PETROLEUM DEVELOPMENT CORP
Form 10-Q
November 08, 2010
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

x Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended September 30, 2010

or

o Transition Report Pursuant to Section 13 of 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 x No o

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 £ 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 the 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 £	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 o No x

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 19,272,750 shares of the Company's Common Stock ($.01 par value) were outstanding as of October 29, 2010.

EXPLANATORY NOTE

Effective July 15, 2010, Petroleum Development Corporation began conducting business as PDC Energy. A new logo and corporate identity accompanied this change. Our common stock continues to trade on the NASDAQ Global Select Market under the ticker symbol PETD. We continue to maintain our website address, www.petd.com, which reflects the new PDC Energy name and brand identity. This change reflects the transitioning in our business model, from a company that was predominately a sponsor of limited partnerships to a natural gas and oil company that explores for and acquires, develops, produces and markets natural gas and oil resources. We believe that the name PDC Energy more fully portrays the range of business activities in which we engage.

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PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)

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PART I – FINANCIAL INFORMATION

PART II – OTHER INFORMATION

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. 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, which include statements of estimated natural gas and oil production and reserves, drilling plans, future cash flows, anticipated liquidity, anticipated capital expenditures and our management's strategies, plans and objectives. However, these 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 risks and uncertainties incidental to the exploration for, and the acquisition, development, production and marketing of natural gas and 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, worldwide demand and commodity prices for natural gas and oil;
- changes in estimates of proved reserves;
- declines in the values of our natural gas and oil properties resulting in impairments;
- the timing and extent of our success in discovering, acquiring, developing and producing natural gas and oil reserves;
- our ability to acquire leases, drilling rigs, supplies and services at reasonable prices;
- the availability and cost of capital to us, including the availability of funding for the consideration payable by us to consummate the prospective mergers of the four 2004 partnerships;
- the timing and closing, if consummated, of the mergers of the four 2004 partnerships;
- reductions in the borrowing base under our credit facility;
- risks incident to the drilling and operation of natural gas and oil wells;
- future production and development costs;
- the availability of sufficient pipeline and other transportation facilities to carry our production and the impact of these facilities on price;
- the effect of existing and future laws, governmental regulations and the political and economic climate of the United States of America ("U.S.");
- changes in environmental laws and the regulations and enforcement related to those laws;
- the identification of and severity of environmental events and governmental responses to the events;
- the effect of natural gas and oil derivative activities;
- conditions in the capital markets; and
- losses possible from pending or future litigation.

Further, we urge you to carefully review and consider the cautionary statements made in this report, our annual report on Form 10-K for the year ended December 31, 2009, filed with the Securities and Exchange Commission ("SEC") on March 4, 2010, as amended August 31, 2010 ("2009 Form 10-K"), and our other filings with the SEC and public disclosures. We caution you not to place undue reliance on forward-looking statements, which speak only as of the date made. Other than as required under the securities laws, 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.

REFERENCES

Unless the context otherwise requires, references to "PDC Energy," "the Company," "we," "us," "our," "ours" or "ourselves" in this report refer to the registrant, Petroleum Development Corporation ("PDC"), together with its wholly owned subsidiaries, an entity in which it has a controlling financial interest and its proportionate share of affiliated partnerships and PDC Mountaineer, LLC ("PDCM"), a joint venture with Lime Rock Partners.

References to "the three months ended 2010" and "the nine months ended 2010" refer to the three or nine months ended September 30, 2010, as applicable. References to "the three months ended 2009" and "the nine months ended 2009" refer to the three or nine months ended September 30, 2009, as applicable.

PART I - FINANCIAL INFORMATION
Item 1. Financial Statements
PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
Condensed Consolidated Balance Sheets
(unaudited; in thousands, except share data)

	September 30, 2010	December 31, 2009*
Assets		
Current assets:		
Cash and cash equivalents	$13,299	$31,944
Restricted cash	2,478	2,490
Accounts receivable, net	49,013	56,491
Accounts receivable affiliates	11,753	7,956
Fair value of derivatives	52,605	42,223
Income tax receivable	—	27,728
Prepaid expenses and other current assets	1,878	8,538
Total current assets	131,026	177,370
Properties and equipment, net	1,029,011	979,373
Assets held for sale	—	28,820
Fair value of derivatives	54,949	20,228
Accounts receivable affiliates	12,067	15,473
Other assets	23,511	29,063
Total Assets	$1,250,564	$1,250,327
Liabilities and Equity		
Liabilities		
Current liabilities:		
Accounts payable	$42,104	$36,845
Accounts payable affiliates	12,788	13,015
Production tax liability	15,099	24,849
Fair value of derivatives	22,558	20,208
Funds held for distribution	27,654	28,256
Other accrued expenses	20,880	21,261
Total current liabilities	141,083	144,434
Long-term debt	302,374	280,657
Deferred income taxes	182,188	178,012
Asset retirement obligation	26,339	29,314
Fair value of derivatives	36,969	48,779
Accounts payable affiliates	17,531	5,996
Other liabilities	23,234	24,542
Total liabilities	729,718	711,734
COMMITMENTS AND CONTINGENT LIABILITIES		
Equity		
Shareholders' equity:		
Preferred shares, par value $.01 per share; authorized 50,000,000 shares; issued: none	—	—
Common shares, par value $.01 per share; authorized 100,000,000 shares; issued: 19,274,031 shares for 2010 and 19,242,219 for 2009	193	192

Additional paid-in capital	69,692	64,406
Retained earnings	450,983	426,629
Treasury shares, at cost; 8,273 shares for 2010 and for 2009	(312)	(312)
Total shareholders' equity	520,556	490,915
Noncontrolling interest	290	47,678
Total equity	520,846	538,593
Total Liabilities and Equity	$1,250,564	$1,250,327

*Derived from audited 2009 balance sheet.

See accompanying notes to condensed consolidated financial statements.

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,	
	2010	2009	2010	2009
Revenues:				
Natural gas and oil sales	$48,070	$42,871	$156,133	$121,440
Sales from natural gas marketing	18,337	11,062	53,613	43,200
Commodity price risk management gain (loss), net	19,029	(13,813)	74,508	(13,414)
Well operations, pipeline income and other	2,173	2,264	6,941	7,698
Total revenues	87,609	42,384	291,195	158,924
Costs, expenses and other:				
Natural gas and oil production and well operations costs	16,685	14,705	48,217	44,242
Cost of natural gas marketing	18,300	10,179	52,830	41,420
Exploration expense	3,737	6,586	13,985	15,363
General and administrative expense	10,426	9,627	30,975	36,505
Depreciation, depletion and amortization	28,219	31,935	82,992	99,080
Gain on sale of leaseholds	(57)	—	(153)	(120)
Total costs, expenses and other	77,310	73,032	228,846	236,490
Operating income (loss)	10,299	(30,648)	62,349	(77,566)
Interest income	21	208	60	240
Interest expense	(8,174)	(9,221)	(23,646)	(27,024)
Income (loss) from continuing operations before income taxes	2,146	(39,661)	38,763	(104,350)
Provision (benefit) for income taxes	(1,020)	(14,707)	12,746	(39,795)
Income (loss) from continuing operations	3,166	(24,954)	26,017	(64,555)
Income (loss) from discontinued operations, net of tax	188	179	(1,729)	966
Net income (loss)	3,354	(24,775)	24,288	(63,589)
Less: net loss attributable to noncontrolling interest	(5)	(299)	(66)	(331)
Net income (loss) attributable to shareholders	$3,359	$(24,476)	$24,354	$(63,258)
Amounts attributable to shareholders:				
Income (loss) from continuing operations	$3,171	$(24,655)	$26,083	$(64,224)
Income (loss) from discontinued operations	188	179	(1,729)	966
Net income (loss) attributable to shareholders	$3,359	$(24,476)	$24,354	$(63,258)
Earnings (loss) per share attributable to shareholders:				
Basic				
Income (loss) from continuing operations	$0.16	$(1.45)	$1.36	$(4.13)
Income (loss) from discontinued operations	0.01	0.01	(0.09)	0.06
Net income (loss) attributable to shareholders	$0.17	$(1.44)	$1.27	$(4.07)
Diluted				
Income (loss) from continuing operations	$0.16	$(1.45)	$1.35	$(4.13)
Income (loss) from discontinued operations	0.01	0.01	(0.09)	0.06
Net income (loss) attributable to shareholders	$0.17	$(1.44)	$1.26	$(4.07)

Weighted average common shares outstanding:				
Basic	19,250	16,962	19,218	15,530
Diluted	19,406	16,962	19,319	15,530

See accompanying notes to condensed consolidated financial statements.

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

	Nine Months Ended September 30,	
	2010	2009
Cash flows from operating activities:		
Net income (loss)	$24,288	$(63,589)
Adjustments to net income (loss) to reconcile to cash provided by operating activities:		
Deferred income taxes	10,835	(33,529)
Depreciation, depletion and amortization	84,086	100,796
Exploratory dry hole costs	4,057	1,078
Amortization and impairment of unproved properties	2,211	4,760
Impairment of proved natural gas and oil properties	4,666	—
Unrealized loss (gain) on derivative transactions	(36,056)	95,735
Other	7,728	9,455
Changes in assets and liabilities	14,977	(14,735)
Net cash provided by operating activities	116,792	99,971
Cash flows from investing activities:		
Capital expenditures	(106,795)	(124,821)
Acquisitions	(85,511)	—
Proceeds from the sale of assets	23,250	378
Deconsolidation/change in ownership effect on cash and cash equivalents	(3,472)	—
Net cash used in investing activities	(172,528)	(124,443)
Cash flows from financing activities:		
Proceeds from credit facility	244,000	226,000
Repayment of credit facility	(222,500)	(269,500)
Payment of debt issuance costs	(205)	(8,980)
Proceeds from sale of equity	—	48,454
Excess tax benefits from stock-based compensation	215	—
Change in ownership interest in PDCM	16,173	—
Purchase of treasury stock	(592)	(312)
Net cash provided by (used in) financing activities	37,091	(4,338)
Net decrease in cash and cash equivalents	(18,645)	(28,810)
Cash and cash equivalents, beginning of period	31,944	50,950
Cash and cash equivalents, end of period	$13,299	$22,140
Supplemental cash flow information:		
Cash payments (receipts) for:		
Interest, net of capitalized interest	$28,651	$30,155
Income taxes, net of refunds	(26,998)	(3,522)
Non-cash investing activities:		
Change in accounts payable related to purchases of properties and equipment	7,108	(36,383)
Change in asset retirement obligation, with a corresponding increase to natural gas and oil properties, net of disposals	2,239	260

See Note 14 for non-cash transactions related to PDCM

See accompanying notes to condensed consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
Notes to Condensed Consolidated Financial Statements
September 30, 2010
(unaudited)

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

We are a domestic independent natural gas and oil company engaged in the exploration for and the acquisition, development, production and marketing of natural gas and oil. As of September 30, 2010, we owned an interest in and operated approximately 5,000 gross wells located primarily in the Rocky Mountain Region and Appalachian Basin. We are engaged in two primary business segments: natural gas and oil sales and natural gas marketing.

The accompanying unaudited condensed consolidated financial statements include the accounts of PDC, our wholly owned subsidiaries, an entity in which we have a controlling financial interest and our proportionate share of PDCM and our affiliated partnerships. All material intercompany accounts and transactions have been eliminated in consolidation. We account for our investment in PDCM and our interests in natural gas and oil limited partnerships under the proportionate consolidation method. Accordingly, our accompanying condensed consolidated financial statements include our pro rata share of assets, liabilities, revenues and expenses of 34 entities which we proportionately consolidate. Our proportionate share of all significant transactions between us and these entities has been eliminated. See Notes 2 and 14 for the impact of new accounting changes on the consolidation of PDCM, a variable interest entity, on January 1, 2010.

In our opinion, the accompanying financial statements contain all adjustments (consisting of only normal recurring adjustments) necessary for a fair presentation of our financial statements for interim periods in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, pursuant to such rules and regulations, certain notes and other financial information included in audited financial statements have been condensed or omitted. The information presented in this quarterly report on Form 10-Q should be read in conjunction with our audited consolidated financial statements and notes thereto included in our 2009 Form 10-K. Our accounting policies are described in the Notes to Consolidated Financial Statements in our 2009 Form 10-K and updated, as necessary, in this Form 10-Q. The results of operations for the nine months ended September 30, 2010, and the cash flows for the same period, are not necessarily indicative of the results to be expected for the full year or any other future period.

Certain prior year amounts in the accompanying financial statements and related notes have been reclassified to conform to the current year presentation. The reclassifications are directly related to the sale of our Michigan assets and related 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 the divestiture of our Michigan assets and discontinued operations.

2. RECENT ACCOUNTING STANDARDS

Recently Adopted Accounting Standards

Consolidation - Variable Interest Entities. In June 2009, the Financial Accounting Standards Board ("FASB") issued changes regarding an entity's analysis to determine whether any of its variable interests constitute controlling financial interests in a variable interest entity. This analysis identifies the primary beneficiary of a variable interest entity as the enterprise that has both of the following characteristics:

- the power to direct the activities of a variable interest entity that most significantly impact the entity's economic performance; and
- the obligation to absorb losses of the entity that could potentially be significant to the variable interest entity or the right to receive benefits from the entity that could potentially be significant to the variable interest entity.

Additionally, the entity is required to assess whether it has an implicit financial responsibility to ensure that a variable interest entity operates as designed when determining whether it has the power to direct the activities of the variable interest entity that most significantly impact the entity's economic performance. The guidance also requires ongoing reassessments of whether an enterprise is the primary beneficiary of a variable interest entity. We adopted these changes effective January 1, 2010. Upon adoption, we deconsolidated PDCM based upon the fact that power over the activities that significantly impact this joint venture is equally shared with our investment partner. No cumulative effect adjustment to retained earnings was recognized upon adoption. See Note 14 for the impact of adoption on our financial statements.

Fair Value Measurements and Disclosures. In January 2010, the FASB issued changes clarifying existing disclosure requirements related to fair value measurements. The update also added a new requirement to disclose fair value transfers in and out of Levels 1 and 2 and describe the reasons for the transfers. The adoption of these changes as of January 1, 2010, did not have a material impact on our financial statements.

Recently Issued Accounting Standards

Fair Value Measurements and Disclosures. In January 2010, the 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 will be effective for our financial statements issued for annual reporting periods beginning after December 15, 2010. We do not expect the adoption of this change to have a material impact on our financial statements.

3. FAIR VALUE MEASUREMENTS

Derivative Financial Instruments. We measure the fair value of our derivative instruments based upon quoted market prices, where available. Our valuation determination includes: (1) identification of the inputs to the fair value methodology through the review of counterparty statements and other supporting documentation, (2) determination of the validity of the source of the inputs, (3) 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. The methods described above may produce a fair value calculation that may not be indicative of future fair values. Our valuation determination also gives consideration to nonperformance risk on our own liabilities as well as the credit standing of our counterparties. We primarily use financial institutions, which are also major lenders in our credit facility agreement, as counterparties to our 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 for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, as of September 30, 2010, the impact of nonperformance risk on the fair value of our derivative assets and liabilities was not significant. Validation of our contracts' fair value is performed internally and 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 these valuation methods are appropriate and consistent with those used by other market participants, the use of different methodologies, or assumptions, to determine the fair value of certain financial instruments could result in a different estimate of fair value.

The following table presents, by hierarchy level, our derivative financial instruments, including both current and non-current portions, measured at fair value.

	September 30, 2010			December 31, 2009		
	Quoted Prices in Active Markets (Level 1)	Significant Unobservable Inputs (Level 3)	Total	Quoted Prices in Active Markets (Level 1)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)					
Assets:						

Commodity based derivatives	$75,561	$31,937	$107,498	$25,598	$36,796	$62,394
Basis protection derivative contracts	—	56	56	—	57	57
Total assets	75,561	31,993	107,554	25,598	36,853	62,451
Liabilities:						
Commodity based derivatives	70	10,811	10,881	3,140	9,932	13,072
Basis protection derivative contracts	—	48,646	48,646	—	55,915	55,915
Total liabilities	70	59,457	59,527	3,140	65,847	68,987
Net asset (liability)	$75,491	$(27,464)	$48,027	$22,458	$(28,994)	$(6,536)

PETROLEUM DEVELOPMENT CORPORATION
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The following table presents the changes in our Level 3 derivative financial instruments measured on a recurring basis.

	(in thousands)
Fair value, net liability, as of December 31, 2009	$(28,994)
Changes in fair value included in statement of operations line items:	
Commodity price risk management gain (loss), net	28,466
Sales from natural gas marketing	493
Cost of natural gas marketing	(5,160)
Changes in fair value included in balance sheet line items [1]:	
Accounts receivable affiliates	2,572
Accounts payable affiliates	(4,465)
Settlements included in statement of operations line items:	
Commodity price risk management gain (loss), net	(23,895)
Sales from natural gas marketing	(289)
Cost of natural gas marketing	3,808
Fair value, net liability, as of September 30, 2010	$(27,464)
Changes in unrealized gains (losses) relating to assets (liabilities) still held as of September 30, 2010, included in statement of operations line items:	
Commodity price risk management gain (loss), net	$23,114
Sales from natural gas marketing activities	187
Cost of natural gas marketing activities	(2,257)
	$21,044

[1] 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 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 portion of our long-term debt related to our 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, we estimate the fair value of this portion of our long-term debt to be $225.6 million or 111.2% of par value as of September 30, 2010. We determined this valuation based upon measurements of trading activity.

We assess our natural gas and oil properties for possible impairment, upon a triggering event, by comparing net capitalized costs to estimated undiscounted future net cash flows on a field-by-field basis using estimated production based upon prices at which we reasonably estimate the commodity to be sold. The estimates of future prices may differ from current market prices of natural gas and oil. Certain events, including but not limited to, downward revisions in estimates to our reserve quantities, expectations of falling commodity prices or rising operating costs, could result in a triggering event and, therefore, a possible impairment of our natural gas and oil properties. If net capitalized costs exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value utilizing a future discounted cash flows analysis and is measured by the amount by which the net capitalized costs exceed their fair value. In May 2010, pursuant to our entry into an agreement to sell our Michigan assets, we reclassified our Michigan assets and related liabilities to held for sale. See Note 12. The agreement to sell these assets, a triggering event, required us to perform an impairment test as long lived assets held for sale are required to be measured at the lower of carrying value or fair value less costs to sell. We compared the transactional sales price, considered a Level 3 input, less costs to sell to the carrying value of our Michigan net assets. Since the net carrying value exceeded the net sales price, we were required to recognize an impairment charge by reducing the carrying value of the net assets to reflect the net sales price. As a result, during the nine months ended September 30, 2010, we recorded an impairment charge of $4.7 million related to the sale of our Michigan assets. The impairment charge is reflected in discontinued operations in the statement of operations.

We estimate the fair value of our plugging and abandonment obligations based on a discounted cash flows analysis. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. Changes in estimated asset retirement obligations can result from changes in estimated retirement costs or changes in the estimated timing of payments to settle the asset retirement obligations. See Note 8 for changes in our asset retirement obligations.

4. DERIVATIVE FINANCIAL INSTRUMENTS

As of September 30, 2010, we had derivative instruments in place related to a portion of our anticipated production through 2013 for a total of 39.9 Bcf of natural gas and 2.2 million Bbls of oil. These derivative instruments were comprised of commodity floors, collars and swaps, basis protection swaps and, related to natural gas marketing, physical sales and purchases.

The following table summarizes the line items and fair value amounts of our derivative instruments in the accompanying balance sheets.

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Derivatives instruments not designated as hedges [1]		Balance sheet line item	Fair Value September 30, 2010 (in thousands)	December 31, 2009
Derivative assets:	Current			
	Commodity contracts			
	Related to natural gas and oil sales	Fair value of derivatives	$49,148	$39,107
	Related to natural gas marketing	Fair value of derivatives	3,408	3,077
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	49	39
			52,605	42,223
	Non Current			
	Commodity contracts			
	Related to natural gas and oil sales	Fair value of derivatives	54,737	19,680
	Related to natural gas marketing	Fair value of derivatives	205	530
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	7	18
			54,949	20,228
Total derivative assets [2]			$107,554	$62,451
Derivative liabilities:	Current			
	Commodity contracts			
	Related to natural gas and oil sales	Fair value of derivatives	$4,505	$2,451
	Related to natural gas marketing	Fair value of derivatives	2,988	2,626
	Basis protection contracts			
	Related to natural gas and oil sales	Fair value of derivatives	15,064	15,127
	Related to natural gas marketing	Fair value of derivatives	1	4
			22,558	20,208
	Non Current			
	Commodity contracts			
	Related to natural gas and oil sales	Fair value of derivatives	3,203	7,572
	Related to natural gas marketing	Fair value of derivatives	185	423
	Basis protection contracts			
	Related to natural gas and oil sales	Fair value of derivatives	33,581	40,784
			36,969	48,779

Total derivative liabilities (3)	$59,527	$68,987

(1) As of September 30, 2010, and December 31, 2009, none of our derivative instruments were designated as hedges.

(2) Includes derivative positions that have been designated to our affiliated partnerships; accordingly, our accompanying balance sheets include a corresponding payable to our affiliated partnerships of $28.9 million and $13.4 million as of September 30, 2010, and December 31, 2009, respectively, representing their proportionate share of the derivative assets.

(3) Includes derivative positions that have been designated to our affiliated partnerships; accordingly, our accompanying balance sheets include a corresponding receivable from our affiliated partnerships of $18 million and $21 million as of September 30, 2010, and December 31, 2009, respectively, representing their proportionate share of the derivative liabilities.

PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)

The following table summarizes the impact of our derivative instruments on our accompanying statements of operations for the three and nine months ended September 30, 2010 and 2009.

	2010			2009		
Statement of operations line items	Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	Realized and Unrealized Gains (Losses) For the Current Period	Total	Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	Realized and Unrealized Gains (Losses) For the Current Period	Total
	(in thousands)					
Three months ended September 30,						
Commodity price risk management gain (loss), net						
Realized gains (losses)	$5,688	$1,832	$7,520	$21,139	$685	$21,824
Unrealized gains (losses)	(5,688)	17,197	11,509	(21,139)	(14,498)	(35,637)
Total commodity price risk management gain (loss), net [1]	$—	$19,029	$19,029	$—	$(13,813)	$(13,813)
Sales from natural gas marketing						
Realized gains (losses)	$1,384	$222	$1,606	$1,601	$282	$1,883
Unrealized gains (losses)	(1,384)	1,624	240	(1,601)	(625)	(2,226)
Total sales from natural gas marketing [2]	$—	$1,846	$1,846	$—	$(343)	$(343)
Cost of natural gas marketing						
Realized gains (losses)	$(1,169)	$(280)	$(1,449)	$(1,568)	$(256)	$(1,824)
Unrealized gains (losses)	1,169	(1,563)	(394)	1,568	1,322	2,890
Total cost of natural gas marketing [2]	$—	$(1,843)	$(1,843)	$—	$1,066	$1,066
Nine months ended September 30,						
Commodity price risk management gain (loss), net						
Realized gains (losses)	$19,927	$18,410	$38,337	$62,548	$20,197	$82,745
Unrealized gains (losses)	(19,927)	56,098	36,171	(62,548)	(33,611)	(96,159)
Total commodity price risk management gain (loss), net [1]	$—	$74,508	$74,508	$—	$(13,414)	$(13,414)
Sales from natural gas marketing						
Realized gains (losses)	$2,078	$2,392	$4,470	$4,244	$2,472	$6,716
Unrealized gains (losses)	(2,078)	3,266	1,188	(4,244)	887	(3,357)
	$—	$5,658	$5,658	$—	$3,359	$3,359

Total sales from natural gas marketing [2]						
Cost of natural gas marketing						
Realized gains (losses)	$(1,752)	$(2,402)	$(4,154)	$(4,009)	$(3,000)	$(7,009)
Unrealized gains (losses)	1,752	(3,055)	(1,303)	4,009	(228)	3,781
Total cost of natural gas marketing [2]	$—	$(5,457)	$(5,457)	$—	$(3,228)	$(3,228)

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

Concentration of Credit Risk. A significant component of our future liquidity is concentrated in derivative instruments that enable us to manage a portion of our exposure to price volatility from producing natural gas and oil. These arrangements expose us to the risk of nonperformance by our counterparties. To date, we have had no counterparty defaults.

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With regard to derivative assets, the following table presents the counterparties that expose us to credit risk as of September 30, 2010.

Counterparty Name	Fair Value of Derivative Assets September 30, 2010 (in thousands)
JPMorgan Chase Bank, N.A. (1)	$50,055
Credit Agricole CIB (1) (3)	32,907
Wells Fargo Bank, N.A. (1) (4)	18,450
Various (2)	6,142
Total	$107,554

(1) Major lender in our credit facility. See Note 7.
(2) Represents a total of 52 counterparties, including five lenders in our credit facility.
(3) Formerly known as Calyon New York Branch.
(4) Formerly known as Wachovia Bank, N.A.

5. PROPERTIES AND EQUIPMENT

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

	September 30, 2010	December 31, 2009
	(in thousands)	
Natural gas and oil properties (successful efforts method of accounting)		
Proved	$1,328,824	$1,281,529
Unproved	85,832	38,626
Total natural gas and oil properties	1,414,656	1,320,155
Pipelines and related facilities	33,898	36,909
Transportation and other equipment	31,740	33,432
Land and buildings	14,133	14,699
Construction in progress	31,535	9,131
	1,525,962	1,414,326
Accumulated DD&A	(496,951)	(434,953)
Properties and equipment, net (1)	$1,029,011	$979,373

(1) As a result of the deconsolidation of and our change in ownership interest in PDCM, properties and equipment were reduced by $67.1 million, net of accumulated depreciation, depletion and amortization ("DD&A") of $20.6 million, from December 31, 2009. See Notes 2 and 14.

6. INCOME TAXES

We evaluate our estimated annual effective income tax rate on a quarterly basis based on current and forecasted operating results and enacted 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 ordinary 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 ordinary income or tax benefit on ordinary loss at the most recent estimated annual effective tax rate, adjusted for the effect of discrete items.

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The effective tax rate for continuing operations for the nine months ended 2010, was 32.8% (provision on income) compared to a benefit on loss of 38.1% for the nine months ended 2009. The difference in the tax rates is due to the fact that our net permanent deductions, primarily percentage depletion, reduced the tax provision on income in this period, while increasing the tax benefit on our loss for the same prior year period. In addition, a $1.6 million net discrete tax benefit was recorded during the three months ended 2010, resulting in a reduction of our rate for the nine months ended 2010. Our rate for the period excluding discrete items was 36.8%. The net discrete tax benefit was primarily the result of a reduction in our deferred tax rate from 38.4% to 38%. This rate reduction was due to a change in our state deferred rate based upon changes in both projected future state taxing jurisdictions and projected taxable income apportionments to various states. We consistently review and update our estimated deferred tax rate, with an annual adjustment being common in the period when prior year's federal and state tax returns are filed. There were no significant discrete items recorded during the three and nine months ended 2009.

As of September 30, 2010, we had a gross liability for uncertain tax benefits of $1 million compared to a liability of $0.6 million as of December 31, 2009. If recognized, $0.9 million of the $1 million liability would affect our effective tax rate. This liability is reflected in federal and state income taxes payable in our accompanying balance sheet. During the three months ended June 30, 2010, the Internal Revenue Service ("IRS") commenced an examination of our 2007, 2008 and 2009 tax years. Therefore, we expect the liability for uncertain tax benefits to decrease significantly during the next twelve-month period as items are either resolved without change, converted to amounts due to the IRS or removed due to the expiration of the statute of limitations.

We filed a refund request in May 2010 to reflect our federal 2009 net operating loss ("NOL") carry-back to our 2005 and 2006 tax years. We received our requested federal tax refund of approximately $25.9 million in June 2010. This refund reduced our income tax receivable balance that was recorded at December 31, 2009. Our 2009 NOL is carried forward for state tax purposes and the net benefit of $2.7 million is included as a deferred tax asset and netted against deferred tax liabilities on our balance sheet.

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.

7. LONG-TERM DEBT

The following table presents the components of long-term debt.

	September 30, 2010	December 31, 2009
	(in thousands)	
12% Senior notes due 2018:		
Principal amount	$203,000	$203,000
Unamortized discount	(2,126)	(2,343)
12% Senior notes due 2018, net of discount	200,874	200,657
Credit facility	101,500	80,000
Total long-term debt	$302,374	$280,657

12% Senior Notes Due 2018

In February 2008, we issued 12% senior notes with a total principal amount of $203 million payable at maturity on February 15, 2018. Interest is payable in cash semi-annually in arrears on each February 15th and August 15th. The senior notes were issued at a discount, 98.6% of the principal amount. The original discount and the deferred note issuance costs are being amortized to interest expense over the term of the debt using the effective interest method. As of September 30, 2010, we had $6.2 million in original discount being amortized at a rate of $0.2 million per quarter. We were in compliance with all covenants as of September 30, 2010, and expect to remain in compliance throughout the next year.

Credit facility

We have a credit facility arranged by JPMorgan Chase Bank, N.A., dated as of November 4, 2005, as amended last on December 18, 2009 ("the Eighth Amendment"), with an aggregate revolving commitment of $305 million, which expires on May 22, 2012. The credit facility, through the series of amendments, includes commitments from eleven additional banks. The maximum allowable commitment under the credit facility is $500 million. The credit facility is guaranteed by PDC and its wholly owned subsidiaries, with the exception of certain immaterial subsidiaries, individually and in the aggregate; it is not guaranteed by PDCM. The subsidiary guarantees are full and unconditional and joint and several. The credit facility is subject to and collateralized by our natural gas and oil reserves, exclusive of our proportionate share of PDCM's natural gas and oil reserves. The credit facility requires an aggregated security of a value no less than 80% of the value of the direct interests included in the borrowing base properties. Our credit facility borrowing base is subject to size redeterminations each May and November based upon a quantification of reserves at December 31st and June 30th, respectively; additionally, we or our lenders may request a redetermination upon the occurrence of certain events. A commodity price deck reflective of the current and future commodity pricing environment, as determined by our lenders, is utilized to quantify the reserves used in the borrowing base calculation and thus determines the underlying borrowing base.

We have an $18.7 million irrevocable standby letter of credit in favor of a third party transportation service provider. This letter of credit reduces the amount of available funds under our credit facility by an equal amount. We pay a fronting fee of 0.25% per annum and an additional quarterly maintenance fee equivalent to the spread over Eurodollar loans (2.5% as of September 30, 2010) for the period the letter of credit remains outstanding. The letter of credit expires on May 22, 2012.

As of September 30, 2010, we had $4.2 million in debt issuance costs being amortized at a rate of $0.7 million per quarter; the funds available under our credit facility were $184.8 million; and the interest on our borrowings, inclusive of our standby letter of credit, was accruing at a rate of 3.6% per annum. We were in compliance with all covenants at September 30, 2010, and expect to remain in compliance throughout the next year.

See Note 17 regarding the completion of our November 2010 redetermination and the corresponding entry into a second amended and restated credit agreement.

PDCM Credit Facility

In April 2010, PDCM entered into a credit facility arranged by BNP Paribas ("BNP"), dated as of April 30, 2010, with an initial borrowing base of $10 million. The maximum allowable commitment under the credit facility is $100 million. PDCM is required to pay a commitment fee of 0.5% per annum on the unused portion of the activated credit facility. Based upon PDCM's discretion, interest accrues at either an alternative base rate ("ABR") or an adjusted LIBOR. The ABR is the greater of BNP's prime rate, the federal funds effective rate plus 0.5% or the adjusted LIBOR for a three month interest period plus 1%. ABR and adjusted LIBOR borrowings are assessed an additional margin based upon the outstanding balance as a percentage of the available balance. ABR borrowings are assessed an additional margin of 1.5% to 2.25%. Adjusted LIBOR borrowings are assessed an additional margin spread of 2.5% to 3.25%. Debt issuance costs are amortized using the effective interest rate method over the remaining term of the credit facility. As of September 30, 2010, the unamortized debt issuance costs were immaterial. No principal payments are required until the credit agreement expires on April 30, 2014, or in the event that the borrowing base would fall below the outstanding balance. The credit facility is subject to and collateralized by PDCM's natural gas and oil reserves. The credit facility borrowing base is subject to size redeterminations each May and November based upon a quantification of PDCM's reserves at December 31st and June 30th, respectively; 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.

The credit facility contains covenants customary for agreements of this type, including, but not limited to, limitations on PDCM's ability to: (a) incur additional indebtedness and guarantees, (b) create liens and other encumbrances on their assets, (c) consolidate, merge or sell assets, (d) pay dividends and other distributions, (e) make certain investments, loans and advances, (f) enter into sale/leaseback transactions, and (g) engage in hedging activities unless certain requirements are satisfied. The credit facility also requires PDCM to execute and deliver specified mortgages and other evidences of security and to deliver specified opinions of counsel and other evidences of title. Further, PDCM is required to comply with certain financial tests and maintain certain financial ratios, as defined by the credit facility, on a quarterly basis. The financial tests and ratios include requirements to: (a) maintain a minimum current ratio of 1.0 to 1.0, (b) not to exceed a debt to EBITDAX ratio of 3.5 to 1.0 and (c) maintain a minimum interest coverage ratio of 2.5 to 1.0.

As of September 30, 2010, there were no amounts outstanding related to this credit facility. Should borrowings occur, our financial statements would include our proportionate share of the liability, cost and expenses. As of September 30, 2010, PDCM was in compliance with all covenants.

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8. ASSET RETIREMENT OBLIGATION

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

	Amount (in thousands)
Balance at December 31, 2009 [1]	$29,564
Deconsolidation of PDCM and change in ownership interest	(6,257)
Obligations incurred with development activities and assumed with acquisitions	3,119
Accretion expense	1,043
Obligations discharged with disposal of properties and asset retirements	(880)
Balance at September 30, 2010	26,589
Less current portion	(250)
Long-term portion	$26,339

(1) Includes $0.8 million as of December 31, 2009, related to assets held for sale and divested in July 2010. See Note 12.

9. COMMITMENTS AND CONTINGENCIES

Purchase and Sale Agreement

See Note 17 regarding our entry into a purchase and sale agreement ("PSA") on October 14, 2010, whereby we expect to acquire producing assets and undeveloped acreage located in the Permian Basin in West Texas for $40 million in cash.

Merger Agreements

In June 2010, we and a wholly owned subsidiary of ours (the "merger subsidiary") entered into separate merger agreements with each of PDC 2004-A Limited Partnership, PDC 2004-B Limited Partnership, PDC 2004-C Limited Partnership and PDC 2004-D Limited Partnership. 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 "investor partners"), as well as the satisfaction of other customary closing conditions, then the applicable partnership will merge with and into the merger subsidiary, with the merger subsidiary being the surviving entity. If all four partnerships are acquired, we will pay an aggregate of approximately $36.5 million for the limited partnership units of the investor partners of these partnerships. Definitive proxy statements for each of the partnerships requesting approval from the applicable investor partners for, among other things, the merger agreements were mailed to the investor partners in early October 2010. The special meetings whereby investor partners will have an opportunity to vote and approve the applicable merger agreement are currently scheduled for December 8, 2010, for each of the partnerships. If the required approvals are received at the special meetings, each of the mergers is expected to close shortly thereafter and no later than December 31, 2010.

We intend to borrow the required funds for the aforementioned mergers under our revolving credit facility. There are no material conditions in our ability to obtain the funds and we have not established an alternative financing arrangement. We expect to repay such borrowings with cash from operations in the ordinary course of business.

Drilling Rig Contract

In order to secure the services of a drilling rig, PDCM entered into a commitment with a drilling contractor for the use of a drilling rig. As of September 30, 2010, our proportionate share of PDCM's related maximum commitment was $5.1 million. The commitment expires in October 2012.

Firm Transportation Agreements

We have entered 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 other companies, working interest owners and our

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affiliated partnerships. These contracts require us to pay these transportation and processing charges whether the required volumes are delivered or not. Satisfaction of the volume requirements include volumes produced by us and PDCM, volumes purchased from third parties and volumes produced by our affiliated partnerships. As of September 30, 2010, based on a review of our drilling plans and volume projections, we do not expect to meet all future volume requirements for a firm transportation agreement in our Piceance Basin. Accordingly, as of September 30, 2010, we have a related liability in the amount of $3 million, primarily recorded in prior periods, included in other liabilities on the balance sheet. We are currently working with the third party to renegotiate the terms and timing of our volume requirements under this agreement. If we are not able to renegotiate this agreement or meet our expected future volumes, an additional liability may result.

The following table presents gross volume information related to our long-term firm sales, processing and transportation agreements for pipeline capacity, including our proportionate share of a commitment related to PDCM. We record in our financial statements only our share of costs incurred based upon our working and net revenue interest in the wells. If the volumes below are not met, we will bear all costs related to the volume shortfall.

		For the Twelve Months Ending September 30,					
Area	Total	2011	2012	2013	2014	Thereafter	Expiration Date
Volume (MMcf)							
Piceance	200,227	32,111	32,699	31,518	26,649	77,250	May 31, 2021
Appalachian Basin (1)	163,856	3,426	6,852	16,510	16,475	120,593	August 31, 2022
NECO	13,700	3,650	2,285	1,825	1,825	4,115	December 31, 2016
Total	377,783	39,187	41,836	49,853	44,949	201,958	
Dollar commitment (in thousands)	$182,640	$19,441	$20,421	$24,604	$22,041	$96,133	

(1) Includes a precedent agreement that becomes effective when the planned pipeline is placed in service, currently estimated to be September 2012 and represents 10,629 MMcf, 10,629 MMcf and 84,215 MMcf of the total MMcf presented for the twelve months ending September 30, 2013, 2014 and thereafter, respectively. 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.

Royalty Owner Class Action

Gobel et al v. Petroleum Development Corporation, Case No. 09-C-40 in U. S. District Court, Northern District of West Virginia, filed on January 27, 2009

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 "Gobel lawsuit"). The allegations state that the Company improperly deducted certain charges and costs before applying the royalty percentage. Punitive damages are requested in addition to breach of contract, tort and fraud allegations. On August 31, 2010, the federal judge issued an order remanding the case to state court. On October 27, 2010, the state court set a trial date of April 2012. The Company and the plaintiff have been engaged in settlement discussions. During the three months ended 2010, the Company recorded a charge to natural gas and oil sales in the statement of operations of $3.3 million. As of September 30, 2010, the Company has a total accrual of $6.2 million related to this suit. Given the inherent uncertainty in actions of this nature, the Company is unable to predict the ultimate outcome of this case at this time; however, it could result in a loss in excess of the amount accrued.

We are involved in various other legal proceedings that we consider normal to our business. Although the results cannot be known with certainty, we believe that the ultimate results of such proceedings will not have a material adverse effect on our financial position, results of operations or liquidity.

Environmental

Due to the nature of the natural gas and oil industry, we are exposed to environmental risks. We have various policies and procedures to avoid environmental contamination and mitigate the risks from environmental contamination. We conduct periodic reviews to identify changes in our environmental risk profile. Liabilities are accrued when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. As of September 30, 2010, we have accrued environmental liabilities in the amount of $2 million included in other accrued liabilities on the balance sheet. We are not aware of any environmental claims existing as of September 30, 2010, which have not been provided for or would otherwise have a material impact on our financial statements. However, there can be no assurance that current regulatory requirements will not change or unknown past non-compliance with environmental laws will not be discovered on our properties.

In July 2008, the Company self-reported to the Colorado Department of Public Health and Environment (the "CDPHE") certain non-compliance with air laws at a compressor station in the Piceance Basin. The CDPHE subsequently initiated a review and inspection of air compliance at this station. In November and December 2009, the Company received related compliance advisories for alleged non-compliance. On May 27, 2010, we entered into a settlement agreement providing for a civil penalty of $163 thousand, which was accrued in periods prior to settlement and paid in the second quarter of 2010.

In December 2008, we received a Notice of Violation/Cease and Desist Order (the "Notice") from the CDPHE, related to the stormwater permit for the Garden Gulch Road. The Company manages this private road for Garden Gulch LLC. The Company is one of eight users of this road, all of which are natural gas and oil companies operating in the Piceance region of Colorado. Operating expenses, including this fine, if any, are allocated among the users of the road based upon their respective usage. The Notice alleges a deficient and/or incomplete stormwater management plan, failure to implement best management practices and failure to conduct required permit inspections. The Notice requires corrective action and states that the recipient shall cease and desist such alleged violations. The Notice states that a violation could result in civil penalties up to $10,000 per day. The Company's responses were submitted on February 6, 2009, and April 8, 2009. Commencing in December 2009, the Company entered negotiations with the CDPHE regarding this notice and continues to work to bring this matter to closure. Given the inherent uncertainty in administrative actions of this nature, the Company is unable to predict with certainty the ultimate outcome of this administrative action; however, the Company does not believe that the ultimate outcome will have a material adverse effect on the Company's financial position or results of operations.

Partnership Repurchase Provision

Substantially all of our 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 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, 2010, the maximum annual repurchase obligation, based upon the minimum price described above, was approximately $11.6 million. We believe we have adequate liquidity to meet this obligation. For the nine months ended September 30, 2010, 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 Chief Executive Officer, Chief Financial Officer and other executive officers. The employment agreements provide for annual base salaries, eligibility for performance bonus compensation and other various benefits, including retirement and 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, the severance benefits equal two times to 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 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 the benefits noted in the preceding sentence. For this purpose, a change of control and good reason correspond to the respective definitions of change of control and good reason under Section 409A of the Internal Revenue Code of 1986 (IRC) and the supporting treasury regulations, with some differences. Under any of the above circumstances, the executive officer is also entitled to (i) vesting of any unvested equity compensation (excluding all long-term performance 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 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 401(k) and profit sharing plan, although those benefits are not increased or 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 the remaining executive officers, 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 upon presentation by the executive officer of an accounting of such expenses in accordance with our normal practices 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 409A and the supporting treasury regulations. The benefits will (i) in the case of death 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 base salary.

Partnership Casualty Losses

As managing general partner of 33 partnerships, we have liability for potential 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.

10. STOCK-BASED COMPENSATION PLANS

2010 Long-Term Equity Compensation Plan

In June 2010, our shareholders approved a long-term equity compensation plan for our employees and non-employee directors (the "2010 Plan"). In accordance with the 2010 Plan, up to 1,400,000 new shares of our common stock are authorized for issuance. Shares issued may be either authorized but unissued shares, treasury shares or any combination of these shares. Additionally, the 2010 Plan permits the reuse or reissuance of shares of common stock which were canceled, expired, forfeited or, in the case of stock appreciation rights ("SARs"), paid out in the form of cash. Awards may be issued to our employees in the form of stock options, SARs, restricted stock, restricted stock units ("RSUs"), performance shares and performance units and to our non-employee directors in the form of non-qualified stock options, SARs, restricted stock and RSUs. Awards may vest over periods set at the discretion of the Compensation Committee of our Board of Directors (the "Compensation Committee") with certain minimum vesting periods. With regard to options and SARs, awards have a maximum exercisable period of ten years. In no event may an award be granted under the 2010 Plan on or after April 1, 2020. As of September 30, 2010, 194,596 shares of restricted stock had been awarded pursuant to the 2010 Plan.

Other Long-Term Equity Compensation Plans

As of September 30, 2010, 2,608 shares remain available for issuance in our 2004 Long-Term Equity Compensation Plan and five shares remain available for issuance in our 2005 Non-Employee Director Restricted Stock Plan. All outstanding and non-vested awards pursuant to these plans will continue to be outstanding and vest pursuant to their original terms.

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

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009 [1]
	(in thousands)			
Total stock-based compensation expense	$1,624	$918	$3,845	$4,901
Income tax benefit (based on deferred rate)	(617)	(350)	(1,461)	(1,870)
Net income impact	$1,007	$568	$2,384	$3,031

(1) Includes $1.7 million related to agreements with a former chief executive officer and executive vice president.

Stock-Based Compensation Awards

There have been no material changes in our stock options or market-based restricted stock awards during the nine months ended September 30, 2010.

SARs. In April 2010, our Compensation Committee granted SARs to our executive officers. The SARs will vest over a three-year period and may be exercised at any point after vesting through April 2020. 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, 2010
Weighted average value per SAR granted during the period:	$13.26
Assumptions:	
Expected term	5 years
Risk-free interest rate	2.5%
Volatility	62.0%

The following table presents the changes in our SARs for the nine months ended September 30, 2010.

	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, 2009	—	$—	—	$—
Awarded	57,282	24.44	9.6	—
Outstanding at September 30, 2010	57,282	24.44	9.6	181
Vested and expected to vest at September 30, 2010	51,554	24.44	9.6	163

Exercisable at September 30, 2010	—	—	—	—

The total compensation cost related to SARs granted and not yet recognized in our statement of operations as of September 30, 2010, was $0.6 million. The cost is expected to be recognized over a weighted average period of 2.8 years.

Restricted Stock Awards. During the nine months ended September 30, 2010, our Compensation Committee granted a total of 151,404 shares of restricted stock to our executive officers and non-employee directors at a weighted average grant date fair value of $23.63 per share and 189,063 shares to our key employees at a weighted average grant date fair value of $25.11 per share. Pursuant to the terms of the awards, the shares will vest over a period of one to four years.

The following table presents the changes in our non-vested time-based awards for the nine months ended September 30, 2010.

	Shares	Weighted Average Grant Date Fair Value
Non-vested at December 31, 2009	305,328	$27.55
Granted	340,467	24.45
Vested	(106,624)	28.20
Forfeited	(17,778)	29.30
Non-vested at September 30, 2010	521,393	25.33

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, 2010, was $10 million. The cost is expected to be recognized over a weighted average period of 2.4 years.

11.EARNINGS PER SHARE

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Weighted average common shares outstanding - basic	19,250	16,962	19,218	15,530
Dilutive effect of stock-based compensation:				
Restricted stock	109	—	80	—
SARs	39	—	13	—
Non employee director deferred compensation	8	—	8	—
Weighted average common shares outstanding - diluted	19,406	16,962	19,319	15,530

For the three and nine months ended September 30, 2009, the weighted average common shares outstanding for both basic and diluted were the same because the effect of dilutive securities was anti-dilutive due to our net loss attributable to shareholders for the periods. 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.

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Weighted average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:				
Restricted stock	130	236	266	283
Stock options	10	10	10	10
Non employee director deferred compensation	—	8	—	8
Total anti-dilutive common share equivalents	140	254	276	301

12. DIVESTITURE AND DISCONTINUED OPERATIONS

Michigan Divestiture. On July 30, 2010, we divested our Michigan asset group and related liabilities for net cash proceeds of $22 million and realized a loss on sale of $4.7 million in the form of an impairment charge recorded during the nine months ended 2010 (see Note 3 regarding the impairment charge). We do not have significant continuing involvement in the operations of or cash flows from this asset group. Accordingly, the results of operations related to the Michigan assets have been separately reported as discontinued operations for all periods presented.

Selected financial information related to assets divested and discontinued operations. The tables below set forth selected financial and operational information related to net assets divested, net assets related to discontinued operations and operating results related to discontinued operations. Assets held for sale including related liabilities present the assets that were sold and liabilities that were assumed by the purchaser. Assets and liabilities related to discontinued operations include those assets sold and liabilities assumed by the purchaser as well as all other related assets and liabilities, consisting of accounts receivable and production tax liability, which were not sold. While the reclassification of revenues and expenses related to discontinued operations for prior periods had no impact upon previously reported net earnings, the statement of operations and operational tables present the revenues, expenses and production volumes that were reclassified from the specified statement of operations line items to discontinued operations.

	December 31, 2009	
Balance Sheet	Net Assets Held for Sale (1)	Net Assets Related to Discontinued Operations
	(in thousands)	
Assets		
Current assets		
Accounts receivable, net	$—	$1,240
Total current assets	—	1,240
Properties and equipment, net	28,820	28,820
Total assets	28,820	30,060
Liabilities		
Current liabilities		
Production tax liability	—	37
Total current liabilities	—	37
Asset retirement obligation	775	775
Total liabilities	775	812
Net assets	$28,045	$29,248

(1) See Note 8 for additional information regarding the asset retirement obligation related to assets held for sale and divested in July 2010.

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Statement of Operations - Discontinued Operations	Three Months Ended September 30, 2010	2009	Nine Months Ended September 30, 2010	2009 [1]
	(in thousands)			
Revenues				
Natural gas and oil sales	$408	$1,135	$3,437	$3,866
Sales from natural gas marketing	568	1,382	3,328	4,000
Well operations, pipeline income and other	120	299	491	651
Total revenues	1,096	2,816	7,256	8,517
Costs, expenses and other				
Natural gas and oil production and well operations costs	248	513	1,260	1,381
Cost of natural gas marketing	537	1,377	3,265	4,005
Depreciation, depletion and amortization	—	641	1,094	1,716
Impairment of proved natural gas and oil properties	160	—	4,666	—
Total costs, expenses and other	945	2,531	10,285	7,102
Income (loss) from discontinued operations	151	285	(3,029)	1,415
Provision (benefit) for income taxes	(37)	106	(1,300)	562
Income (loss) from discontinued operations, net of tax	$188	$179	$(1,729)	$853
Operational Data				
Production				
Natural gas (Mcf)	54,694	390,320	755,606	1,042,256
Oil (Bbls)	38	697	2,137	2,275
Natural gas equivalent (Mcfe)	54,922	394,502	768,428	1,055,906

[1] Represents only the impact of the divestiture of our Michigan assets; excludes revenues of $193 thousand ($113 thousand, net of tax) related to our natural gas and oil well drilling segment, which was reported as discontinued operations in March 2009.

13. ACQUISITION

On July 30, 2010, we acquired various producing assets located in the Wolfberry oil trend in the Permian Basin in West Texas. In conjunction with the divestiture of our Michigan asset group we entered into a like-kind exchange agreement, in accordance with Internal Revenue Code Section 1031 ("IRC 1031"), with a qualified intermediary. The Wolfberry assets were identified as our replacement property in accordance with IRC 1031. Sales proceeds in the amount of $19.3 million from the Michigan divestiture were transferred directly to the qualified intermediary and used, along with $55.7 million from our credit facility, to fund our Wolfberry acquisition. The sale of our Michigan assets resulted in a gain for income tax purposes of $19.2 million, which then resulted in a tax liability of $7.3 million. With the favorable deferral aspects of IRC 1031, we were able to defer $6.5 million of this tax liability.

The following table presents the adjusted purchase price and preliminary allocation thereof based on estimates of fair value.

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	Amount (in thousands)
Cash consideration paid to seller	$74,996
Payable to seller	590
Total consideration for net assets	$75,586
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Proved natural gas and oil properties	$29,187
Unproved natural gas and oil properties	48,657
Asset retirement obligation	(1,272)
Environmental liability	(986)
Total identifiable net assets	$75,586

Pro Forma Information. The results of operations for our Permian acquisition have been included in our consolidated financial statements from the date of acquisition. The pro forma effect of the inclusion in our consolidated statement of operations of the results of operations of these assets as if the acquisition had occurred at the beginning of the periods presented, is not presented as it would not be materially different from the information presented in the accompanying interim statement of operations.

14. NONCONTROLLING INTEREST

The following table presents the changes in noncontrolling interest.

	Amount (in thousands)
Balance at December 31, 2009	$47,678
Deconsolidation of PDCM	(47,322)
Net loss attributable to noncontrolling interest	(66)
Balance at September 30, 2010	$290

PDCM

In October 2009, we entered into a joint venture arrangement to form PDCM. At that time, the joint venture was determined to be a variable interest entity due to the disproportionate voting rights compared to our ownership interest; accordingly, we consolidated 100% of the joint venture as we were the primary beneficiary as of and for the period ended December 31, 2009. As of January 1, 2010, pursuant to the adoption of new accounting changes related to variable interest entities (see Note 2), the joint venture was deconsolidated from 100% and proportionately consolidated at 67.4%, representing only our ownership interest. Further, on April 1, 2010, our joint venture partner made a cash capital contribution to PDCM of $28 million, resulting in a change in our ownership interest in PDCM of approximately 9.6%, decreasing from 67.4% to 57.8%, which continues to represent our interest ownership as of September 30, 2010.

The following table presents the impact on our balance sheet resulting from the deconsolidation of PDCM on January 1 and our change in ownership interest on April 1. The changes below are non-cash items with the exception of the changes in cash and cash equivalents, which are reflected in the statement of cash flows.

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	Decreased/(Increased) January 1, 2010	April 1, 2010		Decreased/(Increased) January 1, 2010	April 1, 2010
	(in thousands)			(in thousands)	
Assets			Liabilities and Equity		
Current assets			Current liabilities		
Cash and and cash equivalents	$3,074	$398	Accounts payable	$813	$426
Accounts receivable, net	1,335	335	Production tax liability	17	15
Accounts receivable affiliates	(2,399)	(356)	Fair value of derivatives	434	—
Fair value of derivatives	2	251	Funds held for distribution	322	168
Prepaid expenses and other current assets	131	34	Other accrued expenses	—	15
Total current assets	2,143	662	Total current liabilities	1,586	624
Properties and equipment, net	51,765	15,324	Fair value of derivatives	83	—
Fair value of derivatives	70	163	Asset retirement obligation	4,815	1,442
Other assets	419	144	Other liabilities	591	198
Total assets	$54,397	$16,293	Total liabilities	7,075	2,264
			Shareholders' equity	—	14,029
			Noncontrolling interest	47,322	—
			Total equity	47,322	14,029
			Total liabilities and equity	$54,397	$16,293

WWWV, LLC

In 2007, we contributed $0.8 million for a 50% interest in WWWV, LLC (the "LLC"), a limited liability company for which we serve as the managing member. The LLC's only asset is an aircraft and the LLC was formed for the purpose of owning and operating the aircraft. We consolidate the entity based on a controlling financial interest. We have commenced activities to divest the asset and dissolve the entity, which will not have a material impact on our financial statements.

15. TRANSACTIONS WITH AFFILIATES

We enter into derivative instruments for our own production as well as for our 33 affiliated partnerships' production. As of September 30, 2010, we had a payable to affiliates of $28.9 million representing their designated portion of the fair value of our gross derivative assets and a receivable from affiliates of $18 million representing their designated portion of the fair value of our gross derivative liabilities.

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 $1.3 million and $3.4 million for the three and nine months ended September 30, 2010, respectively, related to the marketing of natural gas on behalf of PDCM and our affiliated partnerships. For the three and nine months ended September 30, 2009, sales from natural gas marketing include $0.1 million and $0.4 million, respectively, related to the marketing of natural gas on behalf of our affiliated partnerships.

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.

We provide certain well operating and administrative services for PDCM. Amounts billed to PDCM for these services were $2.6 million and $8.3 million for the three and nine months ended September 30, 2010, respectively. Our statements of operations include only our proportionate share of these billings: $0.9 million, $0.2 million and $0.4 million is reflected in natural gas and oil production and well operations costs, exploration expense and general and administrative expense, respectively, for the three months ended 2010 and $2.8 million, $0.7 million and $1.6 million, respectively, for the nine months ended 2010.

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16. BUSINESS SEGMENTS

We separate our operating activities into two segments: natural gas and 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, reclassified for discontinued operations. The assets and operating results related to our divested Michigan assets were previously included in our natural gas and oil sales segment.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Revenues:				
Natural gas and oil sales	$69,274	$31,297	$237,545	$115,646
Natural gas marketing	18,337	11,062	53,613	43,200
Unallocated	(2)	25	37	78
Total	$87,609	$42,384	$291,195	$158,924
Segment income (loss) from continuing operations before income taxes:				
Natural gas and oil sales	$21,411	$(20,919)	$94,833	$(40,432)
Natural gas marketing	39	885	769	1,788
Unallocated	(19,304)	(19,627)	(56,839)	(65,706)
Total	$2,146	$(39,661)	$38,763	$(104,350)

	September 30, 2010	December 31, 2009
	(in thousands)	
Segment assets:		
Natural gas and oil sales	$1,196,187	$1,123,340
Natural gas marketing	15,096	22,614
Unallocated	39,281	75,553
Assets held for sale	—	28,820
Total	$1,250,564	$1,250,327

17. SUBSEQUENT EVENTS

Purchase and Sale Agreement

On October 14, 2010, we entered into a purchase and sale agreement with an unrelated party to acquire 100% of the interest in producing assets and undeveloped acreage located in the Wolfberry oil trend in the Permian Basin in West Texas for $40 million in cash. The assets are located on a primarily contiguous 5,760 net acre block, with over 100 identified oil drilling locations on 40-acre spacing. The producing assets currently produce approximately 330 barrels of oil equivalent ("BOE") per day from six wells. The acquisition is expected to be funded with a draw from our credit facility and is expected to close on November 19, 2010, with an effective date of November 1, 2010.

Second Amended and Restated Credit Agreement

On November 5, 2010, we entered into a second amended and restated credit agreement co-arranged by JPMorgan Chase Bank, N.A. and BNP Paribas, dated as of November 5, 2010. This new agreement amends and restates our original credit agreement dated as of November 4, 2005. The second amended and restated credit agreement increases our aggregate revolving commitment to $350 million. This $45 million increase in our borrowing base from $305 million was based upon the quantification of our estimated June 30, 2010, reserves. The new credit facility includes commitments from three additional participating banks: Capital One, N.A.; Comerica Bank; and Natixis. The second amended and restated credit agreement amends certain other provisions, including, but not limited to, a reduction in our borrowing rate, which continues to be based on an alternative base rate ("ABR") or an adjusted LIBOR. Pursuant to the new agreement, ABR borrowings are assessed an additional margin of 1% to 2%, down from previous rates of 1.375% to 2.375%, and adjusted LIBOR borrowings are assessed an additional margin of 2% to 3%, down from 2.25% to 3.25%.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Non-GAAP Financial Measures

We use "adjusted cash flow from operations," "adjusted net income (loss) from continuing operations" and "adjusted EBITDA," non-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 (loss) from continuing operations, cash flows from operations, investing or financing activities. These measures should not be used as liquidity measures or indicators of cash flows reported in accordance with U.S. GAAP. The non-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-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-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.

Overview

During the third quarter of 2010, we made significant strides in achieving our new corporate direction. In July, we announced that we would begin conducting business under a new name, PDC Energy; further, we rolled out our new three-year business plan. As we had already shifted away from a business model that primarily raised capital through sponsoring drilling partnerships, our new business plan moves us toward becoming a more traditional exploration and production ("E&P") company.

As part of our analyst day presentation, in July, we provided insight into our management philosophy and goals as we position ourselves for the future. Two of our key goals are to again grow our year-over-year production beginning in 2011 and to diversify our commodity mix, increasing the oil component of our asset base to a goal of 35% over the next five years. With these goals in mind, we completed a $75 million acquisition of various producing assets in the Permian Basin in West Texas. The acquisition was funded by our credit facility and the sale of our Michigan assets. This acquisition allows us to advance the above goals as the Permian assets provide for over 100 potential well sites and are rich in oil and natural gas liquids; we estimate total reserves in this area to comprise up to 70% oil. While our Michigan assets were predictable and profitable, they were primarily gas and did not have significant additional growth opportunity.

We began the fourth quarter of 2010 with three drilling rigs operating in our Wattenberg Field carrying out our vertical drilling program and added a fourth rig in October to initiate our horizontal Niobrara drilling program. We anticipate that this initial horizontal well will be the first of many in our Wattenberg Basin. With our Wattenberg wells historically producing an oil/natural gas liquids/natural gas mix of 50/20/30 and the steps highlighted above, we believe that we are well on our way to meeting our natural gas/oil production mix goal of 65/35. For the nine months ended 2010, our natural gas/oil production mix was 78/22 compared to 81/19 for the nine months ended 2009.

Another strategic goal reiterated in July is our desire, over a three-year period, to purchase company sponsored partnerships. In early October, we initiated the first phase of the purchase program and mailed definitive proxy statements for each of the 2004 partnerships, consisting of PDC 2004-A Limited Partnership, PDC 2004-B Limited Partnership, PDC 2004-C Limited Partnership and PDC 2004-D Limited Partnership, to the limited partner investors in the applicable 2004 partnership. The proxy statements provide the holders of limited partnership units, who are not affiliated with PDC ("investor partners"), the opportunity to approve a merger of the applicable 2004 partnership with and into a wholly owned merger subsidiary of ours, effectively converting such investor partner's limited partnership units into a right to receive cash consideration, as provided in the proxy statements, for each limited partnership unit held by that investor partner. Closing of each merger is conditioned on approval by a majority vote of, the investor partners of the applicable partnership to, among other things, approve the merger agreement for such partnership. Upon completion of each merger, the merger subsidiary will be the surviving entity, the applicable partnership will cease as a separate business entity and we will hold all of the interests of the merger subsidiary. The offer price for each of the 2004 partnerships took into consideration such partnership's existing and future production. The prospective acquisition of these partnerships provides us with the opportunity to accelerate development of existing well sites, eliminate duplicative general and administrative costs and help reinforce our corporate image as an independent E&P company. If approved by the investor partners, these mergers will add to the production of our Wattenberg and Piceance fields.

Lastly, through our joint venture, we hope to continue to exploit our Marcellus assets. With three horizontal wells now turned in line and producing, we are acquiring significant insight into our geological play. In July, PDCM entered into a drilling rig commitment through October 2012. We expect to capitalize on the knowledge acquired during the process of drilling these first few horizontal wells and apply such knowledge to a more continuous drilling program.

Operating results for the three and nine months ended 2010 reveal increased natural gas and oil sales revenue of 12.1% and 28.6% or $5.2 million and $34.7 million, respectively, compared to the three and nine months ended 2009. These increases in sales revenue were driven primarily by the improved commodity price environment and the increase in our oil production as a percentage of our total production. Average sales price per Mcfe, excluding the impact of realized derivative gains and the provision for underpayment of natural gas sales, was $5.60 and $6.02 for the three and nine months ended 2010 compared to $4.07 and $3.85 for the three and nine months ended 2009, respectively. Realized derivative gains from natural gas and oil sales contributed to total revenues an additional $0.82 per Mcfe and $1.45 per Mcfe or $7.5 million and $38.3 million for the three and nine months ended 2010, respectively. Comparatively, the total per Mcfe price realized, consisting of the average sales price and realized derivative gains, increased 4.6% to $6.42 for the three months ended 2010 from $6.14 for the three months ended 2009 and 16.5% to $7.47 for the nine months ended 2010 from $6.41 for the nine months ended 2009. While production volumes for the three and nine months ended 2010 decreased 13.1% and 17.9%, respectively, compared to the same prior year periods, production from continuing operations for the third quarter of 2010 increased 6.5% from the second quarter of 2010.

Operating results for the nine months ended 2010 remain in line with our 2010 guidance, as revised on July 15, 2010. We continue to believe that our positive operating results coupled with our liquidity position provide us with flexibility and stability to capitalize on future opportunities and lessen the impact of unforeseen challenges.

Results of Operations

Summary of Continuing Operations

The following table sets forth selected information regarding our results of continuing operations, including production volumes, natural gas and oil sales, average sales price received, average sales price including realized derivative gains, average lifting cost and other operating income and expenses. See Note 12, Divestitures and Discontinued Operations, for production and sales information related to our divested Michigan assets.

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	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Change	2010	2009	Change
	(dollars in thousands, except per unit data)					
Production [1]						
Natural gas (Mcf)	7,147,140	8,668,522	(17.6)%	20,691,149	26,259,718	(21.2)%
Oil (Bbls)	336,010	311,850	7.7%	961,720	997,021	(3.5)%
Natural gas equivalent (Mcfe) [2]	9,163,200	10,539,622	(13.1)%	26,461,469	32,241,844	(17.9)%
Natural Gas and Oil Sales						
Natural gas	$27,299	$23,862	14.4%	$89,741	$73,214	22.6%
Oil	24,023	19,009	26.4%	69,644	50,807	37.1%
Provision for underpayment of natural gas sales	(3,252)	—	*	(3,252)	(2,581)	(26.0)%
Total natural gas and oil sales	$48,070	$42,871	12.1%	$156,133	$121,440	28.6%
Realized Gain on Derivatives, net [3]						
Natural gas	$5,361	$18,318	(70.7)%	$32,094	$67,127	(52.2)%
Oil	2,159	3,506	(38.4)%	6,243	15,618	(60.0)%
Total realized gain on derivatives, net	$7,520	$21,824	(65.5)%	$38,337	$82,745	(53.7)%
Average Sales Price (excluding gains/losses on derivatives)						
Natural gas (per Mcf)	$3.82	$2.75	38.9%	$4.34	$2.79	55.6%
Oil (per Bbl)	$71.49	$60.96	17.3%	$72.42	$50.96	42.1%
Natural gas equivalent (per Mcfe)	$5.60	$4.07	37.6%	$6.02	$3.85	56.4%
Average Sales Price (including realized gains/losses on derivatives)						
Natural gas (per Mcf)	$4.57	$4.87	(6.2)%	$5.89	$5.34	10.3%
Oil (per Bbl)	$77.92	$72.20	7.9%	$78.91	$66.62	18.4%
Natural gas equivalent (per Mcfe)	$6.42	$6.14	4.6%	$7.47	$6.41	16.5%
Average Lifting Cost (per Mcfe) [4]	$1.21	$0.79	53.2%	$1.16	$0.78	48.7%
Natural gas marketing [5]	$37	$883	(95.8)%	$783	$1,780	(56.0)%
Other Costs and Expenses						
Exploration expense	$3,737	$6,586	(43.3)%	$13,985	$15,363	(9.0)%
General and administrative expense	$10,426	$9,627	8.3%	$30,975	$36,505	(15.1)%
Depreciation, depletion and amortization	$28,219	$31,935	(11.6)%	$82,992	$99,080	(16.2)%

Amounts may not calculate due to rounding
*Percentage change not meaningful or greater than 300%

(1)

Production is net and determined by multiplying the gross production volume of properties in which we have an interest by the percentage of the leasehold or other property interest we own.

(2) A ratio of energy content of natural gas and oil (six Mcf of natural gas equals one Bbl of oil) was used to obtain a conversion factor to convert oil production into equivalent Mcf of natural gas.

(3) Amounts represent realized derivative gains and losses related to natural gas and oil sales; the amounts do not include realized derivative gains and losses related to natural gas marketing.

(4) Lifting costs represent natural gas and oil operating expenses, which exclude production taxes.

(5) Represents sales from natural gas marketing less cost of natural gas marketing.

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Natural Gas and Oil Sales

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Percentage Change	2010	2009	Percentage Change
Production						
Natural gas (Mcf)						
Rocky Mountain Region	6,457,832	7,683,151	(15.9)%	18,764,728	23,195,519	(19.1)%
Appalachian Basin (1)	612,447	968,494	(36.8)%	1,813,690	2,971,374	(39.0)%
Other	76,861	16,877	*	112,731	92,825	21.4 %
Total	7,147,140	8,668,522	(17.6)%	20,691,149	26,259,718	(21.2)%
Oil (Bbls)						
Rocky Mountain Region	322,182	308,277	4.5 %	946,045	989,035	(4.3)%
Appalachian Basin (1)	2,334	3,338	(30.1)%	4,181	7,241	(42.3)%
Other	11,494	235	*	11,494	745	*
Total	336,010	311,850	7.7 %	961,720	997,021	(3.5)%
Natural gas equivalent (Mcfe)						
Rocky Mountain Region	8,390,924	9,532,813	(12.0)%	24,440,998	29,129,729	(16.1)%
Appalachian Basin (1)	626,451	988,522	(36.6)%	1,838,776	3,014,820	(39.0)%
Other	145,825	18,287	*	181,695	97,295	86.7 %
Total	9,163,200	10,539,622	(13.1)%	26,461,469	32,241,844	(17.9)%

*Percentage change not meaningful or greater than 300%

(1) For the three and nine months ended 2010, the decreases in production were primarily the result of our contribution of natural gas and oil properties to PDCM.

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	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Percentage Change	2010	2009	Percentage Change
Average Sales Price (excluding derivative gains/losses)						
Natural gas (per Mcf)						
Rocky Mountain Region	$3.69	$2.70	36.7 %	$4.27	$2.65	61.1 %
Appalachian Basin	4.52	3.08	46.8 %	4.76	3.89	22.4 %
Other (1)	8.71	7.70	13.1 %	8.70	1.40	*
Weighted average price	3.82	2.75	38.9 %	4.34	2.79	55.6 %
Oil (per Bbl)						
Rocky Mountain Region	71.38	60.80	17.4 %	72.38	50.97	42.0 %
Appalachian Basin	75.29	75.29	*	77.23	50.14	54.0 %
Other	73.77	68.57	7.6 %	73.79	47.10	56.7 %
Weighted average price	71.49	60.96	17.3 %	72.42	50.96	42.1 %
Natural gas equivalent (per Mcfe)						
Rocky Mountain Region	5.58	4.14	34.8 %	6.08	3.84	58.3 %
Appalachian Basin	4.70	3.27	43.7 %	4.87	3.96	23.0 %
Other (1)	10.41	7.99	30.3 %	10.07	1.70	*
Weighted average price	5.60	4.07	37.6 %	6.02	3.85	56.4 %

(1) For the three and nine months ended 2010, the increases in average sales price were the result of our new Permian assets containing a much higher natural gas liquid content than our previously existing assets.

Natural gas and oil sales revenue for the three and nine months ended 2010, excluding the provision for underpayment of gas sales, increased $8.5 million and $35.4 million, compared to the three and nine months ended 2009, respectively. Approximately $14 million and $57.6 million of the increase in natural gas and oil sales revenue for the three and nine months ended 2010, respectively, was due to pricing, offset in part by decreased production, which reduced natural gas and oil sales by $5.6 million and $22.2 million, respectively. For the three and nine months ended 2010, our natural gas/oil revenue mix was 53/47 and 56/44, respectively, compared to 56/44 and 59/41 for the three and nine months ended 2009.

Natural Gas and Oil Pricing. Our results of operations depend upon many factors, particularly the price of natural gas and oil and our ability to market our production effectively. Natural gas and oil prices are among the most volatile of all commodity prices. These price variations have a material impact on our financial results. Natural gas prices vary by region and locality, depending upon the distance to markets, the supply and demand relationships in that region or locality and the availability of sufficient pipeline capacity. This can be especially true in the Rocky Mountain Region. The combination of increased drilling activity and the lack of local markets have 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. Oil pricing, unlike natural gas pricing, is driven predominantly by global supply and demand relationships.

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 Colorado Interstate Gas ("CIG") prices as well as Mid-Continent or other nearby regional prices. The CIG Index, and other indices for production delivered to other Rocky Mountain pipelines, has historically been less than the price received for natural gas produced in the eastern regions, which is

New York Mercantile Exchange ("NYMEX")-based. This negative differential has narrowed in the last year and is lower than historical variances. This negative differential between NYMEX and CIG averaged $0.72 and $1.16 for the three and nine months ended 2009, respectively, and narrowed to an average of $0.51 and $0.88 for the three and nine months ended 2010, respectively.

The table below identifies the market for our natural gas and oil sales based on production for the three months ended 2010. The pricing basis is the market index that most closely relates to the price under which our natural gas and oil was sold.

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Energy Market Exposure
For the Three Months Ended September 30, 2010

Area	Market	Commodity	Percent of Production	
Rocky Mountain Region				
Piceance/Wattenberg	Colorado Interstate Gas	Gas	42	%
Wattenberg/Piceance/North Dakota	NYMEX	Oil	22	%
Piceance	San Juan Basin/Southern California	Gas	15	%
NECO	Mid Continent (Panhandle Eastern)	Gas	9	%
Wattenberg	Colorado Liquids	Gas	3	%
Total Rocky Mountain Region			91	%
Appalachian Basin	NYMEX	Gas	7	%
Other	Other	Gas/Oil	2	%
			100	%

Natural Gas and Oil Production and Well Operations Costs. Natural gas and oil production and well operations costs include our lease operating expenses, production taxes, the cost to operate wells and pipelines for our affiliated partnerships and other third parties (whose income is included in well operations, pipeline income and other) and certain production and engineering staff-related overhead costs.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Lease operating expenses	$11,116	$8,291	$30,811	$25,166
Production taxes	3,102	2,577	7,957	7,173
Costs of well operations and pipeline income	1,832	1,851	5,636	5,113
Overhead and other production expenses	635	1,986	3,813	6,790
Total natural gas and oil production and well operations costs	$16,685	$14,705	$48,217	$44,242

Lease operating expenses. Lifting costs per Mcfe increased to $1.21 per Mcfe for the three months ended 2010 from $0.79 per Mcfe for the same period in 2009, and increased to $1.16 per Mcfe for the nine months ended 2010 from $0.78 per Mcfe for the same period in 2009. The increases in per Mcfe cost were partially due to decreases in production volumes of 13.1% and 17.9% for the three and nine months ended 2010, respectively, which results in the fixed cost portion of our lease operating expenses being absorbed by a reduced number of units. Contributing to the increases in lease operating expenses for the three and nine months ended 2010 were well workovers, which include tubing and casing repairs of $2.1 million and $4 million, and environmental remediation charges of $1 million and $2.4 million, respectively.

Production taxes. Production taxes for the three months ended 2010 increased $0.5 million compared to the three months ended 2009. The increase was primarily related to the increase in sales revenues. For the nine months ended 2010, production taxes increased by $0.8 million compared to the nine months ended 2009. The increase was primarily related to increase in sales revenues, offset in part by a reduction of ad valorem tax rates for certain counties and an increase in the number of wells exempt from severance taxes, due to their re-characterization as stripper wells.

Overhead and other production expenses. The decreases in overhead and other production expenses for the three and nine months ended 2010 compared to the same 2009 periods were primarily the result of the reduction in expenses related to the deconsolidation of PDCM, $0.6 million for the three months ended 2010 and $1.6 million for the nine months then ended. The remaining decrease includes reductions in various other expenses including, pipeline and compressor maintenance.

Commodity Price Risk Management, Net

Commodity price risk management, net includes realized gains and losses and unrealized changes in the fair value of derivative instruments related to our natural gas and oil production. Commodity price risk management, net does not include derivative transactions related to natural gas marketing, which are included in sales from and cost of natural gas marketing. See Note 3, Fair Value Measurements, and Note 4, Derivative Financial Instruments, to our accompanying financial statements included in this report for additional details of our derivative financial instruments.

The following table presents the realized and unrealized derivative gains and losses included in commodity price risk management, net.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Commodity price risk management gain (loss), net:				
Realized gains:				
Natural gas	$5,361	$18,318	$32,094	$67,127
Oil	2,159	3,506	6,243	15,618
Total realized gain, net	7,520	21,824	38,337	82,745
Unrealized gains (losses):				
Reclassification of realized gains included in prior periods unrealized	(5,688)	(21,139)	(19,927)	(62,548)
Unrealized gains (losses) for the period	17,197	(14,498)	56,098	(33,611)
Total unrealized gain (loss), net	11,509	(35,637)	36,171	(96,159)
Total commodity price risk management gain (loss), net	$19,029	$(13,813)	$74,508	$(13,414)

The realized derivative gains for the three and nine months ended 2010 were primarily a result of lower natural gas and 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 total realized gain related to natural gas derivatives consisted of a gain of $7.9 million on our commodity positions and a loss of $2.5 million on our basis position. Similarly, for the nine months ended 2010, the total realized gain related to natural gas derivatives consisted of a gain of $40.2 million related to commodity positions and a loss of $8.1 million related to our basis 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, offset in part by unrealized losses on our oil positions, as the forward strip price shifted upward 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 oil positions and our CIG basis swaps were $8 million and $1.6 million, respectively. For the nine months ended 2010, the unrealized gains were primarily due to a downward shift in the forward strip price of natural gas and oil, as the forward strip price shifted downward and the basis differential between NYMEX and CIG narrowing during the year. Unrealized gains on our natural gas and oil positions for the nine months ended 2010 were $58.5 million and $0.3 million, respectively, offset in part by unrealized losses on our CIG basis swaps were $2.7 million.

For the three and nine months ended 2009, we realized significant gains as a result of lower natural gas and oil prices at settlement compared to the respective derivative strike prices. Unrealized losses for the periods were primarily related to oil swaps as the forward strip price of oil rebounded during the periods and the CIG basis swaps as the forward basis differential between NYMEX and CIG continued to narrow during the periods from the strike price of the derivative position.

Natural Gas and Oil Sales Derivative Instruments. We use various derivative instruments to manage fluctuations in natural gas and oil prices. We have in place a variety of floors, collars, fixed-price swaps and a basis swap on a portion of our estimated natural gas and oil production. See Note 4, Derivative Financial Instruments, to Consolidated Financial Statements in our 2009 Form 10-K for an additional discussion of how each derivative type impacts our cash flows.

The following table presents our derivative positions (including our proportionate share of both the derivative positions held by PDCM and those designated to our affiliated partnerships) in effect as of September 30, 2010, related to natural gas and oil production by area.

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	Floors		Collars			Fixed-Price Swaps		CIG Basis Protection Swaps		
Commodity/ Index/ Maturity Period	Quantity (Oil - Bbls)	Weighted Average Contract Price	Quantity (Gas - MMBtu [1] Oil - Bbls)	Weighted Average Contract Price Floors	Ceilings	Quantity (Gas - MMBtu [1] Oil - Bbls)	Weighted Average Contract Price	Quantity (MMBtu) [1]	Weighted Average Contract Price	Fair Value September 30, 2010 [2] (in thousands)
Natural gas										
NYMEX										
10/01 - 12/31/2010	—	$ —	649,733	$ 6.00	$ 9.43	2,307,507	$ 6.45	1,794,831	$ (1.88)	$ 4,587
01/01 - 03/31/2011	—	—	817,088	6.03	9.39	1,364,664	7.25	1,201,028	(1.88)	3,729
04/01 - 06/30/2011	—	—	—	—	—	2,885,360	6.88	2,216,370	(1.88)	4,596
07/01 - 09/30/2011	—	—	—	—	—	2,817,240	6.84	2,160,483	(1.88)	3,933
10/01 - 12/31/2011	—	—	—	—	—	2,739,336	6.89	2,094,683	(1.88)	2,862
2012-2013	—	—	9,212,724	6.05	8.43	8,564,920	7.09	14,618,947	(1.88)	7,872
CIG										
10/01 - 12/31/2010	—	—	680,630	4.75	9.45	234,319	5.05	—	—	1,110
01/01 - 03/31/2011	—	—	1,020,945	4.75	9.45	187,211	5.81	—	—	1,295
04/01 - 06/30/2011	—	—	—	—	—	330,752	5.81	—	—	674
07/01 - 09/30/2011	—	—	—	—	—	243,103	5.81	—	—	454
10/01 - 12/31/2011	—	—	—	—	—	198,677	5.81	—	—	300
PEPL										
10/01 - 12/31/2010	—	—	360,000	5.55	9.38	427,624	5.95	—	—	1,638
01/01 - 03/31/2011	—	—	390,000	5.76	9.56	271,628	6.18	—	—	1,276
04/01 - 06/30/2011	—	—	—	—	—	636,998	6.18	—	—	1,414
07/01 - 09/30/2011	—	—	—	—	—	615,584	6.18	—	—	1,265
10/01 - 12/31/2011	—	—	—	—	—	593,214	6.18	—	—	1,015
2012-2013	—	—	—	—	—	2,346,224	6.18	—	—	3,146
Total natural gas	—		13,131,120			26,764,361		24,086,342		41,166

Oil										
NYMEX										
10/01 - 12/31/2010	21,000	65.38	—	—	—	142,096	92.30	—	—	1,394
01/01 - 03/31/2011	21,000	65.38	67,814	73.00	99.80	147,592	76.45	—	—	(966)
04/01 - 06/30/2011	21,000	65.38	60,691	73.00	99.80	136,449	76.09	—	—	(1,094)
07/01 - 09/30/2011	21,000	65.38	54,293	73.00	99.80	128,312	75.78	—	—	(1,187)
10/01 - 12/31/2011	20,000	65.38	48,654	73.00	99.80	122,336	75.50	—	—	(1,275)
2012-2013	36,000	65.38	686,148	75.00	102.63	417,902	83.58	—	—	(1,431)
Total oil	140,000		917,600			1,094,687		—		(4,559)
Total natural gas and oil										$ 36,607

(1) A standard unit of measurement for natural gas (one MMBtu equals one Mcf).

(2) Approximately 39% of the fair value of our derivative assets and 100% of our derivative liabilities were measured using significant unobservable inputs (Level 3); see Note 3, Fair Value Measurements, to the accompanying financial statements.

Natural Gas Marketing

Sales from Natural Gas Marketing. The $7.3 million increase in sales from natural gas marketing for the three months ended 2010 compared to the three months ended 2009 is primarily due to an increase in commodity prices and an increase in unrealized gains on derivatives. For the three months ended 2010, prices on sales were 35.2% higher on average than in the three months ended 2009, resulting in a $4.3 million increase in sales. Unrealized derivative gains for the three months ended 2010 increased $2.4 million from a $2.2 million loss for the three months ended 2009 to unrealized gains of $0.2 million for the three months ended 2010.

Sales from natural gas marketing for the nine months ended 2010 increased $10.4 million to $53.6 million from $43.2 million for the nine months ended 2009. The increase is primarily due to an 18.2% increase in commodity prices, which contributed $7.4 million to the increase. Unrealized derivative gains for the nine months ended 2010 increased $4.5 million from a $3.3 million loss for the nine months ended 2009 to an unrealized gain of $1.2 million for the nine months ended 2010 offset in part by a decrease in realized gains of $2.2 million.

Cost of Natural Gas Marketing. Cost of natural gas marketing increased $8.1 million for the three months ended 2010 compared to the three months ended 2009. This increase was primarily due to a 37.2% increase in prices, contributing $4.4 million to the increase, and a $3.3 million increase in unrealized derivative losses.

The $11.4 million increase in cost of natural gas marketing for the nine months ended 2010 compared to the nine months ended 2009 is primarily due to a 22.1% increase in commodity prices, contributing $8.4 million to the increase, and an increase in unrealized derivative losses of $5.1 million, offset in part by a decrease in realized derivative losses of $2.9 million.

Natural Gas Marketing Derivative Instruments. Our 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. We do not take speculative positions on commodity prices.

The following table presents our derivative positions in effect as of September 30, 2010, related to natural gas marketing.

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Commodity/ Derivative Instrument/ Maturity Period	Collars			Fixed-Price Swaps		NYMEX Basis Protection Swaps		
	Quantity (MMBtu)[1]	Weighted Average Contract Price Floors	Weighted Average Contract Price Ceilings	Quantity (MMBtu)[1]	Weighted Average Contract Price	Quantity (MMBtu)[1]	Weighted Average Contract Price	Fair Value September 30, 2010 [2] (in thousands)
Natural gas								
Sales								
Physical								
10/01 - 12/31/2010	—	$—	$ —	70,058	$5.77	62,930	$0.49	$127
01/01 - 03/31/2011	—	—	—	37,875	4.84	106,045	0.38	29
04/01 - 06/30/2011	—	—	—	2,080	5.60	7,535	0.89	8
07/01 - 09/30/2011	—	—	—	1,685	5.60	1,870	0.78	3
10/01 - 12/31/2011	—	—	—	630	5.60	5,145	0.94	4
01/01 - 04/30/2012	—	—	—	—	—	3,150	1.40	4
Financial								
10/01 - 12/31/2010	52,500	4.53	7.16	606,100	6.62	—	—	1,654
01/01 - 03/31/2011	52,500	4.53	7.16	454,200	6.42	—	—	989
04/01 - 06/30/2011	—	—	—	189,000	6.28	—	—	380
07/01 - 09/30/2011	—	—	—	142,500	6.30	—	—	265
10/01 - 12/31/2011	—	—	—	112,500	6.63	—	—	204
Purchases								
Physical								
10/01 - 12/31/2010	52,500	4.53	7.14	606,250	6.59	—	—	(1,499)
01/01 - 03/31/2011	52,500	4.53	7.14	454,200	6.37	—	—	(839)
04/01 - 06/30/2011	—	—	—	189,000	6.27	—	—	(341)
07/01 - 09/30/2011	—	—	—	142,500	6.32	—	—	(239)
10/01 - 12/31/2011	—	—	—	112,500	6.67	—	—	(185)
Financial								
10/01 - 12/31/2010	—	—	—	69,859	4.92	60,000	0.20	(67)
01/01 - 03/31/2011	—	—	—	37,875	4.39	90,000	0.20	(2)
04/01 - 06/30/2011	—	—	—	2,080	4.48	—	—	—
07/01 - 09/30/2011	—	—	—	1,685	4.48	—	—	—
10/01 - 12/31/2011	—	—	—	630	4.48	—	—	—
Total natural gas	210,000			3,233,207		336,675		$495

(1) A standard unit of measurement for natural gas (one MMBtu equals one Mcf)

(2) Approximately 6.4% of the fair value of our derivative assets and 97.8% of our derivative liabilities were measured using significant unobservable inputs (Level 3); see Note 3, Fair Value Measurements, to the accompanying financial statements.

Costs, Expenses and Other

Exploration Expense

The following table presents the major components of exploration expense.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Amortization/impairment of unproved properties	$1,055	$3,628	$2,211	$4,760
Exploratory dry hole costs	505	140	4,057	1,078
Geological and geophysical costs	328	464	2,198	931
Operating, personnel and other	1,849	2,354	5,519	8,594
Total exploration expense	$3,737	$6,586	$13,985	$15,363

Amortization/impairment of unproved properties. The approximately $2.6 million decrease in amortization/impairment of unproved properties for the three and nine months ended 2010, compared to the same prior year periods was primarily due to a third quarter 2009, termination of an exploration agreement and its related impairment of North Dakota acreage.

Exploratory dry hole costs. Exploratory dry hole costs for the nine months ended 2010 includes the fracturing and testing of several exploratory zones on a well drilled in a prior year located in the Piceance Basin and an oil test well drilled in the NECO area.

Geological and geophysical costs. The increase in geological and geophysical costs for the nine months ended 2010 compared to the nine months ended 2009 was primarily related to geological and seismic work in the Marcellus Shale as we have intensified our efforts in this area.

Operating, personnel and other. Operating, personnel and other decreased for the three and nine months ended 2010 compared to the same prior year periods primarily due to costs associated with the 2009 demobilization of drilling rigs in the Piceance Basin of $0.6 million and $1.8 million, respectively, and an inventory impairment of $0.7 million included in the nine months ended 2009.

General and Administrative Expense

General and administrative expense increased $0.8 million for the three months ended 2010 compared to the three months ended 2009. The three month increase was primarily related to payroll and payroll related expenses, of which $0.5 million was stock compensation expense.

General and administrative expense decreased $5.5 million for the nine months ended 2010 compared to the nine months ended 2009. The decrease was primarily related to charges recorded during the prior year period, of which $2.9 million related to a separation agreement with a former executive vice president, $1.5 million related to the expensing of previously capitalized 2008 acquisition costs pursuant to the adoption of a new accounting standard and $1.2 million related to corporate relocation costs. The decrease was offset by an increase in payroll and payroll related expenses in the current year.

Depreciation, Depletion and Amortization

Natural gas and oil properties. The reductions in DD&A expense related to natural gas and oil properties for the three and nine months ended 2010 compared to the three and nine months ended 2009 were directly related to decreases in production volumes.

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

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	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Change	2010	2009	Change
	(per Mcfe)					
Rocky Mountain Region:						
Wattenberg Field	$3.36	$3.81	(11.8)%	$3.52	$3.93	(10.4)%
Piceance Basin	2.61	2.22	17.6%	2.51	2.32	8.2%
NECO	2.00	1.81	10.5%	2.00	1.80	11.1%
Weighted average	2.89	2.88	0.3%	2.93	2.97	(1.3)%
Appalachian Basin	2.73	1.90	43.7%	2.69	1.86	44.6%
Total weighted average	2.87	2.79	2.9%	2.89	2.87	0.7%

Non-natural gas and oil properties. Depreciation expense for non-natural gas and oil properties was $1.7 million and $5.4 million for the three and nine months ended 2010, compared to $2 million and $5.9 million for the three and nine months ended 2009, respectively.

Provision/Benefit for Income Taxes

See Note 6, Income Taxes, for a discussion of the changes in our effective tax rate during the nine months ended 2010 compared to the nine months ended 2009. Due to the relatively low net income and the significant discrete tax benefit recorded for the three months ended 2010, we believe that a comparison of our tax rate with the three months ended 2009 is not meaningful.

Beginning with our 2010 tax year, we have been accepted into and have agreed to participate in the IRS Compliance Assurance Process Program. As part of our entrance into this program, we have agreed to an accelerated timeline for the IRS examination of our 2007, 2008 and 2009 tax years. This examination commenced in May 2010 and is currently ongoing along with the compliance assurance of our 2010 tax year.

Pursuant to our election to carry-back our 2009 net operating loss ("NOL"), we filed for and received our requested $25.9 million federal tax refund during the three months ended June 30, 2010. Our 2009 NOL was carried forward for state tax purposes and the net $2.7 million future state tax benefit is recorded as a deferred tax asset and netted against deferred tax liabilities on our balance sheet.

Discontinued Operations

Michigan Divestiture. In July 2010, we completed the sale of our Michigan assets. During the nine months ended 2010, in conjunction with our decision to divest our Michigan assets we recorded a pre-tax impairment charge of $4.7 million. The impairment charge was the primary cause for the decreases in discontinued operations for the three and nine months ended 2010 compared to the same 2009 periods. See Note 3, Fair Value Measurements, and Note 12, Divestiture and Discontinued Operations, for additional information regarding the divestiture of our Michigan assets.

Natural Gas and Oil Well Drilling Operations. As of June 30, 2009, we had concluded all partnership drilling and completion activities and reported our natural gas and oil well drilling activities as discontinued operations.

Net Income (Loss) from Continuing Operations/Adjusted Net Income (Loss) from Continuing Operations

Net income (loss) from continuing operations for the three and nine months ended 2010 was net income of $3.2 million and $26 million compared to net losses of $25 million and $64.6 million for the three and nine months ended 2009, respectively. Adjusted net income (loss) from continuing operations, a non-GAAP financial measure, for the three and nine months ended 2010 was a net loss of $1.9 million and net income of $5.7 million compared to a net loss of $3.4 million and

$4 million for the three and nine months ended 2009, respectively. The factors driving changes in the metric net income (loss) from continuing operations are discussed above. These same factors similarly impact the metric adjusted net income (loss) from continuing operations, with the exception of the unrealized derivative gains and losses on derivatives and provision for underpayment of gas sales, adjusted for taxes. See Reconciliation of Non-GAAP Financial Measures, below, for a more detailed discussion of this non-GAAP financial measure.

Financial Condition

Capital Resources and Liquidity

Our primary sources of cash, in addition to our bank credit facility, for the nine months ended 2010 were from funds generated from the sale of natural gas and oil production, funds received from the federal government for our 2009 NOL carry-back, realized gains from our derivative positions and the sale of our Michigan asset group. These sources of cash were primarily used to fund our operating costs, general and administrative activities, capital expenditures and our Permian asset acquisition.

Our primary sources of cash from operations are sales of natural gas and oil. Fluctuations in our operating cash flow are substantially driven by changes in commodity prices and production volumes. Commodity prices are volatile and we attempt to manage this volatility through our derivative program. The primary sources of our cash flow from operations become the net activity between our natural gas and oil sales and realized derivative gains and losses. We hold economic hedges for no more than 80% of our expected future production from producing wells, nor do we engage in speculative positions. Consequently, we may still have significant fluctuations in our cash flows from operations, which may result in an increase or decrease in our expected developmental and exploratory activities in the future. As of September 30, 2010, we had natural gas and oil derivative positions in place for the remainder of 2010 covering 64.5% of our expected natural gas production and 44.3% of our expected oil production, at an average price of $5.23 per Mcf and $88.84 per Bbl, respectively. See Results of Operations for further discussion of the impact of prices and volumes on sales from operations and the impact of derivative activities on our revenues.

From time to time, our working capital will reflect a surplus, while at other times it will reflect a deficit. The primary factors affecting our working capital are our current unrealized derivative position, the timing of our payments to reduce our borrowings on our credit facility and the other variables discussed above. Our working capital was reduced by $43 million from a surplus of $32.9 million at December 31, 2009, to a deficit of $10.1 million at September 30, 2010. The majority of this decrease is due to the decrease in cash and cash equivalents of $18.6 million and income tax receivable of $27.7 million.

We ended September 2010 with cash and cash equivalents of $13.3 million and availability under our credit facility of $184.8 million for a total liquidity position of $198.1 million compared to $238.2 million at December 31, 2009. This decrease in liquidity was due to our acquisition of assets in the Permian Basin. The cash consideration paid of $75 million was offset in part by the $22 million received from the sale of our Michigan asset group. With our current liquidity position and expected cash flow from operations, we believe that we have sufficient capital for operations and our planned uses of capital through 2011. Planned uses of capital include, the potential acquisition of our 2004 partnerships investor units for $36.5 million and our anticipated second acquisition of producing assets and undeveloped acreage located the Permian Basin in West Texas for $40 million. Additionally, with the execution of our second amended and restated credit agreement on November 5, 2010, the draw on liquidity for our planned uses is offset in part by the $45 million increase in our borrowing base. See Note 17, Subsequent Events, to our accompanying financial statements for more details regarding our planned second Permian acquisition and our new second amended and restated credit agreement.

Cash flows from operations are impacted by commodity prices, production volumes, realized gains and losses from our derivative positions, operating costs and general and administrative expenses. The increase in cash provided by operating activities was primarily due to the increase in natural gas and oil sales, excluding the provision for underpayment of natural gas sales, of $35.4 million and the income tax refund of $25.9 million from our 2009 NOL carry-back received during the second quarter of 2010 offset by a decrease in realized derivative gains of $43.8 million. The remaining change in our operating cash flow was primarily due to changes in our assets and liabilities related to the timing of cash payments and receipts. The key components for the changes in our cash flows from operations are described in more detail in our Results of Operations above.

Adjusted cash flows from operations decreased to $101.8 million for the nine months ended 2010 compared to $114.7 million for the nine months ended 2009. Adjusted EBITDA was $109.3 million for the nine months ended 2010 compared to $117.2 million for the nine months ended 2009. These changes were 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, which includes the receipt of our income tax refund. See Reconciliation of Non-GAAP Financial Measures, below, for a more detailed discussion of these non-GAAP financial measures.

Cash flows used for investing activities, primarily drilling capital expenditures and acquisitions, increased $48.1 million, or 38.6%, from $124.4 million for the nine months ended 2009 to $172.5 million for the nine months ended 2010. The increase in cash flows was due primarily to a use of funds for the acquisition of the Permian Basin assets of $75 million offset in part by the $22 million received from the divestiture of our Michigan asset group. Our vertical drilling program currently consists of one rig operating in the Piceance Basin and three rigs operating in the oil and liquids-rich sections of the Wattenberg Field. We added a fourth rig in the Wattenberg field to initiate our horizontal Niobrara drilling program, a rig in the Marcellus shale supporting our horizontal drilling program and will soon add a rig in the Permian Basin to support our development efforts there.

We received cash of $37.1 million for financing activities for the first nine months of 2010 compared to a use of $4.3 million in the first nine months of 2009. The majority of the change was due to the shift from net payment on borrowings of $43.5 million for the nine months ended 2009 period to a net borrowing of $21.5 million for the nine months ended 2010 as we funded the above acquisitions. Additionally, our PDCM joint venture partner contributed $28 million to PDCM, which is included in cash flows from financing activities in our nine months ended 2010 at $16.2 million, thereby reflecting our decreased ownership interest in PDCM from 67.4% to 57.8%.

Our revised planned 2010 capital expenditures of $309 million, excluding joint venture related projects and including our July 2010 Wolfberry oil acquisition and our anticipated partnership purchases and second Permian acquisition, represent an approximate 115% increase from our 2009 capital expenditures. We believe, based on the current commodity price environment, our cash flows from operations will fund the majority of our organic 2010 capital spending program and borrowings from our credit facility will fund the completed and anticipated acquisitions. In order to grow our production, we would need to commit greater amounts of capital in 2011 and beyond. If capital is not available or is constrained in the future, we will be limited to our cash flows from operations and liquidity under our credit facility as the sources of funding for our capital expenditures. Because natural gas and oil produced from our existing properties declines rapidly in the first few years of production, we cannot maintain our current level of natural gas and oil production and cash flows from operations if capital markets and commodity prices return to their 2009 depressed state for a prolonged period of time, which could have a material negative impact on our operations in the future.

We have experienced no impediments in our ability to access borrowings under our current bank credit facility or the capital markets, as demonstrated by our August 2009 sale of equity and the execution of our second amended and restated credit agreement. See Note 17, Subsequent Events, to our accompanying financial statements. We continue to monitor market events and circumstances and their potential impacts on each of the fifteen lenders that comprise our new bank credit facility. Our $350 million bank credit facility's 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. Our next scheduled redetermination will be in May 2011. While we will continue 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.

We are subject to quarterly financial debt covenants on our bank credit facility. The indenture governing our senior notes contains customary representations and warranties as well as typical restrictive and incurrence covenants. Our debt covenants are described in Note 8, Long-Term Debt, to Consolidated Financial Statements in our 2009 Form 10-K and updated, as necessary, in this Form 10-Q. See Note 17, Subsequent Events, to our accompanying financial statements. We were in compliance with all debt covenants as of September 30, 2010. We believe we have sufficient liquidity and capital resources to remain compliant with our debt covenants throughout the next year based upon our cash flow projections, anticipated capital requirements, the discretionary nature of our capital expenditures and available capacity under our bank credit facility. However, we cannot predict with any certainty the impact to our future business of any continued uncertainty or further deterioration in the financial or commodity markets. We will continue to closely monitor our liquidity and the credit markets and may choose to access them opportunistically should conditions and capital market liquidity improve.

We have a shelf registration statement on Form S-3 filed with the SEC on November 26, 2008, declared effective on January 30, 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 efforts 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. We have available $448.2 million of our shelf from which we may utilize to raise capital.

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

Contractual Obligations, Commitments and Contingencies

The table below presents our contractual obligations, commitments and contingencies.

	Payments due by period				
As of September 30, 2010	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(in thousands)				
Long-term liabilities reflected on the balance sheet (1)					
Long-term debt (2)	$304,500	$—	$101,500	$—	$203,000
Derivative contracts (3)	57,286	20,317	33,448	3,521	—
Derivative contracts - affiliated partnerships (4)	25,955	8,424	15,940	1,591	—
Production tax liability	28,498	15,099	13,399	—	—
Other liabilities (5)	9,835	272	3,589	604	5,370
Asset retirement obligations	26,589	250	394	789	25,156
	452,663	44,362	168,270	6,505	233,526
Commitments, contingencies and other arrangements (6)					
Interest on long-term debt (7)	186,818	28,716	51,527	48,720	57,855
Operating leases	6,174	1,829	2,555	1,775	15
Rig commitment (8)	5,149	2,427	2,722	—	—
Drilling commitment	1,040	—	—	—	1,040
Firm transportation and processing agreements (9)	182,640	19,441	45,025	41,033	77,141
Other	625	125	250	250	—
	382,446	52,538	102,079	91,778	136,051
Total	$835,109	$96,900	$270,349	$98,283	$369,577

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(1) Table does not include deferred income tax liability to taxing authorities of $182.2 million, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations. Further, it includes the short-term portion of derivative contracts maturing greater than one year.

(2) Amount presented does not agree with the balance sheet in that it does not include $2.1 million in unamortized notes discount.

(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 $18 million as of September 30, 2010.

(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 for plugging liabilities related to wells we operate and deferred officer compensation.

(6) Table does not include maximum annual repurchase obligations to investing partners of $11.6 million as of September 30, 2010, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these

obligations.

(7) Amounts presented for long term debt consist of amounts related to our 12% senior notes and our outstanding credit facility. The interest on long-term debt includes $179.6 million payable to the holders of our 12% senior notes and $7.2 million related to our outstanding balance of $101.5 million on our credit facility, including interest of $0.5 million related to our letter of credit, based on an imputed interest rate of 3.6%.

(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 amounts for volumes transported or sold on behalf of our affiliated partnerships and other working interest owners. We will recognize in our financial statements our proportionate share based on our working interest. See Note 9, Commitments and Contingencies - Firm Transportation Agreements, to our accompanying financial statements.

As managing general partner of 33 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, see Note 9, Commitments and Contingencies - Litigation, to our accompanying financial statements included in this report. From time to time we are a party to various other legal proceedings in the ordinary course of business. We believe that the ultimate results of these other proceedings will not have a materially adverse effect on our business, financial condition, results of operations, or liquidity.

Drilling Activity

The following table summarizes our development 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 spud, turned in line and producing during the period. In-process wells represent wells that have been spud, drilled and waiting to be fractured and/or for gas pipeline connection during the period.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2010		2009		2010		2009	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells:								
Productive								
Rocky Mountain Region	16	13.5	—	—	105	89.4	39	36.9
Appalachian Basin	—	—	—	—	—	—	1	1.0
Total productive	16	13.5	—	—	105	89.4	40	37.9
In-Process								
Rocky Mountain Region	26	24.8	19	17.0	33	29.5	26	19.8
Appalachian Basin	—	—	1	1.0	—	—	1	1.0
Total in-process	26	24.8	20	18.0	33	29.5	27	20.8
Dry								
Rocky Mountain Region	—	—	—	—	—	—	1	0.5
Total dry	—	—	—	—	—	—	1	0.5
Total development	42	38.3	20	18.0	138	118.9	68	59.2
Exploratory Wells:								
Productive								
Rocky Mountain Region	—	—	—	—	—	—	1	0.5
Appalachian Basin	—	—	1	1.0	1	0.6	3	3.0
Total productive	—	—	1	1.0	1	0.6	4	3.5
In-Process								
Rocky Mountain Region	—	—	—	—	—	—	1	0.5
Appalachian Basin	2	1.4	2	2.0	5	3.1	2	2.0
Total in-process	2	1.4	2	2.0	5	3.1	3	2.5
Total exploratory	2	1.4	3	3.0	6	3.7	7	6.0
Total drilling activity	44	39.7	23	21.0	144	122.6	75	65.2

Recompletions/refractures	6	4.1	12	11.9	22	18.8	15	14.8

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Commitments and Contingencies

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

Recent Accounting Standards

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

Critical Accounting Polices and Estimates

The preparation of the accompanying 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.

With the exception of the following, there have been no other 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 2009 Form 10-K.

Consolidation and Accounting for Variable Interest Entities

Under applicable accounting guidance, a variable interest entity ("VIE") is consolidated by the entity's primary beneficiary. The primary beneficiary of a VIE has both the following characteristics: (1) the power to direct the activities of the VIE that most significantly impact the entity's economic performance and (2) the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

In determining whether we are the primary beneficiary of the VIE, we consider a number of factors, including our ability to direct the activities that most significantly affect the entity's economic success and our contractual rights and responsibilities under the arrangement. These considerations impact the way we account for our existing joint venture relationship. Further, as certain events occur, we reconsider whether those events have caused us to become the primary beneficiary. The consolidation status of our VIE may change if the composition of the board of managers changes or we enter into new or modified contractual arrangements. A reconsideration event may also occur when we acquire new or additional interests in a VIE.

Reconciliation of Non-GAAP Financial Measures

Adjusted cash flow from operations. We define adjusted cash flow 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 flow from operations as well as cash flow 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.

Adjusted net income (loss) from continuing operations. We define adjusted net income (loss) from continuing operations as net income (loss) from continuing operations plus unrealized derivative losses and provisions for underpayment of gas sales minus unrealized derivative gains, each adjusted for tax effect based on the deferred tax rate. We believe it is important to consider adjusted net income (loss) from continuing operations as well as net income (loss) from continuing operations. We believe it often provides more transparency into the trends of our ongoing operations, such as production, prices, operating costs, realized gains and losses from derivatives and related factors, without regard to changes in our net income (loss) from continuing operations from our mark-to-market adjustments resulting from unrealized gains and losses from derivatives. Additionally, other items, such as the provision for underpayment of gas sales, which are not indicative of future results, may be excluded to clearly identify trends in our continuing operations.

Adjusted EBITDA. We define adjusted EBITDA as net income (loss) from continuing operations plus unrealized derivative losses, interest expense, net of interest income, income taxes and depreciation, depletion and amortization for the period minus unrealized derivative gains. 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-GAAP financial measures to its nearest U.S. GAAP measure.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Adjusted cash flow from operations:				
Adjusted cash flow from operations	$23,636	$37,300	$101,815	$114,706
Changes in assets and liabilities	(2,215)	2,012	14,977	(14,735)
Net cash provided by operating activities	$21,421	$39,312	$116,792	$99,971
Adjusted net income (loss) from continuing operations:				
Adjusted net income (loss) from continuing operations	$(1,859)	$(3,400)	$5,675	$(3,963)
Unrealized gain (loss) on derivatives, net	11,355	(34,973)	36,056	(95,735)
Provision for underpayment of gas sales	(3,252)	—	(3,252)	(2,581)
Tax effect of above adjustments	(3,078)	13,419	(12,462)	37,724
Net income (loss) from continuing operations	$3,166	$(24,954)	$26,017	$(64,555)
Adjusted EBITDA:				
Adjusted EBITDA	$27,163	$36,260	$109,285	$117,249
Unrealized gain (loss) on derivatives, net	11,355	(34,973)	36,056	(95,735)
Interest expense, net	(8,153)	(9,013)	(23,586)	(26,784)
Income tax benefit (expense)	1,020	14,707	(12,746)	39,795
Depreciation, depletion and amortization	(28,219)	(31,935)	(82,992)	(99,080)
Net income (loss) from continuing operations	$3,166	$(24,954)	$26,017	$(64,555)

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

We are exposed to risk resulting from changes in interest rates primarily as it relates to interest we earn on our deposit accounts, including cash, cash equivalents, restricted cash (current and non-current) and interest we pay on borrowings under our revolving credit facility. Our interest-bearing deposit accounts include money market accounts, certificates of deposit and checking and savings accounts with various banks. As of September 30, 2010, we held interest-bearing deposits totaling $20.6 million earning an average interest rate of 0.6% per annum. The $20.6 million represents our aggregate bank balances, which includes checks issued and outstanding. Based on a sensitivity analysis of our interest bearing deposits and our credit facility borrowings as of September 30, 2010, it was estimated that if market interest rates were to increase or decrease by 1%, the impact on our interest income would be immaterial and our annual interest expense would correspondingly change by $1 million.

Commodity Price Risk

We are exposed to the effect of market fluctuations in the prices of natural gas and oil. Price risk represents the potential risk of loss from adverse changes in the market price of natural gas and oil commodities. We utilize commodity based derivative instruments to manage a portion of our exposure to price volatility with regard to our natural gas and oil sales and natural gas marketing. We utilize both financial and physical instruments. The financial instruments generally consist of floors, collars, swaps and basis swaps and are NYMEX-traded and CIG and PEPL-based contracts. We may utilize derivatives based on other indices or markets where appropriate. Our policies prohibit the use of commodity derivatives for speculative purposes and permit utilization of derivatives only if there is an underlying physical position. We manage price risk on only a portion of our anticipated production, so the remaining portion of our production is subject to the full fluctuation of market pricing. As of September 30, 2010, we had natural gas and oil derivative positions in place for the remainder of 2010 covering 64.5% of our expected natural gas production and 44.3% of our expected oil production, at an average price of $5.23 per Mcf and $88.84 per Bbl, respectively.

Derivative Strategies. Our derivative strategies with regard to natural gas and oil sales and natural gas marketing are discussed below. We believe our derivative instruments continue to be effective in achieving the risk management objectives for which they were intended.

- For our natural gas and oil sales, we enter into, for our own and affiliated partnerships' production, derivative contracts to protect against price declines in future periods. The contracts economically provide price stability for anticipated natural gas and oil sales, generally forecasted to occur within the next four-year period. 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 our natural gas marketing, we enter into fixed-price physical purchase and sale agreements that qualify as derivative contracts. The contracts economically provide price stability for committed and anticipated natural gas and oil purchases and sales, generally forecasted to occur within the next two-year period. 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.

Based on a sensitivity analysis as of September 30, 2010, it was estimated that a 10% increase in natural gas and oil prices, inclusive of basis, over the entire period for which we have derivatives then in place would result in a decrease in fair value of $37.3 million; whereas, a 10% decrease in prices would result in an increase in fair value of $37.7 million. See Note 4, Derivative Financial Instruments, to the accompanying 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, 2010.

The following table presents monthly average NYMEX and CIG closing prices for natural gas and oil for the periods presented, as well as the average sales prices we realized for the respective commodities.

	Nine Months Ended September 30, 2010	Year Ended December 31, 2009
Average Index Closing Price		
Natural gas (per MMBtu)		
CIG	$4.08	$3.07
NYMEX	4.59	3.99
Oil (per Bbl)		
NYMEX	76.79	58.36
Average Sales Price Realized		
Excluding realized derivative gains/(losses)		
Natural gas (per MMbtu)	4.34	3.12

Oil (per Bbl)	72.42	55.03
Including realized derivative gains/(losses)		
Natural gas (per MMbtu)	5.89	5.63
Oil (per Bbl)	78.91	68.87

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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. We have had no counterparty default losses.

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.

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 agreement, as counterparties to our 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 for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, the impact of nonperformance of our counterparties on the fair value of our derivative instruments was not significant.

Disruptions 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 of a financial institution.

Disclosure of Limitations

Because the information above includes only those exposures that existed at September 30, 2010, 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 hedging 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, 2010, 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 are 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 financial 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, 2010.

Changes in Internal Control over Financial Reporting

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 Securities Exchange Act of 1934) during the quarter ended September 30, 2010, that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

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PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)

PART II - OTHER INFORMATION

Item 1. Legal Proceedings

Information regarding our legal proceedings can be found in Note 9, Commitments and Contingencies, to our accompanying 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 2009 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 2009 Form 10-K, except for the following:

Possible additional regulation could have an adverse effect on our operations.

The BP oil spill in the Gulf of Mexico and anti-industry sentiment may result in new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. Although we have no operations in the Gulf of Mexico, this incident could result in regulatory initiatives in other areas as well that could limit our ability to drill wells and increase our costs of exploration and production. Furthermore, the U.S. Environmental Protection Agency has recently focused on citizen concerns about the risk of water contamination and public health problems from drilling and hydraulic fracturing activities, including public meetings around the country on this issue which have been well publicized and well attended. This renewed focus could lead to additional federal and state laws and regulations affecting our drilling, fracturing and operations. Additional laws, regulations or other changes could significantly reduce our future growth, increase our costs of operations and reduce our cash flow, in addition to undermining the demand for the natural gas and oil we produce.

New derivatives legislation and regulation could adversely affect our ability to hedge natural gas and oil prices and increase our costs.

On July 21, 2010, U. S. President Barack Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”). The Dodd-Frank Act regulates derivative transactions, including our natural gas and oil hedging swaps (swaps are broadly defined to include most of our hedging instruments). The new law requires the issuance of new regulations and administrative procedures related to derivatives within one year. The effect of such future regulations on our business is currently uncertain. In particular, note the following:

- The Dodd-Frank Act may decrease our ability to enter into hedging transactions which would expose us to additional risks related to commodity price volatility; commodity price decreases would then have an immediate significant adverse affect on our profitability and revenues. Reduced hedging may also impair our ability to have certainty with respect to a portion of our cash flow, which could lead to decreases in capital spending and, therefore, decreases in future production and reserves.

- We expect that the cost to hedge will increase as a result of fewer counterparties in the market and the pass-through of increased counterparty costs. Our derivatives counterparties may be subject to significant new capital, margin and business conduct requirements imposed as a result of the new legislation.

- The Dodd-Frank Act contemplates that most swaps will be required to be cleared through a registered clearing facility and traded on a designated exchange or swap execution facility. There are some exceptions to these requirements for entities that use swaps to hedge or mitigate commercial risk. While we may ultimately be eligible for such exceptions, the scope of these exceptions currently is somewhat uncertain, pending further definition through rulemaking proceedings.

- The above factors could also affect the pricing of derivatives and make it more difficult for us to enter into hedging transactions on favorable terms.

Drilling for and producing natural gas and oil are high risk activities with many uncertainties that could adversely affect our business, financial condition and results of operations.

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Drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for natural gas and oil can be unprofitable, not only due to dry holes, but also due to curtailments, delays or cancellations as a result of other factors, including:

- unusual or unexpected geological formations;
- pressures;
- fires;
- blowouts;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delivery delays of equipment and services;
- compliance with environmental and other governmental requirements; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and regulatory penalties. We maintain insurance against various losses and liabilities arising from operations; however, insurance against all operational risks is not available. Additionally, our management may elect not to obtain insurance if the cost of available insurance is excessive relative to the perceived risks presented. Thus, losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business activities, financial condition and results of operations.

Our hydrocarbon drilling, transportation and processing activities are subject to a range of applicable federal, state and local laws and regulations. A loss of containment of hydrocarbons during these activities could potentially subject us to civil and/or criminal liability and the possibility of substantial costs, including environmental remediation, depending upon the circumstances of the loss of containment, the nature and scope of the loss and the applicable laws and regulations.

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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, 2010	6,768	$25.24	—	—
August 1-31, 2010	157	26.90	—	—
September 1-30, 2010	2,993	28.03	—	—
	9,918	26.11		

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

Item 3. Defaults Upon Senior Securities - None

Item 4. [Removed and Reserved]

Item 5. Other Information – None

Item 6. Exhibits Index

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PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
10.1*	Non-Employee Director Deferred Compensation Plan.	S-8	333-118222	99.1	8/13/2004	
10.2*	2004 Long-Term Equity Compensation Plan amended and restated as of March 8, 2008.	10-K	000-07246	10.26	2/27/2009	
10.3*	2010 Short-Term Incentive Compensation Performance Metrics for Executive Officers.	8-K	000-07246		3/18/2010	
10.4*	Non-Employee Director Compensation for the 2010-2011 Term.	8-K	000-07246		4/23/2010	
10.5*	Executive Compensation and Short-Term Incentive Targets for 2010.	8-K	000-07246		4/23/2010	
10.6*	Employment Agreement with Richard W. McCullough, Chief Executive Officer, dated as of April 19, 2010.	8-K	000-07246	10.1	4/23/2010	
10.7*	Employment Agreement with Gysle R. Shellum, Chief Financial Officer, dated as of April 19, 2010.	8-K	000-07246	10.2	4/23/2010	
10.8*	Employment Agreement with Daniel W. Amidon, General Counsel and Corporate Secretary, dated as of April 19, 2010.	8-K	000-07246	10.3	4/23/2010	
10.9*	Employment Agreement with Lance A. Lauck, Senior Vice President of Business Development, dated as of April 19, 2010.	8-K	000-07246	10.4	4/23/2010	
10.10*	Employment Agreement with Barton R. Brookman, Jr., Senior Vice President of Exploration and Production, dated as of April 19, 2010.	8-K	000-07246	10.5	4/23/2010	
10.11*	2010 Long-Term Equity Compensation Plan.	S-8	333-167945	99.1	7/1/2010	
10.12	Domestic Crude Oil Purchase Agreement between Suncor Energy Marketing, Inc. and PDC, dated May 18, 2009.	10-Q	000-53201	10.1	5/18/2009	
10.13			000-53201	10.8	3/31/2009	

	Gas Purchase Agreement between Williams Production RMT Company, Riley Natural Gas and Petroleum Development Corporation, dated as of March 31, 2009.	10/A No. 3				
10.14	Gas Purchase and Processing Agreement between Duke Energy Field Services, Inc.; United States Exploration, Inc.; and Petroleum Development Corporation, dated as of October 28, 1999.	10/A No. 3	000-53201	10.4	3/31/2009	
12.1	Computation of Ratio of Earnings to Fixed Charges.					X
23.1	Consent of Wright & Company, Inc., Petroleum Consultants.					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.					X
99.1	Report of Independent Petroleum Consultants - Wright & Company, Inc.					X

* Management contract or compensatory plan or arrangement.

Index
PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)

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 8, 2010

/s/ Richard W. McCullough
Richard W. McCullough
Chairman and Chief Executive Officer

/s/ Gysle R. Shellum
Gysle R. Shellum
Chief Financial Officer

/s/ R. Scott Meyers
R. Scott Meyers
Chief Accounting Officer