ANGIODYNAMICS INC
Form 4
October 19, 2006

FORM 4

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

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

OMB APPROVAL	
OMB Number:	3235-0287
Expires:	January 31, 2005
Estimated average burden hours per response...	0.5

(Print or Type Responses)

1. Name and Address of Reporting Person *
Stern Linda B

(Last) (First) (Middle)

603 QUEENSBURY AVE.

(Street)

QUEENSBURY, NY 12804

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
ANGIODYNAMICS INC [ANGO]

3. Date of Earliest Transaction (Month/Day/Year)
10/17/2006

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

_____ Director __X__ 10% Owner
_____ Officer (give title below) _____ Other (specify below)

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Stock	10/17/2006		S (1)		2,750	D	$ 23.5616	14,641	D	
Common Stock								1,572,796	I	as Executor / Benef. (2)

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

Persons who respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB control number.

SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)	
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares
Non-Qualified Stock Option (right to buy)	$ 4.3478							12/28/2005	12/28/2006	Common Stock	86,773
Non-Qualified Stock Option (right to buy)	$ 13.18							12/28/2005	12/28/2006	Common Stock	6,000
Non-Qualified Stock Option (right to buy)	$ 24.21							12/28/2005	12/28/2006	Common Stock	6,000

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Stern Linda B 603 QUEENSBURY AVE. QUEENSBURY, NY 12804		X		

Signatures

By: Ronald F. Lamy For: Linda B. Stern	10/19/2006
**Signature of Reporting Person	Date

Explanation of Responses:

***** If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

****** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) Transaction executed pursuant to an approved selling plan established under SEC rule 10b5-1.

(2)

On January 13, 2006, the Nassau County Surrogate's Court issued Letters Testamentary appointing Linda Stern, Howard S. Stern's wife, the executor of the Estate of Howard S. Stern under the last will and testament of Howard Stern (the "H. Stern Will"). Under the H. Stern Will, Mrs. Stern is a discretionary beneficiary of a "credit shelter" trust, the sole lifetime beneficiary of a "QTIP" trust, which is the beneficiary of one-half of Mr. Stern's residuary estate, and the direct outright beneficiary of the other half of the residuary estate.

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- the availability and cost of capital to us;
- 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 ("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 of this report. 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.

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PART I - FINANCIAL INFORMATION

Item 1. Financial Statements

PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
Condensed Consolidated Balance Sheets
(unaudited; in thousands, except share data)

	June 30, 2010	December 31, 2009*
Assets		
Current assets:		
Cash and cash equivalents	$19,447	$ 31,944
Restricted cash	2,490	2,490
Accounts receivable, net	44,929	56,491
Accounts receivable affiliates	8,133	7,956
Fair value of derivatives	39,504	42,223
Income tax receivable	-	27,728
Prepaid expenses and other current assets	1,914	8,538
Total current assets	116,417	177,370
Properties and equipment, net	938,920	979,373
Assets held for sale	23,293	28,820
Fair value of derivatives	45,873	20,228
Accounts receivable affiliates	13,045	15,473
Other assets	30,094	29,063
Total Assets	$1,167,642	$ 1,250,327
Liabilities and Equity		
Liabilities		
Current liabilities:		
Accounts payable	$43,197	$ 36,845
Accounts payable affiliates	9,802	13,015
Production tax liability	15,008	24,849
Fair value of derivatives	18,691	20,208
Funds held for distribution	23,422	28,256
Other accrued expenses	23,175	21,261
Total current liabilities	133,295	144,434
Long-term debt	237,802	280,657
Deferred income taxes	184,642	178,012
Asset retirement obligation	24,466	29,314
Fair value of derivatives	38,038	48,779
Accounts payable affiliates	13,362	5,996
Other liabilities	20,073	24,542
Total liabilities	651,678	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: 19,264,213 shares for 2010 and 19,242,219 for 2009	193	192
Additional paid-in capital	68,163	64,406
Retained earnings	447,624	426,629
Treasury shares, at cost; 8,273 shares in 2010 and in 2009	(312)	(312)
Total shareholders' equity	515,668	490,915
Noncontrolling interest	296	47,678
Total equity	515,964	538,593
Total Liabilities and Equity	$1,167,642	$ 1,250,327

*Derived from audited 2009 balance sheet.

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Revenues:				
Natural gas and oil sales	$49,401	$40,402	$108,063	$78,569
Sales from natural gas marketing	12,589	11,306	35,276	32,138
Commodity price risk management gain (loss), net	12,257	(23,284)	55,479	399
Well operations, pipeline income and other	2,167	2,772	4,768	5,434
Total revenues	76,414	31,196	203,586	116,540
Costs, expenses and other:				
Natural gas and oil production and well operations costs	16,385	13,677	31,532	29,537
Cost of natural gas marketing	12,207	10,895	34,530	31,241
Exploration expense	3,830	3,134	10,248	8,777
General and administrative expense	9,855	14,784	20,549	26,878
Depreciation, depletion and amortization	27,117	33,259	54,773	67,145
Gain on sale of leaseholds	(96)	-	(96)	(120)
Total costs, expenses and other	69,298	75,749	151,536	163,458
Operating income (loss)	7,116	(44,553)	52,050	(46,918)
Interest income	34	12	39	32
Interest expense	(7,672)	(9,420)	(15,472)	(17,803)
Income (loss) from continuing operations before income taxes	(522)	(53,961)	36,617	(64,689)
Provision (benefit) for income taxes	(192)	(20,663)	13,766	(25,088)
Income (loss) from continuing operations	(330)	(33,298)	22,851	(39,601)
Income (loss) from discontinued operations, net of tax	(2,405)	203	(1,917)	787
Net income (loss)	(2,735)	(33,095)	20,934	(38,814)
Less: net loss attributable to noncontrolling interest	(6)	(16)	(61)	(32)
Net income (loss) attributable to shareholders	$(2,729)	$(33,079)	$20,995	$(38,782)
Amounts attributable to shareholders:				
Income (loss) from continuing operations	$(324)	$(33,282)	$22,912	$(39,569)
Income (loss) from discontinued operations	(2,405)	203	(1,917)	787
Net income (loss) attributable to shareholders	$(2,729)	$(33,079)	$20,995	$(38,782)
Earnings (loss) per share attributable to shareholders:				
Basic				
Income (loss) from continuing operations	$(0.02)	$(2.25)	$1.19	$(2.67)
Income (loss) from discontinued operations	(0.13)	0.01	(0.10)	0.05
Net income (loss) attributable to shareholders	$(0.15)	$(2.24)	$1.09	$(2.62)

Diluted				
Income (loss) from continuing operations	$(0.02)	$(2.25)	$1.19	$(2.67)
Income (loss) from discontinued operations	(0.13)	0.01	(0.10)	0.05
Net income (loss) attributable to shareholders	$(0.15)	$(2.24)	$1.09	$(2.62)
Weighted average common shares outstanding:				
Basic	19,213	14,811	19,202	14,802
Diluted	19,213	14,811	19,296	14,802

See accompanying notes to condensed consolidated financial statements.

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

	Six Months Ended June 30, 2010	2009
Cash flows from operating activities:		
Net income (loss)	$20,934	$(38,814)
Adjustments to net income (loss) to reconcile to cash provided by operating activities:		
Deferred income taxes	11,885	(21,986)
Depreciation, depletion and amortization	55,867	68,220
Exploratory dry hole costs	3,552	937
Amortization and impairment of unproved properties	1,156	1,132
Impairment of proved natural gas and oil properties	4,506	-
Unrealized loss (gain) on derivative transactions	(24,701)	60,762
Other	4,980	7,155
Changes in assets and liabilities	17,192	(16,747)
Net cash provided by operating activities	95,371	60,659
Cash flows from investing activities:		
Capital expenditures	(77,861)	(104,371)
Deconsolidation/change in ownership effect on cash and cash equivalents	(3,472)	-
Other	746	328
Net cash used in investing activities	(80,587)	(104,043)
Cash flows from financing activities:		
Proceeds from credit facility	130,000	170,500
Repayment of credit facility	(173,000)	(147,000)
Payment of debt issuance costs	(205)	(8,943)
Excess tax benefits from stock-based compensation	84	-
Change in ownership interest in PDCM	16,173	-
Purchase of treasury stock	(333)	(219)
Net cash provided by (used in) financing activities	(27,281)	14,338
Net decrease in cash and cash equivalents	(12,497)	(29,046)
Cash and cash equivalents, beginning of period	31,944	50,950
Cash and cash equivalents, end of period	$19,447	$21,904
Supplemental cash flow information:		
Cash payments (receipts) for:		
Interest, net of capitalized interest	$15,607	$17,190
Income taxes, net of refunds	(27,042)	(3,600)
Non-cash investing activities:		
Change in accounts payable related to purchases of properties and equipment	10,944	(37,699)
	723	667

Change in asset retirement obligation, with a corresponding increase to natural gas and oil properties, net of disposals	
See Note 13 for non-cash transactions related to PDCM	

See accompanying notes to condensed consolidated financial statements.

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PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
Notes to Condensed Consolidated Financial Statements
June 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 June 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 13 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 six months ended June 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 our assets held for sale 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 13 for the impact of adoption on our financial statements.

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

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, who 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 June 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.

	June 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	$55,826	$ 29,488	$85,314	$25,598	$ 36,796	$62,394
Basis protection derivative contracts	-	63	63	-	57	57
Total assets	55,826	29,551	85,377	25,598	36,853	62,451
Liabilities:						
Commodity based derivatives	(51)	(6,080)	(6,131)	(3,140)	(9,932)	(13,072)
Basis protection derivative contracts	-	(50,598)	(50,598)	-	(55,915)	(55,915)
Total liabilities	(51)	(56,678)	(56,729)	(3,140)	(65,847)	(68,987)
Net asset (liability)	$55,775	$ (27,127)	$28,648	$22,458	$ (28,994)	$(6,536)

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

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		26,610
Sales from natural gas marketing		352
Cost of natural gas marketing		(3,388)
Changes in fair value included in balance sheet line items (1):		
Accounts receivable affiliates		2,344
Accounts payable affiliates		(4,247)
Settlements included in statement of operations line items:		
Commodity price risk management gain (loss), net		(22,023)
Sales from natural gas marketing		(183)
Cost of natural gas marketing		2,402
Fair value, net liability, as of June 30, 2010	$	(27,127)
Changes in unrealized gains (losses) relating to assets (liabilities) still held as of June 30, 2010, included in statement of operations line items:		
Commodity price risk management gain (loss), net	$	22,148
Sales from natural gas marketing activities		176
Cost of natural gas marketing activities		(1,879)
	$	20,445

(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 $207.3 million or 103.2% of par value as of June 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 three months ended June 30, 2010, we recorded an impairment charge of $4.5 million related to the sale of our Michigan assets. The impairment charge is reflected in discontinued operations in the statement of operations.

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

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 June 30, 2010, we had derivative instruments in place related to a portion of our anticipated production through 2013 for a total of 44,872,376 MMbtu of natural gas and 1,731,769 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.

Derivatives instruments not designated as hedges (1)		Balance sheet line item	Fair Value June 30, 2010	Fair Value December 31, 2009
			(in thousands)	
Derivative assets:	Current			
	Commodity contracts			
	Related to natural gas and oil sales	Fair value of derivatives	$ 36,302	$ 39,107
	Related to natural gas marketing	Fair value of derivatives	3,147	3,077
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	55	39
			39,504	42,223
	Non Current			
	Commodity contracts			
	Related to natural gas and oil sales	Fair value of derivatives	45,590	19,680
	Related to natural gas marketing	Fair value of derivatives	275	530
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	8	18
			45,873	20,228

Total derivative assets (2)			$ 85,377	$ 62,451
Derivative liabilities:	Current			
	Commodity contracts			
	Related to natural gas and oil sales	Fair value of derivatives	$ (1,726)	$ (2,451)
	Related to natural gas marketing	Fair value of derivatives	(2,602)	(2,626)
	Basis protection contracts			
	Related to natural gas and oil sales	Fair value of derivatives	(14,362)	(15,127)
	Related to natural gas marketing	Fair value of derivatives	(1)	(4)
			(18,691)	(20,208)
	Non Current			
	Commodity contracts			
	Related to natural gas and oil sales	Fair value of derivatives	(1,570)	(7,572)
	Related to natural gas marketing	Fair value of derivatives	(233)	(423)
	Basis protection contracts			
	Related to natural gas and oil sales	Fair value of derivatives	(36,235)	(40,784)
			(38,038)	(48,779)
Total derivative liabilities (3)			$ (56,729)	$ (68,987)

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(1) As of June 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 $21.1 million and $13.4 million as of June 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 $18.2 million and $21 million as of June 30, 2010, and December 31, 2009, respectively, representing their proportionate share of the derivative liabilities.

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

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

Statement of operations line items	2010 Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	2010 Realized and Unrealized Gains (Losses) For the Current Period	2010 Total	2009 Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	2009 Realized and Unrealized Gains (Losses) For the Current Period	2009 Total
	(in thousands)					
Three months ended June 30,						
Commodity price risk management gain (loss), net						
Realized gains (losses)	$7,503	$390	$7,893	$25,699	$(1,404)	$24,295
Unrealized gains (losses)	(7,503)	11,867	4,364	(25,699)	(21,880)	(47,579)
Total commodity price risk management gain (loss), net (1)	$-	$12,257	$12,257	$-	$(23,284)	$(23,284)
Sales from natural gas marketing						
Realized gains (losses)	$1,984	$(179)	$1,805	$2,055	$68	$2,123
Unrealized gains (losses)	(1,984)	(580)	(2,564)	(2,055)	99	(1,956)
Total sales from natural gas marketing(2)	$-	$(759)	$(759)	$-	$167	$167
Cost of natural gas marketing						
Realized gains (losses)	$(1,747)	$138	$(1,609)	$(1,996)	$(330)	$(2,326)
Unrealized gains (losses)	1,747	664	2,411	1,996	(35)	1,961
Total cost of natural gas marketing(2)	$-	$802	$802	$-	$(365)	$(365)
Six months ended June 30,						
Commodity price risk management gain (loss), net						
Realized gains (losses)	$21,604	$9,213	$30,817	$47,587	$13,334	$60,921
Unrealized gains (losses)	(21,604)	46,266	24,662	(47,587)	(12,935)	(60,522)
Total commodity price risk management gain (loss), net (1)	$-	$55,479	$55,479	$-	$399	$399
Sales from natural gas marketing						

Realized gains (losses)	$1,481	$1,383	$2,864	$3,344	$1,489	$4,833
Unrealized gains (losses)	(1,481)	2,429	948	(3,344)	2,213	(1,131)
Total sales from natural gas marketing(2)	$-	$3,812	$3,812	$-	$3,702	$3,702
Cost of natural gas marketing						
Realized gains (losses)	$(1,329)	$(1,376)	$(2,705)	$(3,148)	$(2,037)	$(5,185)
Unrealized gains (losses)	1,329	(2,238)	(909)	3,148	(2,257)	891
Total cost of natural gas marketing(2)	$-	$(3,614)	$(3,614)	$-	$(4,294)	$(4,294)

(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.

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

Counterparty Name	Fair Value of Derivative Assets June 30, 2010 (in thousands)
JPMorgan Chase Bank, N.A. (1)	$ 43,073
Calyon (1)	21,018
Wachovia (1)	12,004
Various (2)	9,282
Total	$ 85,377

(1) Major lender in our credit facility, see Note 7.
(2) Represents a total of 51counterparties, including four lenders in our credit facility.

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5. PROPERTIES AND EQUIPMENT

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

	June 30, 2010	December 31, 2009
	(in thousands)	
Natural gas and oil properties (successful efforts method of accounting)		
Proved	$ 1,256,530	$ 1,281,529
Unproved	37,669	38,626
Total natural gas and oil properties	1,294,199	1,320,155
Pipelines and related facilities	33,395	36,909
Transportation and other equipment	31,064	33,432
Land and buildings	14,272	14,699
Construction in progress	34,760	9,131
	1,407,690	1,414,326
Accumulated DD&A	(468,770)	(434,953)
Properties and equipment, net (1)	$ 938,920	$ 979,373

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(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 13.

The following table presents the capitalized exploratory well costs pending determination of proved reserves and included in properties and equipment on the balance sheets.

	Amount (in thousands)	Number of Wells
Balance at December 31, 2009	$ 1,174	2
Deconsolidation of PDCM and change in ownership interest	(441)	-
Additions to capitalized exploratory well costs pending the determination of proved reserves	9,874	5
Reclassifications to proved natural gas and oil properties based on the determination of proved reserves	(3,111)	(1)

Capitalized exploratory well costs charged to expense		(280	)	-
Balance at June 30, 2010	$	7,216		6

As of June 30, 2010, none of the six suspended wells awaiting the determination of proved reserves have been capitalized for a period greater than one year after the completion of drilling.

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. 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 three and six months ended June 30, 2010, was 36.8% (benefit on a loss) and 37.6% (provision on income) compared to benefits on losses of 38.3% and 38.8% for the same prior year periods, respectively. The loss realized for the three and six months ended June 30, 2009, exceeded our projected loss for the year. As a result, we calculated our 2009 three and six month tax benefits by multiplying the period loss by the statutory tax rate and then adding other statutory tax benefits such as percentage depletion. This required tax calculation did not limit the tax benefit for the 2009 three months ended June 30, 2009, but did limit the tax benefit realized during the six months then ended by $0.7 million. No similar limitation calculation was required for the three and six months ended June 30, 2010. There were no significant discrete items recorded during the three and six months ended June 30, 2009 or 2010.

As of June 30, 2010, we had a gross liability for uncertain tax benefits of $0.8 million compared to a liability of $0.6 million as of December 31, 2009. If recognized, $0.8 million of this 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 during the next twelve-month period as items are either resolved without change or converted to amounts due to the IRS.

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 $2.6 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.

	June 30, 2010	December 31, 2009
	(in thousands)	
Credit facility	$ 37,000	$ 80,000
12% Senior notes due 2018, net of discount of $2.2 million	200,802	200,657
Total long-term debt	$ 237,802	$ 280,657

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 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. In May 2010, our redetermination, based on our December 31, 2009, reserves, was completed and our aggregate revolving commitment was unchanged.

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 (2.25% as of June 30, 2010) for the period the letter of credit remains outstanding. The letter of credit expires on May 22, 2012.

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As of June 30, 2010, we had remaining $4.9 million in debt issuance costs being amortized at a rate of $0.7 million per quarter; the funds available under our credit facility were $249.3 million; and the interest on our borrowings, inclusive of our standby letter of credit, was accruing at a rate of 4.9% per annum. We were in compliance with all covenants at June 30, 2010, and expect to remain in compliance throughout the next year.

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, 98.572% 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 June 30, 2010, we had remaining $6.4 million in original discount and costs being amortized at a rate of $0.2 million per quarter. We were in compliance with all covenants as of June 30, 2010, and expect to remain in compliance throughout the next year.

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 June 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 June 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 June 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	(6,239)
Obligations incurred with development activities	786
Accretion expense	668
Obligations discharged with disposal of properties and asset retirements	(63)
Balance at June 30, 2010	24,716
Less current portion	(250)
Long-term portion (1)	$ 24,466

(1) Includes $0.8 million as of December 31, 2009, and June 30, 2010, related to assets held for sale.

9. COMMITMENTS AND CONTINGENCIES

Merger Agreements

In June 2010, PDC and a wholly owned subsidiary of PDC entered into a merger agreement with each of PDC 2004-A Limited Partnership, PDC 2004-B Limited Partnership, PDC 2004-C Limited Partnership and PDC 2004-D Limited Partnership. PDC serves as the managing general partner of each of these partnerships. Pursuant to each merger agreement, if the merger is approved by the holders of a majority of the limited partner units held by limited partners of that partnership not affiliated with PDC, as well as the satisfaction of other customary closing conditions, then PDC will acquire such partnership. If all four partnerships are acquired, PDC will pay an aggregate of approximately $36.4 million for the limited partnership units of these partnerships. On July 8 and July 14, 2010, we filed the preliminary proxy statements with the SEC and anticipate, upon clearance by the SEC, that the definitive proxy statements will be mailed to investors in September 2010. If the required approvals are received, we expect the mergers to be completed in the fourth quarter of 2010. Funding for these acquisitions is expected to be provided through the utilization of our credit facility.

Purchase and Sale Agreements

In May 2010, we entered into agreements with unaffiliated third parties, whereby it was our intent to acquire various producing assets located primarily in the Wolfberry oil trend in West Texas and sell our Michigan natural gas assets. These transactions were consummated on July 30, 2010; see Note 12 for additional information regarding this transaction.

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 affiliated partnerships. These contracts require us to pay these transportation and processing charges whether the required volumes are delivered or not. Satisfaction of the volumes requirements include volumes produced by us, volumes purchased from third parties and volumes produced by our affiliated partnerships. As of June 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 June 30, 2010, we have a related liability in the amount of $2.9 million, previously 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.

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The following table presents gross volume information related to our long-term firm sales, processing and transportation agreements for pipeline capacity. 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 June 30,					
Area	Total	2011	2012	2013	2014	Thereafter	Expiration Date
Volume (MMbtu)							
Appalachian Basin (1)	111,110,050	686,250	591,300	9,264,620	10,993,800	89,574,080	August 31, 2022
Piceance	208,195,158	31,933,342	32,612,837	32,576,935	28,181,550	82,890,494	May 31, 2021
NECO	920,000	920,000	-	-	-	-	December 31, 2010
NECO	11,875,000	1,825,000	1,825,000	1,825,000	1,825,000	4,575,000	December 31, 2016
Total	332,100,208	35,364,592	35,029,137	43,666,555	41,000,350	177,039,574	
Dollar commitment (in thousands)	$170,705	$18,179	$18,150	$22,603	$21,202	$90,571	

(1) Includes a precedent agreement that becomes effective when the planned pipeline is placed in service, currently estimated to be September 2012 and represents 8,823,360 MMbtu, 10,628,800 MMbtu and 86,894,080 MMbtu of the total MMbtu presented for the twelve months ending June 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

We are involved in various legal proceedings that we consider normal to our business. Although the results cannot be known with certainty, we believe that we have properly accrued reserves.

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 as representative of the class of all similarly situated individuals and entities, 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. The stay in effect as of December 31, 2009, lapsed in February 2010. The parties have filed briefs on Gobel's Motion to Remand to state court. We are awaiting a ruling from the court on that motion.

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 business, 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 June 30, 2010, we have accrued environmental liabilities in the amount of $1.1 million included in other accrued liabilities on the balance sheet. We are not aware of any environmental claims existing as of June 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 $162,900, which was accrued in prior periods and paid at settlement.

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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 the ultimate outcome of this administrative action at this time.

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 June 30, 2010, the maximum annual repurchase obligation, based upon the minimum price described above, was approximately $11.4 million. We believe we have adequate liquidity to meet this obligation. During the first two quarters of 2010, the repurchases 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 termination benefits.

In the event of termination following a change of control of the Company, or where the Company terminates the executive officer without cause or where an executive officer terminates employment for good reason, the severance benefits range from 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. 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. 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 up to 18 months, 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 shall 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 shall 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 shall (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.

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Derivative Contracts

We are exposed to the effect of market fluctuations in the prices of natural gas and oil. To manage the risks associated with these market fluctuations, we utilize derivative instruments. Should the counterparties to our derivative instruments not perform, our exposure to market fluctuations in commodity prices would increase significantly. We have had no counterparty defaults.

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 cancelled, 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 June 30, 2010, 8,603 shares of restricted stock had been awarded pursuant to the 2010 Plan. Subsequent to June 30, 2010, pursuant to the 2010 Plan, the Compensation Committee awarded to key employees 173,058 shares of restricted stock with a total aggregate fair market value of $4.4 million, which will be expensed over a weighted average vesting period of 3.2 years.

Other Long-Term Equity Compensation Plans

As of June 30, 2010, 2,134 shares remain available in our 2004 Long-Term Equity Compensation Plan and five shares remain available 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.

	Three Months Ended	Six Months Ended

	June 30,		June 30,	
	2010	2009 (1)	2010	2009 (2)
	(in thousands)			
Total stock-based compensation expense	$ 1,216	$ 2,345	$ 2,221	$ 3,984
Income tax benefit	(467)	(895)	(852)	(1,520)
Net income impact	$ 749	$ 1,450	$ 1,369	$ 2,464

(1) Includes $1 million related to agreements with a former chief executive officer and executive vice president.
(2) Includes $1.3 million related to agreements with a former chief executive officer and executive vice president.

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Stock-Based Compensation Awards

There have been no material changes in our stock options or market-based restricted stock awards during the six months ended June 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.

	Six Months Ended June 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 six months ended June 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	9.8	-
Outstanding at June 30, 2010	57,282	24.44	9.8	68
Vested and expected to vest at June 30, 2010	57,282	24.44	9.8	68

Exercisable at June 30, 2010	-	-	-	-

The total compensation cost related to SARs granted and not yet recognized in our statement of operations as of June 30, 2010, was $0.7 million. The cost is expected to be recognized over a weighted average period of 2.8 years.

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Restricted Stock Awards. During the three months ended June 30, 2010, our Compensation Committee granted a total of 148,327 shares of restricted stock to our executive officers and non-employee directors. Pursuant to the terms of the awards, the shares will vest over a period of one to three years.

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

	Shares	Weighted Average Grant Date Fair Value
Non-vested at December 31, 2009	305,328	$ 27.55
Granted	148,327	23.30
Vested	(58,930)	35.18
Forfeited	(10,488)	33.39
Non-vested at June 30, 2010	384,237	24.58

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 June 30, 2010, was $7.5 million. The cost is expected to be recognized over a weighted average period of 2.2 years.

11. EARNINGS PER SHARE

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)			
Weighted average common shares outstanding - basic	19,213	14,811	19,202	14,802
Dilutive effect of stock-based compensation:				
Restricted stock	-	-	86	-
Non employee director deferred compensation	-	-	8	-
Weighted average common shares outstanding - diluted	19,213	14,811	19,296	14,802

For the three months ended June 30, 2010, and three and six months ended June 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 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.

	Three Months Ended June 30,		Six Months Ended June 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	434	286	181	297
Stock options	10	10	10	10
SARs	57	-	57	-
Non employee director deferred compensation	8	8	-	8
Total anti-dilutive common share equivalents	509	304	248	315

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12. ASSETS HELD FOR SALE AND DISCONTINUED OPERATIONS

Michigan Divestiture. In May 2010, pursuant to a sale agreement with unaffiliated third parties, we reclassified our Michigan assets and related liabilities as held for sale. On July 30, 2010, we completed the divestiture for $22.5 million in net cash proceeds and realized a loss on sale of $4.5 million in the form of an impairment charge recorded during the three months ended June 30, 2010 (see Note 3 regarding the impairment charge). The sale involved our Michigan asset group. We will not have any 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.

In conjunction with the sale agreement, we entered into a like-kind exchange agreement, in accordance with Internal Revenue Code Section 1031 ("IRC 1031"), with a qualified intermediary. Proceeds in the amount of $20.6 million were transferred directly to the qualified intermediary to be held in trust and were used to complete on July 30, 2010, our acquisition of various producing assets located in the Wolfberry oil trend in West Texas, which was identified as our replacement property in accordance with IRC 1031. The gain for income tax purposes on the divested properties was $18.9 million. With the favorable deferral aspects of IRC 1031, we were able to defer the associated tax liability of $7.2 million.

Natural Gas and Oil Well Drilling. We offered our last sponsored drilling partnership in October 2007. As of June 30, 2009, all remaining contractual drilling and completion obligations were completed for all partnerships and we reported our natural gas and oil well drilling activities as discontinued operations.

Selected financial information related to assets held for sale and discontinued operation. The tables below sets forth selected financial and operational information related to assets held for sale, assets and liabilities 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 pursuant to the sale agreement. Assets and liabilities related to discontinued operations include those assets sold and liabilities assumed 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 presents the revenues, expenses and production volumes that were reclassified from the specified statement of operations line items to discontinued operations.

	June 30, 2010		December 31, 2009	
Balance Sheet	Assets Held for Sale including Related Liabilities (1)	Assets and Liabilities Related to Discontinued Operations	Assets Held for Sale including Related Liabilities (1)	Assets and Liabilities Related to Discontinued Operations
	(in thousands)			

Assets								
Current assets								
Accounts receivable, net	$	-	$	1,067	$	-	$	1,240
Total current assets		-		1,067		-		1,240
Properties and equipment, net		23,293		23,293		28,820		28,820
Total assets	$	23,293	$	24,360	$	28,820	$	30,060
Liabilities								
Current liabilities								
Production tax liability	$	-	$	-	$	-	$	37
Total current liabilities		-		-		-		37
Asset retirement obligation		808		808		775		775
Total liabilities	$	808	$	808	$	775	$	812

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Statement of Operations - Discontinued Operations	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009 (2)
	(in thousands)			
Revenues				
Natural gas and oil sales	$ 1,323	$ 1,156	$ 3,029	$ 2,731
Sales from natural gas marketing	1,136	1,061	2,760	2,618
Well operations, pipeline income and other	127	176	371	352
Total revenues	2,586	2,393	6,160	5,701
Costs, expenses and other				
Natural gas and oil production and well operations costs	483	367	1,012	868
Cost of natural gas marketing	1,197	1,096	2,728	2,628
Depreciation, depletion and amortization	361	601	1,094	1,075
Impairment of proved natural gas and oil properties	4,506	-	4,506	-
Total costs, expenses and other	6,547	2,064	9,340	4,571
Income (loss) from discontinued operations	(3,961)	329	(3,180)	1,130
Provision (benefit) for income taxes	(1,556)	126	(1,263)	456
Income (loss) from discontinued operations, net of tax	$ (2,405)	$ 203	$ (1,917)	$ 674
Operational Data				
Production				
Natural gas (Mcf)	344,205	366,119	700,912	651,936
Oil (Bbls)	1,015	755	2,099	1,578
Natural gas equivalent (Mcfe)	350,295	370,649	713,504	661,404

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

(2) 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 June 2009.

13. 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	(61)
Balance at June 30, 2010	$ 295

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%.

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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.

	Decreased/(Increased) January 1, 2010	Decreased/(Increased) April 1, 2010		Decreased/(Increased) January 1, 2010	Decreased/(Increased) 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	1,424
Other assets	419	144	Other liabilities	591	216
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.

14. TRANSACTIONS WITH AFFILIATES

We enter into derivative instruments for our own production as well as for our 33 affiliated partnerships' production. As of June 30, 2010, we had a payable to affiliates of $21.1 million representing their designated portion of the fair value of our gross derivative assets and a receivable from affiliates of $18.2 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 $1.1 million and $2.1 million for the three and six months ended June 30, 2010, respectively, related to the marketing of natural gas on behalf of PDCM and our affiliated partnerships. For the three and six months ended June 30, 2009, sales from natural gas marketing include $0.2 million and $0.3 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 $2.7 million and $5.6 million for the three and six months ended June 30, 2010, respectively. Our statements of operations include only our proportionate share of the billings. Natural gas and oil production and well operations costs, exploration expense and general and administrative expense in the statements of operations reflect $0.9 million, $0.2 million and $0.5 million, respectively, for the three months ended June 30, 2010, related to these services and $1.9 million, $0.5 million and $1.2 million, respectively, for the six months ended June 30, 2010.

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15. 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 June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(in thousands)			
Revenues:				
Natural gas and oil sales	$ 63,789	$ 19,879	$ 168,271	$ 84,349
Natural gas marketing	12,589	11,306	35,276	32,138
Unallocated	36	11	39	53
Total	$ 76,414	$ 31,196	$ 203,586	$ 116,540
Segment income (loss) from continuing operations before income taxes:				
Natural gas and oil sales	$ 17,305	$ (29,449)	$ 73,422	$ (19,513)
Natural gas marketing	373	413	730	903
Unallocated	(18,200)	(24,925)	(37,535)	(46,079)
Total	$ (522)	$ (53,961)	$ 36,617	$ (64,689)

	June 30, 2010	December 31, 2009
	(in thousands)	
Segment assets:		
Natural gas and oil sales	$ 1,089,563	$ 1,123,340
Natural gas marketing	14,070	22,614
Unallocated	40,716	75,553
Assets held for sale	23,293	28,820
Total	$ 1,167,642	$ 1,250,327

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

References to "the three months ended 2010" and "the six months ended 2010" shall refer to the three or six months ended June 30, 2010, as applicable. References to "the three months ended 2009" and "the six months ended 2009" shall refer to the three or six months ended June 30, 2009, as applicable.

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

Natural gas and oil sales revenue increased 22.3% and 37.5% or $9 million and $29.5 million for the three and six months ended 2010, respectively, compared to the three and six months ended 2009, although production volumes decreased 20.6% and 20.3%, respectively. These increases 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 $5.74 and $6.25 for the three and six months ended 2010 compared to $3.73 and $3.75 for the three and six months ended 2009, respectively. Realized derivative gains from natural gas and oil sales contributed to total revenues an additional $0.92 per Mcfe and $1.78 per Mcfe or $7.9 million and $30.8 million for the three and six months ended 2010, respectively. Comparatively, the total per Mcfe price realized, consisting of the average sales price and realized derivative gains, increased 11.6% to $6.66 for the three months ended 2010 from $5.97 for the three months ended 2009 and 22.6% to $8.03 for the six months ended 2010 from $6.55 for the six months ended 2009.

The decreases in total costs and expenses for the three and six months ended 2010 compared to the three and six months ended 2009 were primarily due to decreases in DD&A, which was a direct result of lower production volumes. The loss from discontinued operations for the three and six months ended 2010 were due to the impairment of our Michigan assets resulting from our decision to sell these assets.

The improved commodity price environment and our $25.9 million carry-back federal tax refund were the major contributors to our improved cash flows from operations, increasing from $60.7 million for the six months ended 2009 to $95.4 million for the six months ended 2010. Our positive operating cash flows allowed us the opportunity to further pay down our outstanding draw on our credit facility by $43 million.

During the three months ended 2010, our liquidity position showed continued improvement as the availability under our credit facility increased to $249.3 million and cash and cash equivalents were $19.4 million for a total liquidity position of $268.7 million at June 30, 2010, compared to $238.2 million at December 31, 2009. We 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.

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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, other operating income and expenses. See Note 12, Discontinued Operations, for production and sales information related to our divested Michigan assets.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
	(dollars in thousands, except per unit data)					
Production (1)						
Natural gas (Mcf)	6,626,189	8,786,752	-24.6 %	13,544,009	17,591,196	-23.0 %
Oil (Bbls)	330,115	342,110	-3.5 %	625,710	685,171	-8.7 %
Natural gas equivalent (Mcfe) (2)	8,606,879	10,839,412	-20.6 %	17,298,270	21,702,222	-20.3 %
Natural Gas and Oil Sales						
Natural gas	$25,517	$21,562	18.3 %	$62,442	$49,353	26.5 %
Oil	23,884	18,840	26.8 %	45,621	31,797	43.5 %
Provision for underpayment of natural gas sales	-	-	*	-	(2,581)	100.0 %
Total natural gas and oil sales	$49,401	$40,402	22.3 %	$108,063	$78,569	37.5 %
Realized Gain on Derivatives, net (3)						
Natural gas	$5,854	$19,477	-69.9 %	$26,733	$48,809	-45.2 %
Oil	2,039	4,818	-57.7 %	4,084	12,112	-66.3 %
Total realized gain on derivatives, net	$7,893	$24,295	-67.5 %	$30,817	$60,921	-49.4 %
Average Sales Price (excluding gains/losses on derivatives)						
Natural gas (per Mcf)	$3.85	$2.45	57.1 %	$4.61	$2.82	63.5 %
Oil (per Bbl)	$72.35	$55.07	31.4 %	$72.91	$46.41	57.1 %
Natural gas equivalent (per Mcfe)	$5.74	$3.73	53.9 %	$6.25	$3.75	66.7 %
Average Sales Price (including realized gains/losses on derivatives)						
Natural gas (per Mcf)	$4.73	$4.67	1.3 %	$6.58	$5.58	17.9 %
Oil (per Bbl)	$78.53	$69.15	13.6 %	$79.44	$64.08	24.0 %
	$6.66	$5.97	11.6 %	$8.03	$6.55	22.6 %

Natural gas equivalent (per Mcfe)										
Average Lifting Cost (per Mcfe) (4)	$	1.24	$	0.64	93.8	%	$	1.14	$	0.78	46.2	%
Natural gas marketing (5)	$	382	$	411	-7.1	%	$	746	$	897	-16.8	%
Other Costs and Expenses										
Exploration expense	$	3,830	$	3,134	22.2	%	$	10,248	$	8,777	16.8	%
General and administrative expense	$	9,855	$	14,784	-33.3	%	$	20,549	$	26,878	-23.5	%
Depreciation, depletion and amortization	$	27,117	$	33,259	-18.5	%	$	54,773	$	67,145	-18.4	%

Amounts may not calculate due to rounding
*Percentage change not meaningful or greater than 250%

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(1) Production is net and determined by multiplying the gross production volume of properties in which we have an interest by the percentage 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 June 30, 2010	Three Months Ended June 30, 2009	Percentage Change	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Percentage Change
Production						
Natural gas (Mcf)						
Rocky Mountain Region	6,031,678	7,724,334	-21.9 %	12,306,896	15,512,368	-20.7 %
Appalachian Basin (1)	570,733	1,027,199	-44.4 %	1,201,243	2,002,880	-40.0 %
Other	23,778	35,219	-32.5 %	35,870	75,948	-52.8 %
Total	6,626,189	8,786,752	-24.6 %	13,544,009	17,591,196	-23.0 %
Oil (Bbls)						
Rocky Mountain Region	328,990	339,575	-3.1 %	623,863	680,758	-8.4 %
Appalachian Basin (1)	1,125	2,199	-48.8 %	1,847	3,903	-52.7 %
Other	-	336	-100.0 %	-	510	-100.0 %
Total	330,115	342,110	-3.5 %	625,710	685,171	-8.7 %
Natural gas equivalent (Mcfe)						
Rocky Mountain Region	8,005,616	9,761,784	-18.0 %	16,050,092	19,596,916	-18.1 %
Appalachian Basin (1)	577,485	1,040,393	-44.5 %	1,212,326	2,026,298	-40.2 %
Other	23,778	37,235	-36.1 %	35,852	79,008	-54.6 %
Total	8,606,879	10,839,412	-20.6 %	17,298,270	21,702,222	-20.3 %

(1) For the three months ended 2010, approximately 84.3%, 46.3% and 83.8%, of the decrease in natural gas, oil and natural gas equivalent, respectively, was the result of our contribution of natural gas and oil properties to PDCM; for the six months ended 2010, approximately 84.3%, 29.5% and 83.5% of the decrease in natural gas, oil and natural gas equivalent, respectively, was the result of our contribution of natural gas and oil properties to PDCM.

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Percentage Change	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Percentage Change
Average Sales Price (excluding derivative gains/losses)						
Natural gas (per Mcf)						
Rocky Mountain Region	$3.81	$2.30	65.7 %	$4.57	$2.61	75.1 %
Appalachian Basin	4.20	3.63	15.7 %	4.88	4.34	12.4 %
Other	5.77	4.18	38.0 %	8.67	8.92	-2.8 %
Weighted average price	3.85	2.45	57.1 %	4.61	2.82	63.5 %
Oil (per Bbl)						
Rocky Mountain Region	72.32	55.09	31.3 %	72.89	46.42	57.0 %
Appalachian Basin	80.29	50.91	57.7 %	80.06	44.09	81.6 %

Other	-	45.50	-100.0	%	-	42.00	-100.0	%
Weighted average price	72.35	55.07	31.4	%	72.91	46.41	57.1	%
Natural gas equivalent (per Mcfe)								
Rocky Mountain Region	5.84	3.73	56.6	%	6.34	3.68	72.3	%
Appalachian Basin	4.31	3.65	18.1	%	4.95	4.35	13.8	%
Other	5.77	4.36	32.3	%	8.67	8.78	-1.3	%
Weighted average price	5.74	3.73	53.9	%	6.25	3.75	66.7	%

*Percentage change not meaningful or greater than 250%

Despite decreases in production for the three and six months ended 2010, natural gas and oil sales revenue for these periods, excluding the provision for underpayment of gas sales in 2009, increased $9 million and $26.9 million, compared to the three and six months ended 2009, respectively. Approximately $17.3 million and $43.4 million of the increase in natural gas and oil sales revenue for the three and six months ended 2010, respectively, was due to pricing, offset in part by decreased production, which reduced natural gas and oil sales by $8.3 million and $16.5 million, respectively.

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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 $1.13 and $1.38 for the three and six months ended 2009, respectively, and narrowed to an average of $0.48 and $0.32 for the three and six 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 index that most closely relates to the price under which our natural gas and oil was sold.

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

Area	Market	Commodity	Percent of Production
Rocky Mountain Region			
Piceance/Wattenberg	Colorado Interstate Gas	Gas	42%
Wattenberg/Piceance/North Dakota	NYMEX	Oil	23%
Piceance	San Juan Basin/Southern California	Gas	14%
NECO	Mid Continent (Panhandle Eastern)	Gas	10%
Wattenberg	Colorado Liquids	Gas	4%
Total Rocky Mountain Region			93%
Appalachian Basin	NYMEX	Gas	6%
Other	Other	Gas/Oil	1%
			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 June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)			
Lease operating expenses	$ 10,641	$ 6,936	$ 19,695	$ 16,875
Production taxes	2,503	2,753	4,855	4,596
Costs of well operations and pipeline income	1,914	1,657	3,804	3,262
Overhead and other production expenses	1,327	2,331	3,178	4,804
Total natural gas and oil production and well operations costs	$ 16,385	$ 13,677	$ 31,532	$ 29,537

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Lease operating expenses. Lifting costs per Mcfe increased to $1.24 per Mcfe for the three months ended 2010 from $0.64 per Mcfe for the same period in 2009, and increased to $1.14 per Mcfe for the six months ended 2010, from $0.78 per Mcfe for the same period in 2009. The increases in per Mcfe cost were due to decreases in production volumes of 20.6% and 20.3% for the three and six month periods ended 2010, respectively, which results in the fixed cost portion of our lease operating expenses being absorbed by a reduced number of units. Also contributing to the increases for the three and six months ended 2010 compared to the same 2009 periods were related to well workovers, which include tubing and casing repairs of $1.2 million and $1.5 million, and environmental remediation charges of $1.3 million and $1.5 million, respectively.

Production taxes. Production taxes for the three months ended 2010 decreased $0.3 million compared to the three months ended 2009. The decrease was primarily related to 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, offset in part by an increase in overall sales prices. For the six months ended 2010, production taxes increased by $0.3 million compared to the six months ended 2009. The increase was primarily related to increase in overall sales prices, offset in part by a reduction of ad valorem tax rates for certain counties and an increase in the number of stripper wells.

Costs of well operations and pipeline income. The increases of $0.3 million and $0.5 million in cost of well operations and pipeline income for the three and six months ended 2010, respectively, compared to same 2009 periods were the result of increased costs related to pipeline maintenance and compressor expenses.

Overhead and other production expenses. The decreases in overhead and other production expenses for the three and six months ended 2010 compared to the same 2009 periods were the result of the reduction in expenses related to the deconsolidation of PDCM along with various other decreases.

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 June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)			
Commodity price risk management gain (loss), net:				
Realized gains:				
Natural gas	$ 5,854	$ 19,477	$ 26,733	$ 48,809
Oil	2,039	4,818	4,084	12,112

Total realized gain, net	7,893	24,295	30,817	60,921
Unrealized gains (losses):				
Reclassification of realized gains included in prior periods unrealized	(7,503)	(25,699)	(21,604)	(47,587)
Unrealized gains (losses) for the period	11,867	(21,880)	46,266	(12,935)
Total unrealized gain (loss), net	4,364	(47,579)	24,662	(60,522)
Total commodity price risk management gain (loss), net	$ 12,257	$ (23,284)	$ 55,479	$ 399

The realized derivative gains for the three and six 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 month period, realized gains related to natural gas derivatives were $11.4 million and realized losses on our CIG basis swaps were $5.6 million. For the six month period, realized gains related to natural gas and oil derivatives were $32.3 million and $4.1 million, respectively, and realized losses on our CIG basis swaps were $5.6 million.

For the three month period, the unrealized gains were primarily related to our oil positions, as the forward strip price shifted downward during the quarter, and the widening of the NYMEX-CIG basis differential. Unrealized gains on our oil positions and our CIG basis swaps for the three months ended 2010 were $8 million and $4 million, respectively. For the six month period, the unrealized gains were primarily a downward shift in the natural gas and oil forward curves. For the six months ended 2010, unrealized gains on our natural gas and oil positions were $37.3 million and $9.2 million, respectively.

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For the three and six 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 continuing 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 basis swaps 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 June 30, 2010, related to natural gas and oil production by area.

	Floors		Collars			Fixed-Price Swaps		CIG Basis Protection Swaps		
Commodity/Operating Area/Index/ Maturity Period	Quantity (Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMBtu Oil-Bbls)	Weighted Average Contract Price Floors	Ceilings	Quantity (Gas-MMBtu Oil-Bbls)	Weighted Average Contract Price	Quantity (MMBtu)	Weighted Average Contract Price	Fa Va June 3 (1 (i thous
Natural gas										
Rocky Mountain Region										
CIG										
07/01 - 09/30/2010	-	$-	-	$-	$-	392,505	$5.05	-	$-	$41
10/01 - 12/31/2010	-	-	680,411	4.75	9.45	234,319	5.05	-	-	57
01/01 - 03/31/2011	-	-	1,020,617	4.75	9.45	187,211	5.81	-	-	66
04/01 - 06/30/2011	-	-	-	-	-	330,752	5.81	-	-	39
07/01 - 12/31/2011	-	-	-	-	-	441,780	5.81	-	-	40
PEPL										
07/01 - 09/30/2010	-	-	300,000	5.00	8.90	526,993	5.93	-	-	1,0
10/01 - 12/31/2010	-	-	360,000	5.55	9.38	427,624	5.95	-	-	1,0
01/01 - 03/31/2011	-	-	390,000	5.76	9.56	271,628	6.18	-	-	74
04/01 - 06/30/2011	-	-	-	-	-	636,998	6.18	-	-	88
07/01 - 12/31/2011	-	-	-	-	-	1,208,798	6.18	-	-	1,2
2012-2013	-	-	-	-	-	2,346,224	6.18	-	-	1,7
NYMEX										
07/01 - 09/30/2010	-	-	152,202	5.85	10.15	2,969,035	6.02	2,542,131	(1.88)	1,2
10/01 - 12/31/2010	-	-	569,044	5.94	9.15	1,758,300	6.66	1,794,323	(1.88)	1,5

01/01 - 03/31/2011	-	-	724,551	5.96	9.10	930,958	7.47	1,200,677	(1.88)	99
04/01 - 06/30/2011	-	-	-	-	-	2,317,139	6.90	2,215,694	(1.88)	1,2
07/01 - 12/31/2011	-	-	-	-	-	4,456,746	6.89	4,253,857	(1.88)	89
2012-2013	-	-	8,785,211	6.05	8.43	7,410,257	7.08	14,614,306	(1.88)	(2,
Appalachia										
NYMEX										
07/01 - 09/30/2010	-	-	7,160	5.85	10.15	385,779	5.35	-	-	27
10/01 - 12/31/2010	-	-	7,235	6.45	11.48	378,662	5.36	-	-	15
01/01 - 03/31/2011	-	-	8,434	6.61	11.60	361,093	6.38	-	-	36
04/01 - 06/30/2011	-	-	-	-	-	358,275	6.38	-	-	44
07/01 - 12/31/2011	-	-	-	-	-	690,193	6.37	-	-	63
2012-2013	-	-	-	-	-	72,007	7.23	-	-	10
Other										
NYMEX										
07/01 - 09/30/2010	-	-	73,305	5.85	10.15	181,093	6.73	-	-	46
10/01 - 12/31/2010	-	-	73,224	6.45	11.47	169,930	6.80	-	-	42
01/01 - 03/31/2011	-	-	83,823	6.62	11.64	72,184	8.85	-	-	37
04/01 - 06/30/2011	-	-	-	-	-	208,959	7.43	-	-	47
07/01 - 12/31/2011	-	-	-	-	-	407,712	7.44	-	-	80
2012-2013	-	-	427,363	6.05	8.43	1,076,642	7.17	-	-	1,7
Total natural gas	-		13,662,580			31,209,796		26,620,988		19,
Oil										
Rocky Mountain Region										
NYMEX										
07/01 - 09/30/2010	21,000	65.38	-	-	-	155,196	91.42	-	-	2,1
10/01 - 12/31/2010	21,000	65.38	-	-	-	142,070	92.30	-	-	1,9
01/01 - 03/31/2011	21,000	65.38	67,814	73.00	99.80	92,610	74.29	-	-	(13
04/01 - 06/30/2011	21,000	65.38	60,691	73.00	99.80	90,000	74.01	-	-	(23
07/01 - 12/31/2011	41,000	65.38	102,947	73.00	99.80	173,293	73.62	-	-	(67
2012-2013	36,000	65.38	686,148	75.00	102.63	-	-	-	-	2,4
Total oil	161,000		917,600			653,169		-		5,5
Total natural gas and oil										$25,

(1) Approximately 43.7% 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.

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Natural Gas Marketing

Sales from Natural Gas Marketing. The $1.3 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, offset in part by an increase in unrealized losses on derivatives. For the three months ended 2010, prices on sales were 18% higher on average than in the three months ended 2009, resulting in a $2 million increase in sales. Unrealized derivative losses for the three months ended 2010 increased $0.6 million from $2 million for the three months ended 2009 to unrealized losses of $2.6 million for the three months ended 2010. Sales from natural gas marketing for the six months ended 2010 increased $3.2 million to $35.3 million from $32.1 million for the six months ended 2009. The increase is primarily due to an 11% increase in commodity prices, which contributed $3.1 million to the increase. The increase in unrealized derivative gains of $2.1 million for the six months ended 2010 compared to the same 2009 period were predominantly offset by a comparable decrease in realized gains.

Cost of Natural Gas Marketing. Cost of natural gas marketing increased $1.3 million for the three months ended 2010 compared to the three months ended 2009. This increase was primarily due to a 22% increase in prices, contributing $2.3 million to the increase, offset in part by a $0.7 million decrease in realized derivative losses and a $0.4 million increase in unrealized gains on derivatives. The $3.3 million increase in cost of natural gas marketing for the six months ended 2010 compared to the six months ended 2009 is primarily due to a 15.3% increase in commodity prices, contributing $4 million to the increase, and an increase in unrealized derivative losses of $1.8 million, offset in part by a decrease in realized derivative losses of $2.5 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 June 30, 2010, related to natural gas marketing.

	Collars			Fixed-Price Swaps		NYMEX Basis Protection Swaps		
Commodity/Derivative Instrument/ Maturity Period	Quantity (MMBtu)	Weighted Average Contract Price Floors	Ceilings	Quantity (MMBtu)	Weighted Average Contract Price	Quantity (MMBtu)	Weighted Average Contract Price	Fair Value June 30, 2010 (1) (in thousands)
Natural gas								
Physical sales								
07/01 - 09/30/2010	-	$-	$-	42,415	$6.80	13,429	$0.65	$ 81
10/01 - 12/31/2010	-	-	-	49,573	6.16	72,930	0.45	59
01/01 - 03/31/2011	-	-	-	-	-	126,045	0.36	20
04/01 - 06/30/2011	-	-	-	-	-	7,535	0.89	6
07/01 - 12/31/2011	-	-	-	-	-	7,015	0.90	5
01/01 - 04/30/2012	-	-	-	-	-	3,150	1.40	3

Financial purchases								
07/01 - 09/30/2010	-	-	-	41,938	5.44	-	-	(31)
10/01 - 12/31/2010	-	-	-	49,374	5.25	60,000	0.20	(9)
01/01 - 03/31/2011	-	-	-	-	-	90,000	0.20	2
Financial sales								
07/01 - 09/30/2010	52,500	4.53	7.16	698,100	6.53	-	-	1,303
10/01 - 12/31/2010	52,500	4.53	7.16	606,100	6.62	-	-	1,005
01/01 - 03/31/2011	52,500	4.53	7.16	454,200	6.42	-	-	468
04/01 - 06/30/2011	-	-	-	189,000	6.28	-	-	219
07/01 - 12/31/2011	-	-	-	255,000	6.45	-	-	257
Physical purchases								
07/01 - 09/30/2010	52,500	4.53	7.14	698,550	6.49	-	-	(1,138)
10/01 - 12/31/2010	52,500	4.53	7.14	606,250	6.59	-	-	(863)
01/01 - 03/31/2011	52,500	4.53	7.14	454,200	6.37	-	-	(338)
04/01 - 06/30/2011	-	-	-	189,000	6.27	-	-	(185)
07/01 - 12/31/2011	-	-	-	255,000	6.47	-	-	(215)
Total natural gas	315,000			4,588,700		380,104		$ 649

(1) Approximately 7.1% of the fair value of our derivative assets and 98.2% of our derivative liabilities were measured using significant unobservable inputs (Level 3); see Note 3, Fair Value Measurements, to the accompanying financial statements.

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Costs, Expenses and Other

Exploration Expense

The following table presents the major components of exploration expense.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)			
Amortization/impairment of unproved properties	$ 556	$ 518	$ 1,156	$ 1,132
Exploratory dry hole costs	650	106	3,552	937
Geological and geophysical costs	823	214	1,870	467
Operating, personnel and other	1,801	2,296	3,670	6,241
Total exploration expense	$ 3,830	$ 3,134	$ 10,248	$ 8,777

For the three months ended 2010, exploratory dry hole costs includes an oil test well in our Northeastern Colorado ("NECO") area and additional expenses on Piceance tests performed in the first quarter of 2010. The $0.6 million increase in geological and geophysical costs for the three months ended 2010 period compared to the same prior year period was primarily related to seismic work in the Marcellus Shale. Operating, personnel and other decreased $0.5 million for the period compared to the same prior year period primarily due to costs associated with 2009's rig demobilization in the Piceance Basin.

Exploratory dry hole costs for the six 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. Additional fracturing and testing of different exploratory zones for these wells are planned for the second half of 2010. The increase in geological and geophysical costs for the period six months ended 2010 compared to the six 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 decreased for the six months ended 2010 compared to the six months ended 2009 primarily due to the demobilization of drilling rigs in the Piceance Basin of $1.2 million and an inventory impairment of $0.7 million in 2009.

General and Administrative Expense

General and administrative expense decreased from $14.8 million and $26.9 million for the three and six months ended 2009 to $9.9 million and $20.5 million for the three and six months ended 2010, a decrease of $4.9 million and $6.4 million, respectively. The three month decrease was primarily related to a charge of $2.9 million related to a separation agreement with a former executive vice president and $1 million related to corporate relocation costs recorded in the three months ended 2009. In addition to the previously mentioned charges, the six month decrease was also related to the expensing of previously capitalized 2008 acquisition costs of $1.5 million during the three months ended March 31, 2009, pursuant to the adoption of a new accounting standard.

Depreciation, Depletion and Amortization

Natural gas and oil properties. The reduction in DD&A expense related to natural gas and oil properties for the three and six months ended 2010 compared to the three and six months ended 2009 was directly related to the decrease in production volumes as the weighted average DD&A rate for the three and six months ended 2010 was relatively unchanged at $2.94 per Mcfe and $2.95 per Mcfe, respectively, compared to $2.89 per Mcfe and $2.91 per Mcfe for the three and six months ended 2009, respectively.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
			(per Mcfe)			
Rocky Mountain Region:						
Wattenberg Field (1)	$ 3.54	$ 3.90	-9.2 %	$ 3.60	$ 3.99	-9.8 %
Piceance Basin	2.47	2.36	4.7 %	2.46	2.36	4.2 %
NECO	2.00	1.79	11.7 %	2.01	1.80	11.7 %
Weighted average	2.94	3.00	-2.0 %	2.95	3.02	-2.3 %
Appalachian Basin	2.71	1.81	49.7 %	2.67	1.84	45.1 %

(1) Although the Wattenberg Field development costs and DD&A rates are higher than the other fields, the relative value of its oil production currently more than offsets this cost difference.

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Non-natural gas and oil properties. Depreciation expense for non-natural gas and oil properties was $1.8 million and $3.7 million for the three and six months ended 2010, compared to $2 million and $3.9 million for the three and six months ended 2009, respectively.

Interest Expense

The decrease in interest expense for the three and six months ended 2010 compared to the same 2009 periods was primarily due to lower outstanding balances on our credit facility, offset in part by higher debt amortization costs due to our second quarter 2009 refinancing.

Provision/Benefit for Income Taxes

The effective income tax rate for continuing operations ("rate") for the three and six months ended 2010 was 36.8% (benefit on a loss) and 37.6% (provision on income) compared to 38.3% (benefit on a loss) and 38.8% (benefit on a loss) in the three and six months ended 2009. The rates for each period presented reflect a tax benefit from our statutory percentage depletion deduction. Discrete items did not have a material impact on the rates for the periods presented.

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.

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 2010. Our 2009 NOL was carried forward for state tax purposes and the net $2.6 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 May 2010, we entered into an agreement to divest our Michigan assets. On July 30, 2010, the sale was completed. The sale involved our Michigan asset group. We will not have any 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. During the three months ended 2010, in conjunction with our decision to divest our Michigan assets we recorded a pre-tax impairment charge of $4.5 million. The impairment charge was the primary cause for the decreases in discontinued operations for the three and six months ended 2010 compared to the same 2009 periods. See Note 3, Fair Value Measurements, and Note 12, Assets Held for Sale and Discontinued Operations, for additional information regarding the divestiture of our Michigan assets.

Natural Gas and Oil Well Drilling Operations. We have not had significant revenue from our well drilling activities since 2007. In January 2008, we announced that we had no plans to sponsor new drilling partnerships. 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. Prior period financial statements have been reclassified to present the activities of our natural gas and oil well drilling operations 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 six months ended 2010 was a net loss of $0.3 million and net income of $22.9 million compared to net losses of $33.3 million and $39.6 million for the three and six months ended 2009, respectively. Adjusted net income (loss) from continuing operations, a non-GAAP financial measure, for the three and six months ended 2010 was a net loss of $3 million and net income of $7.4 million compared to a net loss of $3.9 million and a net loss of $0.8 million for the three and six months ended 2009. 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.

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Financial Condition

Capital Resources and Liquidity

Our primary sources of cash for the six 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 and the realized gains from our derivative positions. These sources of cash were primarily used to fund our operating costs, general and administrative activities and our capital expenditures, including both our developmental and exploratory activities. Additionally, we were able to improve our liquidity position by reducing borrowings outstanding under the credit facility. 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 have historically been volatile and we manage this volatility through our derivative program. Therefore, 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. However, we do not hold economic hedges for 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 June 30, 2010, we had natural gas and oil derivative positions in place covering 64.3% of our expected natural gas production and 58.2% of our expected oil production for the remainder of 2010, at an average price of $5.05 per Mcf and $88.56 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 $49.8 million from a surplus of $32.9 million at December 31, 2009, to a deficit of $16.9 million at June 30, 2010. The majority of this decrease is due to the decrease in cash and cash equivalents of $12.5 million, accounts receivable of $11.6 million and income tax receivable of $27.7 million and the corresponding use of these amounts to reduce debt.

We ended June 2010 with cash and cash equivalents of $19.4 million and availability under our credit facility of $249.3 million for a total liquidity position of $268.7 million compared to $238.2 million at December 31, 2009. Our operating cash flows of $95.4 million for the six months ended 2010 provided us with ample capital to reduce our borrowings under our credit facility by $43 million, net of borrowings, and consequently contribute to the $30.5 million or 12.8% increase in our liquidity position. 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. On July 30, 2010, as a result of closing our acquisition of producing assets located in the Wolfberry oil trend and divesting our Michigan assets, we used approximately $50 million of our June 30, 2010, available liquidity.

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 of $29.5 million and the income tax refund of $25.9 million from our 2009 NOL carry-back filed and received during the three months ended 2010, offset by a decrease in realized derivative gains of $29.6 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 remained relatively unchanged from $78.2 million for the six months ended 2010 compared to $77.4 million for the six months ended 2009. Adjusted EBITDA was $82.1 million for the six months ended 2010 compared to $81 million for the six 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, decreased $23.4 million, or 22.5%, from $104 million for the six months ended 2009 to $80.6 million for the six months ended 2010. The decrease in cash flows was due primarily to the carryover to the six months ended 2009 of approximately $42 million of accounts payable related to our 2008 drilling program. The capital spent in the six months ended 2009 unrelated to 2008 carryover capital was approximately $62 million. Therefore, when comparing our 2010 capital program to our 2009 capital program, the 2010 program has increased $18.6 million or 30%. We’ve projected our 2010 developmental capital program to be $141 million versus $79 million for 2009. We currently have one rig operating in the Piceance Basin and two rigs operating in the oil and liquids-rich sections of the Wattenberg Field.

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We used cash of $27.3 million for financing activities for the first six months of 2010; whereas, the first six months of 2009 provided a source of cash in the amount of $14.3 million. The majority of the change was due to the shift from net borrowings of $23.5 million for the six months ended 2009 period to a net payment on borrowings of $43 million for the six months ended 2010. Additionally, our PDCM joint venture partner contributed $28 million to PDCM, which is included in cash flows from financing activities in our six months ended 2010 statement of cash flows 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 $232 million, excluding joint venture related projects and including our July 2010 Wolfberry oil trend acquisition and our anticipated partnership purchases, represent an approximate 113% 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 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 considered the possibility of reduced available liquidity in planning our 2010 drilling program and believe we will have adequate cash flows from operations during the year to execute our planned capital expenditures. Currently, we operate approximately 95% of our properties, allowing us to direct the pace of substantially all of our planned capital expenditures. Consequently, we may elect to defer a substantial portion of our planned capital expenditures for 2010 and beyond if market conditions worsen.

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. We continue to monitor market events and circumstances and their potential impacts on each of the twelve lenders that comprise our bank credit facility. Our $305 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. On May 5, 2010, based on our December 31, 2009, reserves, our borrowing base was reaffirmed at $305 million. 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. We were in compliance with all debt covenants as of June 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 2010 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.

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Contractual Obligations, Commitments and Contingencies

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

As of June 30, 2010	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			Payments due by period (in thousands)		
Long-term liabilities reflected on the balance sheet (1)					
Long-term debt (2)	$ 240,000	$ -	$ 37,000	$ -	$ 203,000
Derivative contracts (3)	54,251	16,213	31,785	6,253	-
Derivative contracts - affiliated partnerships (4)	17,057	3,695	11,095	2,267	-
Production tax liability	25,346	15,008	10,338	-	-
Other liabilities (5)	9,736	272	3,509	604	5,351
Asset retirement obligations (6)	24,716	250	394	789	23,283
	371,106	35,438	94,121	9,913	231,634
Commitments, contingencies and other arrangements (7)					
Interest on long-term debt (8)	190,919	27,091	51,163	48,720	63,945
Operating leases	6,258	1,750	2,499	1,776	233
Drilling commitment	1,040	-	-	-	1,040
Firm transportation and processing agreements (9)	170,705	18,179	40,753	39,227	72,546
Other	625	125	250	250	-
	369,547	47,145	94,665	89,973	137,764
Total	$ 740,653	$ 82,583	$ 188,786	$ 99,886	$ 369,398

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(1) Table does not include deferred income tax liability to taxing authorities of $184.6 million, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

(2) Amount presented does not agree with the balance sheet in that it does not include $2.2 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 $18.2 million.

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

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

(6) Includes $0.8 million related to assets held for sale.

(7) Table does not include maximum annual repurchase obligations to investing partners of $11.4 million, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

(8) 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 $185.7 million payable to the holders of our 12% senior notes and $5.2 million related to our outstanding balance of $37 million on our credit facility, including interest of $0.5 million related to our letter of credit, based on an imputed interest rate of 4.9%.

(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 are not currently a party to any litigation that we believe would have a materially adverse affect on our business, financial condition, results of operations, or liquidity.

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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 producing wells and wells capable of commercial production.
As of June 30, 2010, a total of 38 productive wells, all of which were drilled in 2010, were waiting to be fractured and/or for gas pipeline connection.

	Three Months Ended June 30,				Six Months Ended June 30,			
	2010		2009		2010		2009	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells:								
Productive								
Rocky Mountain Region	53	42.4	24	19.7	96	80.7	46	40.0
Appalachian Basin	-	-	-	-	-	-	1	1.0
Total productive	53	42.4	24	19.7	96	80.7	47	41.0
Dry								
Rocky Mountain Region	-	-	-	-	-	-	1	0.5
Total dry	-	-	-	-	-	-	1	0.5
Total development	53	42.4	24	19.7	96	80.7	48	41.5
Exploratory Wells:								
Productive								
Rocky Mountain Region	-	-	-	-	-	-	2	1.0
Appalachian Basin	3	1.7	-	-	4	2.3	2	2.0
Total productive	3	1.7	-	-	4	2.3	4	3.0
Total exploratory	3	1.7	-	-	4	2.3	4	3.0
Total drilling activity	56	44.1	24	19.7	100	83.0	52	44.5
Recompletions/refractures	5	4.2	3	2.9	16	14.7	3	2.9

As of June 30, 2010, a total of 38 productive wells, all of which were drilled in 2010, were waiting to be fractured and/or for gas pipeline connection.

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, such policies include revenue recognition, derivatives instruments, natural gas and oil properties, deferred income tax asset valuation and purchase accounting.

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.

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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 as a result of a change in the composition of the board of managers 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. 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 June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)			
Adjusted cash flow from operations:				

Adjusted cash flow from operations	$ 28,850	$ 37,665	$ 78,179	$ 77,406
Changes in assets and liabilities	15,176	(12,885)	17,192	(16,747)
Net cash provided by operating activities	$ 44,026	$ 24,780	$ 95,371	$ 60,659
Adjusted net income (loss) from continuing operations:				
Adjusted net income (loss) from continuing operations	$ (2,974)	$ (3,947)	$ 7,421	$ (836)
Unrealized gain (loss) on derivatives, net	4,211	(47,574)	24,701	(60,762)
Provision for underpayment of gas sales	-	-	-	(2,581)
Tax effect of above adjustments	(1,567)	18,223	(9,271)	24,578
Net income (loss) from continuing operations	$ (330)	$ (33,298)	$ 22,851	$ (39,601)
Adjusted EBITDA:				
Adjusted EBITDA	$ 30,022	$ 36,280	$ 82,122	$ 80,989
Unrealized gain (loss) on derivatives, net	4,211	(47,574)	24,701	(60,762)
Interest expense, net	(7,638)	(9,408)	(15,433)	(17,771)
Income tax benefit (expense)	192	20,663	(13,766)	25,088
Depreciation, depletion and amortization	(27,117)	(33,259)	(54,773)	(67,145)
Net income (loss) from continuing operations	$ (330)	$ (33,298)	$ 22,851	$ (39,601)

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

Market-Sensitive Instruments and Risk Management

We are exposed to market risks associated with interest 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 June 30, 2010, we held interest-bearing deposits totaling $34.5 million earning an average interest rate of 0.6% per annum. The $34.5 million represents our aggregate bank balances, which includes outstanding checks issued. Based on a sensitivity analysis of the credit facility borrowings as of June 30, 2010, it was estimated that if market interest rates were to increase or decrease by 1%, our 2010 interest expense would correspondingly change by $0.4 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 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 June 30, 2010, we had natural gas and oil derivative positions in place covering 64.3% of our expected natural gas production and 58.2% of our expected oil production for the remainder of 2010, at an average price of $5.05 per Mcf and $88.56 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 June 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 $38.6 million; whereas, a 10% decrease in prices would result in an increase in fair value of $39.1 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 June 30, 2010.

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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.

	Six Months Ended June 30, 2010	Year Ended December 31, 2009
Average Index Closing Price		
Natural gas (per MMBtu)		
CIG	$ 4.38	$ 3.07
NYMEX	4.70	3.99
Oil (per Bbl)		
NYMEX	77.16	58.36
Average Sales Price Realized		
Excluding realized derivative gains/(losses)		
Natural gas (per MMbtu)	4.61	3.12
Oil (per Bbl)	72.91	55.03
Including realized derivative gains/(losses)		
Natural gas (per MMbtu)	6.58	5.63
Oil (per Bbl)	79.44	68.87

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, who 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 the 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 June 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.

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of June 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 June 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 June 30, 2010, that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

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 other 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.

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- 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.

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
April 1-30, 2010	120	$ 23.36	-	-
May 1-31, 2010	2,480	21.22	-	-
June 1-30, 2010	1,688	21.74	-	-
	4,288	21.49		

(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

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PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)

Item 6. Exhibits Index

Exhibit Number	Exhibit Description	Form	Incorporated by Reference 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	8-K	000-07246	10.4	4/23/2010	

	19, 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	
12.1	Computation of Ratio of Earnings to Fixed Charges.					X
31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	Certifications by Chief Executive Officer and Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.					X

*Management contract or compensatory plan or arrangement.

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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:	August 9, 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

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