PETROLEUM DEVELOPMENT CORP
Form 10-Q
November 03, 2011
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2011

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
PETROLEUM DEVELOPMENT CORPORATION
(Exact name of registrant as specified in its charter)
(Doing Business as PDC Energy)

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 Web site, 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 £	Accelerated filer x
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: 23,611,160 shares of the Company's Common Stock ($0.01 par value) were outstanding as of October 21, 2011.

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PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This periodic report 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 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 include: estimated natural gas, natural gas liquids ("NGLs") and crude oil production and reserves; expected operational, midstream and marketing synergies from PDCM's Seneca-Upshur acquisition; anticipated capital expenditures, including our ability to fund our 2011 capital plan; our expected production growth from continuing operations in 2011 and our increased 2011 capital expenditure budget; increased focus on the Wattenberg Field and liquid-rich areas; our divestiture plans of our properties in the Permian Basin, northeast Colorado and other miscellaneous properties in the next six months; the divestiture by PDCM of its Pennsylvania Marcellus acreage; our plans to focus on primarily two regions, the Rocky Mountain and Appalachia; our compliance with our debt covenants and the indenture restrictions governing our senior notes; sufficient liquidity to meet our partnership repurchase obligations; our belief that the acquisition of partnerships will provide us with growth in production and proved reserves; the adequacy of our casualty insurance coverage as managing general partner of numerous partnerships and as operator of our own wells; the impact of decreased commodity prices on future borrowing base redeterminations; the effectiveness of our derivative policies in achieving our risk management objectives; our expected remaining liability for uncertain tax positions; our acquisition of certain Utica Shale acreage and our ability to secure a joint venture partner; the impact of outstanding legal issues; our ability to benefit from crude oil and natural gas price differential; and our 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 natural gas, NGLs and crude oil, 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 natural gas, NGLs and crude oil;
- changes in estimates of proved reserves;
- inaccuracy of reserve estimates and expected production rates;
- declines in the values of our natural gas and crude oil properties resulting in impairments;
- the future cash flow, liquidity and financial position of the Company;
- the timing and extent of our success in discovering, acquiring, developing and producing reserves;
- our ability to acquire leases, drilling rigs, supplies and services at reasonable prices;
- reductions in the borrowing base under our credit facility;
- risks incidental to the drilling and operation of natural gas and crude oil wells;
- the potential for production decline rates from our wells to be greater than expected;
- the availability of sufficient pipeline and other transportation facilities to carry our production and the impact of these facilities on price;
- changes in environmental laws, the regulation and enforcement of those laws and the costs to comply with those laws;
- the impact of environmental events, governmental responses to the events and our ability to insure adequately against such events;

- the timing and receipt of necessary regulatory permits;
- competition in the oil and gas industry;
- the success of the Company in marketing oil and gas;
- the effect of natural gas and crude oil derivatives activities;
- the availability and cost of capital to us;
- the cost of pending or future litigation;
- our ability to retain or attract senior management and key technical employees; and
- the success of strategic plans, expectations and objectives for future operations of the Company.

Further, we urge you to carefully review and consider the cautionary statements and disclosures, specifically those under the heading "Risk Factors," made in this report, our annual report on Form 10-K for the year ended December 31, 2010, filed with the United States Securities and Exchange Commission ("SEC") on February 24, 2011, as amended April 21, 2011, and May 18, 2011 ("2010 Form 10-K"), and our other filings with the SEC for further information on risks and uncertainties that could affect the Company's business, financial condition and results of operations, 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.

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REFERENCES

Unless the context otherwise requires, references to "PDC," "PDC Energy," "the Company," "we," "us," "our," "ours" or "ourselves" in this report refer to the registrant, Petroleum Development Corporation, and its consolidated entities. See Note 1, Nature of Operations and Basis of Presentation, to our condensed consolidated financial statements included in this report for a description of our consolidated entities.

References to "the three months ended 2011" and "the nine months ended 2011" refer to the three and nine months ended September 30, 2011, respectively. References to "the three months ended 2010" and "the nine months ended 2010" refer to the three and nine months ended September 30, 2010, respectively.

References to "quarter-over-quarter" refer to the three months ended 2011 compared to the three months ended 2010. References to "year-over-year" refer to the nine months ended 2011 compared to the nine months ended 2010.

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PART I - FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
Condensed Consolidated Balance Sheets
(unaudited; in thousands, except share and per share data)

	September 30, 2011	December 31, 2010 (1)
Assets		
Current assets:		
Cash and cash equivalents	$32,310	$54,372
Restricted cash	11,065	2,474
Accounts receivable, net	46,723	53,978
Accounts receivable affiliates	37,158	11,448
Fair value of derivatives	56,793	42,953
Prepaid expenses and other current assets	11,483	11,598
Total current assets	195,532	176,823
Properties and equipment, net	1,303,775	1,120,038
Assets held for sale	—	5,191
Restricted cash	21,619	2,601
Fair value of derivatives	39,220	44,464
Accounts receivable affiliates	4,284	8,478
Other assets	26,925	31,440
Total Assets	$1,591,355	$1,389,035
Liabilities and Equity		
Liabilities		
Current liabilities:		
Accounts payable	$63,711	$47,271
Accounts payable affiliates	9,735	9,605
Production tax liability	18,685	16,226
Fair value of derivatives	21,154	29,998
Funds held for distribution	29,405	29,755
Accrued interest payable	5,798	10,051
Other accrued expenses	21,801	17,723
Total current liabilities	170,289	160,629
Long-term debt	480,238	295,695
Deferred income taxes	191,820	187,999
Asset retirement obligations	28,472	27,797
Fair value of derivatives	20,500	36,644
Accounts payable affiliates	7,093	12,111
Other liabilities	21,738	25,919
Total liabilities	920,150	746,794
Commitments and contingent liabilities		
Equity		
Shareholders' equity:		
Preferred shares, par value $0.01 per share; authorized 50,000,000	—	—

shares; issued: none		
Common shares, par value $0.01 per share; authorized 100,000,000	236	235
shares; issued: 23,618,831 in 2011 and 23,462,326 in 2010		
Additional paid-in capital	216,562	209,198
Retained earnings	454,644	432,843
Treasury shares, at cost: 7,671 in 2011 and 2,938 in 2010	(237)	(111)
Total shareholders' equity	671,205	642,165
Noncontrolling interest in subsidiary	—	76
Total equity	671,205	642,241
Total Liabilities and Equity	$1,591,355	$1,389,035

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(1) Derived from audited 2010 balance sheet.

See accompanying Notes to Condensed Consolidated Financial Statements

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PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
Condensed Consolidated Statements of Operations
(unaudited; in thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Revenues:				
Natural gas, NGL and crude oil sales	$79,374	$47,295	$215,468	$153,851
Sales from natural gas marketing	17,209	18,337	51,308	53,613
Commodity price risk management gain, net	46,706	19,029	43,361	74,508
Well operations, pipeline income and other	1,693	2,159	5,350	6,896
Total revenues	144,982	86,820	315,487	288,868
Costs, expenses and other:				
Production costs	15,846	16,524	56,559	47,489
Cost of natural gas marketing	17,227	18,300	50,427	52,830
Exploration expense	1,666	3,712	5,537	13,960
General and administrative expense	13,683	10,426	47,065	30,975
Depreciation, depletion and amortization	34,316	28,024	99,347	82,427
Gain on sale of properties and equipment	(32)	(57)	(32)	(153)
Total costs, expenses and other	82,706	76,929	258,903	227,528
Income from operations	62,276	9,891	56,584	61,340
Interest income	36	21	47	60
Interest expense	(9,496)	(8,174)	(27,625)	(23,646)
Income from continuing operations before income taxes	52,816	1,738	29,006	37,754
Provision (benefit) for income taxes	20,256	(1,156)	9,825	12,410
Income from continuing operations	32,560	2,894	19,181	25,344
Income (loss) from discontinued operations, net of tax	—	460	2,620	(1,056)
Net income	32,560	3,354	21,801	24,288
Less: net loss attributable to noncontrolling interests	—	(5)	—	(66)
Net income attributable to shareholders	$32,560	$3,359	$21,801	$24,354
Amounts attributable to Petroleum Development Corporation shareholders:				
Income from continuing operations	$32,560	$2,899	$19,181	$25,410
Income (loss) from discontinued operations, net of tax	—	460	2,620	(1,056)
Net income attributable to shareholders	$32,560	$3,359	$21,801	$24,354
Earnings per share attributable to shareholders:				
Basic				
Income from continuing operations	$1.38	$0.15	$0.82	$1.32
Income (loss) from discontinued operations	—	0.02	0.11	(0.05)
Net income attributable to shareholders	$1.38	$0.17	$0.93	$1.27
Diluted				
Income from continuing operations	$1.37	$0.15	$0.81	$1.31
Income (loss) from discontinued operations	—	0.02	0.11	(0.05)

Net income attributable to shareholders	$1.37	$0.17	$0.92	$1.26
Weighted average common shares outstanding:				
Basic	23,569	19,250	23,497	19,218
Diluted	23,783	19,406	23,712	19,319

See accompanying Notes to Condensed Consolidated Financial Statements

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PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
Condensed Consolidated Statements of Cash Flows
(unaudited, in thousands)

	Nine Months Ended September 30, 2011	2010
Cash flows from operating activities:		
Net income	$21,801	$24,288
Adjustments to net income to reconcile to net cash provided by operating activities:		
Unrealized gain on derivatives, net	(32,608)	(36,056)
Depreciation, depletion and amortization	99,347	84,086
Amortization and impairment of natural gas and crude oil properties	1,718	6,877
Exploratory dry hole costs	171	4,057
Loss (gain) from sale of properties and equipment	(3,886)	134
Deferred income taxes	12,387	10,835
Stock-based compensation	7,242	3,845
Amortization of debt issuance costs	5,104	2,671
Other	(168)	1,078
Changes in assets and liabilities	(5,641)	14,977
Net cash provided by operating activities	105,467	116,792
Cash flows from investing activities:		
Capital expenditures	(241,150)	(106,795)
Acquisition of natural gas and crude oil properties, net of cash acquired	(41,372)	(85,511)
Advance to PDCM for the acquisition of properties	(28,594)	—
Deconsolidation/change in ownership effect on cash and cash equivalents	(133)	(3,472)
Proceeds from sale of properties and equipment	10,140	23,250
Increase in restricted cash	(19,063)	—
Net cash used in investing activities	(320,172)	(172,528)
Cash flows from financing activities:		
Proceeds from credit facility	295,194	244,000
Payment of credit facility	(113,213)	(222,500)
Contribution by investing partner in PDCM	12,464	16,173
Other	(1,802)	(582)
Net cash provided by financing activities	192,643	37,091
Net decrease in cash and cash equivalents	(22,062)	(18,645)
Cash and cash equivalents, beginning of period	54,372	31,944
Cash and cash equivalents, end of period	$32,310	$13,299
Supplemental cash flow information:		
Cash payments (receipts) for:		
Interest, net of capitalized interest	$26,694	$28,651
Income taxes, net of refunds	3,171	(26,998)
Non-cash investing activities:		
	14,551	7,108

Change in accounts payable related to purchases of properties and equipment		
Change in asset retirement obligation, with a corresponding increase to natural gas and crude oil properties, net of disposals	379	2,239

See accompanying Notes to Condensed Consolidated Financial Statements

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NOTE 1 - NATURE OF OPERATIONS AND BASIS OF PRESENTATION

PDC Energy is a domestic independent natural gas and crude oil company engaged in the exploration for and the acquisition, development, production and marketing of natural gas, NGLs and crude oil. As of September 30, 2011, we owned an interest in approximately 5,200 wells located primarily in the Rocky Mountain Region and the Appalachian and Permian Basins. We operate through two business segments: (1) natural gas and crude oil sales and (2) natural 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"), a joint venture between PDC Energy and Lime Rock Partners for the acquisition and development of Marcellus Shale properties, and 26 affiliated partnerships. Our accompanying 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. As of September 30, 2011, PDCM was consolidated at 50% and the 26 partnerships were consolidated at varying percentages.

As of December 31, 2010, PDCM was consolidated at 55.8%, representing our ownership interest. Through a series of capital contributions by our investing partner, our ownership interest in PDCM decreased to 50% as of September 30, 2011. Each change in our ownership interest resulted in a decrease in our proportionate share of net assets and any future earnings. As of September 30, 2011, we concluded that PDCM was no longer a variable interest entity ("VIE") because our voting rights had become proportionately equal to our economic interests and the activities of the entity were being conducted equally for the benefit of both investing partners. The status change of PDCM to a non-VIE did not have an impact on our financial statements, as we continue to proportionately consolidate PDCM.

The following table presents a detailed summary of the 2011 capital contributions made by our investing partner and our resulting ownership interest.

Date	Investing Partner Contribution (in thousands)	PDC's Ownership Interest in PDCM
January 1, 2011	$7,000	53.9%
March 1, 2011	5,000	52.7%
September 23, 2011	11,500	50.0%

In our opinion, the accompanying financial statements contain all adjustments (consisting of only normal recurring adjustments) necessary for a fair statement of our financial statements for interim periods in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, pursuant to such rules and regulations, certain notes and other financial information included in audited financial statements have been condensed or omitted. The 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 2010 Form 10-K. The results of operations for the three and nine months ended 2011, and the cash flows for the nine months ended 2011, 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, specifically related to our discontinued operations. The reclassifications had no impact on previously reported cash flows, net income, earnings per share or shareholders' equity. See Note 12 for additional information regarding our discontinued operations. Additionally, certain reclassifications have been made to correct the prior period disclosures to conform to the current year presentation, specifically related to the fair value level classification of certain derivative instruments. The reclassification had no impact on previously reported financial position, cash flows, net income, earnings per share or shareholders' equity. See Note 3 for additional information regarding the fair value classification of our natural gas and crude oil derivative instruments.

NOTE 2 - RECENT ACCOUNTING STANDARDS

Recently Adopted Accounting Standards

Fair Value Measurements and Disclosures. In January 2010, the Financial Accounting Standards Board ("FASB") issued changes related to fair value measurements requiring gross presentation of activities within the Level 3 roll forward, whereby entities must present separately information about purchases, sales, issuances and settlements. These changes were effective for our financial statements issued for the annual reporting period, and for interim reporting periods within the year, beginning after December 15, 2010. The adoption of this change did not have a material impact on our financial statements.

Recently Issued Accounting Standards

Fair Value Measurement. On May 12, 2011, the FASB issued changes related to fair value measurement. The changes represent the converged guidance of the FASB and the International Accounting Standards Board ("IASB") on fair value measurement. Many of the changes eliminate unnecessary wording differences between International Financial Reporting Standards ("IFRS") and U.S. GAAP. The changes expand existing disclosure requirements for fair value measurements categorized in Level 3 by requiring (1) a quantitative disclosure of the unobservable inputs and assumptions used in the measurement, (2) a description of the valuation processes in place and (3) a narrative description of the sensitivity of the fair value to changes in unobservable inputs and the interrelationships between those inputs. In addition, the changes require the categorization by level in the fair value hierarchy of items that are not measured at fair value in the statement of financial position whose fair value must be disclosed. These changes are to be applied prospectively and are effective for public entities during interim and annual periods beginning after December 15, 2011. Early application is not permitted. With the exception of the disclosure requirements, the adoption of these changes is not expected to have a significant impact on our financial statements.

Presentation of Comprehensive Income. On June 16, 2011, the FASB issued changes related to the presentation of comprehensive income. These changes eliminate the current option to report other comprehensive income and its components in the statement of changes in equity. These changes are intended to enhance comparability between entities that report under U.S. GAAP and those that report under IFRS, and to provide a more consistent method of presenting non-owner transactions that affect an entity's equity. An entity may elect to present items of net income and other comprehensive income in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive, statements. Each component of net income and each component of other comprehensive income, together with totals for comprehensive income and its two parts, net income and other comprehensive income, would need to be displayed under either alternative. The statement(s) would need to be presented with equal prominence as the other primary financial statements. The new requirement is effective for public entities as of the beginning of a fiscal year that begins after December 15, 2011, and interim and annual periods thereafter. Early adoption is permitted, but full retrospective application is required under both sets of accounting standards. We do not expect the adoption of these changes to have a material impact on our financial statements.

NOTE 3 - FAIR VALUE MEASUREMENTS AND DISCLOSURES

Derivative Financial Instruments

Determination of fair value. Fair value accounting standards have established a fair value hierarchy that prioritizes the inputs used in applying a valuation methodology. 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. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. 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 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) in active markets for identical assets or liabilities.

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including (i) quoted prices for similar assets or liabilities in active markets, (ii) quoted prices for identical or similar assets or liabilities in inactive markets, (iii) inputs other than quoted prices that are observable for the asset or liability and (iv) 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 for the asset or liability.

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PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

Derivative Financial Instruments. We measure the fair value of our derivative instruments based on a pricing model that utilizes market-based inputs, including but not limited to the contractual price of the underlying position, current market prices, natural gas and crude oil 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. The counterparties to our derivative instruments are primarily financial institutions who are also major lenders in our credit facility agreement. We validate our fair value measurement through (1) the review of counterparty statements and other supporting documentation, (2) the determination that the source of the inputs are valid, (3) the corroboration of the original source of inputs through access to multiple quotes, if available, or other information and (4) monitoring changes in valuation methods and assumptions. While we use common industry practices to develop our valuation techniques, changes in our pricing methodologies or the underlying assumptions could result in significantly different fair values. While we believe our valuation method is appropriate and consistent with those used by other market participants, the use of a different methodology, or assumptions, to determine the fair value of certain financial instruments could result in a different estimate of fair value.

The following table presents, for each hierarchy level, our derivative assets and liabilities, both current and non-current portions, including the derivative assets and liabilities designated to our affiliated partnerships and our proportionate share of PDCM's derivative assets and liabilities, measured at fair value on a recurring basis.

	September 30, 2011			December 31, 2010 (a)		
	Level 2 (b)	Level 3 (c)	Total	Level 2 (b)	Level 3 (c)	Total
	(in thousands)					
Assets:						
Commodity based derivatives contracts	$72,405	$23,553	$95,958	$72,880	$14,426	$87,306
Basis protection derivative contracts	3	52	55	10	101	111
Total assets	72,408	23,605	96,013	72,890	14,527	87,417
Liabilities:						
Commodity based derivatives contracts	2,051	142	2,193	16,304	3,758	20,062
Basis protection derivative contracts	39,461	—	39,461	46,573	7	46,580
Total liabilities	41,512	142	41,654	62,877	3,765	66,642
Net asset	$30,896	$23,463	$54,359	$10,013	$10,762	$20,775

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(a) We reclassified our NYMEX-based natural gas fixed-price swaps from Level 1 to Level 2 (decreasing the previously reported net asset in Level 1 by $64.1 million, with a corresponding increase in Level 2), Panhandle Eastern Pipeline ("PEPL") and Colorado Interstate Gas ("CIG") -based natural gas fixed-price swaps, crude oil fixed-price swaps, basis swaps and natural gas physical purchases from Level 3 to Level 2 (decreasing the previously reported net liability in Level 3 by $54.1 million, with a corresponding increase in Level 2). The amounts presented reflect these reclassifications and conform to current period presentation.

(b) Includes our fixed-price swaps, basis swaps and physical purchases.

(c) Includes our natural gas and crude oil collars, crude oil puts and physical sales.

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PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following table presents a reconciliation of our Level 3 fair value measurements.

	Nine Months Ended September 30,	
	2011	2010 (1)
	(in thousands)	
Fair value, net asset, beginning of period	$10,762	$15,048
Changes in fair value included in statement of operations line item:		
Commodity price risk management gain, net	15,285	15,655
Sales from natural gas marketing	51	493
Cost of natural gas marketing	—	24
Changes in fair value included in balance sheet line item (2):		
Accounts receivable affiliates	49	10
Accounts payable affiliates	(568)	(677)
Settlements included in statement of operations line items:		
Commodity price risk management gain, net	(2,022)	(11,583)
Sales from natural gas marketing	(94)	(289)
Cost of natural gas marketing	—	(23)
Fair value, net asset, end of period	$23,463	$18,658
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, net	$9,974	15,469
Sales from natural gas marketing	(4)	187
	$9,970	$15,656

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(1) We reclassified our PEPL and CIG-based natural gas fixed-price swaps, crude oil fixed-price swaps, basis swaps and natural gas physical purchases from Level 3 to Level 2 (decreasing the previously reported net liability at the beginning of the period by $44 million). The amounts presented reflect these reclassifications and conform to current period presentation.

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

See Note 4 for additional disclosure related to our derivative financial instruments.

Non-Derivative Financial Assets and Liabilities

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

The liability associated with our non-qualified deferred compensation plan for non-employee directors may be settled in cash or shares of our common stock. The carrying value of this obligation is based on the quoted market price of our common stock, which is a Level 1 input. As of September 30, 2011, and December 31, 2010, the liability related to this plan was immaterial.

The portion of our long-term debt related to our corporate credit facility, as well as our proportionate share of PDCM's credit facility, approximates fair value due to the variable nature of its related interest rate. We have not elected to account for the portion of our long-term debt related to our senior notes under the fair value option; however, as of September 30, 2011, we estimate the fair value of our 3.25% convertible senior notes due 2016 to be $92 million and the fair value of our 12% senior notes due 2018 to be $217.7 million. We determined these valuations based upon measurements of broker/dealer quotes and trading activity, respectively.

NOTE 4 - DERIVATIVE FINANCIAL INSTRUMENTS

As of September 30, 2011, we had derivative instruments in place for a portion of our anticipated production through 2015 for a total of 34,986.7 BBtu of natural gas and 2,324 MBbls of crude oil.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following table presents the location and fair value amounts of our derivative instruments on the balance sheets. These derivative instruments were comprised of commodity floors, collars and swaps, basis protection swaps and physical sales and purchases.

Derivatives instruments not designated as hedges (1):		Balance sheet line item	Fair Value September 30, 2011	December 31, 2010
			(in thousands)	
Derivative assets:	Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	$47,625	$32,837
	Related to affiliated partnerships (2)	Fair value of derivatives	7,916	8,231
	Related to natural gas marketing	Fair value of derivatives	1,200	1,811
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	52	74
			56,793	42,953
	Non Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	32,035	32,270
	Related to affiliated partnerships (2)	Fair value of derivatives	7,093	12,111
	Related to natural gas marketing	Fair value of derivatives	89	46
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	3	37
			39,220	44,464
Total derivative assets			$96,013	$87,417
Derivative liabilities:	Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	$813	$10,636
	Related to affiliated partnerships (3)	Fair value of derivatives	238	1,676
	Related to natural gas marketing	Fair value of derivatives	1,031	1,492
	Basis protection contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	15,095	11,725
	Related to affiliated partnerships (3)	Fair value of derivatives	3,968	4,462
	Related to natural gas marketing	Fair value of derivatives	9	7
			21,154	29,998
	Non Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	7	6,231
	Related to affiliated partnerships (3)	Fair value of derivatives	23	(3)

	Related to natural gas marketing	Fair value of derivatives	81	30
	Basis protection contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	16,129	21,905
	Related to affiliated partnerships (3)	Fair value of derivatives	4,261	8,481
	Related to natural gas marketing	Fair value of derivatives	(1)	—
			20,500	36,644
Total derivative liabilities			$41,654	$66,642

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(1) As of September 30, 2011, and December 31, 2010, none of our derivative instruments were designated as hedges.

(2) Our balance sheets include a corresponding payable to our affiliated partnerships of $15 million and $20.3 million as of September 30, 2011, and December 31, 2010, respectively.

(3) Our balance sheets include a corresponding receivable from our affiliated partnerships of $8.5 million and $14.6 million as of September 30, 2011, and December 31, 2010, respectively.

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

Statement of operations line item	2011 Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	2011 Realized and Unrealized Gains (Losses) For the Current Period	2011 Total	2010 Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	2010 Realized and Unrealized Gains (Losses) For the Current Period	2010 Total
	(in thousands)					
Three Months Ended September 30,						
Commodity price risk management gain, net						
Realized gains	$2,815	$2,132	$4,947	$5,688	$1,832	$7,520
Unrealized gains	(2,815)	44,574	41,759	(5,688)	17,197	11,509
Total commodity price risk management gain, net (1)	$—	$46,706	$46,706	$—	$19,029	$19,029
Sales from natural gas marketing						
Realized gains	$418	$88	$506	$1,384	$222	$1,606
Unrealized gains	(418)	958	540	(1,384)	1,624	240
Total sales from natural gas marketing (2)	$—	$1,046	$1,046	$—	$1,846	$1,846
Cost of natural gas marketing						
Realized losses	$(347)	$(104)	$(451)	$(1,169)	$(280)	$(1,449)
Unrealized losses	347	(944)	(597)	1,169	(1,563)	(394)
Total cost of natural gas marketing (2)	$—	$(1,048)	$(1,048)	$—	$(1,843)	$(1,843)
Nine Months Ended September 30,						
Commodity price risk management gain, net						
Realized gains	$9,033	$1,505	$10,538	$19,927	$18,410	$38,337
Unrealized gains	(9,033)	41,856	32,823	(19,927)	56,098	36,171
Total commodity price risk management gain, net (1)	$—	$43,361	$43,361	$—	$74,508	$74,508
Sales from natural gas marketing						
Realized gains	$1,624	$516	$2,140	$2,078	$2,392	$4,470
Unrealized gains (losses)	(1,624)	1,130	(494)	(2,078)	3,266	1,188
Total sales from natural gas marketing (2)	$—	$1,646	$1,646	$—	$5,658	$5,658
Cost of natural gas marketing						
Realized losses	$(1,287)	$(525)	$(1,812)	$(1,752)	$(2,402)	$(4,154)
Unrealized gains (losses)	1,287	(1,008)	279	1,752	(3,055)	(1,303)
Total cost of natural gas marketing (2)	$—	$(1,533)	$(1,533)	$—	$(5,457)	$(5,457)

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(1) Represents realized and unrealized gains and losses on derivative instruments related to natural gas and crude oil sales.

(2) Represents realized and unrealized gains and losses on derivative instruments related to natural gas marketing.

Concentration of Credit Risk. We make extensive use of over-the-counter derivative instruments that enable us to manage a portion of our exposure to price volatility from producing and marketing natural gas and crude oil. These arrangements expose us to credit risk of nonperformance by our counterparties. We primarily use financial institutions, who are also major lenders in our credit facility agreement, as counterparties to our derivative contracts. To date, we have had no counterparty default losses. We have evaluated the credit risk of our derivative assets from our counterparties using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, the impact of the nonperformance of our counterparties on the fair value of our derivative instruments was not significant.

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The following table presents the derivative counterparties that expose us to credit risk.

Counterparty Name	Fair Value of Derivative Assets As of September 30, 2011 (in thousands)
JPMorgan Chase Bank, N.A. (1)	$37,858
Crèdit Agricole CIB (1)	23,242
Wells Fargo Bank, N.A. (1)	15,372
BNP Paribas (1)	13,612
Various (2)	5,929
Total	$96,013

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(1)Major lender in our credit facility, see Note 7.
(2)Represents a total of 14 counterparties, including three lenders in our credit facility.

NOTE 5 - PROPERTIES AND EQUIPMENT

The following table presents the components of properties and equipment, net.

	September 30, 2011	December 31, 2010
	(in thousands)	
Properties and equipment, net:		
Natural gas and crude oil properties		
Proved	$1,674,983	$1,429,667
Unproved	77,403	79,053
Total natural gas and crude oil properties	1,752,386	1,508,720
Pipelines and related facilities	33,861	34,262
Transportation and other equipment	31,790	32,410
Land, buildings and leasehold improvements	14,476	13,379
Construction in progress	74,875	42,128
	1,907,388	1,630,899
Accumulated DD&A	(603,613)	(510,861)
Properties and equipment, net	$1,303,775	$1,120,038

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 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 2011 was 38.4% and 33.9% (provisions on income), respectively, compared to 66.5% (discrete benefit on income) and 32.9% (provision on income) for the three and nine months ended 2010, respectively. The effective tax rate for the nine months ended 2011 and 2010 differs from the statutory rate primarily due to net permanent deductions, largely percentage depletion, decreasing the tax provision on pretax income. During the three months ended 2010, we recorded a net discrete tax benefit of $1.6 million due to a reduction of our deferred tax rate which reduced our net deferred tax liability. The rate excluding discrete items for the three months ended 2010 was 25.4% (provision on income). The rate for the three months ended 2011 did not include any material discrete items. However, for reasons noted above, a comparison of the quarter-over-quarter rates would not be meaningful.

As of September 30, 2011, we had a gross liability for unrecognized tax benefits of $0.4 million compared to $1.1 million at December 31, 2010. If recognized, all of this liability would affect our effective tax rate. This liability is reflected in other accrued expenses on our accompanying balance sheet. In June 2011, the Internal Revenue Service ("IRS") completed its examination of our 2007, 2008 and 2009 tax years. During the nine months ended 2011, we reduced our liability by $0.6 million for uncertain tax benefits that were resolved without change by the completion of the IRS examination and reduced the liability by $0.1 million due to the expiration of the statute of limitations related to another tax position. During the three months ended 2011, we decreased the liability by $0.2 million due to a change in estimate for tax positions of the current year. We expect our remaining liability for uncertain tax positions to decrease by $0.2 million in the next 12 months as a remaining uncertain tax position is reviewed under the IRS Compliance Assurance Process ("CAP") program.

As of the date of this filing, we are current with our income tax filings in all applicable state jurisdictions and currently have no state income tax returns in the process of examination.

NOTE 7 - LONG-TERM DEBT

Long-term debt consists of the following:

	September 30, 2011	December 31, 2010
	(in thousands)	
Senior notes		
3.25% Convertible senior notes due 2016:		
Principal amount	$115,000	$115,000
Unamortized discount	(17,426)	(20,252)
3.25% Convertible senior notes due 2016, net of discount	97,574	94,748
12% Senior notes due 2018:		
Principal amount	203,000	203,000
Unamortized discount	(1,836)	(2,053)
12% Senior notes due 2018, net of discount	201,164	200,947
Total senior notes	298,738	295,695
Credit facilities		
Corporate	172,500	—
PDCM	9,000	—
Total credit facilities	181,500	—
Total long-term debt	$480,238	$295,695

Senior Notes

3.25% Convertible Senior Notes Due 2016. In November 2010, we issued $115 million of 3.25% convertible senior notes due 2016 in a private placement. The maturity for the payment of principal is May 15, 2016. Interest at the rate of 3.25% per year is payable in cash semiannually in arrears on each May 15 and November 15, which commenced on May 15, 2011. 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 on the fair value of similar debt instruments, excluding the conversion feature, with similar terms and priced on the same day we issued our convertible notes. The original issue discount and the deferred note issuance costs are being amortized to interest expense over the term of the debt 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 $1,000 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.

12% Senior Notes Due 2018. In 2008, we issued $203 million of 12% senior notes due 2018 in a private placement. The maturity for the payment of principal is February 15, 2018. Interest at the rate of 12% per year is payable in cash semiannually in arrears on each February 15 and August 15. The senior notes were issued at a discount, 98.572% of the principal amount. The indenture governing the notes contains customary representations and warranties as well as typical restrictive covenants. The original issue discount and the deferred note issuance costs are being amortized to interest expense over the term of the debt using the effective interest method.

We were in compliance with all covenants related to our senior notes as of September 30, 2011, and expect to remain in compliance throughout the next twelve-month period.

Bank Credit Facilities

Corporate Bank Credit Facility. We operate under a credit facility dated as of November 5, 2010, as amended last on May 6, 2011, with an aggregate revolving commitment or borrowing base of $350 million. The maximum allowable facility amount is $600 million. The credit facility is with certain commercial lending institutions and is available for working capital requirements, capital expenditures, acquisitions, general corporate purposes and to support letters of credit.

Our credit facility borrowing base is subject to size redetermination biannually based on a valuation of our natural gas and crude oil reserves at December 31 and June 30 and is also subject to a redetermination upon the occurrence of certain events. The borrowing base of the credit facility will be the loan value assigned to the proved reserves attributable to our natural gas and crude oil interests, excluding proved reserves attributable to PDCM and our 26 affiliated partnerships. The credit facility is secured by a pledge of the stock of certain of our subsidiaries, mortgages of certain producing natural gas and crude oil properties and substantially all of our other assets. Neither PDCM nor the various limited partnerships that we have sponsored and continue to serve as the managing general partner are guarantors of the credit facility.

Our outstanding principal amount accrues interest at a varying interest rate that fluctuates with an alternate base rate (equal to the greater of JPMorgan Chase Bank, N.A.'s prime rate, the federal funds rate plus a premium and 1-month LIBOR plus a premium), or at our election, a rate equal to the rate for dollar deposits in the London interbank market for certain time periods. Additionally, commitment fees, interest margin and other bank fees, charged as a component of interest, vary with our utilization of the facility. No principal payments are required until the credit agreement expires on November 5, 2015, or in the event that the borrowing base would fall below the outstanding balance. The credit facility contains covenants customary for agreements of this type.

We have outstanding an undrawn $18.7 million irrevocable standby letter of credit in favor of a third party transportation service provider. This letter of credit reduced the amount of available funds under our credit facility by an equal amount. We pay a fronting fee of 0.125% per annum and an additional quarterly maintenance fee equivalent to the spread over Eurodollar loans (2.5% per annum as of September 30, 2011) for the period the letter of credit remains outstanding. The letter of credit is set to expire on May 22, 2012.

As of September 30, 2011, we had an outstanding balance of $172.5 million on our credit facility compared to no outstanding draws as of December 31, 2010. We pay a fee of 0.5% per annum on the unutilized commitment on the available funds under our credit facility. As of September 30, 2011, the available funds under our credit facility, including a reduction for the $18.7 million irrevocable standby letter of credit in effect, was $158.8 million. The weighted average borrowing rate on our credit facility was 2.2% per annum as of September 30, 2011.

On October 12, 2011, we completed the redetermination of our corporate bank credit facility's borrowing base. See Note 16 for a more detailed discussion.

PDCM Credit Facility. PDCM has a credit facility dated as of April 30, 2010, as amended on April 20, 2011, with an aggregate revolving commitment or borrowing base of $40 million. In addition to the increase in borrowing base, the April 20, 2011, amendment permits PDCM to enter into swap agreements on new properties which were not included in the most recent reserve report and which have been producing for at least 30 days. The credit facility is subject to and secured by PDCM's properties, including our proportionate share of such properties. The credit facility borrowing base is subject to size redetermination semiannually based upon a valuation of PDCM's reserves at December 31 and June 30; further, either PDCM or the lenders may request a redetermination upon the occurrence of certain events. Pursuant to the interests of the joint venture, the credit facility will be utilized by PDCM for the exploration and development of its Appalachian assets. As of September 30, 2011, our proportionate share of PDCM's outstanding credit facility draw was $9 million. As of December 31, 2010, there were no amounts outstanding related to this credit facility. PDCM pays a fee of 0.5% per annum on the unutilized commitment on the available funds under this credit facility. The weighted average borrowing rate on PDCM's credit facility was 1.8% per annum as of September 30, 2011.

As of September 30, 2011, both the Company and PDCM were in compliance with all bank credit facility covenants and expect to remain in compliance 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 natural gas and crude oil properties.

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	Amount (in thousands)
Balance at December 31, 2010 (1)	$28,047
Change in ownership interest of PDCM	(916)
Obligations incurred with development activities and assumed with acquisitions	955
Accretion expense	1,212
Obligations discharged with disposal of properties and asset retirements	(254)
Revisions in estimated cash flows	(322)
Balance at September 30, 2011	28,722
Less current portion	(250)
Long-term portion	$28,472

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(1) Includes $0.2 million as of December 31, 2010, related to assets held for sale.

NOTE 9 - COMMITMENTS AND CONTINGENCIES

Purchase Agreement. On September 23, 2011, PDCM executed a purchase agreement, effective as of July 1, 2011, with an unrelated third party to acquire 100% of the membership interests of Seneca-Upshur Petroleum, LLC ("Seneca-Upshur"), a West Virginia limited liability company, for a purchase price of $152.5 million ($76.2 million net to PDC). The transaction includes all rights and all depths to an estimated 100,000 net acres: 90,000 acres prospective for the Marcellus Shale primarily located in Harrison, Taylor, Barbour, Upshur, Lewis and Randolph counties of north central West Virginia and 10,000 acres prospective for the Huron Shale primarily located in Mingo and McDowell counties in southwest West Virginia. The acreage is held by production from approximately 1,400 wells producing from the shallow Devonian, which were included in the transaction. The acquisition of these assets are complementary to PDCM's existing properties due to their close proximity. The transaction closed on October 3, 2011, see Note 16 for a further discussion.

Utica Shale Leasehold Agreements. During the three months ended 2011, we entered into a series of leasehold agreements with multiple parties for the option to acquire acreage targeting the wet natural gas and crude oil phases of the Utica Shale play throughout southeastern Ohio. Pursuant to the agreements, we have the right, after confirmation of title, to acquire an estimated 30,000 net acres in the prospective Utica Shale play. Should we confirm title on all 30,000 acres, we estimate that the purchase price of these leaseholds will approximate $50 million. Further, subsequent to September 30, 2011, we have entered into additional leasehold agreements giving us the opportunity to purchase an estimated additional 10,000 acres, subject to confirmation of title, for up to $20 million. Currently, we are actively pursuing an industry joint venture partner to participate in and share in funding the growth and development in this play; however, we cannot guarantee we will be successful in securing a partner.

Merger Agreements. On June 20, 2011, pursuant to our previously announced partnership acquisition plan, we entered into separate merger agreements with five of our affiliated partnerships: PDC 2003-A Limited Partnership, PDC 2003-B Limited Partnership, PDC 2003-C Limited Partnership, PDC 2003-D Limited Partnership and PDC 2002-D Limited Partnership (collectively, the "2003/2002-D Partnerships"). We serve as the managing general partner of each of the 2003/2002-D Partnerships. Pursuant to each merger agreement, if the merger is approved by the holders of a majority of the limited partnership units held by limited partners of that partnership not owned by us (the "non-affiliated investor partners"), as well as the satisfaction of other customary closing conditions, we will then acquire such partnerships. If all five partnerships are acquired, we expect to pay an aggregate of approximately $29.5 million to the non-affiliated investor partners for the limited partnership units of these partnerships. Definitive proxy statements were filed with the SEC on September 12, 2011, and first mailed to investors on September 14, 2011. On October 28, 2011, the non-affiliated investor partners of the 2003/2002-D Partnerships approved the applicable merger agreements. We expect to fund the purchase price for these acquisitions in November 2011 through a draw on our corporate credit facility. See Note 16 for further details.

Firm Transportation Agreements. We enter into contracts that provide firm transportation, sales and processing charges on pipeline systems through which we transport or sell our natural gas and the natural gas of working interest owners, PDCM, our affiliated partnerships and other third parties. These contracts require us to pay these transportation and processing charges whether the required volumes are delivered or not. Satisfaction of the volume requirements includes volumes produced by us, volumes purchased from third parties and volumes produced by our joint venture and affiliated partnerships. We record in our financial statements only our share of costs based upon our working interest in the wells; however, with the exception of contracts entered into by PDCM, the costs of all volume shortfalls will be borne by PDC.

As of June 30, 2011, we had a liability in the amount of $3.1 million included in other liabilities on the balance sheet related to an agreement in the Piceance Basin. On July 27, 2011, we entered into an amendment with the unrelated third party subject to this agreement whereby the accrued liability was relieved; consequently, during the third quarter of 2011, the accrued liability was eliminated with a corresponding reduction in the statement of operations line item production costs. The amendment did not extend the expiration date of the original agreement. The table below includes the impact of this amendment.

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

	For the Twelve Months Ending September 30,						
Area	2012	2013	2014	2015	2016 Through Expiration	Total	Expiration Date
Volume (MMcf)							
Piceance Basin	18,000	25,254	37,719	31,910	119,149	232,032	May 31, 2021
Appalachian Basin (1)	7,993	20,152	21,265	22,855	196,312	268,577	September 25, 2025
NECO	3,655	2,285	1,825	1,825	2,285	11,875	December 31, 2016
Total	29,648	47,691	60,809	56,590	317,746	512,484	
Dollar commitment (in thousands)	$13,474	$22,898	$29,481	$26,749	$133,740	$226,342	

(1) Includes a precedent agreement that becomes effective when a planned pipeline is placed in service, currently expected to be September 2012 and represents 873 MMcf of the total MMcf presented for the year ending September 30, 2012, 10,627 MMcf for each of the years ending September 30, 2013 through 2015, respectively, and 73,576 MMcf thereafter. This agreement will be null and void if the pipeline is not completed. In August 2009, we issued a letter of credit related to this agreement, see Note 7.

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 are no assurances 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.

Royalty Owner Class Action

Gobel et al v. Petroleum Development Corporation, filed on January 27, 2009, in Circuit Court of Harrison County, CA No. 09-C-40-2

David W. Gobel, individually and allegedly as representative of all royalty owners in the Company's West Virginia oil and gas wells, filed a lawsuit against the Company alleging that we failed to properly pay royalties. The allegations stated that the Company improperly deducted certain charges and costs before applying the royalty percentage. Punitive damages were requested in addition to breach of contract, tort and fraud allegations. On October 27, 2010, the state court set a trial date of April 2012.

In April 2011, the Company entered into an oral settlement agreement with respect to this lawsuit, settling all claims between the parties for an aggregate payment of $8.7 million. On June 15, 2011, subject to court approval, a written settlement agreement was signed confirming these terms. On June 30, 2011, the state court granted initial approval of the settlement agreement, subject to notice to class members and final court approval. Initial notice was then sent to the class members. The date for objection by class members was October 24, 2011, with no objections received. The hearing to consider final approval of the settlement is scheduled for December 19, 2011. The total settlement amount of $8.7 million was accrued as of September 30, 2011, and included in other accrued expenses on the accompanying balance sheet. An escrow account was funded on July 22, 2011, for the entire settlement amount and included in restricted cash - current on the balance sheet, with no impact to the accrued liability or statement of operations during the third quarter of 2011.

Environmental. Due to the nature of the natural gas and oil industry, we are exposed to environmental risks. We have various policies and procedures in place 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 accrued when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. As of September 30, 2011, and December 31, 2010, we had accrued environmental liabilities in the amount of $1.9 million and $1.7 million, respectively, included in other accrued expenses on the balance sheet. We are not currently aware of any environmental claims existing as of September 30, 2011, which have not been provided for or would otherwise have a material impact on our accompanying 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. Although we have not sponsored a partnership drilling program since 2007, substantially all of our partnership drilling programs contain a repurchase provision where investing partners may request that we purchase their partnership units at any time beginning with the third anniversary of the respective partnership's 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, 2011, the maximum annual repurchase obligation, based upon the minimum price described above, was approximately $5.2 million. We believe we have adequate liquidity to meet this obligation. For the nine months ended 2011, amounts paid for the repurchase of partnership units pursuant to this provision were immaterial.

Employment Agreements with Executive Officers. We have employment agreements with our executive officers. The employment agreements provide for annual base salaries, eligibility for performance bonus compensation and other various benefits, including severance benefits.

If, within two years following a change of control of the Company ("change in control period"), either the Company terminates the executive officer without cause or the executive officer terminates employment for good reason, then the severance benefits owed equals three times the sum of the executive's highest annual base salary during the previous two years of employment immediately preceding the termination date and the executive's highest annual bonus paid or, in the case of one executive officer, paid or payable during the same two-year period. For one executive, in this calculation, the target bonus will be used as the minimum value for the first two years of employment. Where the Company terminates the executive officer without cause or the executive officer terminates employment for good reason outside of the change in control period, the severance benefits range from two times to three times, specific to the executive officer, the benefits noted above. For this purpose, a change of control and good reason correspond to the respective definitions of change of control and good reason under Internal Revenue Code ("IRC") Section 409A and the supporting Treasury regulations, with some differences. Under any of the above circumstances, the executive officer is also entitled under his employment agreement to (i) vesting of any unvested equity compensation (excluding all long-term incentive shares), (ii) reimbursement for any unpaid expenses, (iii) retirement benefits earned under the current and/or previous agreements, (iv) continued coverage under our medical plan at the Company's cost for the federal COBRA health continuation coverage period and (v) payment of any earned and unpaid bonus amounts. In addition, the executive officer is entitled to receive any benefits that he would have otherwise been entitled to receive under our qualified retirement plan, although those benefits are not increased or payment accelerated.

In the event that an executive officer is terminated for just cause, we are required to pay the executive officer his base salary through the termination date plus a partial year bonus, incentive, deferred, retirement or other compensation and to provide any other benefits, which have been earned or become payable as of the termination date.

In the event that an executive officer voluntarily terminates his employment for other than good reason, he is entitled to receive (i) his base salary and bonus, provided, however, that with respect to the bonus, for certain executive officers, there will be no proration of the bonus if such executive leaves prior to the last day of the year and, with respect to one executive officer, there will be no proration of the bonus in the event such executive officer leaves prior to March 31 in the year of his termination, (ii) any incentive, deferred or other compensation which has been earned or has become payable, but which has not yet been paid under the schedule originally contemplated in the agreement under which they were granted, (iii) any unpaid expense reimbursement and (iv) any other payments for benefits earned under the employment agreement or our plans.

In the event of death or disability, the executive is entitled to receive certain benefits. For this purpose, the definition of "disability" corresponds to the definition under IRC Section 409A and the supporting Treasury regulations. The benefits will (i) in the case of death be paid in a lump sum and be equal to the base salary that would otherwise have been paid for a six-month period following the termination date and (ii) in the case of disability be up to thirteen weeks of ongoing base salary plus a lump sum equal to six months of base salary.

See Note 13 for a discussion related to the separation agreement entered into with our former chief executive officer during the nine months ended 2011.

Partnership Casualty Losses. As managing general partner of numerous partnerships, we have a potential liability for casualty losses in excess of the partnership assets and insurance. We believe the casualty insurance coverage that we and our subcontractors carry is adequate to meet this potential liability.

NOTE 10 - COMMON STOCK

Stock-Based Compensation Plans

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

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PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011 (1)	2010
	(in thousands)			
Total stock-based compensation expense	$1,693	$1,624	$7,242	$3,845
Income tax benefit	(643)	(617)	(2,751)	(1,461)
Net income impact	$1,050	$1,007	$4,491	$2,384

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(1) Includes a total of $2.5 million, pretax, related to a separation agreement with our former chief executive officer.

Stock Appreciation Rights ("SARs")

In March 2011, the Compensation Committee of our Board of Directors (the "Compensation Committee") awarded 31,552 SARs to our executive officers. The SARs will vest ratably over a three-year period and may be exercised at any point after vesting through March 2021. Pursuant to the terms of the awards, upon exercise, the executives 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.

The fair value of each SAR award was estimated on the date of grant using a Black-Scholes pricing model using the assumptions presented in the table below. 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 dividends, nor do we expect to declare dividends in the foreseeable future.

	Nine Months Ended September 30, 2011
Expected term of the award	6 years
Risk-free interest rate	2.5 %
Volatility	60.2 %
Weighted average grant date fair value per share	$25.22

The following table presents the changes in our SARs for the nine months ended 2011.

	Number of Shares Underlying SARs	Grant Date Market Price Per Share	Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2010	57,282	$24.44	9.3	$—
Awarded	31,552	43.95	9.7	—
Exercised	(2,814)	24.44		
Forfeited	(35,549)	31.57		
Outstanding at September 30, 2011	50,471	31.61	8.9	—
	46,488	31.45	8.9	—

Vested and expected to vest at September 30, 2011				
Exercisable at September 30, 2011	10,636	24.44	8.6	—

Pursuant to a separation agreement with our former chief executive officer and the original terms of the award, during the nine months ended 2011, 29,906 SARs were accelerated to vest, resulting in the acceleration of $0.6 million in stock-based compensation expense. The total compensation cost related to SARs granted and not yet recognized in our statement of operations as of September 30, 2011, was $0.5 million. The cost is expected to be recognized over a weighted average period of 1.5 years.

Restricted Stock Awards

Time-Based Awards. For the nine months ended 2011, the Compensation Committee awarded a total of 101,378 time-based restricted shares to our executive officers that primarily vest ratably over three years from date of grant and 23,360 time-based restricted shares to our non-employee directors also vesting ratably over three years from date of grant.

Pursuant to a separation agreement with our former chief executive officer and the original terms of the award, during the nine months ended 2011, the vesting of 64,442 time-based restricted shares was accelerated, resulting in the acceleration of $1.9 million in stock-based compensation expense. The total compensation cost related to non-vested time-based awards expected to vest and not yet recognized in our statements of operations as of September 30, 2011, was $11.6 million. This cost is expected to be recognized over a weighted average period of 2.5 years.

The following table presents the changes in non-vested time-based awards for the nine months ended 2011.

	Shares	Weighted Average Grant-Date Fair Value per Share
Non-vested at December 31, 2010	525,715	$25.53
Granted	267,748	34.14
Vested	(235,495)	27.02
Forfeited	(31,146)	26.93
Non-vested at September 30, 2011	526,822	29.16

	As of / Nine Months Ended September 30, 2011 (in thousands, except per share data)
Total intrinsic value of time-based awards vested	$8,615
Total intrinsic value of time-based awards non-vested	10,215
Market price per common share	19.39

Market-Based Awards. The fair value of the market-based restricted shares is amortized ratably over the requisite service period, primarily three years. Generally, the market-based shares vest if the participant is continuously employed throughout the performance period and the market-based performance measure is achieved, with a maximum vesting period of five years. All compensation cost related to the market-based awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved.

In March 2011, the Compensation Committee awarded a total of 13,531 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 11 peer companies. The shares are measured over a three-year period ending on December 31, 2013, and can result in a payout between zero 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 weighted average assumptions presented in the table below.

Nine Months Ended
September 30, 2011

Expected term of award	3 years	
Risk-free interest rate	1.1	%
Volatility	74.2	%
Weighted average grant date fair value per share	$58.53	

Expected volatility was based on a blend of our historical and implied volatility. The expected lives of the awards were 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 or modification and extrapolated to approximate the life of the award. We do not expect to pay dividends, nor do we expect to declare dividends in the foreseeable future.

The following table presents the change in non-vested market-based awards for the nine months ended 2011.

	Shares	Weighted Average Grant-Date Fair Value per Share
Non-vested at December 31, 2010	79,550	$32.52
Granted	13,531	58.53
Vested	(4,109)	6.47
Forfeited	(21,927)	34.32
Non-vested at September 30, 2011	67,045	38.78

Pursuant to a separation agreement with our former chief executive officer and the original terms of the award, during the nine months ended 2011, the vesting of 4,109 market-based restricted shares was accelerated and 21,927 market-based restricted shares were forfeited. The impact on stock-based compensation for the vesting and forfeiture of these market-based restricted shares was immaterial. The total compensation cost related to non-vested market-based awards expected to vest and not yet recognized in our statement of operations as of September 30, 2011, was $0.3 million. This cost is expected to be recognized over a weighted average period of 2.2 years.

Treasury Share Purchases

In accordance with our stock-based compensation plans, employees and directors may surrender shares of the Company's common stock to cover tax withholding obligations upon the vesting and exercise of share-based awards. The shares acquired may be retired or reissued to service awards under our 2010 Long-Term Equity Compensation Plan (the "2010 Plan"). For shares that are retired, we first charge any excess of cost over the par value to additional paid-in-capital ("APIC") to the extent we have amounts in APIC, with any remaining excess cost charged to retained earnings. For shares reissued to service awards under the 2010 Plan, shares are recorded at cost and upon reissuance, we reduce the carrying value of shares acquired and held pursuant to the 2010 Plan by the weighted average cost per share with an offsetting charge to APIC. During the nine months ended September 30, 2011, we acquired 81,051 shares pursuant to our stock-based compensation plans for payment of tax liabilities, of which 8,760 shares were reissued pursuant to our 2010 Plan and the remaining 67,558 shares retired.

NOTE 11 - EARNINGS PER SHARE

The following is a reconciliation of weighted average diluted shares outstanding.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Weighted average common shares outstanding - basic	23,569	19,250	23,497	19,218
Dilutive effect of share-based compensation:				
Restricted stock	162	109	167	80
SARs	49	39	45	13
Non employee director deferred compensation	3	8	3	8

Weighted average common and common share equivalents outstanding - diluted	23,783	19,406	23,712	19,319

The following table sets forth 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,	
	2011	2010	2011	2010
	(in thousands)			
Weighted average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:				
Restricted stock	198	130	173	266
Stock options	9	10	10	10
SARs	29	—	23	—
Total anti-dilutive common share equivalents	236	140	206	276

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In November 2010, we issued 115,000 convertible senior notes, $1,000 principal amount, that give the holders the right to convert the principal amount into 2.7 million common shares at a conversion price of $42.40 per share. The convertible notes could have a dilutive impact on our earnings per share if the average market share price exceeds the conversion price. The table above does not include those shares issuable upon conversion as the average share price of our common stock did not exceed the conversion price during the three and nine months ended 2011.

NOTE 12 - DIVESTITURES AND DISCONTINUED OPERATIONS

North Dakota. During the fourth quarter of 2010, we developed a plan to divest our North Dakota assets. The plan included 100% of our North Dakota assets, consisting of producing wells, undeveloped leaseholds and related facilities primarily located in Burke County. The plan received approval from our Board of Directors (the "Board") and, in December 2010, we effected a letter of intent with an unrelated third party. Following the sale to the unrelated party, we do not have significant continuing involvement in the operations of or cash flows from these assets; accordingly, the North Dakota assets were reclassified as held for sale as of December 31, 2010, and the results of operations related to those assets have been separately reported as discontinued operations in the accompanying financial statements for all periods presented. In February 2011, we executed a purchase and sale agreement and subsequently closed with the same unrelated party. Proceeds from the sale were $9.5 million, net of non-affiliated investor partners' share of $3.8 million, resulting in a pretax gain on sale of $3.9 million.

Selected financial information related to divested and discontinued operations. The table below presents selected operational information related to discontinued operations. While the reclassification of revenues and expenses related to discontinued operations for prior period had no impact upon previously reported net earnings, the statement of operations table below presents the revenues and expenses that were reclassified from the specified statement of operations line items to discontinued operations. There was no activity recorded for discontinued operations for the three months ended 2011. The three and nine months ended 2010, in addition to the discontinued operations data of our North Dakota assets, includes operations data related to the July 2010 divestiture of our Michigan assets.

Statement of Operations - Discontinued Operations	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	2010
	(dollars in thousands)		
Revenues			
Natural gas, NGL and crude oil sales	$1,183	$447	$5,719
Sales from natural gas marketing	568	—	3,328
Well operations, pipeline income and other	134	10	536
Total revenues	1,885	457	9,583
Costs, expenses and other			
Production costs	409	132	1,988
Cost of natural gas marketing	537	—	3,265
Exploration expense	25	—	25
Impairment of natural gas and crude oil properties	160	—	4,666
Depreciation, depletion and amortization	195	—	1,659
Gain on sale of properties and equipment	—	(3,854)	—
Total costs, expenses and other	1,326	(3,722)	11,603

Income (loss) from discontinued operations	559	4,179	(2,020)
Provision (benefit) for income taxes	99	1,559	(964)
Income (loss) from discontinued operations, net of tax	$460	$2,620	$(1,056)

NOTE 13 - TRANSACTIONS WITH AFFILIATES AND OTHER RELATED PARTIES

Former Executive Officer. In June 2011, Richard W. McCullough resigned from his positions as our Chief Executive Officer and the Chairman of the Board, effective immediately. In connection with his resignation, in July 2011, Mr. McCullough and the Company executed a separation agreement, whereby Mr. McCullough will receive those benefits to which he was entitled under Section 7(d) of his employment agreement, dated as of April 19, 2010, including without limitation: (i) separation compensation in the amount of $4.1 million, less required withholdings; (ii) his annual non-qualified deferred supplemental retirement benefit equal to $30,000 for each of the years 2012 through 2021 (not accelerated), less required withholdings; (iii) continued coverage under the Company’s group health plans at the Company’s cost for a period equal to the lesser of 18 months or such period ending as of the date Mr. McCullough is eligible to participate in another employer’s group health plan; (iv) immediate vesting of any unvested Company stock options, stock appreciation rights and restricted stock; and (v) issuance of shares representing the vested portion of his 2009 performance share awards. Related to this separation agreement,

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the statement of operations for the nine months ended 2011 reflects a charge to general and administrative expense of $6.7 million.

Affiliated Partnerships. Amounts due from/to the affiliated partnerships are primarily related to derivative positions and, to a lesser extent, unbilled well lease operating expenses, and costs resulting from audit and tax preparation services. We enter into derivative instruments for our own production as well as for our 26 affiliated partnerships' production. As of September 30, 2011, we had a payable to affiliates of $15 million representing their designated portion of the fair value of our gross derivative assets and a receivable from affiliates of $8.5 million representing their designated portion of the fair value of our gross derivative liabilities.

PDCM. On September 23, 2011, our investing partner made a capital contribution of $11.5 million to PDCM, which resulted in the investing partner obtaining a 50% interest in PDCM. Subsequent to our investing partner earning a 50% interest, all future operating and development funding needed by PDCM will be shared equally between the investing partner and us. Accordingly, to provide the funds needed by PDCM to complete the acquisition of Seneca-Upshur on October 3, 2011, we drew on our corporate credit facility a total of $76.2 million in September 2011, which was transfered to PDCM as of September 30, 2011. Our investing partner funded their portion of the acquisition price in two installments, one for $19.1 million in September 2011 and one on October 3, 2011, for $57.2 million. Our September 30, 2011, balance sheet reflects the funding of this acquisition as follows: $28.6 million, representing our proportionate share of PDCM's cash balance, was included in cash and cash equivalents, $28.6 million was included in accounts receivable affiliates, representing the advance receivable, and $19.1 million included in restricted cash long-term, which represents our portion of the Seneca-Upshur purchase price that was deposited into escrow for utilization at closing. On October 3, 2011, PDCM completed the acquisition of Seneca-Upshur for a total of $152.5 million following a capital contribution by our investing partner.

Our natural gas marketing segment manages the marketing of natural gas for PDCM and our affiliated partnerships with production in the Appalachian Basin. Our sales from natural gas marketing include $3 million and $8.8 million for the three and nine months ended 2011, respectively, and $1.3 million and $3.5 million for three and nine months ended 2010, respectively, related to the marketing of natural gas on behalf of PDCM and our affiliated partnerships. Our cost of natural gas marketing includes $2.9 million and $8.6 million for the three and nine months ended 2011, respectively, and $1.3 million and $3.4 million for the three and nine months ended 2010, respectively, related to these sales.

We provide certain well operating and administrative services for PDCM. Amounts billed to PDCM for these services were $2.4 million and $6.9 million in the three and nine months ended 2011, respectively, and $2.6 million and $8.3 million for the three and nine months ended 2010, respectively. 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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Statement of Operations Line Item	2011	2010	2011	2010
	(in millions)			
Production costs	$0.7	$0.9	$2.2	$2.8
Exploration expense	0.1	0.2	0.3	0.7
General and administrative expense	0.4	0.4	1.1	1.6

We provide well operations and pipeline services to our affiliated partnerships. The majority of our revenue and expenses related to well operations and pipeline income are associated with services provided to our affiliated partnerships.

NOTE 14 - BUSINESS SEGMENTS

We separate our operating activities into two segments: natural gas and crude oil sales and natural gas marketing. All material inter-company accounts and transactions between segments have been eliminated.

The following tables present our segment information.

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Revenues:				
Natural gas and crude oil sales	$127,773	$68,483	$264,179	$235,255
Natural gas marketing	17,209	18,337	51,308	53,613
Total	$144,982	$86,820	$315,487	$288,868
Segment income (loss) before income taxes:				
Natural gas and crude oil sales	$76,702	$21,001	$105,027	$93,861
Natural gas marketing	(19)	39	880	769
Unallocated	(23,867)	(19,302)	(76,901)	(56,876)
Total	$52,816	$1,738	$29,006	$37,754

	September 30, 2011	December 31, 2010
	(in thousands)	
Segment assets:		
Natural gas and crude oil sales	$1,500,674	$1,313,805
Natural gas marketing	10,329	16,338
Unallocated	80,352	53,701
Assets held for sale	—	5,191
Total	$1,591,355	$1,389,035

NOTE 15 - ACQUISITIONS

2005 Partnerships. On June 15, 2011, we acquired from non-affiliated investor partners' the remaining working interest in three of our affiliated partnerships: PDC 2005-A Limited Partnership, PDC 2005-B Limited Partnership and Rockies Region Private Limited Partnership ("2005 Partnerships"). We purchased these partnerships for an aggregate amount of $43.0 million, which was drawn on our corporate credit facility during the third quarter of 2011. These purchases included the non-affiliated investor partners' remaining working interests in a total of 146 gross, 104.5 net, wells located in our Wattenberg and Grand Valley Fields. The acquisitions allow us the opportunity, assuming favorable capital and commodity markets, to accelerate the pace of refracturing the wells acquired, thus allowing us to optimize revenue opportunities.

The following table presents the adjusted purchase price and the preliminary allocation thereof, based on our estimates of fair value, for natural gas and crude oil properties acquired from our 2005 Partnerships.

	(in thousands)
Total acquisition cost	$43,015

Recognized amounts of identifiable assets acquired and liabilities assumed:	
Assets acquired:	
Natural gas and crude oil properties - proved	$39,825
Fair value of derivative instruments, net	479
Other assets	3,369
Total assets acquired	43,673
Liabilities assumed:	
Asset retirement obligation	300
Other liabilities	358
Total liabilities assumed	658
Total identifiable net assets acquired	$43,015

Pro Forma Information. The results of operations for the above acquisition have been included in our consolidated financial statements from the date of acquisition. The pro forma effect of these acquisitions on our results of operations as if the acquisition had occurred as of January 1, 2010, have not been presented, as the pro forma results would not be materially different from the information presented in the accompanying statements of operations.

NOTE 16 - SUBSEQUENT EVENTS

Acquisition of Seneca-Upshur. On October 3, 2011, PDCM acquired from an unrelated third party ("the seller") 100% of the membership interest in Seneca-Upshur for the purchase price of $152.5 million ($76.2 million net to PDC). See Notes 9 and 13 for related disclosure. As of September 30, 2011, we had completely funded our net acquisition contribution through our corporate credit facility. Pursuant to the terms of the purchase agreement, there will be certain post-closing adjustments through April 1, 2012, including with respect to title, environmental and plugging and abandonment matters. In addition, as part of the transaction, the Company took over certain ordinary course litigation. However, the seller retained certain specific litigation matters.

Acquisition of 2003/2002-D Partnerships. On October 28, 2011, the non-affiliated investor partners of the 2003/2002-D Partnerships approved the applicable merger agreements. We will purchase these partnerships for an aggregate amount of $29.5 million, which will be drawn on our corporate credit facility in November 2011. These purchases included the non-affiliated investor partners remaining working interests in a total of 153 gross, 99.7 net, wells located in our Wattenberg and Grand Valley Fields. The acquisitions allow us the opportunity, assuming favorable capital and commodity markets, to accelerate the pace of refracturing the wells acquired, thus allowing us to optimize revenue opportunities. See Note 9 for related disclosure.

Corporate Credit Facility Redetermination. On October 12, 2011, the biannual redetermination of our corporate bank credit facility's borrowing base, which was based upon our natural gas and crude oil reserves as of June 30, 2011, was completed. Based on the redetermination, our aggregate revolving commitment was increased by $50 million to $400 million. There were no other changes to our corporate bank credit facility as a result of the redetermination.

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

EXECUTIVE SUMMARY

Financial Overview

Natural gas, NGL and crude oil sales increased 67.8% quarter-over-quarter and 40% year-over-year. These increases were primarily driven by an increase in production of 23.9% quarter-over-quarter and 21.9% year-over-year and an increase in average price per Mcfe of 26.7% quarter-over-quarter and 12.4% year-over-year. Leading the increases in production were liquids, with crude oil production increasing 65% quarter-over-quarter and 43.4% year-over-year and NGL production increasing 46.9% and 22.8%, respectively. Strategically, it is our goal to increase our liquids to gas ratio. For the three and nine months ended 2011, our liquids to gas ratio (in percentages) was 38/62 and 33/67, respectively, compared to 30/70 for each of the three and nine months ended 2010, with Wattenberg's production accounting for approximately 86% of our total liquids produced during each of the three and nine months ended 2011.

Available liquidity as of September 30, 2011, was $202 million, including $40.1 million related to PDCM for the acquisition and development of Marcellus properties, compared to $379.3 million, which included $23.9 million related to PDCM, as of December 31, 2010. Available liquidity is comprised of cash, cash equivalents and funds available under our credit facility after giving consideration to our undrawn outstanding letters of credit. Cash and cash equivalents as of September 30, 2011, primarily represents our proportionate share of our advance to PDCM on September 30, 2011, for our share of the $152.5 million Seneca-Upshur acquisition, which occurred on October 3, 2011. The source of this advance was a draw on our corporate credit facility. After giving consideration to the closing on this acquisition and our borrowing base redetermination effective October 12, 2011, our available liquidity was $223.4 million, including $11.5 million related to PDCM.

In June 2011, we executed on our second tranche of partnership acquisitions by closing on the acquisition of the 2005 Partnerships. The aggregate purchase price of $43 million was drawn on the corporate credit facility during the third quarter of 2011. Additionally, see Note 16, Subsequent Events, to the accompanying condensed consolidated financial statements included in this report regarding the successful completion of our third tranche of partnership acquisitions, the 2003/2002-D Partnerships, in October 2011 for an aggregate purchase price of $29.5 million.

Natural Gas and Crude Oil Properties Identified for Potential Divestiture

On October 19, 2011, at our Analyst Day presentation, we announced that we had identified certain natural gas and crude oil properties for potential divestiture and that we were seeking an industry joint venture partner to assist us in the development of our Utica Shale play. The potential divestitures include 100% of our interest in the Permian Basin, northeast Colorado and other miscellaneous properties held in various states. Further, PDCM, our Marcellus joint venture, had announced previously its intent to divest its Marcellus acreage in Pennsylvania. While we have engaged the services of two independent financial and technical advisors, one for the potential divestiture of our Permian assets and the other for assisting us in our search for a Utica Shale joint venture partner, none of the potential divestitures qualified for held for sale status as of September 30, 2011. However, we envision the divestiture of these properties to occur within the next six months. The divestitures and a Utica Shale joint venture partner will provide us with capital funding to allow us to accelerate the development of our liquid-rich inventory of projects in the Wattenberg Field, including the horizontal Niobrara and the vertical Codell formations, and the Utica Shale in Ohio. If we are successful in divesting these properties, our drilling and development activities will be focused primarily in two regions: the Rocky Mountain and Appalachia. There can be no assurance that we will be successful in the divestiture of these properties, individually or collectively, or find a Utica Shale joint venture partner, or on terms acceptable to us or at all.

Operational Overview and Update

Drilling Activities. For the nine months ended 2011, we drilled 116 developmental wells in the Wattenberg Field, of which 100 wells were completed and turned in line. We also executed 132 refrac/recompletion projects on 70 wells in this area. Of the 116 wells drilled, 13 were horizontal Niobrara with nine of them producing as of September 30, 2011. We drilled a total of 16 developmental wells in the Permian Basin during the nine months ended 2011 with 10 of them producing and one determined to be a dry hole as of the end of the period. For the nine months ended September 30, 2011, PDCM spudded six horizontal Marcellus wells, none of which had been turned in line as of the end of the period, and completed three horizontal Marcellus wells that were in-process as of December 31, 2010.

Acquisitions and Leasehold Agreements. As discussed above, PDCM completed its acquisition of Seneca-Upshur on October 3, 2011. The acquisitions includes all rights and all depths to an estimated 100,000 net acres: 90,000 acres prospective for the Marcellus Shale primarily located in Harrison, Taylor, Barbour, Upshur, Lewis and Randolph counties of north central West Virginia and 10,000 acres prospective for the Huron Shale primarily located in Mingo and McDowell counties in southwest West Virginia. The acreage is held by production from approximately 1,400 wells producing from the shallow Devonian, which were included in the transaction.We estimate that this acquisition brings with it approximately 5.4 MMcfe per day and 30 Bcfe of proved developed producing reserves net to PDCM.

During the three months ended 2011, we entered into a series of leasehold agreements providing us with an option to acquire acreage targeting the wet natural gas and crude oil phases of the Utica Shale play throughout southeastern Ohio. Pursuant to the agreements, we have the right to acquire an estimated 30,000 net acres. Should we exercise our right to acquire all 30,000 acres, we estimate that the purchase price of such leaseholds will approximate $50 million. Further, subsequent to September 30, 2011, we entered into unrelated leasehold agreements giving us the opportunity to purchase an estimated additional 10,000 acres for up to $20 million. Currently, we are actively pursuing an industry joint venture partner to participate in and share in funding the growth and development in this play. We cannot guarantee we will be successful in securing a partner.

In addition to the 2005 Partnership acquisitions in June 2011, on October 28, 2011, the non-affiliated investor partners in the 2003/2002-D Partnerships approved the applicable merger agreements, whereby we will acquire from the non-affiliated investor partners their remaining working interests in a total of 153 gross, 99.7 net, wells located in our Wattenberg and Grand Valley Fields. The acquisitions allow us the opportunity, assuming favorable capital and commodity markets, to accelerate the pace of refracturing the wells acquired, thus allowing us to optimize revenue opportunities. We estimate that these acquisitions bring with them approximately 2 MMcfe per day and 21 Bcfe of net reserves.

2011 Capital Budget

In July 2011, the Board approved an increase in our 2011 capital budget to $324 million, excluding acquisitions. The original plan was approved in January 2011 for $233 million. We have allocated $285 million of the budget to developmental drilling, with the remaining being allocated to exploration, leasing and other capital expenditures. Most of the increase in developmental drilling has been further allocated to the liquid-rich Wattenberg Field, including an expansion of the horizontal Niobrara program. We expect to drill in the Wattenberg Field a total of 125 vertical wells and 17 horizontal Niobrara wells, and complete 187 refrac/recompletion projects. The revised capital budget includes plans by PDCM to drill nine horizontal Marcellus wells.

We believe that our revised 2011 capital budget, combined with our investment in 2010, will grow production from continuing operations by approximately 24%, from 37.6 Bcfe in 2010 to 46.5 Bcfe in 2011, while increasing the liquids portion of our production as a percentage of our total production, thereby enabling us to benefit from the price differential between crude oil and natural gas. The production growth is expected to come primarily from the Wattenberg Field, including the horizontal Niobrara, Permian Basin and Marcellus Shale development as well as from the wells acquired through our affiliated partnership acquisition plan. Assuming our Permian and northeast Colorado divestitures are consummated, any proceeds received from the divestitures could be used to fund capital projects designed to increase our liquids production. The anticipated uses of such proceeds may include increasing Wattenberg capital expenditures, buying back additional partnerships or increasing exploratory activities in the Utica Shale play.

Non-U.S. GAAP Financial Measures

We use "adjusted cash flow from operations," "adjusted net income (loss) attributable to shareholders" and "adjusted EBITDA," non-U.S. GAAP financial measures, for internal managerial purposes, when evaluating period-to-period comparisons 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, cash flows from operations, investing or financing activities, nor as a liquidity measure or indicator of operating results or 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 below for a detailed description of these measures as well as a reconciliation of each to the nearest U.S. GAAP measure.

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Results of Operations

Summary Operating Results

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	Change	2011	2010	Change
	(dollars in thousands, except per unit data)					
Production (1)						
Natural gas (MMcf)	7,446.1	6,827.6	9.1 %	22,706.4	19,624.4	15.7 %
Crude oil (MBbls)	537.6	325.8	65.0 %	1,335.7	931.2	43.4 %
NGLs (MBbls)	226.6	154.3	46.9 %	543.3	442.5	22.8 %
Natural gas equivalent (MMcfe) (2)	12,031.1	9,707.9	23.9 %	33,979.9	27,866.7	21.9 %
Average MMcfe per day	130.8	105.5	23.9 %	124.5	102.1	21.9 %
Natural Gas, NGL and Crude Oil Sales						
Natural gas	$26,320	$22,284	18.1 %	$76,676	$73,346	4.5 %
Crude oil	44,423	23,283	90.8 %	117,270	67,478	73.8 %
NGLs	8,631	4,980	73.3 %	21,522	16,279	32.2 %
Provision for underpayment of natural gas sales	—	(3,252)	*	—	(3,252)	*
Total natural gas, NGL and crude oil sales	$79,374	$47,295	67.8 %	$215,468	$153,851	40.0 %
Realized Gain (Loss) on Derivatives, net (3)						
Natural gas	$6,508	$5,361	21.4 %	$19,739	$32,094	(38.5)%
Crude oil	(1,561)	2,159	(172.3)%	(9,201)	6,243	(247.4)%
Total realized gain on derivatives, net	$4,947	$7,520	(34.2)%	$10,538	$38,337	(72.5)%
Average Sales Price (excluding gain/loss on derivatives)						
Natural gas (per Mcf)	$3.53	$3.26	8.3 %	$3.38	$3.74	(9.6)%
Crude oil (per Bbl)	82.65	71.47	15.6 %	87.80	72.46	21.2 %
NGLs (per Bbl)	38.08	32.28	18.0 %	39.61	36.79	7.7 %
Natural gas equivalent (per Mcfe)	6.60	5.21	26.7 %	6.34	5.64	12.4 %
Average Sales Price (including gain/loss on derivatives)						
Natural gas (per Mcf)	$4.41	$4.05	8.9 %	$4.25	$5.37	(20.9)%
Crude oil (per Bbl)	79.73	78.09	2.1 %	80.91	79.17	2.2 %
NGLs (per Bbl)	38.08	32.28	18.0 %	39.61	36.79	7.7 %
Natural gas equivalent (per Mcfe)	7.01	5.98	17.2 %	6.65	7.01	(5.1)%
Average Lifting Cost (per Mcfe) (4)	$0.87	$1.13	(23.0)%	$1.04	$1.08	(3.7)%
Natural Gas Marketing (5)	$(18)	$37	(148.6)%	$881	$783	12.5 %

Other Costs and Expenses						
Exploration expense	$1,666	$3,712	(55.1)%	$5,537	$13,960	(60.3)%
General and administrative expense	13,683	10,426	31.2 %	47,065	30,975	51.9 %
Depreciation, depletion and amortization	34,316	28,024	22.5 %	99,347	82,427	20.5 %
Interest Expense, net	$9,460	$8,153	16.0 %	$27,578	$23,586	16.9 %

*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 the percentage interest we own.
(2) Six Mcf of natural gas equals one Bbl of crude oil or NGL.
(3) Represents realized derivative gains and losses related to natural gas and crude oil sales segment, which does not include realized derivative gains and losses related to natural gas marketing.

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(4) Represents lease operating expenses 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.

Natural Gas, NGL and Crude Oil Sales

The following tables present natural gas, NGL and crude oil production and average sales price by area.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	Percentage Change	2011	2010	Percentage Change
Production						
Natural gas (MMcf)						
Rocky Mountain Region	6,231.4	6,153.3	1.3 %	19,170.1	17,720.0	8.2 %
Appalachian Basin	1,073.4	612.5	75.2 %	3,190.5	1,813.7	75.9 %
Permian and other (1)	141.3	61.8	128.6 %	345.8	90.7	281.3 %
Total	7,446.1	6,827.6	9.1 %	22,706.4	19,624.4	15.7 %
Crude oil (MBbls)						
Rocky Mountain Region	469.8	312.0	50.6 %	1,158.2	915.6	26.5 %
Appalachian Basin	1.1	2.3	(52.2)%	3.8	4.1	(7.3)%
Permian and other (1)	66.7	11.5	*	173.7	11.5	*
Total	537.6	325.8	65.0 %	1,335.7	931.2	43.4 %
NGLs (MBbls)						
Rocky Mountain Region	194.0	142.4	36.2 %	475.9	427.4	11.3 %
Permian and other (1)	32.6	11.9	173.9 %	67.4	15.1	*
Total	226.6	154.3	46.9 %	543.3	442.5	22.8 %
Natural gas equivalent (MMcfe)						
Rocky Mountain Region	10,213.8	8,878.9	15.0 %	28,974.2	25,777.5	12.4 %
Appalachian Basin	1,080.0	626.5	72.4 %	3,213.5	1,838.8	74.8 %
Permian and other (1)	737.3	202.5	264.1 %	1,792.2	250.4	*
Total	12,031.1	9,707.9	23.9 %	33,979.9	27,866.7	21.9 %

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

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(1) Our Permian Basin properties were acquired in July and November 2010.

Average Sales Price (excluding gain/loss on derivatives)	Three Months Ended September 30, 2011	2010	Percentage Change	Nine Months Ended September 30, 2011	2010	Percentage Change
Natural gas (per Mcf) (1)						
Rocky Mountain Region	$3.45	$3.14	9.9 %	$3.22	$3.64	(11.5)%
Appalachian Basin	4.27	4.52	(5.5)%	4.36	4.70	(7.2)%
Permian and other (2) (3)	1.87	3.48	(46.3)%	3.09	3.22	(4.0)%
Weighted average price	3.53	3.26	8.3 %	3.38	3.74	(9.6)%
Crude oil (per Bbl)						
Rocky Mountain Region	82.02	71.35	15.0 %	88.07	72.43	21.6 %
Appalachian Basin	67.76	75.44	(10.2)%	76.90	75.24	2.2 %
Permian and other (2)	87.35	73.75	18.4 %	86.27	73.75	17.0 %
Weighted average price	82.65	71.47	15.6 %	87.80	72.46	21.2 %
NGLs (per Bbl)						
Rocky Mountain Region	37.51	31.42	19.4 %	38.56	36.49	5.7 %
Permian and other (2)	41.51	42.71	(2.8)%	47.09	45.44	3.6 %
Weighted average price	38.08	32.28	18.0 %	39.61	36.79	7.7 %
Natural gas equivalent (per Mcfe)						
Rocky Mountain Region	6.59	5.18	27.2 %	6.28	5.68	10.6 %
Appalachian Basin	4.31	4.70	(8.3)%	4.42	4.81	(8.1)%
Permian and other (2)	10.10	7.76	30.2 %	10.73	7.29	47.2 %
Weighted average price	6.60	5.21	26.7 %	6.34	5.64	12.4 %

Amounts may not recalculate due to rounding.

(1) Our average sales price for natural gas is based on the "net-back" method of accounting for transportation, gathering and processing arrangements with natural gas purchasers. See our revenue recognition policy described in Note 2, Summary of Significant Accounting Policies, to consolidated financial statements in our 2010 Form 10-K and Part 1, Item 2, Financial Condition, Liquidity and Capital Resources - Cash Flows, included in this report.

(2) Our Permian Basin properties were acquired in July and November 2010.

(3) Reflects immaterial estimate to actual sales adjustments recorded during the three months ended 2011. These adjustments had a negative impact on the average sales price of $0.99 per Mcf.

The quarter-over-quarter and year-over-year increases in natural gas, NGL and crude oil sales revenue were primarily due to the following:

	September 30, 2011 Three Months Ended (in millions)	Nine Months Ended
Increase in production	$19.5	$44.5
Increase in average crude oil price	6.0	20.5
Increase in average NGL price	1.3	1.5
Increase (decrease) in average natural gas price	2.0	(8.2)
Decrease in provision for underpayment of natural gas sales	3.3	3.3

Total increase in natural gas, NGL and crude oil sales revenue	$32.1	$61.6

Production Costs

Production costs include our lease operating expenses, production taxes, the cost to operate wells and pipelines for our affiliated partnerships and other third parties and certain production and engineering staff-related overhead costs.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in millions)			
Lease operating expenses	$10.4	$10.9	$35.4	$30.0
Production taxes	4.9	3.1	14.3	8.0
Costs of well operations and pipeline services	1.7	1.8	5.4	5.7
Overhead and other production expenses	(1.2)	0.7	1.5	3.8
Total production costs	$15.8	$16.5	$56.6	$47.5

Lease operating expenses. Quarter-over-quarter, the decrease in lease operating expenses, or lifting costs, was primarily due to a $2 million decrease in well workovers, which include tubing and casing repairs, and environmental remediation charges, offset in part by an increase in costs due to the 23.9% increase in production. Year-over-year, the increase in lifting costs was primarily related to the 21.9% increase in production as well as a $1 million increase in well workovers and environmental remediation charges. On a per Mcfe basis, lifting costs decreased 23% quarter-over-quarter and 3.7% year-over-year. The decreases in the per Mcfe cost were primarily due to the increases in production for the three and nine months ended 2011, which resulted in well workovers, environmental charges and the fixed cost portion of our lease operating expenses being absorbed by an increased number of units.

Production taxes. Production taxes fluctuate with natural gas, NGL and crude oil sales. The increases in production taxes quarter-over-quarter and year-over-year were primarily related to higher ad valorem rates in new areas of production, such as the Permian Basin, as well as in existing areas of production, such as certain Colorado counties. Additionally, the increase in production taxes was also impacted by the increases in natural gas, NGL and crude oil sales for the same periods.

Overhead and other production expenses. The quarter-over-quarter and year-over-year decreases in overhead and other production expenses were primarily due to our July 2011 amendment to a firm transportation agreement with an unrelated third party regarding a firm transportation commitment and the corresponding reversal of a $3.1 million accrued liability, which was offset in part by an increase in abandoned undrilled well site costs of $0.8 million.

Commodity Price Risk Management, Net

We use various derivative instruments to manage fluctuations in natural gas and crude oil prices. We have in place a variety of floors, collars, fixed-price swaps and basis swaps on a portion of our estimated natural gas and crude oil production. We sell all of our physical natural gas and crude oil at similar prices to the indices inherent in our derivative instruments. As a result, for the volumes underlying our derivative positions, 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 fixed price related to our swaps.

Commodity price risk management, net, includes realized gains and losses and unrealized mark-to-market changes in the fair value of the derivative instruments related to our natural gas and crude oil 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 Measurements and Disclosures, and Note 4, Derivative Financial Instruments, to the accompanying condensed consolidated financial statements included in this report for additional details of our derivative financial instruments. See Item 3, Quantitative and Qualitative Disclosures About Market Risk, for a detailed presentation of our open derivative positions as of September 30, 2011.

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,	
	2011	2010	2011	2010
	(in millions)			
Commodity price risk management gain, net:				
Realized gains (losses):				
Natural gas	$6.5	$5.4	$19.7	$32.1
Crude oil	(1.6)	2.1	(9.2)	6.2
Total realized gains, net	4.9	7.5	10.5	38.3
Unrealized gains:				
Reclassification of realized gains included in prior periods unrealized	(2.8)	(5.7)	(9.0)	(19.9)
Unrealized gains for the period	44.6	17.2	41.9	56.1
Total unrealized gains, net	41.8	11.5	32.9	36.2
Total commodity price risk management gain, net	$46.7	$19.0	$43.4	$74.5

Realized gains recognized in the three and nine months ended 2011 are primarily the result of lower natural gas spot prices at settlement compared to the respective strike price of our natural gas derivative positions. For the three and nine months ended 2011, realized gains on natural gas, exclusive of basis swaps, were $10.7 million and $30 million, respectively. These gains were reflective of a weighted average strike price of $5.99 and $6.46, respectively, compared to a weighted average settlement price of $4.20 and $4.21, respectively. These gains were offset in part by realized losses of $4.2 million and $10.3 million, respectively, on our basis swap positions as the negative basis differential between NYMEX and CIG was a weighted average of $0.28 and $0.30, respectively, compared to a weighted average strike price of $1.82 and $1.81, respectively.

The realized gains on natural gas derivative positions for the three and nine months ended 2011 were offset in part by realized losses on our crude oil positions as a result of higher spot prices at settlement compared to the respective strike price on our derivative positions. For the three and nine months ended 2011, the realized losses were reflective of a weighted average strike price of $81.02 and $74.92, respectively, compared to a weighted average settlement price of $91.94 and $95.35, respectively.

Unrealized gains during the three and nine months ended 2011 were primarily related to a downward shift in the natural gas and crude oil forward curves and their impact on the fair value of our open positions. For the three months ended 2011, unrealized gains on our natural gas and crude oil positions were $15.9 million and $30.7 million, respectively, offset slightly by the narrowing of the CIG basis forward curve resulting in an unrealized loss of $2 million. For the nine month period, unrealized gains on our natural gas and crude oil derivative positions were $19.9 million and $25.1 million, respectively, offset in part by a narrowing of the CIG basis forward curve resulting in an unrealized loss of $3.1 million.

During the three and nine months ended 2010, realized gains were $7.5 million and $38.3 million, respectively, as a result of lower natural gas and crude oil spot prices at settlement compared to the respective strike price, offset in part by the basis differential between NYMEX and CIG being narrower than the strike price of the derivative position. For the three months ended 2010, the unrealized gains were primarily related to our natural gas positions, as the forward strip price shifted downward during the quarter. Unrealized gains on our natural gas positions for the three months ended 2010 were $26.8 million and unrealized losses on our crude oil positions and our CIG basis swaps were $8.0 million and $1.6 million, respectively. For the nine month period, the unrealized gains were primarily related to a downward shift in the forward strip price of natural gas and crude oil and the basis differential between NYMEX and CIG narrowing during the year. For the nine months ended 2010, unrealized gains on our natural gas and crude oil positions were $58.5 million and $0.3 million, respectively, offset in part by unrealized losses on our CIG basis swaps of $2.7 million.

Natural Gas Marketing

Fluctuations in our natural gas marketing's income contribution are primarily due to fluctuations in natural gas prices, realized and unrealized (mark-to-market adjustments) gains and losses on 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,	
	2011	2010	2011	2010
	(in millions)			
Sales from natural gas marketing				
Natural gas sales revenue	$16.2	$16.5	$49.7	$47.9
Realized derivative gain	0.5	1.6	2.1	4.5
Unrealized derivative gain (loss)	0.5	0.2	(0.5)	1.2
Total sales from natural gas marketing	17.2	18.3	51.3	53.6
Costs of natural gas marketing				
Costs of natural gas purchases	15.9	16.2	48.1	46.5
Realized derivative loss	0.4	1.4	1.8	4.2
Unrealized derivative loss (gain)	0.6	0.4	(0.3)	1.3
Other	0.3	0.3	0.8	0.8
Total costs of natural gas marketing	17.2	18.3	50.4	52.8
Natural gas marketing contribution margin	$—	$—	$0.9	$0.8

Quarter-over-quarter, natural gas sales revenue and costs of natural gas purchases were slightly lower for the current period primarily due to lower natural gas prices. Year-over-year, the increases in natural gas sales revenue and costs of natural gas purchases were primarily due to a 13.2% increase in volume offset in part by decreases in average prices, with a 8.5% decrease in the average natural gas sales price and a 8.8% decrease in the average natural gas purchase price.

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 gas and enter into cash-settled derivative positions with counterparties in order to offset those same physical positions. See Note 4, Derivative Financial Instruments, to our 2010 Form 10-K and Item 3, Quantitative and Qualitative Disclosures About Market Risk, included in this report for a discussion of how each derivative type impacts our cash flows and a detailed presentation of our derivative positions as of September 30, 2011.

Other Costs and Expenses

Exploration Expense

The following table presents the major components of exploration expense.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in millions)			

Amortization of individually insignificant unproved properties	$0.5	$1.1	$1.5	$2.2
Exploratory dry hole costs	—	0.5	0.2	4.1
Geological and geophysical costs	0.3	0.3	1.2	2.2
Operating, personnel and other	0.9	1.8	2.6	5.5
Total exploration expense	$1.7	$3.7	$5.5	$14.0

Exploratory dry hole costs. Exploratory dry hole costs for the three and nine months ended 2010 includes the fracturing and testing of several exploratory zones of a well located in the Grand Valley field as well as an oil test well drilled in the NECO area.

Geological and geophysical costs. The year-over-year decrease in geological and geophysical was primarily related to a reduction in geological and seismic testing. In 2010, our exploration activities in the Marcellus intensified, resulting in increased geological and seismic costs.

Operating, personnel and other. The quarter-over-quarter and year-over-year decreases in operating, personnel and other were primarily related to the reassignment of former exploration department personnel during the first quarter of 2011 to development drilling or administrative activities.

General and Administrative Expense

General and administrative expense increased $3.3 million or 31.2% quarter-over-quarter. The increase was primarily due to an increase in payroll and payroll-related expenses, which was primarily related to the reassignment of former exploration department personnel during the first quarter of 2011 to general and administrative activities and an overall increase in employee benefits.

The year-over-year increase of $16.1 million or 51.9% in general and administrative expense was primarily due to an increase in payroll and payroll-related expense of $11.3 million, of which $6.7 million was related to a separation agreement with our former chief executive officer. Also contributing to the increase in payroll and payroll-related expenses were the reassignment of former exploration department personnel and an overall increase in employee benefits.

Depreciation, Depletion and Amortization

Natural gas and crude oil properties. DD&A expense for natural gas and crude oil properties increased 24% quarter-over-quarter and 22.4% year-over-year. These increases in DD&A expense were primarily related to the increase in our production for the three and nine months ended 2011, which contributed $6.3 million and $16.9 million to the increases, respectively.

The following table presents our DD&A rates for natural gas and crude oil properties by area.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(per Mcfe)			
Rocky Mountain Region:				
Wattenberg Field	$3.05	$2.95	$3.22	$3.11
Grand Valley Field	2.42	2.61	2.48	2.51
Weighted average	2.71	2.71	2.80	2.76
Permian Basin	3.86	2.07	3.59	2.07
Appalachian Basin	2.01	2.73	2.13	2.69
Total weighted average	2.71	2.71	2.77	2.76

Non-natural gas and crude oil properties. Depreciation expense for non-natural gas and crude oil properties was $1.7 million and $5.1 million for the three and nine months ended 2011 compared to $1.7 million and $5.4 million for the three and nine months ended 2010.

Non-Operating Income/Expense

Interest Expense. The quarter-over-quarter increase in interest expense was primarily related to an increase in debt issuance amortization expense. Year-over-year, the increase in interest expense was primarily related to an increase in debt issuance amortization expense as well as a higher average outstanding debt balance, which was primarily related to our November 2010 convertible debt issuance offset in part by lower average outstanding borrowings under our corporate bank credit facility.

Provision/Benefit 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 quarter-over-quarter and year-over-year. Due to tax interim period income fluctuations, full year forecast changes and the different effects of permanent tax adjustments, primarily percentage depletion, the effective tax rate comparison for the three month periods is not meaningful. The tax rates for the nine month periods (provision on income) were comparable and consistent at 33.9% and 32.9%, respectively.

Beginning with our 2010 tax year, we were accepted into and have agreed to participate in the CAP program. As part of this program, we agreed to an accelerated timeline for the IRS examination of our 2007, 2008 and 2009 tax years. This examination was completed during the second quarter of 2011, without any significant increase or decrease in tax expense. See Note 6, Income Taxes, to the accompanying condensed consolidated financial statements, for a discussion on the reduction of our uncertain tax liability due to the conclusion of this examination. We have accepted an offer for continued participation in the IRS CAP program for our 2011 tax year and we have applied for continued participation in this program for the 2012 tax year.

Discontinued Operations

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See Note 12, Divestitures and Discontinued Operations, to the accompanying condensed consolidated financial statements included in this report for additional information regarding the divestiture of our North Dakota and Michigan assets.

We completed the sale of our Michigan assets to an unrelated third party in July 2010. In December 2010, we effected a letter of intent with an unrelated third party, which provided for the sale of 100% of our North Dakota assets. In February 2011, we executed a purchase and sale agreement and subsequently closed with the same unrelated third party. Proceeds from the sale were $9.5 million, net of non-affiliated investor partners' share of $3.8 million, resulting in a pretax gain on sale of $3.9 million.

The table below presents production data previously included in operating results related the assets divested.

	Three Months Ended September 30,	Nine Months Ended September 30,	
Discontinued Operations	2010	2011	2010
Production			
Natural gas (MMcf)	67.2	8.7	790.0
Crude oil (MBbls)	10.4	3.9	33.0
Natural gas equivalent (MMcfe)	129.6	32.1	987.6

Net Income Attributable to Shareholders/Adjusted Net Income (Loss) Attributable to Shareholders

Net income attributable to shareholders for the three months ended 2011 was $32.6 million compared to $3.4 million for the three months ended 2010; net income attributable to shareholders for the nine months ended 2011 was $21.8 million compared to $24.4 million for the nine months ended 2010. Adjusted net income attributable to shareholders, a non-U.S. GAAP financial measure, for the three and nine months ended 2011, was $6.7 million and $1.6 million, respectively, compared to an adjusted net loss, a non-U.S. GAAP financial measure, of $1.5 million and adjusted net income of $4.1 million for the three and nine months ended 2010, respectively. The changes in net income attributable to shareholders are discussed above, with the most significant changes being related to natural gas, NGL and crude oil sales, commodity price risk management activities, general and administrative expense, production costs and for the three months ended 2011, DD&A expense. These same reasons for change similarly impacted adjusted net income (loss) attributable to shareholders, with the exception of the unrealized gains 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 provided by operating activities and our corporate bank credit facility. More recently, as market conditions have permitted, we have utilized the debt and equity markets and engaged in asset monetization transactions as additional sources of financing.

Our primary source of cash flows provided by operating activities is the sale of natural gas, NGL and crude oil. 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 derivative program. 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 two years or less, our debt covenants limit our holdings to 80% of our expected future production on total proved reserves (proved developed producing, proved developed not producing and proved undeveloped). For instruments that mature greater than two years but no more than our designated maximum maturity, our debt covenants limit our holdings to 80% of our expected future production on proved developed producing properties. Therefore, we may still have significant fluctuations in and significant risks to our cash flows provided by 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 our practice of utilizing excess cash to reduce the outstanding borrowings under our credit facility. At September 30, 2011, we had a working capital surplus of $25.2 million compared to a surplus of $16.2 million at December 31, 2010. The increase in working capital was primarily related to the increase in accounts receivable - affiliates due to an advance to PDCM on September 30, 2011 to fund the October closing of the Seneca-Upshur LLC acquisition and the increase in the fair value of derivatives, offset in part by the decrease in cash and cash equivalents as we have executed on our 2011 capital plan.

We ended September 2011 with cash and cash equivalents of $32.3 million and availability under our credit facility of $169.7 million, for a total liquidity position of $202 million compared to $379.3 million at December 31, 2010. The decrease in liquidity of $177.3 million, or 46.7%, was primarily due to capital expenditures of $241.1 million, the acquisition of natural gas and crude oil properties of $41.4 million and the advanced funding to PDCM for the acquisition of properties of $76.2 million, of which $28.6 million was included in our available liquidity as of September 30, 2011, due to the consolidation of our proportionate share of PDCM's cash and cash equivalents. These uses of cash were offset in part by sources of cash provided by operating activities of $105.5 million, an increase in the borrowing base of our corporate credit facility of $28.8 million and $9.5 million from the divestiture of our North Dakota assets in February 2011. On October 3, 2011, the acquisition of Seneca-Upshur was consummated; and, on October 12, 2011, the borrowing base on our corporate credit facility was redetermined at $400 million. After giving consideration to the closing on this acquisition and our borrowing base redetermination, our available liquidity was $223.4 million, including $11.5 million related to PDCM. With our current liquidity position and expected cash flows from operations, we believe that we have sufficient capital for operations and our planned uses of capital for the next twelve-month period.

Capital Expenditures

2011 Capital Budget. We establish a capital plan each calendar year based on our development and exploration opportunities, liquidity position and the expected cash flows provided by operating activities for that year. We may revise our capital plan during the year as a result of acquisitions and dispositions of assets, drilling results, commodity prices, changes in our borrowing capacity and/or significant changes in cash flows. In January 2011, our Board approved our 2011 capital plan of $233 million, exclusive of potential acquisitions, to allow us to take advantage of current market conditions related to liquids. The plan provided for $205 million in developmental drilling, including refrac/recompletion projects, with the remaining $28 million for exploration, acquisition of leases and other capital needs. In July 2011, our Board approved a revised 2011 capital budget. The revised budget includes a capital plan of $324 million, excluding acquisitions. We believe, based on the current commodity price environment and our revised estimated 2011 production of 46.5 Bcfe, an increase of approximately 24% over 2010 production from continuing operations, that our cash flows provided by operating activities will fund a significant portion of our 2011 capital plan, with the balance and any acquisitions being financed through the use of our corporate credit facility, the monetization of assets or a combination of both.

Because production from our existing properties declines rapidly in the first few years of production, in order to grow our production, we need to continue to commit significant amounts of capital year after year. If capital is not available or is constrained in the future, including by reason of the cost of capital, we will be limited to our cash flows provided by operating activities and liquidity under our credit facility as the sources for funding our capital expenditures. We would not be able to maintain our current level of production and cash flows provided by operating activities if capital markets and commodity prices were to become depressed and/or the borrowing base on our credit facility was reduced. The occurrence of such an event may result in our immediate election to defer a substantial portion of our planned capital expenditures for any given future period and could have a material negative impact on our operations in the future.

Utica Shale Leasehold Acquisitions. During the three months ended 2011, we entered into a series of leasehold agreements providing us with an option to acquire acreage targeting the wet natural gas and crude oil phases of the Utica Shale play throughout southeastern Ohio. Pursuant to the agreements, we have the right, after confirmation of title, to acquire an estimated 30,000 net acres. Should we confirm title to all 30,000 acres, we estimate that the purchase price of such leaseholds will approximate $50 million. Further, subsequent to September 30, 2011, we entered into unrelated leasehold agreements giving us the opportunity to purchase an estimated additional 10,000 acres, subject to confirmation of title, for up to $20 million. Currently, we are actively pursuing an industry joint venture partner to participate in and share in funding the growth and development in this play. We cannot guarantee we will be successful in securing a partner.

Partnership Acquisition Plan. We are the managing general partner of various public limited partnerships. In 2010, we disclosed our intent to pursue, beginning in the fall of 2010 and extending through the next three years, the acquisition of the limited partnership units (the “Acquisition Plan”) held by investor partners of the particular partnership other than those held by PDC or its affiliates (“non-affiliated investor partners”), in certain limited partnerships that PDC had previously sponsored. For additional information regarding our intent to pursue the acquisitions of these partnerships, refer to our prior disclosure included in filings made with the SEC. However, such information shall not, by reason of this reference, be deemed to be incorporated by reference in, or otherwise be deemed to be part of, this report. Under the Acquisition Plan, any existing or future merger offer will be subject to the terms and conditions of the related merger agreement, and such agreement does or will likely contemplate the partnership being merged with and into a wholly-owned subsidiary of PDC. Each such merger will also be subject to, among other things, us having sufficient available capital, the economics of the merger and the approval by a majority of the limited partnerships units held by the non-affiliated investor partners of each respective limited partnership. Consummation of any proposed merger of a limited partnership under the Acquisition Plan will result in the termination of the existence of that partnership and the right of non-affiliated investor partners to receive a cash payment for their limited partnership units in that partnership.

We expect that the acquisition of these partnerships will provide us with immediate growth in both production and proved reserves from assets with which we are familiar. We believe that these acquisitions will also allow us the opportunity to identify, pursue and accelerate a refracture program of the wells acquired. See Notes 9 and 16, Commitments and Contingencies – Merger Agreements and Subsequent Events, respectively, to the accompanying condensed consolidated financial statements included in this report for a discussion of the September 30, 2011, pending acquisition of the 2003/2002-D Partnerships and the subsequent investing partners' merger approval, which will require that the purchase price to be funded in November 2011, as well as Note 15, Acquisitions, for a discussion of the completed acquisition of our 2005 Partnerships. We expect to finance any future partnership acquisitions through the utilization of our corporate bank credit facility.

Financing Activities

To date, we have experienced no impediments in our ability to access borrowings under our current corporate bank credit facility or the capital markets, as demonstrated by our November 2010 capital market transactions. We cannot guarantee however, that such access will continue in the future, or be available on terms acceptable to us. We continue to monitor market events and circumstances and their potential impacts on each of the lenders that comprise our corporate bank credit facility. Our corporate bank credit facility borrowing base is subject to size redeterminations each May and November based upon a quantification of our proved reserves at each December 31st and June 30th, respectively. A commodity price deck reflective of the current and future commodity pricing environment is utilized by our lenders to quantify our reserve reports and determine the underlying borrowing base. On October 12, 2011, based on our June 30, 2011, reserves, our borrowing base was increased by $50 million to $400 million. Our next redetermination is scheduled for May 2012. While we continually aim to add producing reserves through our drilling operations, we believe a significant decrease in commodity prices could have a negative impact on our future borrowing base redeterminations, which could then result in a material adverse effect on our operations.

Since the inception of PDCM in October 2009, we have not had to provide any capital to our Marcellus joint venture until our investing partner had obtained a 50% interest in the joint venture. On September 23, 2011, our investing partner made a capital contribution of $11.5 million to PDCM, which resulted in it obtaining a 50% interest. Subsequent to our investing partner obtaining a 50% interest, all future operating and development funding needed by PDCM will be shared equally between the investing partner and us. Accordingly, to provide the funds needed by PDCM to complete the acquisition of Seneca-Upshur on October 3, 2011, we drew on our corporate credit facility a total of $76.2 million in September 2011, which was transfered to PDCM as of September 30, 2011. Our investing partner funded its portion of the acquisition price in two installments, one in the amount of $19.1 million in September 2011 and one on October 3, 2011, in the amount of $57.2 million. Our September 30, 2011, balance sheet reflects the funding of this acquisition as follows: $28.6 million, representing our proportionate share of PDCM's cash balance, was included in cash and cash equivalents, $28.6 million was included in accounts receivable affiliates, representing the advance receivable, and $19.1 million included in restricted cash long-term, which represents our portion of the Seneca-Upshur purchase price that was deposited into escrow for utilization at closing. On October 3, 2011, PDCM completed the acquisition of Seneca-Upshur for a total of $152.5 million following a capital contribution by our investing partner and no additional draws on our corporate credit facility.

We have a shelf registration statement on Form S-3 filed with the SEC in November 2008 and declared effective by the SEC in January 2009. The shelf provides for an aggregate of $500 million, through the potential sale of debt securities, common stock or preferred stock, either separately or represented by depository shares, warrants and 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 should the need arise, and to have the flexibility to raise such funds in one or more offerings should we perceive the market conditions to be favorable. As of September 30, 2011, we have $315.8 million available on our shelf, which we may utilize to raise future capital.

We are subject to quarterly financial debt covenants on our corporate bank credit facility. Currently, our key credit facility debt covenants require that we maintain: 1) total debt of less than 4.25 times earnings before interest, taxes, DD&A expense and exploration expense adjusted for certain non-cash transactions ("EBITDAX") and 2) an adjusted working capital ratio of at least 1.0 to 1.0. Our adjusted working capital ratio is calculated by reducing our current assets and liabilities by any impact of recording the fair value of our natural gas and crude oil derivative instruments and adding our available borrowings on our corporate bank credit facility to our current assets. The impact of any current portion of our debt is eliminated from the current liabilities. Therefore, any change in our available borrowings under our credit facility impacts our working capital ratio. We were in compliance with all debt covenants at September 30, 2011, and expect to remain in compliance throughout the next twelve-month period.

The indenture governing our senior notes contains customary representations and warranties as well as typical 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 or redeem or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) pay dividends or other payments by restricted subsidiaries, (e) create liens that secure debt, (f) enter into transactions with affiliates and (g) merge or consolidate with another company. Additionally, with regard to our 12% senior notes, we are subject to two incurrence covenants: 1) EBITDAX of at least two times interest expense and 2) total debt of less than 4.0 times EBITDAX. We were in compliance with all covenants at September 30, 2011, and expect to remain in compliance throughout the next twelve-month period.

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

Cash Flows

Operating Activities. Our cash flows provided by 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 provided by operating activities decreased year-over-year. The decrease was primarily due to a $27.8 million decrease in net realized derivative gains, an income tax refund of $25.9 million from our 2009 NOL carry-back received during the nine months ended 2010, an increase of $12.7 million in cash related general and administrative expenses and an increase of $9.1 million in production costs, offset in part by a $61.6 million increase in natural gas, NGL and crude oil sales revenue. See Results of Operations above for an additional discussion of the key drivers of cash flows provided by operating activities.

Natural gas, NGL and crude oil prices exhibit a high degree of volatility. These price variations have a material impact on our financial results. Natural gas and NGL prices vary by region and locality, depending upon the distance to markets, the availability of pipeline capacity and the supply and demand relationships in that region or locality. This can be especially true in the Rocky Mountain Region. The combination of increased drilling activity and the lack of local markets has resulted in local market oversupply situations from time to time. Like most producers in the region, we rely on major interstate pipeline companies to construct these pipelines to increase capacity, rendering the timing and availability of these facilities beyond our control. Crude oil pricing is predominately driven by the physical market, supply and demand, the financial markets and global unrest.

The price we receive for our natural gas produced in the Rocky Mountain Region is based on a market basket of prices, which generally includes natural gas sold at, near or below CIG prices as well as other nearby region prices. The CIG Index and other indices for production delivered to other Rocky Mountain pipelines have historically been less than the price received for natural gas produced in the eastern regions, which is NYMEX-based. This negative differential has narrowed over the last few years and is lower than historical variances. The negative differential of CIG relative to NYMEX averaged $0.28 and $0.30 for the three and nine months ended 2011, respectively, compared to an average of $0.51 and $0.88 for the three and nine months ended 2010, respectively.

The price we receive on our natural gas is impacted by our transportation, gathering and processing agreements. We currently use the "net-back" method of accounting for these arrangements related to our natural gas sales. We sell natural gas at the wellhead and collect a price and recognize revenues based on the wellhead sales price since 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.

Adjusted cash flows from operations increased year-over-year. The increase was primarily due to the same factors mentioned above for changes in cash provided by operating activities without regard to timing of cash payments and receipts of our assets and liabilities. See Reconciliation of Non-U.S. GAAP Financial Measures, below, for a more detailed discussion of these non-U.S. GAAP financial measures.

Investing Activities. Net cash used in investing activities was primarily related to the acquisition, exploration and development of natural gas and crude oil properties, net of dispositions of natural gas and crude oil properties. Our capital investment in natural gas and crude oil properties has increased significantly year-over-year as a result of our commitment to growth.

Financing Activities. Year-over-year, net cash provided by financing activities increased significantly as we continue to execute our 2011 capital plan. Additionally, for the nine months ended 2011, financing cash flows include $12.5 million, representing our proportionate share of capital contributed to PDCM by our investing partner.

Drilling Activity

The following tables present our 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.

	Gross Drilling Activity								
	Three Months Ended September 30,				Nine Months Ended September 30,				
	2011		2010		2011			2010	
	Productive	In-Process	Productive	In-Process	Productive	In-Process (1)	Dry	Productive	In-Process
Development Wells									
Rocky Mountain Region	20	19	16	26	106	27	—	105	33
Permian Basin	1	4	—	—	10	5	1	—	—
Appalachian Basin	—	2	—	—	—	6	—	—	—
Total development wells	21	25	16	26	116	38	1	105	33
Exploratory Wells									
Rocky Mountain Region	—	—	—	—	—	1	—	—	—
Appalachian Basin	—	—	—	2	—	—	—	1	5

Other	—	2	—	—	—	2	—	—	—
Total exploratory wells	—	2	—	2	—	3	—	1	5
Total drilling activity	21	27	16	28	116	41	1	106	38
Recompletions/refractures	25		6		71			22	

(1) As of September 30, 2011, a total of 44 wells, including the 41 wells drilled during the nine months ended 2011 and still in-process as of September 30, were waiting to be completed and/or for pipeline connection.

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PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)

	Net Drilling Activity								
	Three Months Ended September 30,				Nine Months Ended September 30,				
	2011		2010		2011			2010	
	Productive	In-Process	Productive	In-Process	Productive	In-Process	Dry	Productive	In-Process
Development Wells									
Rocky Mountain Region	14.8	16.2	13.5	24.8	76.9	22.9	—	89.4	29.5
Permian Basin	1.0	4.0	—	—	10.0	5.0	1.0	—	—
Appalachian Basin	—	1.1	—	—	—	3.1	—	—	—
Total development wells	15.8	21.3	13.5	24.8	86.9	31.0	1.0	89.4	29.5
Exploratory Wells									
Rocky Mountain Region	—	—	—	—	—	1.0	—	—	—
Appalachian Basin	—	—	—	1.4	—	—	—	0.6	3.1
Other	—	1.5	—	—	—	1.5	—	—	—
Total exploratory wells	—	1.5	—	1.4	—	2.5	—	0.6	3.1
Total drilling activity	15.8	22.8	13.5	26.2	86.9	33.5	1.0	90.0	32.6
Recompletions/refractures	21.9		4.1		65.1			18.8	

Off-Balance Sheet Arrangements

As of September 30, 2011, with the exception of those identified below under the caption Contractual Obligations and Contingent Commitments - Commitments, contingencies and other arrangements, we had no existing off-balance sheet arrangements, as defined under SEC rules, that have or are reasonably likely to have a material current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Commitments and Contingencies

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

Contractual Obligations and Contingent Commitments

The table below presents our contractual obligations and contingent commitments as of September 30, 2011.

	Payments due by period				
Contractual Obligations and Contingent Commitments	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(in millions)				
Long-term liabilities reflected on the consolidated balance sheets (1)					
Long-term debt (2)	$499.5	$—	$—	$181.5	$318.0
Derivative contracts (3)	40.2	19.7	20.5	—	—
Derivative contracts - affiliated partnerships (4)	14.4	7.3	7.1	—	—
Production tax liability	33.8	18.7	15.1	—	—
Asset retirement obligations	28.7	0.2	0.4	0.8	27.3

Other liabilities (5)	6.7	0.3	0.6	0.6	5.2
	623.3	46.2	43.7	182.9	350.5
Commitments, contingencies and other arrangements (6)					
Interest on long-term debt (7)	203.6	36.1	71.3	62.7	33.5
Operating leases	8.3	2.1	3.4	1.9	0.9
Rig commitment (8)	3.4	3.2	0.2	—	—
Drilling commitment	0.9	—	—	—	0.9
Firm transportation and processing agreements (9)	226.3	13.5	52.4	51.3	109.1
Other	0.5	0.1	0.3	0.1	—
	443.0	55.0	127.6	116.0	144.4
Total	$1,066.3	$101.2	$171.3	$298.9	$494.9

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(1) Table does not include deferred income tax liability to taxing authorities of $191.8 million, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

(2) Amount presented does not agree with the balance sheet in that the amount above excludes $19.3 million in unamortized debt discount. See Note 7, Long-Term Debt, to the accompanying condensed consolidated financial statements included in this report.

(3) Represents our gross liability related to the fair value of derivative positions, including the fair value of derivative contracts we entered into on behalf of our affiliated partnerships as the managing general partner. We have a related receivable from the partnerships of $8.5 million.

(4) Represents our affiliated partnerships' designated portion of the fair value of our gross derivative assets.

(5) Includes funds held from revenue distribution to third party investors, including our affiliated partnerships, for plugging liabilities related to wells we operate and deferred officer compensation.

(6) Table does not include an undrawn $18.7 million irrevocable standby letter of credit pending issuance to a transportation service provider; see Note 7, Long-Term Debt, in the accompanying condensed consolidated financial statements included in this report. Additionally, the table does not include the annual repurchase obligations to investing partners of our affiliated partnerships or termination benefits related to employment agreements with our executive officers, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations; see Note 9, Commitments and Contingencies - Partnership Repurchase Provision; Employment Agreements with Executive Officers, to the accompanying condensed consolidated financial statements included in this report.

(7) Amounts presented include $17.3 million payable to the holders of our 3.25% convertible senior notes due 2016 and $155.3 million to the holders of our 12% senior notes due 2018. Amounts also include $31 million payable to the participating banks of our revolving credit facilities, of which interest of $3.4 million due on the unutilized commitment at a rate of 0.5% per annum, $27.2 million related to the outstanding borrowings on our credit facilities of $181.5 million on our corporate credit facility and $0.4 million related to our undrawn letters of credit.

(8) Drilling rig commitment in the above table reflects our proportionate share of the maximum obligation for the services of one drilling rig in the Appalachian Basin.

(9) Represents our gross commitment, including our proportionate share of PDCM. We will recognize in our financial statements our proportionate share based on our working interest; however, with the exception of contracts entered into by PDCM, the costs of all volume shortfalls will be borne by PDC only. See Note 9, Commitments and Contingencies - Firm Transportation Agreements, to the accompanying condensed consolidated financial statements included in this report.

As the managing general partner of 26 partnerships, we have liability for potential casualty losses in excess of the partnership assets and insurance. We believe that the casualty insurance coverage we and our subcontractors carry is adequate to meet this potential liability.

For information regarding our legal proceedings and their potential impact on our condensed consolidated financial statements, see Note 9, Commitments and Contingencies – Litigation, to the accompanying condensed consolidated financial statements included in this report.

Recent Accounting Standards

See Note 2, Recent Accounting Standards, to the accompanying condensed consolidated financial statements included in this report.

Critical Accounting Policies and Estimates

The preparation of the accompanying condensed 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 2010 Form 10-K.

Reconciliation of Non-U.S. GAAP Financial Measures

Adjusted cash flows from operations. We define adjusted cash flows from operations as the cash flow earned or incurred from operating activities without regard to the collection or payment of associated receivables or payables. 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 earned or incurred item was collected or paid during the period. We also use this measure because the collection of our receivables or payment of our obligations has not been a significant issue for our business, but merely a timing issue from one period to the next, with fluctuations generally caused by significant changes in commodity prices. See the condensed consolidated statements of cash flows in this report.

Adjusted net income (loss) attributable to shareholders. We define adjusted net income (loss) attributable to shareholders as net income (loss) attributable to shareholders plus unrealized derivative losses, provisions for underpayment of natural gas sales, minus unrealized derivative gains, each adjusted for tax effect. We believe it is important to consider adjusted net income (loss) attributable to shareholders as well as net income (loss) attributable to shareholders. 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) attributable to shareholders from our mark-to-market adjustments resulting from unrealized gains and losses from derivatives.

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Adjusted EBITDA. We define adjusted EBITDA as net income (loss) plus unrealized derivative loss, interest expense, net of interest income, provision for income taxes, and depreciation, depletion and amortization for the period minus unrealized derivative gain and benefit for income taxes. We believe adjusted EBITDA is relevant because it is a measure of cash available to fund our capital expenditures and service our debt and is a widely used industry metric which allows comparability of our results with our peers.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in millions)			
Adjusted cash flows from operations:				
Adjusted cash flows from operations	$50.9	$23.6	$111.1	$101.8
Changes in assets and liabilities	(17.0)	(2.2)	(5.6)	15.0
Net cash provided by operating activities	$33.9	$21.4	$105.5	$116.8
Adjusted net income (loss) attributable to shareholders:				
Adjusted net income (loss) attributable to shareholders	$6.7	$(1.5)	$1.6	$4.1
Provision for underpayment of natural gas sales	—	(3.3)	—	(3.3)
Unrealized gain on derivatives, net	41.7	11.4	32.6	36.1
Tax effect of above adjustments	(15.8)	(3.2)	(12.4)	(12.5)
Net income attributable to shareholders	$32.6	$3.4	$21.8	$24.4
Adjusted EBITDA:				
Adjusted EBITDA	$55.0	$27.3	$127.5	$107.4
Unrealized gain on derivatives, net	41.7	11.4	32.6	36.1
Interest expense, net	(9.5)	(8.2)	(27.6)	(23.6)
Income tax benefit (expense)	(20.3)	1.1	(11.4)	(11.4)
Depreciation, depletion and amortization	(34.3)	(28.2)	(99.3)	(84.1)
Net income attributable to shareholders	$32.6	$3.4	$21.8	$24.4

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market-Sensitive Instruments and Risk Management

We are exposed to market risks associated with interest rates, commodity prices and credit exposure. Management has 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 cash, cash equivalents and restricted cash and the interest we pay on bank credit facilities. All of our other long-term indebtedness have a fixed rate 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, 2011, 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 and cash equivalents, which excludes restricted cash, as of September 30, 2011, was $28.6 million with an average interest rate of 0.1%. The $28.6 million represents our aggregate bank balances, including checks issued and outstanding. Based on a sensitivity analysis of our interest bearing deposits as of September 30, 2011, we estimate that if market interest rates were to increase or decrease by 1%, the impact on our 2011 interest income would be immaterial.

As of September 30, 2011, excluding the $18.7 million irrevocable standby letter of credit, we had outstanding borrowings on our corporate bank credit facility of $172.5 million and, representing our proportionate share, $9 million on PDCM's bank credit facility. We estimate that if market interest rates were to increase or decrease by 1%, our 2011 interest expense would change by approximately $1.4 million.

Commodity Price Risk

We are exposed to commodity price risk, the potential risk of loss from adverse changes in the market price of natural gas and crude oil commodities. 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 natural gas and crude oil 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 for which they were intended.

Derivative Strategies. Our derivative strategies with regard to natural gas and crude oil sales and natural gas marketing are discussed below.

- For natural gas and crude oil 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.

The following table presents the derivative positions related to our natural gas and crude oil sales in effect as of September 30, 2011.

	Floors		Collars			Fixed-Price Swaps		CIG Basis Protection Swaps		
Commodity/ Index/ Maturity Period	Quantity (Oil - MBbls)	Weighted Average Contract Price	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted Average Contract Price Floors	Ceilings	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted Average Contract Price	Quantity (BBtu) (1)	Weighted Average Contract Price	Fair Value September 30, 2011 (2) (in thousands)
Natural Gas										
NYMEX										
2011	—	$ —	—	$—	$—	3,281.6	$ 6.76	2,657.6	$ (1.82)	$5,436
2012	—	—	4,885.7	6.00	8.27	7,822.1	6.61	9,862.3	(1.81)	12,573
2013	—	—	4,438.0	6.10	8.60	6,161.2	6.85	8,904.1	(1.81)	6,150
2014	—	—	—	—	—	720.0	5.49	—	—	244
CIG										
2011	—	—	—	—	—	1,338.7	4.38	—	—	978
2012	—	—	—	—	—	700.0	4.11	—	—	81
2013	—	—	235.0	4.00	5.45	—	—	—	—	9
2014	—	—	1,115.0	4.50	5.67	—	—	—	—	170
2015	—	—	1,040.0	4.50	5.67	—	—	—	—	(18)
PEPL										
2011	—	—	—	—	—	903.2	5.55	—	—	1,660
2012	—	—	—	—	—	1,355.8	6.18	—	—	2,836
2013	—	—	—	—	—	990.4	6.18	—	—	1,584
Total Natural Gas	—		11,713.7			23,273.0		21,424.0		31,703

Crude Oil										
NYMEX										
2011	56.0	78.52	82.7	79.99	104.84	245.3	84.60	—	—	2,015
2012	36.0	65.38	643.6	81.41	106.28	684.0	90.97	—	—	11,974
2013	—	—	317.6	75.00	104.30	186.9	84.15	—	—	1,192
2014	—	—	36.0	90.00	106.15	—	—	—	—	377
2015	—	—	36.0	90.00	106.15	—	—	—	—	357
Total Crude Oil	92.0		1,115.9			1,116.2		—		15,915
Total Natural Gas and Crude Oil										$47,618

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

(2) Approximately 29.2% of the fair value of our derivative assets and 0.4% of our derivative liabilities were measured using significant unobservable inputs (Level 3); see Note 3, Fair Value Measurements and Disclosures, to the accompanying condensed consolidated financial statements.

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The following table presents our derivative positions related to our natural gas marketing in effect as of September 30, 2011.

Commodity/ Derivative Instrument/ Maturity Period	Fixed-Price Swaps Quantity (BBtu)(1)	Fixed-Price Swaps Weighted Average Contract Price	NYMEX Basis Protection Swaps Quantity (BBtu)(1)	NYMEX Basis Protection Swaps Weighted Average Contract Price	Fair Value September 30, 2011 (2) (in thousands)
Natural Gas					
Sales					
Physical					
2011	18.5	$5.07	25.9	$0.91	$36
2012	20.9	5.05	55.1	0.95	51
Financial					
2011	469.4	5.23	64.4	0.07	661
2012	871.6	4.87	227.6	0.07	577
2013	90.0	5.00	—	—	15
Purchases					
Physical					
2011	468.9	5.22	—	—	(597)
2012	870.4	4.85	—	—	(488)
2013	90.0	4.99	—	—	(14)
Financial					
2011	18.4	4.31	12.6	0.13	(10)
2012	20.9	4.31	30.4	0.13	(6)
Total Natural Gas	2,939.0		416.0		$225

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(1) A standard unit of measurement for natural gas (one BBtu equals one MMcf).
(2) Approximately 6.3% of the fair value of our derivative assets were measured using significant unobservable inputs (Level 3); see Note 3, Fair Value Measurements and Disclosures, to the accompanying condensed consolidated financial statements.

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, 2011	Year Ended December 31, 2010
Average Index Closing Price		
Natural Gas (per MMBtu)		
CIG	$3.91	$3.92
NYMEX	4.21	4.39
Crude Oil (per Bbl)		

NYMEX	95.39	77.32
Average Sales Price Realized		
Excluding realized derivative gains/(losses)		
Natural Gas (per Mcf)	$3.38	$3.61
Crude Oil (per Bbl)	87.80	74.03
Including realized derivative gains/(losses)		
Natural Gas (per Mcf)	4.25	5.12
Crude Oil (per Bbl)	80.91	79.62

Based on a sensitivity analysis as of September 30, 2011, we estimate 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, including those designated to our affiliated partnerships, would result in a decrease in the fair value of our derivative positions of $31.1 million; whereas a 10% decrease in prices would result in an increase in fair value of $31.6 million. Excluding the derivatives designated to our affiliated partnerships, the same 10% increase or decrease in natural gas and crude oil prices would result in a decrease in fair value of $28.8 million and an increase in fair value of $29.2 million, respectively.

See Note 3, Fair Value Measurements and Disclosures, and Note 4, Derivative Financial Instruments, to the accompanying condensed consolidated financial statements included in this report for additional disclosure regarding our derivative financial instruments including, but not limited to, a summary of our open derivative positions as of September 30, 2011.

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 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.

With regard to our natural gas and crude oil sales segment, inherent to our industry is the concentration of natural gas, NGL and crude oil sales to a few customers. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic and financial conditions, commodity prices or other conditions. As for our natural gas marketing segment, our receivables are from a diverse group of companies, including major energy companies, both upstream and mid-stream, financial institutions and end-users in various industries. We monitor their creditworthiness through credit reports and rating agency reports. To date, we have had no material counterparty default losses in either of our natural gas and crude oil sales segment or natural gas marketing segment, but there is no guaranty this may not happen in the future.

Our derivative financial instruments expose us to the credit risk of nonperformance by the counterparty to the contracts. We primarily use financial institutions, which are also major lenders in our credit facility, as counterparties to our financial derivative contracts. We have evaluated the credit risk of the counterparties holding our derivative assets using relevant credit market default rates, giving consideration to amounts outstanding from each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant.

Disruption in the credit market may have a significant adverse impact on a number of financial institutions. We monitor the creditworthiness of the financial institutions with which we transact, giving consideration to the reports of credit agencies and their related ratings. While we believe that our monitoring procedures are sufficient and customary, no amount of analysis can guarantee performance by a financial institution.

Disclosure of Limitations

Because the information above included only those exposures that exist as of September 30, 2011, it does not consider those exposures or positions which could arise after that date. As a result, our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, our commodity price risk management strategies at the time, and interest rates and commodity prices at the time.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of September 30, 2011, 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). This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that such information is accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely discussion regarding required disclosure.

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, 2011.

Changes in Internal Control over Financial Reporting

During the three months ended 2011, 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 the accompanying condensed consolidated financial statements included 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 2010 Form 10-K. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC. There have been no material changes from the risk factors previously disclosed in our 2010 Form 10-K.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
July 1 - 31, 2011	37,131	$32.18	—	—
August 1 - 31, 2011	3,628	23.82	—	—
September 1 - 30, 2011	1,657	25.04	—	—
Total	42,416	31.19		

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

ITEM 3. DEFAULTS UPON SENIOR SECURITIES - None

ITEM 4. [REMOVED AND RESERVED]

ITEM 5. OTHER INFORMATION

On November 1, 2011, the Company entered into an employment agreement with James M. Trimble, as Chief Executive Officer and President of the Company. Mr. Trimble will receive an annual base salary of $625,000 per year, and an opportunity to earn an annual performance bonus each year of the term of his employment based on criteria established by the compensation committee of the Company's Board of Directors, which for the upcoming year was established at 100% of his base salary as the target. The agreement is for a term of two years (the "Term"), unless otherwise earlier terminated in accordance with the terms set forth therein. He also received a restricted stock award with an aggregate dollar value of $2 million, or 58,122 shares of common stock (the number of shares underlying such award being determined by dividing the aggregate dollar value of the award by the average closing market price of the Company's common stock for the 15 days preceding the grant date, the formula typically used by the Company to value equity awards), which award will vest pro-rata on each anniversary date of the grant date over a three-year period; provided, however, that in the event Mr. Trimble resigns from the Company after the conclusion of the Term (including in his capacity as a member of the Board of Directors), the unvested portion of the restricted stock award shall immediately vest. The agreement also includes one year non-compete and non-solicitation provisions and a one-time payment in the amount of $225,000 related to relocation and travel expenses. Moreover, the agreement requires that a general release be executed before severance benefits are paid in the event of the termination of the executive officer by the Company without just cause, termination by the executive officer for good reason, or termination of the executive officer following a change of control. Mr. Trimble will not be participating in the nonqualified deferred supplemental retirement benefit received by the Company's two prior Chief Executive Officers. The summary of the agreement in this report is qualified in its entirety to the full text of the agreement, the same being attached hereto as Exhibit 10.2 and incorporated herein by reference.

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ITEM 6. EXHIBITS

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
10.1	Second Amendment to the Second Amended and Restated Credit Agreement dated as of October 12, 2011, by and among the Company as Borrower, certain of its Subsidiaries as Guarantors, JPMorgan Chase Bank, N.A. as Administrative Agent and various other banks as Lenders.	8-K	000-07246	10.1	10/18/2011	
10.2 *	Employment Agreement with James M. Trimble, President and Chief Executive Officer, dated as of November 1, 2011.					X
12.1	Computation of Ratio of Earnings to Fixed Charges.					X
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					
101.SCH **	XBRL Taxonomy Extension Schema Document					
101.CAL **	XBRL Taxonomy Extension Calculation Linkbase Document					
101.DEF **	XBRL Taxonomy Extension Definition Linkbase Document					

101.LAB **	XBRL Taxonomy Extension Label Linkbase Document
101.PRE **	XBRL Taxonomy Extension Presentation Linkbase Document

* Management contract or compensatory plan or arrangement.
** Furnished herewith.

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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.

Petroleum Development Corporation
(Registrant)

Date: November 3, 2011

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

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

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