PETROLEUM DEVELOPMENT CORP
Form 10-Q
November 05, 2009

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

T Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended September 30, 2009

or

£ Transition Report Pursuant to Section 13 of 15(d) of the Securities Exchange Act of 1934
For the transition period from to ____

Commission File Number: 000-07246

PETROLEUM DEVELOPMENT CORPORATION
(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

Large accelerated filer T	Accelerated filer £

Non-accelerated filer £	Smaller reporting company £

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 19,224,897 shares of the Company's Common Stock ($.01 par value) were outstanding as of October 31, 2009.

PETROLEUM DEVELOPMENT CORPORATION

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PART I - FINANCIAL INFORMATION

Item 1. Financial Statements (unaudited)

Petroleum Development Corporation
Condensed Consolidated Balance Sheets
(in thousands, except share data)

	September 30, 2009	December 31, 2008*
Assets		
Current assets:		
Cash and cash equivalents	$ 22,140	$ 50,950
Restricted cash	2,530	19,030
Accounts receivable, net	40,392	69,688
Accounts receivable affiliates	6,870	16,742
Inventory	886	4,310
Fair value of derivatives	69,112	116,881
Prepaid expenses and other assets	9,449	14,836
Total current assets	151,379	292,437
Properties and equipment, net	1,017,519	1,033,078
Fair value of derivatives	9,106	47,155
Accounts receivable affiliates	14,359	1,605
Other assets	31,791	28,429
Total Assets	$ 1,224,154	$ 1,402,704
Liabilities and Equity		
Liabilities		
Current liabilities:		
Accounts payable	$ 31,601	$ 90,532
Accounts payable affiliates	18,419	40,540
Production tax liability	22,149	18,226
Fair value of derivatives	17,045	4,766
Funds held for future distribution	23,411	50,361
Deferred income taxes	2,665	28,355
Other accrued expenses	13,998	28,391
Total current liabilities	129,288	261,171
Long-term debt	351,584	394,867
Deferred income taxes	154,754	162,593
Asset retirement obligation	24,298	23,036
Fair value of derivatives	43,390	5,720
Accounts payable affiliates	1,383	10,136
Other liabilities	19,046	32,906
Total liabilities	723,743	890,429
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: 19,231,330 shares in 2009 and 14,871,870 in 2008		192		149
Additional paid-in capital		57,516		5,818
Retained earnings		442,648		505,906
Treasury shares, at cost; 8,017 shares in 2009 and 7,066 in 2008		(308)		(292)
Total shareholders' equity		500,048		511,581
Noncontrolling interest in WWWV, LLC		363		694
Total equity		500,411		512,275
Total Liabilities and Equity	$	1,224,154	$	1,402,704

*Derived from audited 2008 balance sheet.

See accompanying notes to condensed consolidated financial statements.

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Petroleum Development Corporation
Condensed Consolidated Statements of Operations
(unaudited; in thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Revenues:				
Oil and gas sales	$44,006	$99,422	$125,306	$265,617
Sales from natural gas marketing	12,444	53,372	47,200	107,638
Oil and gas price risk management gain (loss), net	(13,813)	169,402	(13,414)	25,294
Well operations, pipeline income and other	2,563	3,376	8,349	8,203
Total revenues	45,200	325,572	167,441	406,752
Costs and expenses:				
Oil and gas production and well operations cost	15,218	22,582	45,623	62,115
Cost of natural gas marketing	11,556	54,372	45,426	106,610
Exploration expense	6,586	10,212	15,362	17,962
General and administrative expense	9,627	8,106	36,505	27,160
Depreciation, depletion and amortization	32,277	28,645	100,465	71,881
Total costs and expenses	75,264	123,917	243,381	285,728
Gain on sale of leaseholds	-	-	120	-
Income (loss) from operations	(30,064)	201,655	(75,820)	121,024
Interest income	208	151	240	497
Interest expense	(9,221)	(7,817)	(27,024)	(19,143)
Income (loss) from continuing operations before income taxes	(39,077)	193,989	(102,604)	102,378
Provision (benefit) for income taxes	(14,601)	67,834	(39,233)	34,647
Income (loss) from continuing operations	(24,476)	126,155	(63,371)	67,731
Income from discontinued operations, net of tax	-	741	113	4,525
Net income (loss)	$(24,476)	$126,896	$(63,258)	$72,256
Earnings (loss) per share				
Basic				
Continuing operations	$(1.44)	$8.54	$(4.08)	$4.59
Discontinued operations	-	0.05	0.01	0.31
Net income (loss)	$(1.44)	$8.59	$(4.07)	$4.90
Diluted				
Continuing operations	$(1.44)	$8.50	$(4.08)	$4.56
Discontinued operations	-	0.05	0.01	0.30
Net income (loss)	$(1.44)	$8.55	$(4.07)	$4.86
Weighted average common shares outstanding				
Basic	16,962	14,767	15,530	14,749
Diluted	16,962	14,835	15,530	14,858

See accompanying notes to condensed consolidated financial statements.

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Petroleum Development Corporation
Condensed Consolidated Statements of Cash Flows
(unaudited, in thousands)

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Cash flows from operating activities:		
Net income (loss)	$(63,258)	$72,256
Adjustments to net income (loss) to reconcile to cash provided by operating activities:		
Deferred income taxes	(33,529)	45,390
Depreciation, depletion and amortization	100,465	71,881
Exploratory dry hole costs	1,078	5,038
Amortization and impairment of unproved properties	4,760	3,492
Unrealized (gain) loss on derivative transactions	95,735	(45,371)
Other	9,455	6,017
Changes in assets and liabilities	(14,735)	(54,911)
Net cash provided by operating activities	99,971	103,792
Cash flows from investing activities:		
Capital expenditures	(124,821)	(219,273)
Other	378	121
Net cash used in investing activities	(124,443)	(219,152)
Cash flows from financing activities:		
Proceeds from credit facility	226,000	339,500
Repayment of credit facility	(269,500)	(452,500)
Proceeds from senior notes	-	200,101
Payment of debt issuance costs	(8,980)	(5,308)
Proceeds from sale of equity	48,454	-
Proceeds from exercise of stock options	-	605
Excess tax benefits from stock based compensation	-	1,136
Purchase of treasury shares	(312)	(5,521)
Net cash provided by (used in) financing activities	(4,338)	78,013
Net decrease in cash and cash equivalents	(28,810)	(37,347)
Cash and cash equivalents, beginning of period	50,950	84,751
Cash and cash equivalents, end of period	$22,140	$47,404
Supplemental cash flow information:		
Cash payments (receipts) for:		
Interest, net of capitalized interest	$30,155	$16,904
Income taxes, net of refunds	(3,522)	100
Non-cash investing activities:		
Change in accounts payable related to purchases of properties and equipment	(36,383)	6,481
Change in asset retirement obligation, with a corresponding increase to oil and gas properties, net of disposals	260	631

See accompanying notes to condensed consolidated financial statements.

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Petroleum Development Corporation
Condensed Consolidated Statements of Equity
(unaudited; in thousands, except share data)

	September 30, 2009	September 30, 2008
Common shares, par value $.01 per share - shares issued:		
Shares at beginning of period	14,871,870	14,907,679
Adjust prior conversion of predecessor shares	-	100
Shares issued pursuant to equity sale	4,312,500	-
Exercise of stock options	-	19,699
Issuance of stock awards, net of forfeitures	65,459	15,996
Retirement of treasury shares	(18,499)	(82,175)
Shares at end of period	19,231,330	14,861,299
Treasury shares:		
Shares at beginning of period	(7,066)	(5,894)
Purchase of treasury shares	(18,499)	(82,175)
Retirement of treasury shares	18,499	82,175
Non-employee directors' deferred compensation plan	(951)	(666)
Shares at end of period	(8,017)	(6,560)
Common shares outstanding	19,223,313	14,854,739
Equity:		
Shareholders' equity		
Preferred shares, $.01 par:		
Balance at beginning and end of period	$ -	$ -
Common shares		
Balance at beginning of period	149	149
Shares issued pursuant to equity sale	43	-
Balance at end of period	192	149
Additional paid-in capital:		
Balance at beginning of period	5,818	2,559
Proceeds from sale of equity	48,411	-
Exercise of stock options	-	604
Stock based compensation expense	4,901	5,239
Retirement of treasury shares	(312)	(5,073)
Tax benefit (detriment) of stock based compensation	(1,302)	1,136
Balance at end of period	57,516	4,465
Retained earnings:		
Balance at beginning of period	505,906	393,044
Retirement of treasury shares	-	(447)
Net income (loss)	(63,258)	72,256
Balance at end of period	442,648	464,853
Treasury shares, at cost:		
Balance at beginning of period	(292)	(226)
Purchase of treasury shares	(312)	(5,521)
Retirement of treasury shares	312	5,521
Non-employee directors' deferred compensation plan	(16)	(48)
Balance at end of period	(308)	(274)

Total shareholders' equity	500,048	469,193
Noncontrolling interest in WWWV, LLC		
Balance at beginning of period	694	759
Net loss attributed to noncontrolling interest	(331)	(49)
Balance at end of period	363	710
Total noncontrolling interest	363	710
Total Equity	$ 500,411	$ 469,903

See accompanying notes to condensed consolidated financial statements.

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Petroleum Development Corporation
Notes to Condensed Consolidated Financial Statements
September 30, 2009
(unaudited)

1. GENERAL

Petroleum Development Corporation ("PDC"), together with our consolidated entities (the "Company," "we," "our" or "us"), is an independent energy company engaged primarily in the exploration, development, production and marketing of oil and natural gas. Since we began oil and natural gas operations in 1969, we have grown primarily through exploration and development activities, the acquisition of producing oil and natural gas wells and natural gas marketing.

The accompanying condensed consolidated financial statements include the accounts of PDC, our wholly owned subsidiaries and WWWV, LLC, an entity in which we have a controlling financial interest. All material intercompany accounts and transactions have been eliminated in consolidation. We account for our investment in interests in oil and natural gas 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 the limited partnerships in which we participate. Our proportionate share of all significant transactions between us and the limited partnerships has been eliminated.

The accompanying condensed consolidated financial statements have been prepared without audit in accordance with accounting principles generally accepted in the United States of America for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the Securities and Exchange Commission ("SEC"). Accordingly, pursuant to such rules and regulations, certain notes and other financial information included in audited financial statements have been condensed or omitted. In our opinion, the accompanying condensed consolidated financial statements contain all adjustments (consisting of only normal recurring adjustments) necessary to present fairly our financial position, results of operations and cash flows for the periods presented. The results of operations for the nine months ended September 30, 2009, 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.

The accompanying condensed consolidated financial statements should be read in conjunction with our audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2008, as filed with the SEC on February 27, 2009 ("2008 Form 10-K").

Certain prior year amounts have been reclassified to conform to the current year presentation. Such reclassifications are directly related to the presentation of our oil and gas well drilling operations as discontinued operations and to the adoption of disclosure and accounting changes related to noncontrolling interest in a subsidiary. The reclassifications had no impact on previously reported net earnings, earnings per share or equity. See Notes 2 and 11 for additional information regarding these reclassifications.

2. RECENT ACCOUNTING STANDARDS

Recently Adopted Accounting Standards

Accounting Standards Codification

In June 2009, the Financial Accounting Standards Board ("FASB") issued the FASB Accounting Standards Codification™ (the "Codification") thereby establishing the Codification as the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP"). Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. The FASB will no longer issue new standards in the form of Statements, FASB Staff Positions, or Emerging Issues Task Force Abstracts; instead, the FASB will issue Accounting Standards Updates. Accounting Standards Updates will not be authoritative in their own right as they will only serve to update the Codification. Effective July 1, 2009, we adopted the Codification. Other than the manner in which new accounting guidance is referenced, the adoption of the Codification did not have a material impact on our accompanying condensed consolidated financial statements.

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Subsequent Events

In May 2009, the FASB issued changes regarding subsequent events, which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued. Specifically, the guidance sets forth the period after the balance sheet date during which our management should evaluate events or transactions that may occur for potential recognition or disclosure in our financial statements, the circumstances under which we should recognize events or transactions occurring after the balance sheet date in our financial statements, and the disclosures that we should make about events or transactions that occurred after our balance sheet date. We adopted the guidance as of June 30, 2009. See Note 14, Subsequent Events.

Business Combinations

In December 2007, the FASB issued changes regarding the accounting for business combinations. The changes require:

- an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their acquisition-date fair values;
- disclosure of the information necessary for investors and other users to evaluate and understand the nature and financial effect of the business combination; and
- acquisition-related costs be expensed as incurred.

The changes also amend the accounting for income taxes to require the acquirer to recognize changes in the amount of its deferred tax benefits recognizable due to a business combination either in income from continuing operations in the period of the combination or directly in contributed capital, depending on the circumstances. Further, the changes amend the accounting for income taxes to require, subsequent to a prescribed measurement period, changes to acquisition-date income tax uncertainties to be reported in income from continuing operations and changes to acquisition-date acquiree deferred tax benefits to be reported in income from continuing operations or directly in contributed capital, depending on the circumstances.

In April 2009, the FASB again issued changes to the accounting for business combinations. These changes apply to all assets acquired and liabilities assumed in a business combination that arise from contingencies and require:

- an acquirer to recognize at fair value, at the acquisition date, an asset acquired or liability assumed in a business combination that arises from a contingency if the acquisition-date fair value of that asset or liability can be determined during the measurement period; otherwise, the asset or liability should be recognized at the acquisition date if certain defined criteria are met;
- contingent consideration arrangements of an acquiree assumed by the acquirer in a business combination be recognized initially at fair value;
- subsequent measurements of assets and liabilities arising from contingencies be based on a systematic and rational method depending on their nature and contingent consideration arrangements be measured subsequently; and
- disclosures of the amounts and measurements basis of such assets and liabilities and the nature of the contingencies.

The changes above became effective for acquisitions completed on or after January 1, 2009; however, the income tax changes became effective as of that date for all acquisitions, regardless of the acquisition date. We adopted these changes effective January 1, 2009, for which they will be applied prospectively in our accounting for future acquisitions, if any. Upon adoption, we recorded a charge of $1.5 million to general and administrative expense related to acquisition costs deferred at December 31, 2008.

Consolidation – Noncontrolling Interest in a Subsidiary

In December 2007, the FASB issued changes regarding the nature and classification of the noncontrolling interest in a subsidiary in the consolidated financial statements. The changes require the accounting and reporting for minority interests be recharacterized as noncontrolling interests and classified as a component of equity. Additionally, the changes establish reporting requirements that provide sufficient disclosures which clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. We adopted these changes effective January 1, 2009. Upon adoption, we reclassified our noncontrolling interest in WWWV, LLC from the mezzanine section, between liabilities and equity, of the consolidated balance sheets, to a component of equity, separate from our shareholders' equity. Net loss attributable to noncontrolling interest for the three and nine months ended September 30, 2009 and 2008, was immaterial and was recorded in depreciation, depletion and amortization ("DD&A") in the accompanying condensed consolidated statements of operations.

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Fair Value Measurements and Disclosures

In February 2008, the FASB delayed by one year (to January 1, 2009) the fair value measurements and disclosure requirements for nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The January 1, 2009, adoption of the fair value measurements and disclosure requirements for our nonfinancial assets and liabilities did not have a material impact on our accompanying condensed consolidated financial statements. See Note 3, Fair Value Measurements.

Derivatives and Hedging Disclosures

In March 2008, the FASB issued changes regarding the disclosure requirements for derivative instruments and hedging activities. Pursuant to the changes, enhanced disclosures are required to provide information about (a) how and why we use derivative instruments, (b) how we account for our derivative instruments and related hedged items and (c) how derivative instruments and related hedged items affect our financial position, financial performance and cash flows. We adopted these changes effective January 1, 2009. The adoption did not have a material impact on our accompanying condensed consolidated financial statements. See Note 4, Derivative Financial Instruments.

Recently Issued Accounting Standards

Fair Value Measurements and Disclosures

In August 2009, the FASB issued changes regarding fair value measurements and disclosures to reduce potential ambiguity in financial reporting when measuring the fair value of liabilities. These changes clarify existing guidance that in circumstances in which a quoted price in an active market for the identical liability is not available, an entity is required to measure fair value using either a valuation technique that uses a quoted price of either a similar liability or a quoted price of an identical or similar liability when traded as an asset, or another valuation technique that is consistent with the principles of fair value measurements, such as an income approach (e.g., present value technique). This guidance also states that both a quoted price in an active market for the identical liability and a quoted price for the identical liability when traded as an asset in an active market when no adjustments to the quoted price of the asset are required are Level 1 fair value measurements. These changes become effective for us on October 1, 2009. We are evaluating the impact, if any, that these changes will have on our consolidated financial statements, related disclosure and management's discussion and analysis.

Consolidation – Variable Interest Entities

In June 2009, the FASB issued changes surrounding 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. These changes are effective for our financial statements issued for fiscal years beginning after November 15, 2009, with earlier adoption prohibited. We are evaluating the impact, if any, that the adoption of these changes will have on our consolidated financial statements, related disclosure and management's discussion and analysis.

Modernization of Oil and Gas Reporting

In January 2009, the SEC published its final rule regarding the modernization of oil and gas reporting, which modifies the SEC's reporting and disclosure rules for oil and natural gas reserves. The most notable changes of the final rule include the replacement of the single day period-end pricing to value oil and natural gas reserves to a 12-month average of the first day of the month price for each month within the reporting period. The final rule also permits voluntary disclosure of probable and possible reserves, a disclosure previously prohibited by SEC rules. The revised reporting and disclosure requirements are effective for our Form 10-K for the year ending December 31, 2009. Early adoption is not permitted. We are evaluating the impact that adoption of this final rule will have on our consolidated financial statements, related disclosure and management's discussion and analysis.

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3. FAIR VALUE MEASUREMENTS

Determination of Fair Value. Our fair value measurements are estimated pursuant to a fair value hierarchy that requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability, and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels. The three levels of inputs that may be used to measure fair value are defined as:

Level 1 – Quoted prices (unadjusted) in active markets for identical assets or liabilities. Included in Level 1 are our commodity derivative instruments for New York Mercantile Exchange ("NYMEX")-based natural gas swaps.

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

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Included in Level 3 are our commodity derivative instruments for Colorado Interstate Gas ("CIG") and Panhandle Eastern Pipeline ("PEPL")-based natural gas swaps, oil swaps, oil and natural gas collars, and physical sales and purchases and our natural gas basis protection derivative instruments.

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 two 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, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant. As of September 30, 2009, no adjustment for credit risk was recorded. Furthermore, 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.

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The following table presents, by hierarchy level, our derivative financial instruments, including both current and non-current portions, measured at fair value as of December 31, 2008, and September 30, 2009.

	Level 1	Level 3	Total
		(in thousands)	
As of December 31, 2008			
Assets:			
Commodity based derivatives	$ 19,359	$ 144,644	$ 164,003
Basis protection derivative contracts	-	33	33
Total assets	19,359	144,677	164,036
Liabilities:			
Commodity based derivatives	(658)	(5,490)	(6,148)
Basis protection derivative contracts	-	(4,338)	(4,338)
Total liabilities	(658)	(9,828)	(10,486)
Net assets	$ 18,701	$ 134,849	$ 153,550
As of September 30, 2009			
Assets:			
Commodity based derivatives	$ 13,199	$ 64,954	$ 78,153
Basis protection derivative contracts	-	65	65
Total assets	13,199	65,019	78,218
Liabilities:			
Commodity based derivatives	(5,653)	(6,501)	(12,154)
Basis protection derivative contracts	-	(48,281)	(48,281)
Total liabilities	(5,653)	(54,782)	(60,435)
Net assets	$ 7,546	$ 10,237	$ 17,783

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

	(in thousands)
Fair value, net asset, as of December 31, 2008	$ 134,849
Changes in fair value included in statement of operations line item:	
Oil and gas price risk management gain (loss), net	(16,540)
Sales from natural gas marketing	(365)
Cost of natural gas marketing	3,442
Changes in fair value included in balance sheet line item (1):	
Accounts receivable affiliates	(15,858)
Accounts payable affiliates	(22,125)
Settlements	
Oil and gas sales	(73,198)
Natural gas marketing	32
Fair value, net asset, as of September 30, 2009	$ 10,237

Changes in unrealized gains (losses) relating to assets (liabilities) still held as of September 30, 2009, included in

statement of operations line item:		
Oil and gas price risk management gain (loss), net	$	(31,123)
Sales from natural gas marketing		69
Cost of natural gas marketing		(1,209)
	$	(32,263)

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

See Note 4, Derivative Financial Instruments, for additional disclosure related to our derivative financial instruments.

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Non-Derivative Assets and Liabilities. The carrying values of the financial instruments comprising cash and cash equivalents, restricted cash, accounts receivable and accounts payable 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 $201.5 million or 99.25% of par value as of September 30, 2009. We determined this valuation based upon measurements of trading activity and quotes provided by brokers and traders participating in the trading of the securities.

We assess our oil and gas 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 oil and natural gas. 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 oil and gas 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. See Note 5, Properties and Equipment, for a discussion related to an impairment loss recorded during the three and nine months ended September 30, 2009, on certain leases in our North Dakota acreage.

We account for asset retirement obligations by recording the estimated fair value of our plugging and abandonment obligations when incurred, which is when the well is completely drilled. We estimate the fair value of our plugging and abandonment obligations based on a discounted cash flows analysis. Upon initial recognition of an asset retirement obligation, we increase the carrying amount of the long-lived asset by the same amount as the liability. Over time, the liabilities are accreted for the change in their present value, through charges to oil and gas production and well operations costs. The initial capitalized costs are depleted based on the useful lives of the related assets, through charges to DD&A. 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. Revisions in estimated liabilities can result from revisions of estimated inflation rates, escalating retirement costs and changes in the estimated timing of settling asset retirement obligations. See Note 7, Asset Retirement Obligations, for a reconciliation of changes in our asset retirement obligation for the nine months ended September 30, 2009.

4. DERIVATIVE FINANCIAL INSTRUMENTS

We are exposed to the effect of market fluctuations in the prices of oil and natural gas. Price risk represents the potential risk of loss from adverse changes in the market price of oil and natural gas commodities. We employ established policies and procedures to manage the risks associated with these market fluctuations using commodity derivative instruments. Our policy prohibits the use of oil and natural gas derivative instruments for speculative purposes.

Included in the fair value of derivative assets and liabilities on our accompanying condensed consolidated balance sheets are the portion of derivative instruments entered into by us and allocated to our affiliated partnerships, as well as a corresponding offsetting payable to and receivable from the partnerships, respectively. As positions allocated to our affiliated partnerships settle, the realized gains and losses are netted for distribution. Net realized gains are paid to the partnerships and net realized losses are deducted from the partnerships' cash distributions from production. The affiliated partnerships bear their allocated share of counterparty risk.

We recognize all derivative instruments as either assets or liabilities on our accompanying condensed consolidated balance sheets at fair value. We have elected not to designate any of our derivative instruments as hedges. Accordingly, changes in the fair value of those derivative instruments allocated to us are recorded in our accompanying condensed consolidated statements of operations. Changes in the fair value of derivative instruments related to our oil and gas sales activities are recorded in oil and gas price risk management, net. Changes in the fair value of derivative instruments related to our natural gas marketing activities are recorded in sales from and cost of natural gas marketing. Changes in the fair value of the derivative instruments allocated to our affiliated partnerships are recorded in accounts payable affiliates and accounts receivable affiliates in our accompanying condensed consolidated balance sheets.

Validation of a contract's 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. See Note 3, Fair Value Measurements, for a discussion of how we fair value our derivative instruments.

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As of September 30, 2009, we had derivative instruments in place for a portion of our anticipated production through 2012 for a total of 29,895,457 MMbtu of natural gas and 966,608 Bbls of crude oil.

Derivative Strategies. Our results of operations and operating cash flows are affected by changes in market prices for oil and natural gas. To mitigate a portion of our exposure to adverse market changes, we have entered into various derivative contracts.

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

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

We believe our derivative instruments continue to be effective in achieving the risk management objectives for which they were intended.

As of September 30, 2009, our derivative instruments were comprised of commodity collars and swaps, basis protection swaps and physical sales and purchases.

- Collars contain a fixed floor price (put) and ceiling price (call). If the market price falls below the fixed put strike price, we receive the market price from the purchaser and receive the difference between the put strike price and market price from the counterparty. If the market price exceeds the fixed call strike price, we receive the market price from the purchaser and pay the difference between the call strike price and market price to the counterparty. If the market price is between the put and call strike price, no payments are due to or from the counterparty.

- Swaps are arrangements that guarantee a fixed price. If the market price is below the fixed contract price, we receive the market price from the purchaser and receive the difference between the market price and the fixed contract price from the counterparty. If the market price is above the fixed contract price, we receive the market price from the purchaser and pay the difference between the market price and the fixed contract price to the counterparty.

- Basis protection swaps are arrangements that guarantee a price differential for natural gas from a specified delivery point. For CIG basis protection swaps, which have negative differentials to NYMEX, we receive a payment from the counterparty if the price differential is greater than the stated terms of the contract and pay the counterparty if the price differential is less than the stated terms of the contract.

- Physical sales and purchases are derivatives for fixed-priced physical transactions where we sell or purchase third party supply at fixed rates. These physical derivatives are offset by financial swaps: for a physical sale the offset is a swap purchase and for a physical purchase the offset is a swap sale.

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The following table summarizes the location and fair value amounts of our derivative instruments in the accompanying condensed consolidated balance sheets as of September 30, 2009, and December 31, 2008.

Derivatives instruments not designated as hedges (1):		Balance sheet line item	Fair Value September 30, 2009	Fair Value December 31, 2008
			(in thousands)	
Derivative Assets:	Current			
	Commodity contracts			
	Related to oil and gas sales	Fair value of derivatives	$ 66,070	$ 112,036
	Related to natural gas marketing	Fair value of derivatives	2,977	4,820
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	65	25
			69,112	116,881
	Non Current			
	Commodity contracts			
	Related to oil and gas sales	Fair value of derivatives	7,822	45,971
	Related to natural gas marketing	Fair value of derivatives	1,283	1,176
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	1	8
			9,106	47,155
Total Derivative Assets (2)			$ 78,218	$ 164,036
Derivative Liabilities:	Current			
	Commodity contracts			
	Related to oil and gas sales	Fair value of derivatives	$ (4,356)	$ -
	Related to natural gas marketing	Fair value of derivatives	(2,968)	(4,720)
	Basis protection contracts			
	Related to oil and gas sales	Fair value of derivatives	(9,714)	-
	Related to natural gas marketing	Fair value of derivatives	(7)	(46)
			(17,045)	(4,766)
	Non Current			
	Commodity contracts			
	Related to oil and gas sales	Fair value of derivatives	(3,739)	-
	Related to natural gas marketing	Fair value of derivatives	(1,091)	(1,428)
	Basis protection contracts			
	Related to oil and gas sales		(38,560)	(4,292)

	Fair value of derivatives			
			(43,390)	(5,720)
Total Derivative Liabilities (3)		$	(60,435)	$ (10,486)

(1) As of September 30, 2009, and December 31, 2008, none of our derivative instruments were designated as hedges.

(2) Includes derivative positions that have been allocated to our affiliated partnerships; accordingly, our accompanying condensed consolidated balance sheets include a corresponding payable to our affiliated partnerships of $15 million and $37.5 million as of September 30, 2009, and December 31, 2008, respectively.

(3) Includes derivative positions that have been allocated to our affiliated partnerships; accordingly, our accompanying condensed consolidated balance sheets include a corresponding receivable from our affiliated partnerships of $19.1 million and $1.6 million as of September 30, 2009, and December 31, 2008, respectively.

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The following table summarizes the impact of our derivative instruments on our accompanying condensed consolidated statements of operations for the three and nine months ended September 30, 2009 and 2008.

	Three Months Ended September 30, 2009			2008		
Statement of operations line item	Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	Realized and Unrealized Gains (Losses) For the Current Period	Total (in thousands)	Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	Realized and Unrealized Gains (Losses) For the Current Period	Total
Oil and gas price risk management gain (loss), net						
Realized gains (losses)	$21,139	$685	$21,824	$(24,646)	$21,894	$(2,752
Unrealized gains (losses)	(21,139)	(14,498)	(35,637)	24,646	147,508	172,15
Total oil and gas price risk management gain (loss), net (1)	$-	$(13,813)	$(13,813)	$-	$169,402	$169,40
Sales from natural gas marketing						
Realized gains (losses)	$1,601	$3	$1,604	$(4,597)	$3,027	$(1,570
Unrealized gains (losses)	(1,601)	(625)	(2,226)	4,597	13,427	18,024
Total sales from natural gas marketing(2)	$-	$(622)	$(622)	$-	$16,454	$16,454
Cost of natural gas marketing						
Realized gains (losses)	$(1,568)	$1,338	$(230)	$4,946	$(4,945)	$1
Unrealized gains (losses)	1,568	1,322	2,890	(4,946)	(14,205)	(19,15
Total cost of natural gas marketing(2)	$-	$2,660	$2,660	$-	$(19,150)	$(19,15

	Nine Months Ended September 30, 2009			2008		
Statement of operations line item	Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	Realized and Unrealized Gains (Losses) For the Current Period	Total (in thousands)	Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	Realized and Unrealized Gains (Losses) For the Current Period	Total
Oil and gas price risk management gain (loss), net						
Realized gains (losses)	$62,548	$20,197	$82,745	$(436)	$(20,081)	$(20,517
Unrealized gains (losses)	(62,548)	(33,611)	(96,159)	436	45,375	45,811
Total oil and gas price risk management gain (loss), net (1)	$-	$(13,414)	$(13,414)	$-	$25,294	$25,294
Sales from natural gas marketing						
Realized gains (losses)	$4,244	$1,591	$5,835	$1,378	$(4,745)	$(3,367

Unrealized gains (losses)	(4,244)	887	(3,357)	(1,378)	2,711	1,333
Total sales from natural gas marketing(2)	$-	$2,478	$2,478	$-	$(2,034)	$(2,034
Cost of natural gas marketing						
Realized gains (losses)	$(4,009)	$3,226	$(783)	$(878)	$997	$119
Unrealized gains (losses)	4,009	(228)	3,781	878	(2,651)	(1,773
Total cost of natural gas marketing(2)	$-	$2,998	$2,998	$-	$(1,654)	$(1,654

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

Concentration of Credit Risk. A significant portion of our liquidity is concentrated in derivative instruments that enable us to manage a portion of our exposure to price volatility from producing oil and natural gas. These arrangements expose us to credit risk of nonperformance by our counterparties. We primarily use two financial institutions, who are also major lenders in our credit facility agreement, as counterparties to our derivative contracts. To date, we have had no counterparty default losses.

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The following table identifies our counterparty risk as of September 30, 2009.

Counterparty Name	Fair Value of Derivative Assets September 30, 2009 (in thousands)
JPMorgan Chase Bank, N.A. (1)	$ 34,220
BNP Paribas (1)	42,195
Various (2)	1,803
Total	$ 78,218

(1) Major lender in our credit facility, see Note 6.
(2) Represents a total of 44 counterparties, includes five lenders in our credit facility.

5. PROPERTIES AND EQUIPMENT

	September 30, 2009	December 31, 2008
	(in thousands)	
Properties and equipment, net:		
Oil and gas properties (successful efforts method of accounting)		
Proved	$ 1,324,405	$ 1,245,316
Unproved	32,131	32,768
Total oil and gas properties	1,356,536	1,278,084
Pipelines and related facilities	38,132	34,067
Transportation and other equipment	33,642	31,693
Land and buildings	14,383	14,570
Construction in progress	360	275
	1,443,053	1,358,689
Accumulated DD&A	(425,534)	(325,611)
	$ 1,017,519	$ 1,033,078

During the three and nine months ended September 30, 2009, we assessed certain leases in our North Dakota acreage for possible impairment as a result of a triggering event. The event triggering the assessment was the termination of an exploration agreement with an unrelated third party, the determination that no future long-term exploration plan exists for this area and the engaging of an unrelated third party to market the property. As a result of the impairment analysis, we recognized an impairment loss of $2.8 million. The charge is included in exploration expense in the accompanying condensed consolidated statement of operations.

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Suspended Well Costs

The following table identifies the capitalized exploratory well costs that are pending determination of proved reserves and are included in properties and equipment in our accompanying condensed consolidated balance sheets.

	Amount (in thousands)	Number of Wells
Balance at December 31, 2008	$ 1,180	6
Additions to capitalized exploratory well costs pending the determination of proved reserves	7,219	6
Reclassifications to wells, facilities and equipment	(7,067)	(7)
Capitalized exploratory well costs charged to expense	(318)	(2)
Balance at September 30, 2009	$ 1,014	3

As of September 30, 2009, none of the three suspended wells awaiting the determination of proved reserves have been capitalized for a period greater than one year after the completion of drilling.

6. LONG-TERM DEBT

Long-term debt consists of the following:

	September 30, 2009	December 31, 2008
	(in thousands)	
Credit facility	$ 151,000	$ 194,500
12% Senior notes due 2018, net of discount of $2.4 million	200,584	200,367
Total long-term debt	$ 351,584	$ 394,867

Credit facility

We have a credit facility co-arranged by JPMorgan Chase Bank, N.A. ("JPMorgan") and BNP Paribas, dated as of November 4, 2005, as amended last on May 22, 2009 (“the Sixth Amendment”), with an aggregate revolving commitment of $350 million. The credit facility, through a series of amendments, includes commitments from: Bank of America, N.A.; Calyon New York Branch; Bank of Montreal; Wachovia Bank, N.A.; The Royal Bank of Scotland plc; Bank of Oklahoma; Compass Bank; and The Bank of Nova Scotia. The maximum allowable commitment under the current credit facility is $500 million. The credit facility is subject to and secured by our oil and natural gas 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 our 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 our reserves used in the borrowing base calculation and thus determines the underlying borrowing base. As of September 30, 2009, our aggregate revolving commitment was secured by substantially all of our oil and gas properties.

We are required to pay a commitment fee of .5% per annum on the unused portion of the activated credit facility. Interest accrues at an alternative base rate ("ABR") or adjusted LIBOR at our discretion. The ABR is the greater of JPMorgan's prime rate, a secondary market rate of a three-month certificate of deposit plus 1%, one month LIBOR plus 1% or the federal funds effective rate plus .5%. ABR and adjusted LIBOR borrowings are assessed an additional margin spread based upon the outstanding balance as a percentage of the available balance. ABR borrowings are assessed an additional margin of 1.375% to 2.375%. Adjusted LIBOR borrowings are assessed an additional margin spread of 2.25% to 3.25%. Pursuant to the Sixth Amendment, we paid $9 million in debt issuance costs; these costs were capitalized and will be amortized using the effective interest rate method over the three-year term of the credit facility. No principal payments are required until the credit agreement expires on May 22, 2012, or in the event that the borrowing base would fall below the outstanding balance.

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The credit facility contains covenants customary for agreements of this type, including, but not limited to, limitations on our ability to: (a) incur additional indebtedness and guarantees, (b) create liens and other encumbrances on our 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 us to execute and deliver specified mortgages and other evidences of security and to deliver specified opinions of counsel and other evidences of title. Further, we are required to comply with certain financial tests and maintain certain financial ratios on a quarterly basis. The financial tests and ratios include requirements to: (a) maintain a minimum ratio of consolidated current assets to consolidated current liabilities, or current ratio, as defined, of 1.00 to 1.00 and (b) not to exceed a maximum leverage ratio of 4.25 to 1.00 through December 31, 2010, 4.00 to 1.00 through June 30, 2011, and 3.75 to 1.00 thereafter.

In August 2009, we issued a $18.7 million irrevocable standby letter of credit in favor of a third party transportation service provider to secure the construction of certain additions and/or replacements to its facilities to provide firm transportation of the natural gas produced by us and others for whom we market their production in the West Virginia and Southwestern Pennsylvania areas. The letter of credit reduces the amount of available funds under our credit facility by an equal amount. We paid an issuance fee of 0.25% and will pay a quarterly maintenance fee equivalent to the spread over Eurodollar loans (2.5% per annum as of September 30, 2009) for the period the letter of credit remains outstanding. The letter of credit expires on May 22, 2012.

As of September 30, 2009, we had drawn $151 million from our credit facility compared to $194.5 million as of December 31, 2008. The borrowing rate on the outstanding balance was 4.1% as of September 30, 2009, compared to 4.6% as of December 31, 2008. As of September 30, 2009, the available funds under our credit facility were $180.3 million.

See Note 14, Subsequent Events – Seventh Amendment to Credit Facility, for a discussion related to the reduction in our borrowing base as a result of the entering into a joint venture agreement.

12% Senior Notes Due 2018

Our outstanding 12% senior notes were issued on February 8, 2008. The principal amount of the senior notes is $203 million, which is payable at maturity on February 15, 2018. Interest is payable in cash semi-annually in arrears on each February 15 and August 15. The senior notes were issued at a price of 98.572% of the principal amount. In addition, $5.4 million in costs associated with the issuance of the debt has been capitalized as a deferred loan cost. The original discount and the deferred note costs are being amortized to interest expense over the term of the debt using the effective interest method.

The indenture governing the notes contains customary representations and warranties as well as typical restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (a) incur additional debt, (b) make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) pay dividends or other payments by restricted subsidiaries, (e) create liens that secure debt, (f) enter into transactions with affiliates, and (g) merge or consolidate with another company. Additionally, we are subject to two incurrence covenants: 1) earnings before interest, taxes, depreciation, amortization and capital expenditures ("EBITDAX") of at least two times interest expense and 2) total debt of less than 4.0 times EBITDAX. We were in compliance with all covenants as of September 30, 2009, and expect to remain in compliance throughout the next year.

The notes are senior unsecured obligations and rank, in right of payment, equally with all of our existing and future senior unsecured indebtedness and senior to any of our existing and future subordinated indebtedness. The notes are effectively subordinated to any of our existing or future secured indebtedness to the extent of the assets securing such indebtedness.

The notes are not initially guaranteed by any of our subsidiaries. However, subsidiaries may be obligated to guarantee the notes if:

- a subsidiary is a guarantor under our senior credit facility; and
- the subsidiary has consolidated tangible assets that constitute 10% or more of our consolidated tangible assets.

Subject to specified exceptions, any subsidiary guarantor will be restricted from entering into certain transactions including the disposition of all or substantially all of its assets or merging with or into another entity. Subsidiary guarantors may be released from a guarantee under circumstances specified in the indenture. As of September 30, 2009, none of our subsidiaries were obligated as guarantors of our senior notes.

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The indenture provides that at any time, which may be more than once, before February 15, 2011, we may redeem up to 35% of the outstanding notes with proceeds from one or more equity offerings at a redemption price of 112% of the principal amount of the notes redeemed, plus accrued and unpaid interest, as long as:

- at least 65% of the aggregate principal amount of the notes issued on February 8, 2008, remains outstanding after each such redemption; and
- the redemption occurs within 180 days after the closing of the equity offering.

The notes also provide that we may, at our option, redeem all or part of the notes at any time prior to February 15, 2013, at the make-whole price set forth in the indenture, and on or after February 15, 2013, at fixed redemption prices, plus accrued and unpaid interest, if any, to the date of redemption. Further, the indenture provides that upon a change of control, we must give holders of the notes the opportunity to put their notes to us for repurchase at a repurchase price of 101% of the principal amount, plus accrued and unpaid interest.

7. ASSET RETIREMENT OBLIGATIONS

Changes in carrying amounts of the asset retirement obligations associated with our working interest in oil and gas properties are as follows:

	Amount (in thousands)
Balance at December 31, 2008	$ 23,086
Obligations assumed with development activities and acquisitions	789
Accretion expense	1,009
Obligations discharged with disposal of properties and asset retirements	(26)
Revisions in estimated cash flows	(510)
Balance at September 30, 2009	24,348
Less current portion	(50)
Long-term portion	$ 24,298

8. COMMITMENTS AND CONTINGENCIES

Drilling and Development Agreements. In connection with the acquisition of oil and gas properties in October 2007 from an unaffiliated party, we are obligated to drill 100 wells on the acquired acreage in Pennsylvania by January 2016. We will retain a majority interest in each well drilled. For each well we fail to drill, we are obligated to pay to the seller liquidated damages of $25,000 per undrilled well for a total contingent obligation of $2.5 million or reassign to the seller the interest acquired in the number of undrilled well locations. As of September 30, 2009, we have drilled 28 wells pursuant to this agreement.

In September 2008, we entered into a pipeline and processing plants expansion agreement with an unrelated party, who is currently the purchaser of the majority of our Wattenberg Field natural gas production. Pursuant to the agreement, we agreed to make a capital investment of $60 million, for our own benefit, over a three-year period commencing on January 1, 2009, to develop or facilitate production in our Wattenberg Field dedicated to this purchaser and, if the purchaser failed to diligently proceed with the pipeline and processing plants, we would be relieved of our obligations under the agreement. In March 2009, we received from the unrelated party a notice waiving our commitment and stating that the pipeline and processing plant expansions were either on hold or had been delayed. The waiver relieves us of the $60 million capital investment obligation.

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. As of September 30, 2009, based on a review of our drilling plans and volume projections, we may not meet a performance period volume requirement for one of our firm transportation agreements. We are currently working with the third party to renegotiate the terms and timing of our volume requirements under this agreement. We have not recorded a liability for this item as of September 30, 2009.

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The following table sets forth gross volume information related to our long-term firm sales, processing and transportation agreements for pipeline capacity. These agreements require a demand charge whether volumes are delivered or not. We record in our financial statements only our share of costs 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.

	Volume (MMbtu)						
Area	Fourth Quarter 2009	2010	2011	2012	2013	2014 Through Expiration	Expiration Date
Appalachian Basin (1)	158,620	803,900	591,300	4,106,120	10,993,800	94,965,560	August 2022
Grand Valley	-	21,598,788	31,874,191	32,583,997	32,930,072	113,463,080	May 2021
NECO	460,000	1,825,000	-	-	-	-	December 2010
NECO	460,000	1,825,000	1,825,000	1,825,000	1,825,000	5,475,000	December 2016

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(1) Contract is a precedent agreement and becomes effective when the planned pipeline is placed in service, estimated at this time to be 2012. Contract is null and void if pipeline is not completed. In August 2009, we issued a letter of credit related to this agreement, see Note 6.

Drilling Rig Contract. In order to secure the services for drilling rigs, we have a commitment for the use of a drilling rig with a drilling contractor set to expire July 2010. In January 2009, based on our decision to temporarily cease drilling operations in the Piceance Basin, we demobilized this drilling rig. The commitment calls for a minimum of $4,000 daily for a specified amount of time if we cease to use the drilling rig and a maximum of $20,040 daily for a specified amount of time for daily use of the drilling rig. As of September 30, 2009, we have an outstanding minimum commitment for $1.1 million and an outstanding maximum commitment for $5.5 million.

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.

Colorado Royalty. On May 29, 2007, Glen Droegemueller, individually and as representative plaintiff on behalf of all others similarly situated, filed a class action complaint against the Company in the District Court, Weld County, Colorado alleging that we underpaid royalties on natural gas produced from wells operated by us in parts of the State of Colorado (the "Droegemueller Action"). The plaintiff sought declaratory relief and to recover an unspecified amount of compensation for underpayment of royalties paid by us pursuant to leases. We removed the case to Federal Court on June 28, 2007. On October 10, 2008, the court preliminarily approved a settlement agreement between the plaintiffs and the Company, on behalf of itself and the partnerships for which the Company is the managing general partner. Based on the settlement terms, the settlement amount payable by the Company is $5.8 million. Such moneys, in addition to moneys related to the settlement on behalf of the partnerships, were deposited in an escrow account on November 3, 2008. The final settlement was approved by the court on April 7, 2009. Settlement distribution checks were mailed in July 2009.

West Virginia Royalty. On January 21, 2009, a lawsuit was filed in West Virginia state court in Barbour County, styled Beymer v. Petroleum Development Corporation and Riley National Gas Company, CA No. 09-C-3 ("Beymer lawsuit"), alleging a class action on behalf of lessors for failure to properly pay royalties. The allegations state that the Company improperly deducted certain charges and costs before applying the royalty percentage. Punitive damages are requested in addition to breach of contract, tort, and fraud allegations. On January 27, 2009, another suit was filed in West Virginia state court in Harrison County, styled Gobel v. Petroleum Development Corporation, CA No. 09-C-40, alleging a class action with allegations similar to those alleged in the Beymer lawsuit. Both cases have been removed to federal court in the Northern District of West Virginia. Mediation has been ordered on or before November 30, 2009.

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Colorado Stormwater Permit. On December 8, 2008, we received a Notice of Violation/Cease and Desist Order (the "Notice") from the Colorado Department of Public Health and Environment, 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 oil and gas companies operating in the Piceance region of Colorado. Operating expenses, including this fine, if any, are allocated among the eight 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. No civil penalties have been imposed or requested at this time. Given the preliminary stage of this proceeding and 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.

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.

Partnership Repurchase Provision. Substantially all of our drilling programs contain a repurchase provision where investing partners may request that we purchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that we are obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions from production), if repurchase is requested by investors, subject to our financial ability to do so. As of September 30, 2009, the maximum annual repurchase obligation, based upon the minimum price described above, was approximately $11 million. We believe we have adequate liquidity to meet this obligation. For the nine months ended September 30, 2009, we paid $1.6 million under this provision for the purchase of partnership units.

Employment Agreements with Executive Officers. We have employment agreements with our Chief Executive Officer, Chief Financial Officer, Chief Accounting 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 his highest annual base salary during the previous two years of employment immediately preceding the termination date and his highest annual bonus received during the same two year period. For this purpose a "change of control" corresponds to the definition of "change of control" under Section 409A of the Internal Revenue Code of 1986 (IRC) and the supporting treasury regulations. The executive officer is also entitled to (i) vesting of any unvested equity compensation (excluding all long-term incentive 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 any bonus (only for periods completed and accrued, but not paid), incentive, deferred, retirement or other compensation, and to provide any other benefits, which have been earned or become payable as of the termination date but which have not yet been paid or provided.

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, bonus and incremental retirement payment prorated for the portion of the year that the executive officer is employed by the Company, 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 be payable in a lump sum and shall be equal to the compensation and other benefits that would otherwise have been paid for a six-month period following the termination date plus a pro-rated portion of the performance bonus.

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Derivative Contracts. We would be exposed to oil and natural gas price fluctuations on underlying purchase and sale contracts should the counterparties to our derivative instruments or the counterparties to our gas marketing contracts not perform. Nonperformance is not anticipated. We have had no counterparty default losses.

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.

9. EQUITY

Sale of Equity Securities

In August 2009, we sold 4,312,500 shares of our common stock in an underwritten public offering at a price of $12.00 per share. We used the net proceeds of $48.5 million to pay down our credit facility and for general corporate purposes. The offering was made pursuant to an effective shelf registration statement on Form S-3 filed with the SEC on November 26, 2008, and declared effective on January 30, 2009.

Stock Based Compensation

We maintain equity compensation plans for officers, certain key employees and non-employee directors. In accordance with the plans, awards may be issued in the form of stock options, stock appreciation rights, restricted stock, performance shares and performance units. Through the date of this report, we have not issued any stock appreciation rights or performance units.

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 September 30,		Nine Months Ended September 30,	
	2009	2008	2009 (1)	2008 (2)
	(in thousands)			
Total stock-based compensation expense	$ 918	$ 2,293	$ 4,901	$ 5,239
Income tax benefit	(350)	(875)	(1,870)	(1,999)
Net income impact	$ 568	$ 1,418	$ 3,031	$ 3,240

(1) Includes $1.7 million related to a separation agreement with a former executive vice president and an agreement with our former chief executive officer.

(2) Includes $2.2 million related to a separation agreement with our former president and an agreement with our former chief executive officer.

Stock Option Awards. We have granted stock options pursuant to various stock compensation plans. Outstanding options expire ten years from the date of grant and become exercisable ratably over a four year period. There were no stock options awarded for the nine months ended September 30, 2009. For the nine months ended September 30, 2009, pursuant to a separation agreement with a former executive vice president, we accelerated the vesting schedule for 1,094 options, all of which vested pursuant to the original terms of the awards. For the nine months ended

September 30, 2008, pursuant to a separation agreement with our former president and an agreement with our former chief executive officer, we modified options to purchase 9,905 shares by accelerating the vesting schedule, none of which would have vested pursuant to the original terms of the award. The incremental change in fair value per share of the modified awards was immaterial.

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The following table provides a summary of our stock option award activity for the nine months ended September 30, 2009.

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (in years)
Outstanding at December 31, 2008	18,351	$ 41.68	6.8
Forfeited	(8,045)	41.39	
Outstanding at September 30, 2009	10,306	41.90	6.3
Vested and expected to vest at September 30, 2009	10,306	41.90	6.3
Exercisable at September 30, 2009	7,758	41.19	6.0

The options outstanding and exercisable at September 30, 2009, and December 31, 2008, had no intrinsic value as the exercise price of the options exceeded the closing market price of our common stock at the respective dates. Total compensation cost related to stock options granted and not yet recognized in our condensed consolidated statement of operations as of September 30, 2009, was immaterial.

Restricted Stock Awards

Time-Based Awards. The fair value of the time-based awards is amortized ratably over the requisite service period, generally over four years, and five years in connection with succession related grants to executive officers in March 2008. Time-based awards for non-employee directors generally vest on July 1st of the year following the date of the grant.

The following table sets forth the changes in non-vested time-based awards for the nine months ended September 30, 2009.

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2008	218,060	$ 52.59
Granted	136,229	12.99
Vested	(90,181)	53.56
Forfeited	(18,248)	36.36
Non-vested at September 30, 2009	245,860	31.50

The total compensation cost related to non-vested time-based awards expected to vest and not yet recognized in our condensed consolidated statement of operations as of September 30, 2009, was $6.1 million. This cost is expected to be recognized over a weighted average period of 2.5 years. For the nine months ended September 30, 2009, pursuant to a separation agreement with a former executive vice president, we accelerated time-based awards to vest 30,875 shares, all of which would have vested pursuant to the original terms of the award. For the nine months ended September 30, 2008, pursuant to a separation agreement with our former president and an agreement with our former chief executive officer, we modified time-based awards to vest 24,024 shares by accelerating the vesting schedule, none of which would have vested pursuant to the original terms of the award, resulting in an increase in the original fair value of $0.4 million.

Market-Based Awards. The fair value of the market-based awards is amortized ratably over the requisite service period, primarily over three years for market-based awards. The market-based shares vest only upon the achievement of certain per share price thresholds and continuous employment during the vesting period. All compensation cost related to the market-based awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved. In June 2008, pursuant to a separation agreement with a former executive vice president, 21,263 shares were forfeited. For the nine months ended September 30, 2008, pursuant to a separation agreement with our former president and an agreement with our former chief executive officer, we modified market-based awards to vest 38,979 shares by accelerating the vesting schedule, none of which would have vested pursuant to the original terms of the award. The incremental change in fair value per share of the modified awards was immaterial.

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The weighted average grant date fair value per market-based share, including shares modified in 2008 pursuant to agreements with our former president and our former chief executive officer, was computed using the Monte Carlo pricing model using the following weighted average assumptions:

	Nine Months Ended September 30, 2009	2008
Expected term of award	3 years	3 years
Risk-free interest rate	2.0%	2.4%
Volatility	59.0%	47.0%
Weighted average grant date fair value per share	$6.47	$42.44

For 2009, expected volatility was based on a blend of our historical and implied volatility and, for 2008, was based on our historical volatility. The expected lives of the awards were based on the requisite service period. The risk-free interest rate was based on the U.S. Treasury yields in effect at the time of grant or modification and extrapolated to approximate the life of the award. We do not expect to pay dividends, nor do we expect to declare dividends in the foreseeable future.

The following table sets forth the changes in non-vested market-based awards for the nine months ended September 30, 2009.

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2008	72,683	$ 41.62
Granted	28,130	6.47
Forfeited	(21,263)	29.15
Non-vested at September 30, 2009	79,550	32.52

The total compensation cost related to non-vested market-based awards expected to vest and not yet recognized in our condensed consolidated statement of operations as of September 30, 2009, was $0.5 million. This cost is expected to be recognized over a weighted average period of 1.5 years.

10. INCOME TAXES

We evaluate our estimated annual effective income tax rate on a quarterly basis based on current and forecasted business results and enacted tax laws. The estimated annual effective tax rate is adjusted quarterly based upon actual results and updated operating forecasts. Consequently, our effective tax rate may vary quarterly based upon the mix and timing of our actual earnings compared to annual projections. Tax expenses or tax benefits unrelated to current year ordinary income or loss are recognized entirely in the period identified as discrete items of tax. 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.

The loss we realized for the nine months ended September 30, 2009, exceeds our projected loss for the year. As a result, we calculated our nine-month tax benefit by multiplying the current period loss by the statutory tax rate and then adding other statutory tax benefits such as percentage depletion. This required tax calculation limited the tax benefit realized during the nine months ended September 30, 2009, by $0.8 million. No similar limitation calculation was required for the same 2008 period. The tax rates for the three and nine months ended September 30, 2009, were impacted by the recording of $0.4 million and $0.1 million of net discrete tax expense in the respective periods. The rates in the same 2008 periods were primarily impacted by a $2.7 million discrete benefit related to state refund claims based upon implemented 2008 state tax planning strategies. The net discrete expense for the three months ended September 30, 2009, was primarily due to the recognition of previously "uncertain tax positions" due to the expiration of the statute of limitations for the 2005 federal tax return and the adjustment of our deferred tax rate due to state tax law changes and state apportionment changes.

As of September 30, 2009, we had a gross liability for uncertain tax positions of $0.8 million, of which $0.1 million was recorded in the three months ended September 30, 2009. If recognized, all of this liability would affect our effective tax rate. This liability is reflected in federal and state income taxes payable in our accompanying condensed consolidated balance sheet. The IRS has completed its examination of our 2005 and 2006 tax years. As a result, the liability for uncertain tax positions decreased during the nine months ended September 30, 2009. The settlement for these years did not have a material impact on our income tax benefit for the nine months ended September 30, 2009.

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As of the date of this filing, we have received all of the applicable $2.7 million in refunds from West Virginia and Colorado that were claimed for prior tax years via amended returns filed in 2008 to implement state tax strategies.

11. DISCONTINUED OPERATIONS

We offered our last sponsored drilling partnership in October 2007. In January 2008, we first announced that we had no plans to sponsor a new drilling partnership in 2008 and this decision was upheld again in 2009. As of June 30, 2009, all remaining contractual drilling and completion obligations were completed for all partnerships. The unused advance for future drilling contracts of $1.7 million as of December 31, 2008, was fully utilized as of June 30, 2009, with $0.2 million recognized in revenue and $0.3 million refunded to the partnerships.

As all partnership well drilling and completion activities have been completed and we currently do not have any plans in the foreseeable future to sponsor a drilling partnership, we believe it was appropriate to treat our oil and gas well drilling activities as discontinued operation for all periods presented. Prior period financial statements have been restated to present the activities of our oil and gas well drilling operations as discontinued operations.

The tables below sets forth balance sheet and statement of operations data related to discontinued operations.

Balance Sheet Data: (in thousands)	December 31, 2008
Current assets:	
Cash and cash equivalents	$ 1,675
Current liabilities:	
Other accrued expenses	1,675

Statements of Operations Data: (in thousands)

	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Revenues:			
Oil and gas well drilling	$ 1,232	$ 193	$ 7,202
Cost and expenses:			
Cost of oil and gas well drilling (1)	92	-	102
Income from discontinued operations before income taxes	1,140	193	7,100
Provision for income taxes	399	80	2,575
Income from discontinued operations, net of tax	$ 741	$ 113	$ 4,525

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(1) For the three months ended September 30, 2008, and the nine months ended September 30, 2009 and 2008, $0.4 million, $0.6 million and $1 million, respectively, previously included in cost of oil and gas well drilling have been reclassified to oil and gas production and well operations cost.

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12. EARNINGS PER SHARE

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in thousands, except per share data)			
Weighted average common shares outstanding - basic	16,962	14,767	15,530	14,749
Dilutive effect of share-based compensation:				
Unamortized portion of restricted stock	-	27	-	64
Stock options	-	35	-	39
Non employee director deferred compensation	-	6	-	6
Weighted average common and common share equivalent shares outstanding - diluted	16,962	14,835	15,530	14,858
Income (loss) from continuing operations	$(24,476)	$126,155	$(63,371)	$67,731
Income from discontinued operations, net of tax	-	741	113	4,525
Net income (loss)	$(24,476)	$126,896	$(63,258)	$72,256
Earnings (loss) per share - basic				
Continuing operations	$(1.44)	$8.54	$(4.08)	$4.59
Discontinued operations	-	0.05	0.01	0.31
Net income (loss)	$(1.44)	$8.59	$(4.07)	$4.90
Earnings (loss) per share - diluted				
Continuing operations	$(1.44)	$8.50	$(4.08)	$4.56
Discontinued operations	-	0.05	0.01	0.30
Net income (loss)	$(1.44)	$8.55	$(4.07)	$4.86

For the three months and nine months ended September 30, 2009, the weighted average common shares outstanding for both basic and diluted were the same because the effect of dilutive securities were anti-dilutive due to our net loss for each of 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 September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in thousands)			
Weighted average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:				
Unamortized portion of restricted stock	236	133	283	74
Stock options	10	-	10	-
Non employee director deferred compensation	8	-	8	-
Total anti-dilutive common share equivalents	254	133	301	74

13. BUSINESS SEGMENTS

We separate our operating activities into three segments: oil and gas sales, natural gas marketing and well operations and pipeline income. All material inter-company accounts and transactions between segments have been eliminated.

Oil and Gas Sales. Our oil and gas sales segment represents revenues and expenses from the production and sale of oil and natural gas. Segment revenue includes oil and gas sales and oil and gas price risk management, net. Segment income (loss) consists of segment revenue less its allocated share of oil and gas production and well operations cost, exploration expense, direct general and administrative expense and DD&A expense. Segment DD&A expense was $30.7 million and $96.4 million for the three and nine months ended September 30, 2009, and $27.6 million and $68.7 million for the three and nine months ended September 30, 2008, respectively.

Natural Gas Marketing. Our natural gas marketing segment is composed of our wholly owned subsidiary Riley Natural Gas, through which we purchase, aggregate and resell natural gas produced by us and others. Segment income (loss) primarily represents sales from natural gas marketing and direct interest income less costs of natural gas marketing and direct general and administrative expense.

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Well Operations and Pipeline Income. We charge our affiliated partnerships and other third parties competitive industry rates for well operations and natural gas gathering. Segment revenue includes monthly operating and gas gathering fees we charge for each well which we operate that is owned by others, including our affiliated partnerships. Segment income consists of well operations and pipeline income revenues less its allocated share of oil and gas production and well operations cost and direct DD&A expense.

Unallocated amounts. Unallocated income includes unallocated other revenue less corporate general administrative expense, direct DD&A expense, direct interest income and interest expense.

The following information sets forth our segment information, reclassified to exclude discontinued operations.

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(in thousands)			
Revenues:				
Oil and gas sales	$30,193	$268,824	$111,892	$290,911
Natural gas marketing	12,444	53,372	47,200	107,638
Well operations and pipeline income	2,538	3,356	8,271	8,146
Unallocated	25	20	78	57
Total	$45,200	$325,572	$167,441	$406,752
Segment income (loss) before income taxes:				
Oil and gas sales	$(20,446)	$209,682	$(40,208)	$145,971
Natural gas marketing	889	(918)	1,781	1,286
Well operations and pipeline income	100	1,659	1,490	2,980
Unallocated amounts	(19,620)	(16,434)	(65,667)	(47,859)
Total	$(39,077)	$193,989	$(102,604)	$102,378

	September 30, 2009	December 31, 2008
	(in thousands)	
Segment assets:		
Oil and gas sales	$1,110,941	$ 1,247,687
Natural gas marketing	17,611	50,117
Well operations and pipeline income	42,423	50,052
Unallocated amounts	53,179	53,173
Assets related to discontinued oil and gas well drilling operations (1)	-	1,675
Total	$1,224,154	$ 1,402,704

(1) The December 31, 2008, amount excludes $0.4 million previously included in oil and gas well drilling operations, which has been reclassified to unallocated amounts. See Note 11, Discontinued Operations, for additional amounts reclassified.

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14. SUBSEQUENT EVENTS

We have evaluated our activities subsequent to September 30, 2009, through November 5, 2009 (the date the financial statements were issued), and have concluded that, except for those described below, no other subsequent events have occurred that would require recognition in the financial statements or disclosure in the notes to the financial statements.

Joint Venture Formation

On October 29, 2009, we entered into a joint venture agreement with an unrelated third party to develop our Marcellus Shale acreage and shallow Devonian assets in the Appalachian Basin.

Under the terms of the agreement, we contributed acreage, producing properties and related reserves, gathering assets and equipment with an estimated fair value of $158.5 million for which we received a return of capital cash payment of $45 million and an approximate 65% interest at closing, with an option to receive an additional cash withdrawal of $11.5 million by the end of 2010. Our joint venture partner contributed $55 million at closing and will fund up to an additional $58.5 million as needed for drilling and operations until it earns a 50% interest in the joint venture. We anticipate the partner's funding obligation to be reached in 2011. After the 50% interest is earned, all future costs and capital investments will be shared equally.

The assets we contributed consist of (i) approximately 115,000 net acres in the Appalachian Basin, of which approximately 55,000 acres are in the Marcellus fairway; (ii) 12 MMcf per day of existing production from the shallow Devonian sands; and (iii) total proved reserves of 113 Bcfe, also from the shallow Devonian sands. None of our affiliated partnerships' wells were included in the joint venture.

During the 2009 fourth quarter, we expect to pay and expense approximately $8 million in fees and expenses related to this transaction.

Seventh Amendment to Credit Facility

On October 29, 2009, we entered into the Seventh Amendment (the "Seventh Amendment") to our credit facility. Pursuant to the Seventh Amendment, our credit facility was amended to, among other things, permit the contribution of certain oil and gas properties in the Appalachian Basin, to the newly-formed joint venture (described above), facilitate other aspects of the joint venture and permit us to make additional investments in the joint venture so long as certain conditions are satisfied. Until our investor partner earns a 50% interest in the joint venture, such additional investments are limited to $40 million.

The Seventh Amendment also provided for a reduction in our borrowing base under the credit facility from $350 million to $305 million upon the execution of the joint venture agreement and the contribution of our oil and gas properties in the Appalachian Basin to the joint venture. This borrowing base reduction is independent of our November redetermination, which is pending completion. We currently expect the November redetermination to be completed by mid-November and that our lenders will reaffirm our borrowing base at $305 million.

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

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This periodic report contains “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 (“Securities Act”) and Section 21E of the Securities Exchange Act of 1934 (“Exchange Act”) regarding our business, financial condition, results of operations and prospects. All statements other than statements of historical facts included in and incorporated by reference into this report are forward-looking statements. Words such as expects, anticipates, intends, plans, believes, seeks, estimates and similar expressions or variations of such words are intended to identify forward-looking statements herein, which include statements of estimated oil and natural gas production and reserves, drilling plans, future cash flows, anticipated liquidity, anticipated capital expenditures and our management’s strategies, plans and objectives. However, these are not the exclusive means of identifying forward-looking statements herein. Although forward-looking statements contained in this report reflect our good faith judgment, such statements can only be based on facts and factors currently known to us. Consequently, forward-looking statements are inherently subject to risks and uncertainties, including risks and uncertainties incidental to the exploration for, and the acquisition, development, production and marketing of, natural gas and oil, and actual outcomes may differ materially from the results and outcomes discussed in the forward-looking statements. Important factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- changes in production volumes, worldwide demand, and commodity prices for oil and natural gas;
- the timing and extent of our success in discovering, acquiring, developing and producing natural gas and oil reserves;
- our ability to acquire leases, drilling rigs, supplies and services at reasonable prices;
- the availability and cost of capital to us;
- 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;
- the effect of natural gas and oil derivatives 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, 2008, filed with the Securities and Exchange Commission (“SEC”) on February 27, 2009 (“2008 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. 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.

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Results of Operations

Summary of Operations

The following table sets forth selected information regarding our results of operations, including production volumes, oil and gas sales, average sales price received, average sales price including realized derivative gains and losses, average lifting cost, other operating income and expenses for the 2009 and 2008 third quarter and nine-month periods.

	Three Months Ended September 30, 2009	2008	Change	Nine Months 2009
Production (1)				
Oil (Bbls)	312,547	322,133	-3.0 %	999,296
Natural gas (Mcf)	9,058,842	8,239,005	10.0 %	27,301,974
Natural gas equivalent (Mcfe) (2)	10,934,124	10,171,803	7.5 %	33,297,750
Oil and Gas Sales (in thousands)				
Oil sales	$19,045	$34,804	-45.3 %	$50,917
Gas sales	24,961	64,448	-61.3 %	76,970
Provision for underpayment of gas sales	-	170	-100.0%	(2,581)
Total oil and gas sales	$44,006	$99,422	-55.7 %	$125,306
Realized Gain (Loss) on Derivatives, net (in thousands)				
Oil derivatives	$3,506	$(4,157)	184.3 %	$15,618
Natural gas derivatives	18,318	1,405	*	67,127
Total realized gain (loss) on derivatives, net	$21,824	$(2,752)	*	$82,745
Average Sales Price (excluding realized gains (losses) on derivatives)				
Oil (per Bbl)	$60.93	$108.04	-43.6 %	$50.95
Natural gas (per Mcf)	$2.76	$7.82	-64.7 %	$2.82
Natural gas equivalent (per Mcfe)	$4.02	$9.76	-58.8 %	$3.84
Average Sales Price (including realized gains (losses) on derivatives)				
Oil (per Bbl)	$72.15	$95.14	-24.2 %	$66.58
Natural gas (per Mcf)	$4.78	$7.99	-40.2 %	$5.28
Natural gas equivalent (per Mcfe)	$6.02	$9.49	-36.6 %	$6.33
Average Lifting Cost per Mcfe (3)	$0.79	$0.94	-16.0 %	$0.79
Natural gas marketing (in thousands) (4)	$888	$(1,000)	188.8 %	$1,774
Costs and Expenses (in thousands)				
Exploration expense	$6,586	$10,212	-35.5 %	$15,362
General and administrative expense	$9,627	$8,106	18.8 %	$36,505
Depreciation, depletion and amortization ("DD&A")	$32,277	$28,645	12.7 %	$100,465
Interest Expense (in thousands)	$9,221	$7,817	18.0 %	$27,024

*Represents percentages in excess of 250%
Amounts may not calculate due to rounding

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

(4) Represents sales from natural gas marketing less costs of natural gas marketing.

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Even with natural gas prices rebounding somewhat from earlier in 2009, through September 2009, we continued to experience the depressed natural gas prices from the dramatic declines in late July 2008 through the end of 2008. As our production increased to 33.3 Bcfe for the 2009 nine-month period compared to 27.4 Bcfe for the same 2008 period, an increase of 21.3%, our average sales price declined 60.9% or $5.98 per Mcfe. While the significant changes in commodity prices have impacted our results of operations, we believe that we were successful in managing our operations to reduce the negative impacts through our derivative positions. Our realized derivative gains for the 2009 nine-month period of $82.7 million added an average of $2.49 per Mcfe produced during the 2009 nine-month period. At September 30, 2009, we estimate the net fair value of our open derivative positions, excluding the derivative positions attributed to our affiliated partnerships, to be a net asset of $21.9 million.

Depressed commodity prices for the 2009 nine-month period, as compared to the higher prices in the same 2008 period, were the primary contributors to the $38.7 million decrease in revenues from oil and gas price risk management. Of this change, $142 million was related to an increase in unrealized derivative losses, partially offset by an increase in realized derivative gains of $103.3 million. Unrealized gains and losses are non-cash items and these non-cash charges to our condensed consolidated statement of operations will continue to fluctuate with the fluctuation in commodity prices until the positions mature or are closed, at which time they will become realized or cash items. While the required accounting treatment for derivatives that are not designated as hedges may result in significant swings in operating results over the life of the derivatives, the combination of the settled derivative contracts and the revenue received from the oil and gas sales at delivery are expected to result in a more predictable cash flow stream than would the sales contracts without the associated derivatives.

The table below, which demonstrates the volatility in the markets' projected commodity prices, sets forth the average New York Mercantile Exchange ("NYMEX") and Colorado Interstate Gas ("CIG") prices for the next 24 months (forward curve) from the selected dates.

Commodity	Index	June 30, 2008	September 30, 2008	March 31, 2009	September 30, 2009	October 31, 2009
Natural gas:	NYMEX	$ 12.52	$ 8.21	$ 5.44	$ 6.25	$ 6.00
	CIG	8.86	5.46	4.15	5.64	5.49
Oil:	NYMEX	140.15	103.63	59.35	74.64	81.26

Oil and Gas Sales

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2009	2008	Percentage Change	2009	2008	Percentage Change
Production						
Oil (Bbls)						
Rocky Mountain Region	308,512	318,722	-3.2 %	989,780	826,303	19.8 %
Appalachian Basin	3,338	2,467	35.3 %	7,241	5,105	41.8 %
Michigan Basin	697	944	-26.2 %	2,275	2,775	-18.0 %
Total	312,547	322,133	-3.0 %	999,296	834,183	19.8 %
Natural gas (Mcf)						
Rocky Mountain Region	7,700,028	6,916,539	11.3 %	23,288,344	18,389,853	26.6 %
Appalachian Basin	968,494	931,150	4.0 %	2,971,374	2,895,499	2.6 %
Michigan Basin	390,320	391,316	-0.3 %	1,042,256	1,157,659	-10.0 %

Total	9,058,842	8,239,005	10.0	%	27,301,974	22,443,011	21.7	%
Natural gas equivalent (Mcfe)								
Rocky Mountain Region	9,551,100	8,828,871	8.2	%	29,227,024	23,347,671	25.2	%
Appalachian Basin	988,522	945,952	4.5	%	3,014,820	2,926,129	3.0	%
Michigan Basin	394,502	396,980	-0.6	%	1,055,906	1,174,309	-10.1	%
Total	10,934,124	10,171,803	7.5	%	33,297,750	27,448,109	21.3	%

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	Three Months Ended September 30,			Nine Months Ended September 30,		
	2009	2008	Percentage Change	2009	2008	Percentage Change
Average Sales Price (excluding derivative gains/losses)						
Oil (per Bbl)						
Rocky Mountain Region	$60.96	$108.00	-43.6 %	$50.96	$104.45	-51.2 %
Appalachian Basin	55.96	108.68	-48.5 %	50.14	105.93	-52.7 %
Michigan Basin	63.83	118.92	-46.3 %	50.76	112.38	-54.8 %
Weighted average price	60.93	108.04	-43.6 %	50.95	104.48	-51.2 %
Natural gas (per Mcf)						
Rocky Mountain Region	2.70	7.37	-63.4 %	2.65	7.78	-65.9 %
Appalachian Basin	3.18	10.40	-69.4 %	3.96	9.99	-60.4 %
Michigan Basin	2.88	9.67	-70.2 %	3.39	9.24	-63.3 %
Weighted average price	2.76	7.82	-64.7 %	2.82	8.13	-65.3 %
Natural gas equivalent (per Mcfe)						
Rocky Mountain Region	4.14	9.68	-57.2 %	3.84	9.82	-60.9 %
Appalachian Basin	3.24	10.43	-68.9 %	4.00	10.02	-60.1 %
Michigan Basin	2.95	9.84	-70.0 %	3.45	9.38	-63.2 %
Weighted average price	4.02	9.76	-58.8 %	3.84	9.82	-60.9 %

Despite increases in production for both the 2009 third quarter and nine-month periods, oil and gas sales revenue for these periods, excluding the provision for underpayment of gas sales, decreased $55.2 million and $141.8 million, respectively, compared to the same 2008 periods. Approximately $164.2 million of the decrease in oil and gas sales revenue for the 2009 nine-month period was due to pricing, offset in part by increased production, which contributed $22.4 million. The decrease in oil and gas sales revenue was partially offset by increased realized derivative gains for the 2009 third quarter and nine-month periods of $24.6 million and $103.3 million, respectively. See Oil and Gas Price Risk Management, Net discussion below.

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

The price we receive for a large portion of the natural gas produced in the Rocky Mountain Region is based on a market basket of prices, which generally includes gas sold at CIG prices as well as gas sold at Mid-Continent or other nearby region 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 NYMEX based. This negative differential has narrowed in recent months and has even more recently become a positive differential, which contradicts historical variances. For example, CIG was $1.79 lower than NYMEX in January 2009, narrowed to close at only $0.37 lower in October 2009 and has more recently closed at $0.02 higher than NYMEX for November 2009.

The table below identifies the market for our oil and natural gas sales based on production for the 2009 third quarter. The market is the index that most closely relates to the price under which our oil and natural gas is sold.

Energy Market Exposure
For the Three Months Ended September 30, 2009

Area	Market	Commodity	Percent of Production
Piceance/Wattenberg	CIG	Gas	37%
Colorado/North Dakota	NYMEX	Oil	18%
Piceance	San Juan Basin/Southern California	Gas	15%
NECO	Mid Continent (Panhandle Eastern)	Gas	13%
Appalachian	NYMEX	Gas	9%
Michigan	Mich-Con/NYMEX	Gas	4%
Wattenberg	Colorado Liquids	Gas	3%
Other	Other	Gas/Oil	1%
			100%

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in thousands)			
Lifting cost	$8,669	$9,523	$26,192	$29,276
Production taxes	2,645	7,112	7,380	18,695
Costs of well operations and pipeline income	1,855	1,232	5,195	3,973
Overhead and other production expenses	2,049	4,715	6,856	10,171
Total oil and gas production and well operations cost	$15,218	$22,582	$45,623	$62,115

Lifting Costs. Lifting costs per Mcfe decreased 16% and 26.2% to $0.79 per Mcfe for the 2009 third quarter and nine-month periods from $.94 per Mcfe and $1.07 per Mcfe for the same 2008 periods. The decrease per Mcfe is primarily due to lower third party costs from service providers as a result of pressure by purchasers to reduce costs as oil and gas prices deteriorated, our own cost reduction initiatives, and increased production, which allows us to spread the fixed portion of our production costs over the increased volume.

Production Taxes. Production taxes decreased $4.5 million or 62.8% to $2.6 million and $11.3 million or 60.5% to $7.4 million for the 2009 third quarter and nine-month periods, respectively. This decrease is primarily related to the 55.7% and 52.8% decrease in oil and gas sales for the 2009 third quarter and nine-month periods, respectively.

Cost of well operations and pipeline income. The increases in cost of well operations and pipeline income for the 2009 third quarter and nine-month periods over the same 2008 periods were the result of costs related to several pipeline maintenance projects.

Overhead and other production expenses. Overhead and other production expenses decreased in the 2009 third quarter and nine-month periods compared to the same 2008 periods due to the lower cost of field services, including vehicle, lower rates from third parties and less work and services being performed in this low commodity price environment.

Oil and Gas Price Risk Management, Net

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in thousands)			
Oil and gas price risk management gain (loss), net:				
Realized gains (losses):				
Oil	$3,506	$(4,157)	$15,618	$(9,857)
Natural gas	18,318	1,405	67,127	(10,660)
Total realized gains (losses), net	21,824	(2,752)	82,745	(20,517)
Unrealized gains (losses):				
	(21,139)	24,646	(62,548)	436

Reclassification of realized (gains) losses included in prior periods unrealized				
Unrealized gains (losses) for the period	(14,498)	147,508	(33,611)	45,375
Total unrealized gains (losses), net	(35,637)	172,154	(96,159)	45,811
Total oil and gas price risk management gain (loss), net	$(13,813)	$169,402	$(13,414)	$25,294

Realized gains recognized in the 2009 third quarter and nine-month periods are a result of lower oil and gas commodity prices at settlement compared to the respective strike price. During the 2009 third quarter, we recorded derivative unrealized losses on our CIG basis swaps of $7.1 million as the forward basis differential between NYMEX and CIG has continued to narrow along with unrealized losses of $6.5 million on our natural gas positions as the forward strip price has continued to rebound compared to the previous forward curve. Similarly, during the 2009 nine-month period, we recorded derivative unrealized losses of $28.9 million on our CIG basis swaps and $8.5 million on our oil swaps, offset in part by unrealized gains of $3.8 million on our natural gas positions as natural gas prices continued to decline compared to the previous forward curves.

Oil and gas price risk management, net includes realized gains and losses and unrealized changes in the fair value of derivative instruments related to our oil and natural gas production. Oil and gas 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 the accompanying condensed consolidated financial statements for additional details of our derivative financial instruments.

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Oil and Gas Sales Derivative Instruments. We use various derivative instruments to manage fluctuations in oil and natural gas prices. We have in place a series of collars, fixed-price swaps and basis swaps on a portion of our oil and natural gas production. Under our collar arrangements, if the applicable index rises above the ceiling price, we pay the counterparty; however, if the index drops below the floor price, the counterparty pays us. Under our swap arrangements, if the applicable index rises above the swap price, we pay the counterparty; however, if the index drops below the swap price, the counterparty pays us. Because we sell all our physical oil and natural gas at similar prices to the indexes inherent in our derivative instruments, we ultimately realize a price related to our collars of no less than the floor and no more than the ceiling and, for our swaps, we ultimately realize the fixed price related to our swaps.

The following table identifies our derivative positions (excluding the derivative positions allocated to our affiliated partnerships) related to oil and gas sales in effect as of September 30, 2009, on our production by area. Our production volumes for the 2009 third quarter were 312,547 Bbls of oil and 9.1 Bcf of natural gas.

	Collars				Fixed-Price Swaps		Basis Protection Swaps		
	Floors		Ceilings						Fair Value At September 30, 2009 (1)
Commodity/Operating Area/Index	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	(in thousands)
Natural Gas									
Rocky Mountain Region									
CIG									
4Q 2009	2,659,651	$ 6.70	2,659,651	$8.14	1,010,216	$9.20	-	$-	$10,932
2010	2,846,381	6.84	2,846,381	7.97	1,515,324	9.20	6,969,482	1.88	1,034
2011	1,019,893	&#16							