes using the effective interest method.

As of September 30, 2013, 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 twelve-month period.

In connection with the issuance of the 2022 Senior Notes, we entered into a registration rights agreement with the initial purchasers in which we agreed to file a registration statement with the SEC related to an offer to exchange the notes for substantially identical registered notes and to use commercially reasonable efforts to cause the exchange offer to be completed on or prior to September 28, 2013. The registration statement was declared effective by the SEC in July 2013 and the exchange offer was completed in August 2013.

Credit Facilities

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. As of September 30, 2013, the borrowing base was $450 million. 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 21 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. 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 the revolving credit facility. As of September 30, 2013, we had no outstanding draws on our revolving credit facility compared to $49.0 million at a weighted-average interest rate of 2.3% as of December 31, 2012.

The revolving credit facility contains covenants customary for agreements of this type, with the most restrictive being certain financial tests and requirements to maintain certain financial ratios on a quarterly basis. The financial tests and ratios, as defined per the revolving credit facility, include requirements to maintain a minimum current ratio of 1.00 to 1.00 and to not exceed a maximum leverage ratio of 4.25 to 1.00. As of September 30, 2013, we were in compliance with all the revolving credit facility covenants and expect to remain in compliance throughout the next twelve-month period.

As of September 30, 2013, Riley Natural Gas, a wholly owned subsidiary of PDC, had an approximately $11.8 million irrevocable standby letter of credit 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. In addition, PDC had an approximately $6.7 million irrevocable standby letter of credit to secure firm transportation of natural gas that we produce. The letters of credit reduce the amount of available funds under our revolving credit facility by an equal amount. The letters of credit expire on September 17, 2014. As of September 30, 2013, the available funds under our revolving credit facility, including a reduction for the $18.5 million irrevocable standby letters of credit in effect, was $431.5 million.

In October 2013, pursuant to an agreement our $6.7 million irrevocable standby letter of credit will be novated to the buyer of PDCM's shallow upper Devonian properties upon the closing of the transaction. See Note 15, Subsequent Events, for additional information regarding the potential sale. We expect this sale to close in the fourth quarter of 2013. However, there can be no assurance we will be successful in closing this divestiture.

PDCM Credit Facility. PDCM has a credit facility dated April 2010, as amended in May 2013, with a borrowing base of $80 million, of which our proportionate share is $40 million. The maximum allowable facility amount is $400 million. No principal payments are required until the credit agreement expires in April 2017, or in the event that the borrowing base falls below the outstanding balance. The credit facility is subject to and secured by PDCM's properties, including our proportionate share of such properties. The borrowing base is subject to size redetermination semi-annually based upon a valuation of PDCM's reserves at June 30 and December 31. Either PDCM or the lenders may request a redetermination upon the occurrence of certain events. The credit facility will be utilized by PDCM for the exploration and development of its Marcellus Shale assets.

The credit facility contains covenants customary for agreements of this type, with the most restrictive being certain financial tests and financial ratios that must be met on a quarterly basis. The financial tests and ratios, as defined by the credit facility, include requirements to maintain a minimum current ratio of 1.0 to 1.0, not to exceed a debt to EBITDAX ratio of 4.25 to 1.0 (declining to 4.0 to 1.0 on July 1, 2014) and to maintain a minimum interest coverage ratio of 2.5 to 1.0. As of September 30, 2013, our proportionate share of PDCM's outstanding credit facility balance was $34.8 million compared to $26.3 million as of December 31, 2012. The weighted-average borrowing rate on PDCM's credit facility was 3.6% per annum as of September 30, 2013, compared to 3.5% as of December 31, 2012.

As of September 30, 2013, PDCM was not in compliance with the minimum current ratio and debt to EBITDAX ratio covenants under the PDCM credit facility. In October 2013, PDCM received a waiver from Wells Fargo regarding the covenant violation. PDCM expects to maintain compliance with all PDCM credit facility covenants throughout the next twelve-month period.

PDCM Second Lien Term Loan

In July 2013, PDCM entered into a Second Lien Credit Agreement ("Term Loan Agreement") with Wells Fargo Energy Capital as administrative agent and a syndicate of other lenders party thereto. The aggregate commitment under the Term Loan Agreement is $30 million, of which our proportionate share is $15 million. The aggregate commitment may increase periodically up to a maximum of $75 million, as PDCM's assets grow and the covenants under the Term Loan Agreement allow. The Term Loan matures on October 31, 2017. Amounts borrowed accrue interest, at PDCM's discretion, at either an alternative base rate plus a margin of 6% per annum or an adjusted LIBOR for the interest period in effect plus a margin of 7% per annum. As of September 30, 2013, amounts borrowed and outstanding on the Term Loan were $30.0 million, of which our proportionate share is $15.0 million. The weighted-average borrowing rate on the Term Loan was 8.5% per annum as of September 30, 2013.

The Term Loan Agreement contains financial covenants that must be met on a quarterly basis, including requirements to maintain a minimum current ratio of 1.0 to 1.0, not to exceed a debt to EBITDAX ratio of 4.5 to 1.0, to maintain a minimum interest coverage ratio of 2.25 to 1.0 and not to exceed a present value of future net revenues to total debt ratio of 1.50 to 1.00. As of September 30, 2013, PDCM was not in compliance with the minimum current ratio and the debt to EBITDAX ratio covenants under the Term Loan Agreement. In October 2013, PDCM received a waiver from Wells Fargo regarding the covenant violation. PDCM expects to maintain compliance with all Term Loan Agreement covenants throughout the next twelve-month period.

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 December 31, 2012	$62,563
Obligations incurred with development activities	337
Accretion expense	3,667
Revisions in estimated cash flows	251
Obligations discharged with divestitures of properties and asset retirements	(7,376)
Balance at September 30, 2013	59,442
Less: Liabilities held for sale (1)	22,788
Less: Current portion	1,000
Long-term portion	$35,654

(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 Events, for additional information regarding the potential sale of these properties.

NOTE 9 - COMMITMENTS AND CONTINGENCIES

Firm Transportation Agreements. We enter into contracts that provide firm transportation, sales and processing services on pipeline systems through which we transport or sell natural gas. Volumes produced by us, PDCM, our affiliated partnerships and other third-party working interest owners can be used to satisfy volume requirements, as can volumes purchased from third parties. 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 the required volumes are delivered or not. 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:

	For the Twelve Months Ending September 30,						
Area	2014	2015	2016	2017	2018 and Through Expiration	Total	Expiration Date

Volume (MMcf)							
West Virginia	21,428	22,868	24,874	24,862	149,603	243,635	January 31, 2026
Utica Shale	2,282	2,738	2,738	2,738	15,966	26,462	July 22, 2023
Total	23,710	25,606	27,612	27,600	165,569	270,097	
Dollar commitment (in thousands)	$9,601	$10,056	$10,462	$10,294	$47,785	$88,198	

In March 2013, we entered into long-term agreements with a subsidiary of MarkWest Energy Partners, LP to provide midstream services, including gas gathering, processing, fractionation and marketing, to support our Utica Shale operations in Guernsey County in Southeast Ohio. The primary term of the agreements commenced in July 2013 when our natural gas began to flow into the gathering system. The gas processing agreement includes minimum volume commitments as shown in the table above, with certain fees assessed for any shortfall.

In June 2013, we closed a transaction pursuant to which our Piceance Basin and NECO firm gathering commitments were assumed by the buyer of certain of our oil and natural gas properties. See Note 12, Assets Held for Sale, Divestitures, and Discontinued Operations, for additional information regarding the sale of our non-core Colorado assets.

In October 2013, pursuant to a purchase and sale agreement an existing agreement for firm transportation services of approximately 34,572 MMcf, representing a dollar commitment of $16.5 million, in the Appalachian Basin will be novated to the buyer of PDCM's shallow upper Devonian crude oil and natural gas properties, thereby relieving the Company of all obligations or liabilities arising under the agreement. See Note 15, Subsequent Events, for additional information regarding the potential sale. We expect this sale to close in the fourth quarter of 2013. However, there can be no assurance we will be successful in closing this divestiture.

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.

Alleged Class Action Filed Regarding 2010 and 2011 Partnership Purchases

On December 21, 2011 the Company and its wholly-owned merger subsidiary were served with an alleged class action on behalf of certain former partnership unit holders, related to its partnership repurchases completed by mergers 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. On June 15, 2012, the Court denied the Company's motion to dismiss and approved a litigation schedule including a jury trial in May 2014. We have not recorded a liability for claims pending because we believe we have good legal defenses to the asserted claims and because the plaintiffs have not specified damages and it is not possible for management to reasonably estimate what, if any, monetary damages could result from this claim.

Environmental. Due to the nature of the natural gas and oil industry, we are exposed to environmental risks. We have various policies and procedures to avoid environmental contamination and mitigate the risks from environmental contamination. 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, 2013 and December 31, 2012, we had accrued environmental liabilities in the amount of $5.6 million and $8.4 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, 2013 which have not been provided for or would otherwise have a material impact on our financial statements. However, there can be no assurance that current regulatory requirements will not change or unknown past non-compliance with environmental laws will not be discovered on our properties.

Partnership Repurchase Provision. Substantially all of our drilling programs contain a repurchase provision pursuant to which investing partners may request that we purchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that we are obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions from production), if repurchase is requested by investors, subject to our financial ability to do so. As of September 30, 2013, the maximum annual repurchase obligation, based upon the minimum price described above, was approximately $4.2 million. We believe we have adequate liquidity to meet this potential obligation. For the quarter ended September 30, 2013, amounts paid for the repurchase of partnership units pursuant to this provision were immaterial.

Employment Agreements with Executive Officers. Each of our senior executive officers 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.

NOTE 10 - COMMON STOCK

Sale of Equity Securities

In August 2013, we completed a public offering of 5,175,000 shares of our common stock, par value $0.01 per share, at a price to us of $53.37 per share, resulting in total shares outstanding of 35,650,758 as of September 30, 2013. Net proceeds of the offering were approximately $275.8 million, after deducting offering expenses and underwriting discounts, of which $51,750 is included in common shares-par value and approximately $275.8 million is included in additional paid-in capital on the condensed consolidated balance sheet. The shares were issued pursuant to an effective shelf registration statement on Form S-3 filed with the SEC in January 2012.

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

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,	
	2013	2012	2013	2012
	(in thousands)			
Stock-based compensation expense	$3,040	$2,225	$9,991	$6,126
Income tax benefit	(1,161)	(847)	(3,816)	(2,333)
Net stock-based compensation expense	$1,879	$1,378	$6,175	$3,793

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 2013, the Compensation Committee awarded 87,078 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:

	Grant-Year	
	2013	2012
Expected term of award	6 years	6 years
Risk-free interest rate	1.0%	1.1%
Expected volatility	65.5%	64.3%
Weighted-average grant date fair value per share	$21.96	$17.61

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,							
2013				2012			
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,	118,832	$ 30.80	8.4	$ 486	50,471	$ 31.61	8.6	$ 341
Awarded	87,078	37.18	—	—	68,361	30.19	9.3	—
Outstanding at September 30,	205,910	33.50	8.4	5,363	118,832	30.80	8.7	328
Vested and expected to vest at September 30,	198,163	33.41	8.4	5,178	113,426	30.77	8.7	319
Exercisable at September 30,	67,069	29.99	7.3	1,982	27,458	28.84	7.8	153

Total compensation cost related to SARs granted, net of estimated forfeitures, and not yet recognized in our statement of operations as of September 30, 2013 was $2.0 million. The cost is expected to be recognized over a weighted-average period of 2.0 years.

Restricted Stock Awards

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

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

In January 2013, the Compensation Committee awarded a total of 103,050 time-based restricted shares to our executive officers that vest ratably over a three-year period ending on January 16, 2016.

The following table presents the changes in non-vested time-based awards for the nine months ended September 30, 2013:

	Shares		Weighted-Average Grant-Date Fair Value
Non-vested at December 31, 2012	646,490		$27.93
Granted	292,548		44.56
Vested	(265,312	)	27.53
Forfeited	(22,507	)	31.29
Non-vested at September 30, 2013	651,219		35.45

	As of/Year Ended September 30,	
	2013	2012
	(in thousands, except per share data)	
Total intrinsic value of time-based awards vested	$12,562	$4,818
Total intrinsic value of time-based awards non-vested	38,774	21,996
Market price per common share as of September 30,	59.54	31.63
Weighted-average grant date fair value per share	44.56	26.48

Total compensation cost related to non-vested time-based awards, net of estimated forfeitures, and not yet recognized in our statements of operations as of September 30, 2013 was $16.8 million. This cost is expected to be recognized over a weighted-average period of 2.1 years.

Market-Based Awards. The fair value of the market-based restricted shares is amortized ratably over the requisite service period, primarily three years. The market-based shares vest if the participant is continuously employed throughout the performance period and the market-based performance measure is achieved, with a maximum vesting period of three to 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 2013, the Compensation Committee awarded a total of 41,570 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 16 peer companies. The shares are measured over a three-year period ending on December 31, 2015 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,	
	2013	2012
Expected term of award	3 years	3 years

Risk-free interest rate	0.4 %	0.3 %
Expected volatility	56.6 %	65.3 %
Weighted-average grant date fair value per share	$49.04	$36.54

The expected term of the awards was based on the requisite service period. The risk-free interest rate was based on the U.S. Treasury yields in effect at the time of grant and extrapolated to approximate the life of the award. The expected volatility was based on our historical volatility. We do not expect to pay or declare dividends in the foreseeable future.

Table of contents
PDC ENERGY, INC.
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, 2013:

	Shares	Weighted-Average Grant-Date Fair Value per Share
Non-vested at December 31, 2012	40,696	$39.22
Granted	41,570	49.04
Non-vested at September 30, 2013	82,266	44.18

	As of/Year Ended September 30,	
	2013	2012
	(in thousands, except per share data)	
Total intrinsic value of market-based awards non-vested	$4,898	$2,329
Market price per common share as of September 30,	59.54	31.63
Weighted-average grant date fair value per share	49.04	36.54

Total compensation cost related to non-vested market-based awards, net of estimated forfeitures, and not yet recognized in our statement of operations as of September 30, 2013 was $2.0 million. This cost is expected to be recognized over a weighted-average period of 2.0 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands)			
Weighted-average common shares outstanding - basic	33,413	30,214	31,350	26,819
Weighted-average common shares and equivalents outstanding - diluted	33,413	30,214	31,350	26,819

We reported a net loss for each of the three and nine months ended September 30, 2013, and 2012, respectively. As a result, our basic and diluted weighted-average common shares outstanding was the same as the effect of the common share equivalents was anti-dilutive.

18

Table of contents
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,	
	2013	2012	2013	2012
	(in thousands)			
Weighted-average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:				
Restricted stock	805	777	857	688
SARs	83	119	65	115
Stock options	7	7	7	7
Non-employee director deferred compensation	4	3	4	3
Convertible senior notes	671	—	387	—
Total anti-dilutive common share equivalents	1,570	906	1,320	813

In November 2010, we issued our 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 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. 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, 2012 as the conversion price was greater than the average market price of our common stock during the period.

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

Piceance Basin and NECO. In February 2013, we entered into a purchase and sale agreement with certain affiliates of Caerus Oil and Gas LLC (“Caerus”), pursuant to which we agreed to sell to Caerus our Piceance Basin, NECO and certain other non-core Colorado oil and gas properties, leasehold mineral interests and related assets. Additionally, certain firm transportation obligations and natural gas hedging positions were assumed by Caerus. On June 18, 2013, this divestiture was completed with total consideration of approximately $177.6 million, subject to customary post-closing adjustments, with an additional $17.0 million paid to our non-affiliated investor partners in our affiliated partnerships. The sale resulted in a pre-tax loss of $2.3 million. The proceeds from the asset divestiture were used to pay down our revolving credit facility and to fund a portion of our 2013 capital budget. Following the sale to Caerus, 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 all periods presented. The sale of our other non-core Colorado oil and gas properties did not meet the requirements to be accounted for as discontinued operations.

Appalachian Basin. In early 2013, we developed a plan to market all of our shallow upper Devonian (non-Marcellus Shale) Appalachian Basin crude oil and natural gas properties located in West Virginia and Pennsylvania owned directly by us, as well as through our proportionate share of PDCM and our affiliated partnerships. The properties consist of approximately 3,500 gross shallow producing wells, related facilities and associated shallow leasehold acreage, limited to the upper Devonian and shallower formations. The Company will retain all zones, formations and intervals below the upper Devonian formation including the Marcellus Shale, Utica Shale and Huron Shale. We classified the related assets owned directly by us, as well as through our proportionate share of PDCM and our affiliated partnerships, as held for sale in the condensed consolidated balance sheet as of September 30, 2013. The divestiture of these assets does not meet the requirements to be accounted for as discontinued operations. In October 2013, PDCM executed a purchase and sale agreement with an unrelated third-party for the sale of these properties. The aggregate consideration is subject to customary terms and post-closing adjustments. See Note 15, Subsequent Events, for additional information on the potential sale. We expect this sale to close in the fourth quarter of 2013. However, there can be no assurance we will be successful in closing this divestiture.

Permian Basin. In December 2011, we executed a purchase and sale agreement with COG Operating LLC (“COG”), a wholly owned subsidiary of Concho Resources Inc., an unrelated third-party, for the sale of our core Permian Basin assets for a sale price of $173.9 million, subject to customary terms and adjustments. In February 2012, the divestiture closed with total proceeds received of $189.2 million after closing adjustments. Following the sale to COG, we do not have significant continuing involvement in the operations of, or cash flows from, these assets. Accordingly, the results of operations related to the Permian assets have been separately reported as discontinued operations in the condensed consolidated statement of operations for the nine months ended September 30, 2012.

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 represents the Appalachian Basin assets that are expected to be sold, net of liabilities that are expected to be assumed by the purchaser.

19

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

The following table presents balance sheet data related to our pro rata share of these assets held for sale as of September 30, 2013:

Balance Sheet	Net Assets Held for Sale
	(in thousands)
Assets	
Properties and equipment	$130,835
Accumulated depreciation, depletion and amortization	(101,801)
Total Assets	29,034
Liabilities	
Asset retirement obligation	22,788
Net Assets	$6,246

The following table presents statement of operations data related to our discontinued operations for the Piceance Basin, NECO and Permian Basin divestiture:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Statements of Operations - Discontinued Operations	2013	2012	2013	2012
	(in thousands)			
Revenues				
Crude oil, natural gas and NGLs sales	$(58)	$7,624	$20,398	$25,972
Sales from natural gas marketing	1,789	392	2,825	1,149
Well operations, pipeline income and other	31	446	890	1,476
Total revenues	1,762	8,462	24,113	28,597
Costs, expenses and other				
Production costs	18	4,959	7,975	17,743
Cost of natural gas marketing	1,679	338	2,673	1,010
Depreciation, depletion and amortization	—	10,362	2,258	32,873
Other	77	298	2,531	949
(Gain) loss on sale of properties and equipment	1,254	—	2,330	(19,920)
Total costs, expenses and other	3,028	15,957	17,767	32,655
Income (loss) from discontinued operations	(1,266)	(7,495)	6,346	(4,058)
Provision for income taxes	484	2,863	(2,175)	1,590
Income (loss) from discontinued operations, net of tax	$(782)	$(4,632)	$4,171	$(2,468)

While the reclassification of revenues and expenses related to discontinued operations for the prior period had no impact upon previously reported net earnings, the statement of operations table presents the revenues and expenses that were reclassified from the specified statement of operations line items to discontinued operations.

NOTE 13 - TRANSACTIONS WITH AFFILIATES AND OTHER RELATED PARTIES

PDCM and Affiliated Partnerships. Our Gas Marketing segment markets the natural gas produced by PDCM and our affiliated partnerships in the Eastern operating region.

Amounts due from/to the affiliated partnerships have historically been primarily related to derivative positions and, to a lesser extent, unbilled well lease operating expenses, and costs resulting from audit and tax preparation services. Previously, we had entered into derivative instruments on behalf of our affiliated partnerships for a percentage of their estimated production. In June 2013, all remaining derivative positions designated to our affiliated partnerships were liquidated prior to settlement. As a result, there were no amounts due from/to our affiliated partnerships related to derivative positions as of September 30, 2013.

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

The following table presents amounts included in our condensed consolidated statements of operations related to the marketing of natural gas on behalf of PDCM and our affiliated partnerships:

Statement of Operations	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
	(in thousands)			
PDCM:				
Sales from natural gas marketing	$4,774	$2,894	$12,742	$7,459
Cost of natural gas marketing	4,680	2,838	12,492	7,313
Affiliated Partnerships:				
Sales from natural gas marketing	348	145	931	368
Cost of natural gas marketing	341	142	913	360

We provide certain well operating and administrative services for PDCM. Amounts billed to PDCM for these services were $3.6 million and $10.4 million in the three and nine months ended September 30, 2013, respectively, compared to $3.0 million and $9.2 million in the three and nine months ended September 30, 2012. Our statements of operations include only our proportionate share of these billings. The following table presents the statement of operations line item in which our proportionate share is recorded and the amount for each of the periods presented:

Statement of Operations Line Item	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
	(in thousands)			
Production costs	$1,068	$1,022	$3,121	$3,080
Exploration expense	127	110	366	357
General and administrative expense	584	370	1,716	1,168

NOTE 14 - BUSINESS SEGMENTS

We separate our operating activities into two segments: (1) Oil and Gas Exploration and Production and (2) 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 corporate general administrative expense, corporate depreciation, depletion and amortization expense, interest income and interest expense.

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

The following tables present our segment information:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands)			
Segment revenues:				
Oil and gas exploration and production	$60,170	$21,542	$221,552	$192,294
Gas marketing	16,946	11,178	48,695	31,172
Total revenues	$77,116	$32,720	$270,247	$223,466
Segment loss before income taxes:				
Oil and gas exploration and production	$4,573	$(16,266)	$27,243	$76,852
Gas marketing	(181)	(82)	(233)	331
Unallocated	(29,765)	(26,931)	(89,537)	(80,187)
Loss before income taxes	$(25,373)	$(43,279)	$(62,527)	$(3,004)

	September 30, 2013	December 31, 2012
	(in thousands)	
Segment assets:		
Oil and gas exploration and production	$1,874,679	$1,723,011
Gas marketing	35,532	11,090
Unallocated	71,718	92,747
Assets held for sale	29,034	—
Total assets	$2,010,963	$1,826,848

Assets held for sale as of September 30, 2013 relate to our oil and gas exploration and production segment. We do not expect the divestiture of these assets to have a material impact on our financial condition and results of operations.

NOTE 15 - SUBSEQUENT EVENTS

On October 8, 2013, PDCM executed a purchase and sale agreement with an unrelated third-party pursuant to which PDCM agreed to sell its shallow upper Devonian (non-Marcellus Shale) Appalachian Basin crude oil and natural gas properties for aggregate consideration of approximately $18.8 million, of which our proportionate share is $6.2 million, after pre-closing adjustments. The properties consist of approximately 3,500 gross shallow producing wells, related facilities and associated shallow leasehold acreage, limited to the upper Devonian and shallower formations. The aggregate cash consideration is subject to customary terms and post-closing adjustments and by certain firm transportation obligations that will be assumed by the buyer. Concurrent with the closing of the transaction, our $6.7 million irrevocable standby letter of credit and related obligations will be novated to the buyer. We expect this sale to close in the fourth quarter of 2013. However, there can be no assurance we will be successful in closing this divestiture.

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

Crude oil, natural gas and NGLs sales from continuing operations increased during the three and nine months ended September 30, 2013 by $29.8 million, or 57.1%, and $68.5 million, or 40.2%, respectively, compared to the three and nine months ended September 30, 2012. The growth in crude oil, natural gas and NGLs sales was the result of a significant increase in production and higher crude oil and natural gas prices. Our crude oil, natural gas and NGLs production from continuing operations during the three and nine months ended September 30, 2013 averaged 18.6 Mboe per day and 18.4 Mboe per day, respectively, an increase of approximately 29.2% and 26.9%, respectively, compared to the three and nine months ended September 30, 2012. The increases in production are primarily attributable to our successful horizontal Niobrara and Codell drilling program in the Wattenberg Field and, to a lesser extent, certain assets acquired from affiliates of Merit Energy (the "Merit Acquisition") in June 2012. Crude oil production from continuing operations increased 39.9% and 33.2% during the three and nine months ended September 30, 2013, respectively, while NGLs production from continuing operations increased 18.7% and 21.5%, respectively. Our liquids percentage of total production from continuing operations was 49.6% and 52.7% during the three and nine months ended September 30, 2013, respectively, compared to 48.4% and 51.5%, respectively, during the same prior year periods. Natural gas production from continuing operations increased 27.0% and 23.4% during the three and nine months ended September 30, 2013, respectively, compared to the same periods in 2012.

Available liquidity as of September 30, 2013 was $735.3 million, including $5.5 million through PDCM, compared to $398.6 million, including $14.1 million related to PDCM, as of December 31, 2012. Available liquidity is comprised of cash, cash equivalents and funds available under revolving credit facilities. In August 2013, we completed a public offering of 5,175,000 shares of our common stock, par value $0.01 per share, at a price to us of $53.37 per share, for net proceeds of approximately $275.8 million, after deducting offering expenses and underwriting discounts. We expect to use the net proceeds from the offering to fund a portion of an expanded capital program for the remainder of 2013 and 2014 and for general corporate purposes. Our expanded capital program is expected to include the addition of a fourth drilling rig in the Wattenberg Field in the fourth quarter of 2013, as well as the potential for a second rig in the Utica Shale and a fifth rig in the Wattenberg Field in 2014. We may also use a portion of the proceeds to acquire additional Utica Shale acreage. We believe we have sufficient liquidity to allow us to execute our expanded drilling program through 2014.

Operational Overview

Drilling Activities. We continued to execute our strategic goal of increasing production while maintaining our production mix of crude oil and NGLs by focusing our drilling operations primarily in the liquid-rich Wattenberg Field in Colorado and the emerging Utica Shale play in Ohio. We have fully transitioned to multi-well pad drilling to optimize costs and enhance horizontal drilling efficiencies.

In our Western operating region, we currently have three drilling rigs operating in the Wattenberg Field. We are currently test-drilling increased density of 16 horizontal wells per section. During the nine months ended September 30, 2013, we spud 47 horizontal wells in the Wattenberg Field, 25 of which were completed, and participated in 27 gross, 6.6 net, horizontal non-operated drilling projects.

In our Eastern operating region, we spud five horizontal Utica exploratory wells during the nine months ended September 30, 2013, two of which were completed and connected to a gathering line. We also spud four horizontal Utica development wells, all of which were in various stages of completion as of September 30, 2013. In the Marcellus Shale, PDCM spud 11 horizontal wells during the nine months ended September 30, 2013, seven of which were completed and turned-in-line as of September 30, 2013.

Colorado Flooding. In September 2013, we experienced wide spread flooding in our Wattenberg Field operations in Weld County, Colorado, that resulted in a shut-in of approximately 200 vertical wells. As of September 30, 2013, approximately $0.9 million was recorded in accrued environmental liabilities representing the estimated costs, based on initial assessments, to perform remediation operations. Assessment of the full impact of the flooding is on-going and we expect to incur approximately $3 million to $5 million in additional costs during the fourth quarter of 2013 and the first quarter of 2014 to repair and replace damaged well equipment and bring the vertical wells back on-line.

Crude Oil and Natural Gas Properties Divestitures. In February 2013, we entered into a purchase and sale agreement with certain affiliates of Caerus Oil and Gas LLC (“Caerus”), pursuant to which we agreed to sell to Caerus our Piceance Basin, NECO and certain other non-core Colorado oil and gas properties, leasehold mineral interests and related assets. This divestiture was completed in June 2013 with total consideration of approximately $177.6 million, subject to customary post-closing adjustments, with an additional $17.0 million paid to our non-affiliated investor partners in our affiliated partnerships. The sale resulted in a pre-tax loss of $2.3 million. The proceeds from the asset disposal were used to pay down our revolving credit facility and to fund a portion of our 2013 capital budget. Following the sale to Caerus, 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 all periods presented.

On October 8, 2013, PDCM executed a purchase and sale agreement with an unrelated third-party pursuant to which PDCM agreed to sell its shallow upper Devonian (non-Marcellus Shale) Appalachian Basin crude oil and natural gas properties for aggregate consideration of approximately $18.8 million, of which our proportionate share is $6.2 million, after pre-closing adjustments. The properties consist of approximately 3,500 gross shallow producing wells, related facilities and associated shallow leasehold acreage, limited to the upper Devonian and shallower formations. The aggregate cash consideration is subject to customary terms and post-closing adjustments and by certain firm transportation obligations that will be assumed by the buyer. Concurrent with the closing of this transaction, our $6.7 million irrevocable standby letter of credit and related obligations will be novated to the buyer. We expect this sale to close in the fourth quarter of 2013. However, there can be no assurance we will be successful in closing this divestiture.

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 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 a liquidity measure or indicator 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 to 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.

Table of contents
PDC ENERGY, INC.

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,		
	2013	2012	Percentage Change	2013	2012	Percentage Change
	(dollars in millions, except per unit data)					
Production (1)						
Crude oil (MBbls)	601.5	430.0	39.9 %	1,887.5	1,416.7	33.2 %
Natural gas (MMcf)	5,188.0	4,086.3	27.0 %	14,249.3	11,549.8	23.4 %
NGLs (MBbls)	248.2	209.1	18.7 %	763.0	627.9	21.5 %
Crude oil equivalent (MBoe) (2)	1,714.3	1,320.2	29.9 %	5,025.4	3,969.6	26.6 %
Average MBoe per day	18.6	14.4	29.2 %	18.4	14.5	26.9 %
Crude Oil, Natural Gas and NGLs Sales						
Crude oil	$59.0	$36.7	60.6 %	$171.1	$126.2	35.5 %
Natural gas	16.2	10.4	56.7 %	47.4	27.7	70.9 %
NGLs	6.9	5.2	32.7 %	20.7	16.6	24.0 %
Total crude oil, natural gas and NGLs sales	$82.1	$52.3	57.1 %	$239.1	$170.6	40.2 %
Realized Gain (Loss) on Derivatives, net (3)						
Natural gas	$2.8	$12.8	(78.2)%	$13.9	$41.3	(66.3)%
Crude oil	(4.3)	0.3	*	(3.1)	(2.1)	(45.1)%
Total realized gain (loss) on derivatives, net	$(1.5)	$13.1	*	$10.8	$39.2	(72.3)%
Average Sales Price (excluding gain (loss) on derivatives)						
Crude oil (per Bbl)	$98.11	$85.45	14.8 %	$90.63	$89.08	1.7 %
Natural gas (per Mcf)	3.13	2.54	23.2 %	3.33	2.40	38.8 %
NGLs (per Bbl)	27.70	24.76	11.9 %	27.07	26.51	2.1 %
Crude oil equivalent (per Boe)	47.91	39.61	21.0 %	47.58	42.97	10.7 %
Average Lifting Cost (per Boe) (4)						
Western operating region	$5.49	$4.88	12.5 %	$4.67	$4.59	1.7 %
Eastern operating region	7.65	6.52	17.3 %	7.23	7.73	(6.5)%
Weighted-average	5.96	5.21	14.4 %	5.14	5.20	(1.2)%
Natural Gas Marketing Contribution Margin (5)	$(0.2)	$(0.1)	(100.0)%	$(0.2)	$0.4	*
Other Costs and Expenses						
Exploration expense	$2.0	$1.8	14.5 %	$5.2	$6.0	(14.3)%
Impairment of crude oil and natural gas properties	4.5	0.4	*	52.4	1.3	*
General and administrative expense	16.1	13.7	17.3 %	47.0	42.8	9.8 %
Depreciation, depletion and amortization	30.9	22.1	39.6 %	86.6	73.9	17.3 %

Interest Expense	$12.5	$11.4	10.1	%	$39.0	$31.9	22.3	%

*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 realized derivative gains and losses related to crude oil and natural gas sales, which do not include realized derivative gains and losses 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 realized and unrealized derivative gains and losses related to natural gas marketing activities.

Table of contents
PDC ENERGY, INC.

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, 2013	2012	Percentage Change		Nine Months Ended September 30, 2013	2012	Percentage Change	
Crude oil (MBbls)								
Western - Wattenberg Field	580.6	429.2	35.3	%	1,836.8	1,410.2	30.3	%
Eastern - Appalachian Basin	20.9	0.8	*		50.7	6.5	*	
Total	601.5	430.0	39.9	%	1,887.5	1,416.7	33.2	%
Natural gas (MMcf)								
Western - Wattenberg Field	3,091.2	2,503.9	23.5	%	8,982.9	7,018.6	28.0	%
Eastern - Appalachian Basin	2,096.8	1,582.4	32.5	%	5,266.4	4,531.2	16.2	%
Total	5,188.0	4,086.3	27.0	%	14,249.3	11,549.8	23.4	%
NGLs (MBbls)								
Western - Wattenberg Field	246.5	209.1	17.9	%	760.0	627.9	21.0	%
Eastern - Appalachian Basin	1.7	—	*		3.0	—	*	
Total	248.2	209.1	18.7	%	763.0	627.9	21.5	%
Crude oil equivalent (MBoe)								
Western - Wattenberg Field	1,342.3	1,055.7	27.1	%	4,094.0	3,207.9	27.6	%
Eastern - Appalachian Basin	372.0	264.5	40.6	%	931.4	761.7	22.3	%
Total	1,714.3	1,320.2	29.9	%	5,025.4	3,969.6	26.6	%

*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 gain (loss) on derivatives)	Three Months Ended September 30, 2013	2012	Percentage Change	Nine Months Ended September 30, 2013	2012	Percentage Change
Crude oil (per Bbl)						
Western - Wattenberg Field	$97.98	$85.44	14.7%	$90.53	$89.10	1.6%
Eastern - Appalachian Basin	101.52	87.64	15.8%	94.13	84.65	11.2%
Weighted-average price	98.11	85.45	14.8%	90.63	89.08	1.7%
Natural gas (per Mcf)						
Western - Wattenberg Field	$3.09	$2.43	27.2%	$3.27	$2.40	36.3%
Eastern - Appalachian Basin	3.20	2.70	18.5%	3.43	2.41	42.3%
Weighted-average price	3.13	2.54	23.2%	3.33	2.40	38.8%
NGLs (per Bbl)						
Western - Wattenberg Field	$27.65	$24.76	11.7%	$27.02	$26.51	1.9%
Eastern - Appalachian Basin	35.92	—	*	38.24	—	*
Weighted-average price	27.70	24.76	11.9%	27.07	26.51	2.1%
Crude oil equivalent (per Boe)						
Western - Wattenberg Field	$54.57	$45.41	20.2%	$52.80	$49.60	6.5%
Eastern - Appalachian Basin	23.87	16.45	45.1%	24.63	15.07	63.4%

Weighted-average price	47.91	39.61	21.0%	47.58	42.97	10.7%

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

For the three and nine months ended September 30, 2013, crude oil, natural gas and NGLs sales revenue increased compared to the three and nine months ended September 30, 2012 due to the following (in millions):

	September 30, 2013	
	Three Months Ended	Nine Months Ended
Increase in production	$18.4	$52.0
Increase in average crude oil price	7.6	2.9
Increase in average natural gas price	3.1	13.2
Increase in average NGLs price	0.7	0.4
Total increase in crude oil, natural gas and NGLs sales revenue	$29.8	$68.5

In recent periods, our Wattenberg Field production has been adversely impacted by high line pressures on the gathering system operated by our third-party service provider. Ongoing industry drilling activity in the area has resulted in an increase in volumes on the gathering system with an associated increase in system pressures. In addition, higher temperatures resulted in reduced system compressor efficiencies and further increased line pressures in the summer months. The curtailments that have occurred to date in 2013 are consistent with what we expected at the beginning of the year. We, and other operators in the field, are working closely with our primary midstream provider in the Wattenberg Field, who is implementing a multi-year facility expansion program. This expansion will significantly increase the long-term gathering and processing capacity of the system. Initial system improvements have already been implemented with the startup of new field compressor stations, as well as installation and commissioning of gas bypass facilities at two gas processing plants in May and June of 2013. These projects increased midstream system capacity and have helped to mitigate the impact of increased production volumes on system pressures. In addition, the new O'Connor (formerly known as LaSalle) gas plant commenced operations on October 8, 2013 and will be further expanded in early 2014 to accommodate additional system volumes. We have already experienced modest reductions in line pressure and an increase in the system capacity throughput since the startup of the O'Connor gas plant. 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.

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 our Western operating region is based on CIG prices, while natural gas produced in our Eastern operating region is based on NYMEX pricing. Our NGLs price is mainly based on prices from the Conway hub in Kansas where our Wattenberg production is marketed. Crude oil pricing is predominately driven by the physical market, supply and demand, the financial markets and national and international politics. The majority of our crude oil is sold on a calendar-year basis at a fixed differential to NYMEX pricing.

We currently use the "net-back" method of accounting for these arrangements related to our commodity sales. We sell our commodities at the wellhead and collect a price and recognize revenues based on the wellhead sales price as transportation 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.

Production Costs

Production costs include lease operating expenses, production taxes 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,	
	2013	2012	2013	2012
	(in millions)			
Lease operating expenses	$10.2	$6.8	$25.9	$20.6
Production taxes	6.1	3.8	16.8	12.0
Overhead and other production expenses	2.7	5.2	8.4	8.5
Total production costs	$19.0	$15.8	$51.1	$41.1
Total production costs per Boe	$11.12	$11.97	$10.17	$10.36

Lease operating expenses. The $3.4 million increase in lease operating expenses during the three months ended September 30, 2013 compared to the three months ended September 30, 2012 was primarily due to an increase of $1.3 million for workover, compliance and maintenance related projects, an increase of $0.7 million in additional wages and employee benefits, an increase of $0.5 million for the rental of additional compressors used to accommodate high line pressures in the Wattenberg Field, a $0.5 million charge for the estimated cost to bring wells impacted by the September 2013 Colorado flood into compliance with state regulations and an increase of $0.4 million for transportation expense related to Marcellus Shale production. The $5.3 million increase in lease operating expenses during the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2012 was primarily due to an increase of $1.8 million for workover, compliance and maintenance related projects, an increase of $1.1 million for the rental of additional compressors used to accommodate high line pressures in the Wattenberg Field, an increase of $1.0 million for transportation expense related to Marcellus Shale production, an increase of $0.9 million in additional wages and employee benefits and a $0.5 million charge for the estimated cost to bring wells impacted by the September 2013 Colorado flood into compliance with state regulations.

Production taxes. Production taxes are directly related to crude oil, natural gas and NGLs sales. The $2.3 million, or 60.5%, increase in production taxes for the three months ended September 30, 2013 compared to the three months ended September 30, 2012, was primarily related to the 57.1% increase in crude oil, natural gas and NGLs sales. Similarly, the $4.8 million, or 40.0%, increase in production taxes for the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012 was primarily related to the 40.2% increase in crude oil, natural gas and NGLs sales.

Overhead and other production expenses. Overhead and other production expenses decreased $2.5 million for the three months ended September 30, 2013 as compared to the three months ended September 30, 2012, primarily due to non-recurring items in 2012. We recognized $3.2 million of expense during the three months ended September 30, 2012 related to the sale of crude oil inventory that had been acquired at fair market value in the Merit Acquisition and $0.5 million in prepaid well costs charged to expense as a result of changes in our capital spending plan. These amounts were offset by $0.5 million for the unutilized portion of a transportation agreement in the Appalachian Basin and $0.4 million in labor and benefits increases. The $0.1 million decrease for the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2012 was the result of the aforementioned 2012 non-recurring items, offset in part by $1.7 million for the unutilized portion of a transportation agreement and a $0.9 million increase in labor and benefits.

Commodity Price Risk Management, Net

Commodity price risk management, net, includes realized gains and losses and unrealized changes in the fair value of derivative instruments 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 the realized and unrealized derivative gains and losses included in commodity price risk management, net:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in millions)			
Commodity price risk management gain (loss), net:				
Realized gains (losses):				

Natural gas	$2.8	$12.8	$13.9	$41.3
Crude oil	(4.3)	0.3	(3.1)	(2.1)
Total realized gains (losses), net	(1.5)	13.1	10.8	39.2
Unrealized gains (losses):				
Reclassification of realized gains included in prior periods unrealized	(2.9)	(15.0)	(25.3)	(22.8)
Unrealized gains (losses) for the period	(19.2)	(30.0)	(6.8)	1.9
Total unrealized losses, net	(22.1)	(45.0)	(32.1)	(20.9)
Total commodity price risk management gain (loss), net	$(23.6)	$(31.9)	$(21.3)	$18.3

During the three and nine months ended September 30, 2013, realized gains on natural gas, exclusive of basis swaps, were $3.8 million and $21.7 million, respectively. These gains were reflective of a weighted-average strike price of $4.46 and $4.98, respectively, compared to a weighted-average settlement price of $3.58 and $3.67, respectively. These gains were offset in part by realized losses of $1.0 million and $7.8 million, respectively, on our basis swap positions as the negative basis differential between NYMEX and CIG was a weighted-average of $0.23 and $0.22, respectively, compared to a weighted-average strike price of $0.62 and $0.81, respectively. Realized losses for the three and nine months ended September 30, 2013 on our crude oil positions are reflective of a weighted-average strike price of $96.58 for each period compared to weighted-average settlement prices of $105.91 and $99.21, respectively.

During the three and nine months ended September 30, 2013, unrealized losses on our crude oil and natural gas positions were $18.5 million and $4.5 million, respectively, due to the upward shift in the crude oil and natural gas forward curve. The narrowing of the CIG basis forward curve during the three and nine months ended September 30, 2013 resulted in unrealized losses of $0.7 million and $2.3 million, respectively.

During the three and nine months ended September 30, 2012, realized gains on natural gas derivatives, exclusive of basis swaps, were $16.8 million and $53.9 million, respectively. These gains were offset in part by realized losses of $4.0 million and $12.6 million, respectively, on our basis swap positions as the negative basis differential between NYMEX and CIG was narrower than the strike price of the basis positions. Realized gains on crude oil derivatives were $0.3 million for the three months ended September 30, 2012 compared to realized losses of $2.1 million for the nine months ended September 30, 2012.

Unrealized losses of $30 million during the three months ended September 30, 2012 were primarily related to the upward shift in the natural gas and crude oil forward curves during the period, resulting in unrealized losses on our natural gas and crude oil derivative positions of $15.7 million and $14.3 million, respectively. During the nine months ended September 30, 2012, unrealized gains on our crude oil positions were $11.2 million due to the downward shift in the crude oil forward curve. These gains were offset in part by unrealized losses on our natural gas positions of $8.6 million, resulting from the upward shift in the natural gas forward curve and unrealized losses on our CIG basis swaps of $0.7 million due to the narrowing of the CIG basis forward curve.

We use various derivative instruments to manage fluctuations in crude oil and natural gas prices. We have in place a variety of floors, 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.

Natural Gas Marketing

Fluctuations in our Gas Marketing segment's income contribution are primarily due to fluctuations in commodity prices and realized and unrealized mark-to-market adjustments, gains and losses on open derivative positions, 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,	
	2013	2012	2013	2012
	(in millions)			
Natural gas sales revenue	$17.0	$11.5	$48.1	$31.1
Realized derivative gains, net	0.2	0.4	0.3	1.9
Unrealized derivative gains (losses), net	(0.3)	(0.7)	0.3	(1.8)
Total sales from natural gas marketing	16.9	11.2	48.7	31.2
Costs of natural gas purchases	16.5	11.4	46.5	29.7
Realized derivative losses, net	0.2	0.4	0.1	1.9
Unrealized derivative (gains) losses, net	(0.3)	(0.8)	0.3	(1.8)
Other	0.7	0.3	2.0	1.0
Total costs of natural gas marketing	17.1	11.3	48.9	30.8

Natural gas marketing contribution margin	$(0.2)	$(0.1)	$(0.2)	$0.4

Natural gas sales revenue and cost of natural gas purchases increased in the three and nine months ended September 30, 2013 compared to the three and nine months ended September 30, 2012, primarily due 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,	
	2013	2012	2013	2012
	(in millions)			
Exploratory dry hole costs	$—	$0.6	$—	$1.0
Geological and geophysical costs	0.2	0.1	0.7	1.7
Operating, personnel and other	1.8	1.1	4.5	3.3
Total exploration expense	$2.0	$1.8	$5.2	$6.0

Exploratory dry hole costs. Exploratory dry hole costs during the three months ended September 30, 2012 were related to two Rose Run test wells that were determined not to have found commercial quantities of hydrocarbons. The additional exploratory dry hole costs during the nine months ended September 30, 2012 related to the unsuccessful testing of an exploratory zone in two existing Wattenberg Field wells. There were no exploratory dry holes identified in 2013.

Geological and geophysical costs. The decrease during the nine months ended September 30, 2013 of $1.0 million compared to the nine months ended September 30, 2012 is primarily related to costs associated with a decrease in PDCM's geological and seismic testing of the Marcellus Shale in the Appalachian Basin and PDC's reservoir studies in the Utica Shale.

Operating, personnel and other. The $0.7 million and $1.2 million increase during the three and nine months ended September 30, 2013 compared to the three and nine months ended September 30, 2012 is mainly attributable to payroll and employee benefits in the exploration division as a result of increased employee headcount for the Utica Shale operations.

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,	
	2013	2012	2013	2012
	(in millions)			
Impairment of proved properties	$3.8	$—	$48.8	$—
Impairment of individually significant unproved properties	0.2	0.2	1.0	0.5
Amortization of individually insignificant unproved properties	0.6	0.2	2.7	0.9
Total impairment of crude oil and natural gas properties	$4.5	$0.4	$52.4	$1.3

Impairment of proved properties. In 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 owned directly by us, as well as through our proportionate share of PDCM and our affiliated partnerships. The impairment charge represented the excess of the carrying value of the assets over the estimated fair value, less 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 dated October 8, 2013 with an unrelated third-party, 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. See Note 12, Assets Held for Sale, Divestitures and Discontinued Operations, and Note 15, Subsequent Events, included elsewhere in this report for additional information regarding the potential sale of these properties. There can be no assurance we will be successful in closing this divestiture.

Impairment of individually significant unproved properties: The $0.5 million increase during the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012 is primarily related to non-Utica leases in Ohio that were determined to be impaired in June 2013.

Amortization of individually insignificant unproved properties. The $0.4 million and $1.8 million increase during the three and nine months ended September 30, 2013, respectively, compared to the three and nine months ended September 30, 2012, is primarily related to an increase in leases not held by production, primarily in the Utica Shale.

Table of contents
PDC ENERGY, INC.

General and Administrative Expense

General and administrative expense increased $2.4 million to $16.1 million for the three months ended September 30, 2013 compared to $13.7 million for the three months ended September 30, 2012. The increase was primarily due to a $0.9 million increase in payroll and employee benefits, increased stock-based compensation of $0.8 million due to expanding employee participation in our equity incentive program and a $0.7 million increase in other general and administrative expenses.

General and administrative expense increased $4.2 million to $47.0 million for the nine months ended September 30, 2013 compared to $42.8 million for the nine months ended September 30, 2012. The increase was primarily due to increased stock-based compensation of $3.9 million due to expanding employee participation in our equity incentive program and certain award modifications and a $1.4 million increase in payroll and employee benefits, partially offset by a decrease in professional, consulting and legal costs of $1.4 million.

Depreciation, Depletion and Amortization Expense

Crude oil and natural gas properties. Depreciation, depletion and amortization ("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 $29.6 million and $82.9 million for the three and nine months ended September 30, 2013, respectively, compared to $21.0 million and $70.5 million for the three and nine months ended September 30, 2012, respectively. The increase in our production for the three and nine months ended September 30, 2013 contributed $6.3 million and $18.7 million to these increases. Higher weighted-average depreciation, depletion and amortization rates during the three months ended September 30, 2013 resulted in an increase in DD&A expense of $2.3 million, while lower weighted-average depreciation, depletion and amortization rates during the nine months ended September 30, 2013 resulted in a decrease in DD&A expense of $6.3 million.

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	2013	2012	2013	2012
	(per Boe)			
Western				
Wattenberg Field	$18.18	$16.94	$17.69	$19.23
Eastern				
Appalachian Basin	13.88	11.63	11.23	11.51
Total weighted-average	17.25	15.87	16.49	17.75

Non-crude oil and natural gas properties. Depreciation expense for non-crude oil and natural gas properties was $1.3 million and $3.7 million for the three and nine months ended September 30, 2013 compared to $1.2 million and $3.4 million for the three and nine months ended September 30, 2012, respectively.

Interest Expense

Interest expense increased $1.1 million to $12.5 million for the three months ended September 30, 2013 compared to $11.4 million for the three months ended September 30, 2012. The increase is primarily related to $10.0 million of interest expense resulting from the issuance of $500 million 7.75% senior notes due 2022 in October 2012. Partially offsetting this increase were decreases of $6.3 million related to the November 2012 redemption of previously-outstanding 12% senior notes due 2018 and $2.2 million as a result of lower average borrowings on our revolving credit facility during the three months ended September 30, 2013 as compared to the three months ended September 30, 2012.

Interest expense increased $7.1 million to $39.0 million for the nine months ended September 30, 2013 compared to $31.9 million for the nine months ended September 30, 2012. The increase is primarily related to $29.6 million of interest expense resulting from the issuance of $500 million 7.75% senior notes due 2022 in October 2012. Partially offsetting this increase were decreases of $18.9 million related to the November 2012 redemption of previously-outstanding 12% senior notes due 2018 and $3.4 million as a result of lower average borrowings on our revolving credit facility during the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2012.

Provision for Income Taxes

See Note 6, Income Taxes, to the accompanying condensed consolidated financial statements for a discussion of the changes in our effective tax rate for the three and nine months ended September 30, 2013 compared to the three and nine months ended September 30, 2012. 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 current estimated annual effective tax rate.

Discontinued Operations

In February 2013, we entered into a purchase and sale agreement with certain affiliates of Caerus, pursuant to which we agreed to sell to Caerus our Piceance Basin, NECO and certain other non-core Colorado oil and gas properties, leasehold mineral interests and related assets.

On June 18, 2013, this divestiture was completed with total consideration of approximately $177.6 million, subject to customary post-closing adjustments, with an additional $17.0 million paid to our non-affiliated investor partners in our affiliated partnerships. The sale resulted in a pre-tax loss of $2.3 million. The effective date of the transaction was January 1, 2013. Following the sale to Caerus, 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 all periods presented. The sale of our other non-core Colorado oil and gas properties did not meet the requirements to be accounted for as discontinued operations.

In December 2011, we executed a purchase and sale agreement with COG, a wholly owned subsidiary of Concho Resources Inc., an unrelated third-party, for the sale of our then remaining Permian Basin assets and closed the transaction in February 2012. Upon final settlement on June 29, 2012, total proceeds received were $189.2 million. The effective date of the transaction was November 1, 2011. Following the sale to COG, we do not have significant continuing involvement in the operations of, or cash flows from, the Permian Basin assets. 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, 2012.

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
Discontinued Operations	2013	2012	2013	2012
Production				
Crude oil (MBbls)	0.5	9.7	14.6	68.7
Natural gas (MMcf)	35.9	3,993.2	6,679.3	12,618.2
NGLs (MBbl)	—	1.5	—	16.4
Crude oil equivalent (MBoe)	6.5	676.7	1,127.8	2,188.1

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

Net loss for the three and nine months ended September 30, 2013 was $16.0 million and $35.5 million, respectively, compared to a net loss of $32.6 million and $4.5 million for the three and nine months ended September 30, 2012, respectively. Adjusted net loss, a non-U.S. GAAP financial measure, for the three and nine months ended September 30, 2013 was $2.3 million and $15.7 million, respectively, compared to an adjusted net loss of $4.8 million for the three months ended September 30, 2012 and adjusted net income of $8.4 million for the nine months ended September 30, 2012. The quarter-over-quarter changes in net loss are discussed above, with the most significant changes related to the increase in crude oil, natural gas and NGLs sales, impairment of crude oil and natural gas properties and DD&A expense, and the decrease in the loss from commodity price risk management activities. The year-over-year change in net loss are discussed above, with the most significant changes related to the increase in crude oil, natural gas and NGLs sales and impairment of crude oil and natural gas properties, and the decrease in income from commodity price risk management activities. These same reasons for change similarly impacted adjusted net income (loss), with the exception of the unrealized derivative gains and losses on derivatives, adjusted for taxes, as these amounts are 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 monetization transactions. For the nine months ended September 30, 2013, our primary sources of liquidity were the proceeds received from the public offering of our common stock of $275.8 million, proceeds received from the sale of properties and equipment, including acquisition adjustments, of approximately $186.6 million and net cash flows from operating activities of $119.5 million.

Our primary source of cash flows from operating activities is the sale of crude oil, natural gas and NGLs. Fluctuations in our operating cash flows are 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, which has also historically been a source of cash. 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 limit us from entering into hedges that would exceed 85% of our expected future production on total proved reserves (proved developed producing, proved developed not 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, 2013, we had a working capital surplus of $92.9 million compared to a deficit of $31.4 million at December 31, 2012. The working capital surplus as of September 30, 2013 is a direct result of our aforementioned common stock issuance, partially offset by the reclassification of our Convertible Notes to current liabilities.

We ended September 2013 with cash and cash equivalents of $298.5 million and availability under our revolving credit facility and our proportionate share of PDCM's credit facility of $436.8 million, for a total liquidity position of $735.3 million, compared to $398.6 million at December 31, 2012. The increase in liquidity of $336.7 million, or 84.5%, was primarily attributable to $275.8 million received from the public offering of our common stock, $186.6 million received from the sale of properties and equipment, including acquisition adjustments, and cash flows provided by operating activities of $119.5 million, offset in part by capital expenditures of $256.1 million during the nine months ended September 30, 2013. With our current liquidity position and expected cash flows from operations, we believe that we have sufficient capital to fund our drilling operations.

Capital Expenditures

We establish a capital budget annually based upon our development and exploration opportunities, liquidity position and expected cash flows from operating activities. We may revise our capital budget during the year as a result of, among other things, acquisitions or dispositions of assets, drilling results, commodity prices, changes in our borrowing capacity and/or significant changes in cash flows. In March 2013, our Board of Directors approved our current 2013 capital budget of $387 million, excluding our share of PDCM's capital budget. Based on our budget, we expect to allocate $280 million to the Wattenberg Field, where we expect to drill a total of 69 horizontal wells in the liquid-rich Niobrara and Codell formations during 2013. We expect to allocate approximately $96 million to drilling, leasing and completion activity in the Utica Shale, where we expect to maintain a one-rig drilling program throughout 2013 and expect to drill a total of 11 horizontal wells. PDCM's 2013 capital budget is $114 million, of which $57 million represents our share, and is expected to be funded by PDCM's operating activities, proceeds from divestitures and additional borrowings. PDCM's capital budget for 2013 includes funding for the drilling of 15 gross horizontal wells. Based on our drilling operations through September 30, 2013, we expect our 2013 full year capital expenditures to be in line with the established capital budget.

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.

Financing Activities

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 $450 million 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. Our next scheduled redetermination is in November 2013. 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. 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 5,175,000 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, unrealized derivative gains (losses), 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, 2013, we were in compliance with all debt covenants with a 2.6 times debt to EBITDAX ratio and a 2.9 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, 2013, we were in compliance with all covenants and expect to remain in compliance throughout the next year.

The conversion right on our Convertible Notes was triggered on September 30, 2013, when the closing sale price of our common stock exceeded $55.12 (130% of the applicable conversion price) for the 20th trading day in the 30 consecutive trading days ending on September 30, 2013. As a result, the carrying value of the Convertible Notes, net of discount, was classified as a current liability as of September 30, 2013 in our condensed consolidated balance sheet. 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.

As of September 30, 2013, PDCM was not in compliance with the minimum current ratio and debt to EBITDAX ratio covenants under the PDCM credit facility and the Term Loan Agreement. In October 2013, PDCM received a waiver from Wells Fargo regarding both covenant violations. We believe that PDCM will maintain compliance under the PDCM credit facility and the Term Loan Agreement throughout the next twelve-month period by reducing its indebtedness through capital contributions by investor partners, from proceeds from asset sales or other financing transactions. See Note 12, Assets Held for Sale, Divestitures and Discontinued Operations, and Note 15, Subsequent Events, included elsewhere in this report for additional information regarding the potential sale of PDCM's shallow upper Devonian Appalachian Basin producing properties. There can be no assurance we will be successful in closing this divestiture.

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, realized gains and losses from our derivative positions, operating costs and general and administrative expenses. Cash flows from operating activities decreased by $7.6 million for the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012. The decrease in cash provided by operating activities was primarily due to changes in assets and liabilities of $29.7 million related to the timing of cash payments and receipts, the decrease in realized derivative gains of $28.3 million and increases in production costs of $10.0 million and interest expense of $7.1 million. The decrease was offset in part by the increase in crude oil, natural gas and NGLs sales of $68.5 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 $22.0 million during the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012. 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 slightly by $3.0 million during the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012. The increase was primarily the result of the increase in crude oil, natural gas and NGLs sales of $68.5 million, offset in part by the decrease in realized derivative gains of $28.3 million, $19.9 million pre-tax gain on sale of properties and equipment recognized in 2012 related to the sale of our Permian Basin assets and the increase in production costs of $10.0 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. Cash flows from investing activities primarily consist of the acquisition, exploration and development of crude oil and natural gas properties, net of dispositions of crude oil and natural gas properties. During the nine months ended September 30, 2013, our drilling program consisted of three drilling rigs operating in the liquid-rich horizontal Niobrara and Codell plays in our Wattenberg Field, one rig in the Utica shale play and one rig in the Marcellus Shale. Net cash from investing activities of $69.5 million during the nine months ended September 30, 2013 was primarily related to cash utilized for our drilling operations of $256.1 million, offset in part by the $186.6 million received from the sale of properties and equipment, including acquisition adjustments.

Financing Activities. Net cash from financing activities for the nine months ended September 30, 2013 decreased by approximately $16.0 million compared to the nine months ended September 30, 2012. Net cash from financing activities of $246.0 million for the nine months ended September 30, 2013 was primarily related to the $275.8 million received from the issuance of our common stock in August 2013, partially offset by net payments of approximately $25.5 million to pay down amounts borrowed under our revolving credit facility.

Drilling Activity

The following table presents our net developmental and exploratory drilling activity. There is no 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 and are waiting to be completed and/or for gas pipeline connection during the period.

Table of contents
PDC ENERGY, INC.

	Net Drilling Activity									
	Three Months Ended September 30,					Nine Months Ended September 30,				
	2013			2012		2013			2012	
Operating Region/Area	Productive	In-Process	Dry	Productive	In-Process	Productive	In-Process	Dry	Productive	In-Process
Development Wells										
Western	8.6	1.5	0.1	5.2	7.9	21.7	25.3	0.1	15.4	9.4
Eastern	2.0	—	—	—	—	3.5	5.0	—	1.5	—
Total development wells	10.6	1.5	0.1	5.2	7.9	25.2	30.3	0.1	16.9	9.4
Exploratory Wells										
Eastern	0.7	0.7	—	—	1.0	1.5	2.8	—	—	3.0
Total exploratory wells	0.7	0.7	—	—	1.0	1.5	2.8	—	—	3.0
Total drilling activity	11.3	2.2	0.1	5.2	8.9	26.7	33.1	0.1	16.9	12.4

Off-Balance Sheet Arrangements

From time to time, we enter into arrangements and transactions that can give rise to off-balance sheet obligations. These arrangements are identified under the caption Contractual Obligations and Contingent Commitments in our 2012 Form 10-K filed with the SEC on February 27, 2013 and in our Current Report on Form 8-K filed with the SEC on June 28, 2013.

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 requires 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 2012 Form 10-K filed with the SEC on February 27, 2013 and in our Current Report on Form 8-K filed with the SEC on June 28, 2013.

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 historically 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 unrealized derivative losses, less unrealized derivative gains, each adjusted for tax effect. We believe it is important to consider adjusted net income (loss), as well as net income (loss). We believe it often provides more transparency into our operating trends, such as production, prices, operating costs, realized gains and losses from derivatives and related factors, without regard to changes in our net income (loss) from our mark-to-market adjustments resulting from unrealized gains and losses from 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 unrealized derivative loss, 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 unrealized derivative gain. 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), nor as 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:

- our operating performance and return on capital as compared to our peers;
- the 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 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,	
	2013	2012	2013	2012
	(in millions)			
Adjusted cash flows from operations:				
Adjusted cash flows from operations	$36.7	$34.2	$135.4	$113.4
Changes in assets and liabilities	40.8	23.3	(15.9)	13.8
Net cash from operating activities	$77.5	$57.5	119.5	$127.2
Adjusted net income (loss):				
Adjusted net income (loss)	$(2.3)	$(4.8)	$(15.7)	$8.4
Unrealized loss on derivatives, net	(22.2)	(45.0)	(32.1)	(20.9)
Tax effect of above adjustments	8.5	17.2	12.3	8.0
Net loss	$(16.0)	$(32.6)	$(35.5)	$(4.5)
Adjusted EBITDA to net income (loss):				
Adjusted EBITDA	$44.4	$39.7	$159.7	$156.7
Unrealized loss on derivatives, net	(22.2)	(45.0)	(32.1)	(20.9)
Interest expense, net	(12.4)	(11.4)	(38.8)	(31.9)
Income tax provision	10.7	18.1	20.7	2.5
Impairment of crude oil and natural gas properties	(4.4)	(0.4)	(52.4)	(1.4)
Depreciation, depletion and amortization	(30.9)	(32.4)	(88.9)	(106.7)
Accretion of asset retirement obligations	(1.2)	(1.2)	(3.7)	(2.8)
Net loss	$(16.0)	$(32.6)	$(35.5)	$(4.5)
Adjusted EBITDA to net cash from operating activities:				
Adjusted EBITDA	$44.4	$39.7	$159.7	$156.7
Interest expense, net	(12.4)	(11.4)	(38.8)	(31.9)
Exploratory dry hole costs	—	0.6	—	1.0

Stock-based compensation	3.0	2.2	10.0	6.1
Amortization of debt discount and issuance costs	1.7	1.5	5.1	5.1
(Gain) loss on sale of properties and equipment	0.6	(1.5)	1.6	(23.8)
Other	(0.6)	3.1	(2.2)	0.2
Changes in assets and liabilities	40.8	23.3	(15.9)	13.8
Net cash from operating activities	$77.5	$57.5	119.5	$127.2

Table of contents
PDC ENERGY, INC.

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 2022 Senior Notes and 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, 2013, 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, 2013 was $292.8 million with an average interest rate of 0.1%. The $292.8 million represents our aggregate bank balances, which includes checks issued and outstanding. Based on a sensitivity analysis of our interest bearing deposits as of September 30, 2013, it was estimated that if market interest rates would have increased or decreased by 1%, the impact on interest income for the nine months ended September 30, 2013 would result in a change of $2.2 million.

As of September 30, 2013, excluding the $18.5 million irrevocable standby letters of credit, we had no outstanding borrowings on our revolving credit facility and, representing our proportionate share, $34.8 million on PDCM's bank 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, 2013 would have been immaterial.

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. We employ established policies and procedures to manage a portion of the risks associated with these market fluctuations using derivative instruments. These instruments allow us to predict with greater certainty the effective crude oil and natural gas prices to be received for our hedged production as it is produced. We believe that our established derivative policies and procedures are effective in achieving our risk management objectives.

Table of contents
PDC ENERGY, INC.

The following table presents our derivative positions related to crude oil and natural gas sales in effect as of September 30, 2013:

	Floors		Collars			Fixed-Price Swaps		Basis Protection Swaps		
Commodity/ Index/ Maturity Period	Quantity (BBtu) (1)	Weighted-Average Contract Price	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted-Average Contract Price Floors	Weighted-Average Contract Price Ceilings	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted-Average Contract Price	Quantity (BBtu) (1)	Weighted-Average Contract Price	Fair Value September 30, 2013 (2) (in thousands)
Natural Gas										
NYMEX										
2013	341.1	$ 6.10	—	$ —	$ —	3,843.3	$ 4.29	4,200.7	$ (0.46)	$ 2,264.2
2014	—	—	—	—	—	13,447.5	4.11	6,004.0	(0.21)	3,202.7
2015	4,960.0	4.00	—	—	—	7,635.0	4.07	1,620.0	(0.27)	529.7
2016	3,920.0	4.04	—	—	—	7,920.0	3.89	—	—	(1,765.9)
2017	1,630.0	4.25	—	—	—	—	—	—	—	322.2
CIG										
2013	—	—	50.0	4.00	5.45	—	—	—	—	29.7
2014	—	—	—	—	—	4,828.0	4.00	—	—	2,076.3
2015	—	—	—	—	—	2,730.0	4.01	—	—	820.9
Total Natural Gas	10,851.1		50.0			40,403.8		11,824.7		7,479.8
Crude Oil										
NYMEX										
2013	—	—	213.5	79.64	102.99	468.7	97.49	—	—	(2,464.3)
2014	—	—	1,032.0	82.83	102.55	2,672.0	91.13	—	—	(10,756.8)
2015	—	—	36.0	90.00	106.15	3,313.0	88.45	—	—	(68.8)
Total Crude Oil	—		1,281.5			6,453.7		—		(13,289.9)
Total Natural Gas and Crude Oil										$ (5,810.1)

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

(2) Approximately 20.2% of the fair value of our derivative assets and 11.2% 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 monthly average NYMEX and CIG closing prices for natural gas and crude oil for the periods identified, as well as average sales prices we realized for the respective commodities:

	Nine Months Ended September 30, 2013	Year Ended December 31, 2012
Average Index Closing Price:		
Natural gas (per MMBtu)		
CIG	$3.45	$2.58
NYMEX	3.67	2.79
Crude oil (per Bbl)		
NYMEX	$96.15	$94.92
Average Sales Price Realized:		
Excluding realized derivative gains (losses)		
Natural gas (per Mcf)	$3.33	$2.63
Crude oil (per Bbl)	90.63	87.27

Based on a sensitivity analysis as of September 30, 2013, 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 fair value of $85.0 million; whereas a 10% decrease in prices would have resulted in an increase in fair value of $83.4 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 the significance of our credit risk exposure to 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 of our Oil and Gas Exploration and Production or Gas Marketing segments.

Our derivative financial instruments may expose us to the credit 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. Disruption in the credit markets may have a significant adverse impact on a number of financial institutions. 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 sufficient and customary, no amount of analysis can assure performance by a financial institution. To date, we have had no material counterparty default losses from our derivative financial instruments. See Note 4, Derivative Financial Instruments, to our condensed consolidated financial statements included 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, 2013, it does not consider those exposures or positions which may arise after that date. Our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise at the relevant time and our commodity price risk management strategies and interest rates and commodity prices at that time.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of September 30, 2013, 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, 2013.

Changes in Internal Control over Financial Reporting

During the three months ended September 30, 2013, 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 2012 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.

Table of contents

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, 2013	20,636	$53.08
August 1 - 31, 2013	1,946	57.38
September 1 - 30, 2013	—	—
Total second quarter purchases	22,582	53.45

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

ITEM 3. DEFAULTS UPON SENIOR SECURITIES - None.

ITEM 4. MINE SAFETY DISCLOSURES - Not applicable.

ITEM 5. OTHER INFORMATION - None.

Table of contents
PDC ENERGY, INC.

ITEM 6. EXHIBITS

		Incorporated by Reference				
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
10.1	Underwriting Agreement, by and between Merrill Lynch, Pierce, Fenner & Smith Incorporated and PDC Energy, Inc., dated as of August 5, 2013.	8-K	000-07246	1.1	8/8/2013	
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.

Table of contents
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: October 31, 2013

/s/ James M. Trimble
James M. Trimble
Chief Executive Officer and President
(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)