

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

FORM 10-Q

(Mark One)

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 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____

Commission file number: 001-14837

Quicksilver Resources Inc.

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of
incorporation or organization)

75-2756163

(I.R.S. Employer Identification No.)

777 West Rosedale, Fort Worth, Texas

(Address of principal executive offices)

76104

(Zip Code)

(817) 665-5000

(Registrant's telephone number, including area code)

None

(Former name, former address and former fiscal year, if changed since last report)

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 at least the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such file). 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. (Check one):

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company

(Do not check if a 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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Title of Class

Outstanding as of October 26, 2009

Common Stock, \$0.01 par value

169,133,374

QUICKSILVER RESOURCES INC.
INDEX TO FORM 10-Q
For the Period Ending September 30, 2009

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements (Unaudited)

Condensed Consolidated Statements of Income (Loss) and Comprehensive Income (Loss) 5

Condensed Consolidated Balance Sheets 6

Condensed Consolidated Statements of Stockholders' Equity 7

Condensed Consolidated Statements of Cash Flows 8

Notes to Condensed Consolidated Interim Financial Statements 9

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations 31

Item 3. Quantitative and Qualitative Disclosures About Market Risk 47

Item 4. Controls and Procedures 49

PART II. OTHER INFORMATION

Item 1. Legal Proceedings 49

Item 1A. Risk Factors 50

Item 2. Unregistered Sales of Equity Securities 57

Item 3. Defaults Upon Senior Securities 57

Item 4. Submission of Matters to a Vote of Security Holders 57

Item 5. Other Information 57

Item 6. Exhibits 58

Signature 59

Except as otherwise specified and unless the context otherwise requires, references to the "Company," "Quicksilver," "we," "us," and "our" refer to Quicksilver Resources Inc. and its subsidiaries.

DEFINITIONS

As used in this quarterly report unless the context otherwise requires:

- “**Bbl**” or “**Bbls**” means barrel or barrels
- “**Bbld**” means barrel or barrels per day
- “**Bcf**” means billion cubic feet
- “**Bcfd**” means billion cubic feet per day
- “**Bcfe**” means Bcf of natural gas equivalents, calculated as one Bbl of oil or NGLs equaling six Mcf of gas
- “**Btu**” means British Thermal Units, a measure of heating value
- “**Canada**” means the division of Quicksilver encompassing oil and natural gas properties located in Canada
- “**CBM**” means coalbed methane
- “**DD&A**” means Depletion, Depreciation and Accretion
- “**LIBOR**” means London Interbank Offered Rate
- “**MBbl**” or “**MBbls**” means thousand barrels
- “**MBbld**” means thousand barrels per day
- “**MMBbls**” means million barrels
- “**MMBtu**” means million Btu and is approximately equal to 1 Mcf of natural gas
- “**MMBtud**” means million Btu per day
- “**Mcf**” means thousand cubic feet
- “**Mcfe**” means Mcf natural gas equivalents calculated as one Bbl of oil or NGLs equaling six Mcf of gas
- “**MMcf**” means million cubic feet
- “**MMcfd**” means million cubic feet per day
- “**MMcfe**” means MMcf of natural gas equivalents, calculated as one Bbl of oil or NGLs equaling six Mcf of gas
- “**MMcfd**” means MMcf of natural gas equivalents per day, calculated as one Bbl of oil or NGLs equaling six Mcf of gas
- “**NGL**” or “**NGLs**” means natural gas liquids
- “**NYMEX**” means New York Mercantile Exchange
- “**Oil**” includes crude oil and condensate
- “**Tcf**” means trillion cubic feet
- “**Tcfe**” means Tcf of natural gas equivalents, calculated as one Bbl of oil or NGLs equaling six Mcf of gas

COMMONLY USED TERMS

Other commonly used terms and abbreviations include:

- “**ABR**” means adjusted base rate
- “**AOCl**” means accumulated other comprehensive income
- “**Alliance Acquisition**” means the August 8, 2008 purchase of leasehold, royalty and midstream assets in the Barnett Shale in northern Tarrant and southern Denton counties of Texas
- “**Alliance Leasehold**” means the natural gas leasehold and royalty interests acquired in the Alliance Acquisition and developed thereafter
- “**BBEP**” means BreitBurn Energy Partners L.P.
- “**BreitBurn Transaction**” means the November 1, 2007 conveyance of our Northeast Operations in exchange for aggregate proceeds of \$1.47 billion
- “**CMS Litigation**” means litigation against CMS Marketing Services and Trading Company concerning a gas supply contract under which we agreed to deliver 10 MMcfd at a floor price of \$2.49 per Mcf
- “**Eni**” means either or both Eni Petroleum US LLC and Eni US Operating Co. Inc., which are subsidiaries of Eni SpA
- “**Eni Production**” means production attributable to Eni pursuant to the Eni Transaction
- “**Eni Transaction**” means the June 19, 2009 conveyance of a 27.5% working interest in our Alliance Leasehold and royalty assets to Eni for aggregate proceeds of \$280 million
- “**Gas Purchase Commitment**” means the commitment pursuant to the Eni Transaction to purchase Eni’s share of Alliance Leasehold production at \$8.60 per MMBtu less actual costs incurred by us for gathering and processing Eni’s Alliance Production through December 2010, plus the costs that would be incurred to transport such production from the location where it is produced to Henry Hub
- “**FASB**” means the Financial Accounting Standards Board, which promulgates accounting standards in the U.S.

“**FASC**” means the *FASB Accounting Standards Codification*, which is the single source of authoritative U.S. GAAP not promulgated by the SEC

“**GAAP**” means accounting principles generally accepted in the United States

“**KGS**” means Quicksilver Gas Services LP, which is our publicly traded partnership that trades under the ticker symbol “KGS”

“**KGS Credit Agreement**” means the KGS senior secured revolving credit facility

“**Mercury**” means Mercury Exploration Company, which is owned by members of the Darden family

“**Michigan Sales Contract**” means the gas supply contract which expired in March 2009 under which we agreed to deliver 25 MMcfd at a floor price of \$2.49 per Mcf

“**Northeast Operations**” means the oil and gas properties and facilities in Michigan, Indiana and Kentucky which were conveyed to BBEP in November 2007

“**OCI**” means other comprehensive income

“**PCAOB**” means the Public Company Accounting Oversight Board

“**RSU**” means restricted stock unit

“**SEC**” means the United States Securities and Exchange Commission

“**Senior Secured Credit Facility**” means our U.S. senior secured revolving credit facility and our Canadian senior secured revolving credit facility

Forward-Looking Information

Certain statements contained in this report and other materials we file with the SEC, or in other written or oral statements made or to be made by us, other than statements of historical fact, are “forward-looking statements” as defined in the Private Securities Litigation Reform Act of 1995. Forward-looking statements give our current expectations or forecasts of future events. Words such as “may,” “assume,” “forecast,” “position,” “predict,” “strategy,” “expect,” “intend,” “plan,” “estimate,” “anticipate,” “believe,” “project,” “budget,” “potential,” or “continue,” and similar expressions are used to identify forward-looking statements. They can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed. Actual results may vary materially. You are cautioned not to place undue reliance on any forward-looking statements. You should also understand that it is not possible to predict or identify all such factors and should not consider the following list to be a complete statement of all potential risks and uncertainties. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

- changes in general economic conditions;
- fluctuations in natural gas, NGL and crude oil prices;
- failure or delays in achieving expected production from exploration and development projects;
- uncertainties inherent in estimates of natural gas, NGL and crude oil reserves and predicting natural gas, NGL and crude oil reservoir performance;
- effects of hedging natural gas, NGL and crude oil prices;
- fluctuations in the value of certain of our assets and liabilities;
- competitive conditions in our industry;
- actions taken or non-performance by third parties, including suppliers, contractors, operators, processors, transporters, customers and counterparties;
- changes in the availability and cost of capital;
- delays in obtaining oilfield equipment and increases in drilling and other service costs;
- operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- the effects of existing and future laws and governmental regulations;
- the effects of existing or future litigation; and
- certain factors discussed elsewhere in this quarterly report.

This list of factors is not exhaustive, and new factors may emerge or changes to these factors may occur that would impact our business. Additional information regarding these and other factors may be contained in our filings with the SEC, especially on Forms 10-K, 10-Q and 8-K. All such risk factors are difficult to predict, and are subject to material uncertainties that may affect actual results and may be beyond our control. The forward-looking statements included in this report are made only as of the date of this report, and we undertake no obligation to update any of these forward-looking statements to reflect subsequent events or circumstances except to the extent required by applicable law.

All forward-looking statements are expressly qualified in their entirety by the foregoing cautionary statements.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements (Unaudited)

QUICKSILVER RESOURCES INC.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)
In thousands, except for per share data — Unaudited

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Revenue				
Natural gas, NGL and crude oil	\$198,287	\$218,214	\$ 581,156	\$574,717
Sales of purchased natural gas	5,964	—	11,181	—
Other	2,406	18,048	6,293	17,063
Total revenue	<u>206,657</u>	<u>236,262</u>	<u>598,630</u>	<u>591,780</u>
Operating expenses				
Oil and gas production expense	29,064	33,068	92,938	98,443
Production and ad valorem taxes	6,630	4,944	18,437	10,684
Costs of purchased natural gas	2,964	—	11,546	—
Other operating costs	2,066	878	5,337	2,679
Depletion, depreciation and accretion	44,548	51,777	155,210	125,756
General and administrative	17,682	25,605	59,452	56,402
Total expenses	<u>102,954</u>	<u>116,272</u>	<u>342,920</u>	<u>293,964</u>
Impairment related to oil and gas properties	—	—	(967,126)	—
Operating income (loss)	103,703	119,990	(711,416)	297,816
Loss from earnings of BBEP — net	(43,685)	(89,814)	(24,669)	(93,864)
Other expense — net	(645)	(2,113)	(739)	(1,055)
Interest expense	(41,619)	(35,988)	(149,901)	(65,521)
Income (loss) before income taxes	17,754	(7,925)	(886,725)	137,376
Income tax (expense) benefit	(15,595)	5,295	301,125	(46,041)
Net income (loss)	2,159	(2,630)	(585,600)	91,335
Net income attributable to noncontrolling interests	(1,429)	(1,125)	(4,411)	(2,621)
Net income (loss) attributable to Quicksilver	\$ 730	\$ (3,755)	\$(590,011)	\$ 88,714
Other comprehensive income (loss) — net of income tax				
Reclassification adjustments related to settlements of derivative contracts	(63,196)	17,500	(160,183)	40,396
Net change in derivative fair value	1,030	308,096	113,333	46,847
Foreign currency translation adjustment	11,937	(11,044)	18,719	(17,858)
Comprehensive income (loss)	<u>\$ (49,499)</u>	<u>\$310,797</u>	<u>\$(618,142)</u>	<u>\$158,099</u>
Earnings (loss) per common share — basic	\$ —	\$ (0.02)	\$ (3.49)	\$ 0.55
Earnings (loss) per common share — diluted	\$ —	\$ (0.02)	\$ (3.49)	\$ 0.55
Basic weighted average shares outstanding	169,021	164,439	168,917	160,293
Diluted weighted average shares outstanding	170,657	164,439	168,917	171,099

The accompanying notes are an integral part of these condensed consolidated financial statements.

QUICKSILVER RESOURCES INC.
CONDENSED CONSOLIDATED BALANCE SHEETS
In thousands, except for share data — Unaudited

	September 30, 2009	December 31, 2008
ASSETS		
Current assets		
Cash and cash equivalents	\$ 1,568	\$ 2,848
Accounts receivable — net of allowance for doubtful accounts	75,225	143,315
Derivative assets at fair value	147,815	171,740
Other current assets	57,066	75,433
Total current assets	281,674	393,336
Investment in BBEP	114,733	150,503
Property, plant and equipment		
Oil and gas properties, full cost method (including unevaluated costs of \$497,301 and \$543,533, respectively)	2,261,930	3,142,608
Other property and equipment	731,870	655,107
Property, plant and equipment — net	2,993,800	3,797,715
Derivative assets at fair value	34,170	116,006
Deferred income taxes	143,450	—
Other assets	47,728	40,648
	<u>\$ 3,615,555</u>	<u>\$ 4,498,208</u>
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of long-term debt	\$ —	\$ 6,579
Accounts payable	143,989	282,636
Income taxes payable	5,583	40
Accrued liabilities	152,205	66,923
Derivative liabilities at fair value	871	9,928
Deferred income taxes	63,394	52,393
Total current liabilities	366,042	418,499
Long-term debt	2,531,632	2,586,046
Asset retirement obligations	44,902	34,753
Other liabilities	30,049	12,962
Deferred income taxes	36,542	234,385
Commitments and contingencies (Note 10)	—	—
Stockholders' equity		
Preferred stock, par value \$0.01, 10,000,000 shares authorized, none outstanding	—	—
Common stock, \$0.01 par value, 400,000,000 shares authorized; 173,997,988 and 171,742,699 shares issued, respectively	1,740	1,717
Paid in capital in excess of par value	672,475	656,958
Treasury stock of 4,700,335 and 4,572,795 shares, respectively	(36,309)	(35,441)
Accumulated other comprehensive income	156,973	185,104
Retained earnings (deficit)	(213,523)	376,488
Quicksilver stockholders' equity	581,356	1,184,826
Noncontrolling interests	25,032	26,737
Total equity	<u>606,388</u>	<u>1,211,563</u>
	<u>\$ 3,615,555</u>	<u>\$ 4,498,208</u>

The accompanying notes are an integral part of these condensed consolidated financial statements.

QUICKSILVER RESOURCES INC.
CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
In thousands — Unaudited

	Quicksilver Resources Inc. Stockholders						
	Common Stock	Additional Paid-in Capital	Treasury Stock	Accumulated Other Comprehensive Income	Retained Earnings (Deficit)	Noncontrolling Interests	Total
Balances at December 31, 2007	\$ 1,606	\$ 378,622	\$ (12,304)	\$ 40,066	\$ 754,764	\$ 29,714	\$1,192,468
Net income	—	—	—	—	88,714	2,621	91,335
Hedge derivative contract settlements reclassified into earnings from accumulated other comprehensive income, net of income tax of \$20,770	—	—	—	40,396	—	—	40,396
Net change in derivative fair value, net of income tax of \$23,846	—	—	—	46,847	—	—	46,847
Foreign currency translation adjustment	—	—	—	(17,858)	—	—	(17,858)
Stock issuance — Alliance Acquisition	104	261,988	—	—	—	—	262,092
Issuance and vesting of stock compensation	5	11,050	(3,235)	—	—	755	8,575
Stock option exercises	2	1,238	—	—	—	—	1,240
Distributions paid on KGS common units	—	—	—	—	—	(6,343)	(6,343)
Balances at September 30, 2008	<u>\$ 1,717</u>	<u>\$ 652,898</u>	<u>\$ (15,539)</u>	<u>\$ 109,451</u>	<u>\$ 843,478</u>	<u>\$ 26,747</u>	<u>\$1,618,752</u>
Balances at December 31, 2008	\$ 1,717	\$ 656,958	\$ (35,441)	\$ 185,104	\$ 376,488	\$ 26,737	\$1,211,563
Net income (loss)	—	—	—	—	(590,011)	4,411	(585,600)
Hedge derivative contract settlements reclassified into earnings from accumulated other comprehensive income, net of income tax benefit of \$74,629	—	—	—	(160,183)	—	—	(160,183)
Net change in derivative fair value, net of income tax of \$52,317	—	—	—	113,333	—	—	113,333
Foreign currency translation adjustment	—	—	—	18,719	—	—	18,719
Issuance and vesting of stock compensation	23	14,695	(868)	—	—	1,228	15,078
Stock option exercises	—	822	—	—	—	—	822
Distributions paid on KGS common units	—	—	—	—	—	(7,344)	(7,344)
Balances at September 30, 2009	<u>\$ 1,740</u>	<u>\$ 672,475</u>	<u>\$ (36,309)</u>	<u>\$ 156,973</u>	<u>\$ (213,523)</u>	<u>\$ 25,032</u>	<u>\$ 606,388</u>

The accompanying notes are an integral part of these condensed consolidated financial statements.

QUICKSILVER RESOURCES INC.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
In thousands — Unaudited

	For the Nine Months Ended September 30,	
	2009	2008
Operating activities:		
Net income (loss)	\$ (585,600)	\$ 91,335
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Impairment related to oil and gas properties	967,126	—
Depletion, depreciation and accretion	155,210	125,756
Deferred income tax expense (benefit)	(313,556)	43,322
Loss from BBEP in excess of cash distributions, net of impairment	35,770	93,864
Non-cash interest expense	40,553	8,085
Stock-based compensation	16,007	11,810
Non-cash (gain) loss from hedging and derivative activities	2,845	(2,065)
Other	684	1,288
Changes in assets and liabilities		
Accounts receivable	67,555	(16,532)
Derivative assets at fair value	54,896	—
Other assets	4,490	(4,819)
Accounts payable	(34,543)	(9,619)
Income taxes payable	5,542	(46,414)
Accrued and other liabilities	33,614	(21,891)
Net cash provided by operating activities	450,593	274,120
Investing activities:		
Purchases of property, plant and equipment	(561,120)	(985,124)
Alliance Acquisition	—	(990,649)
Proceeds from sales of property, plant and equipment	221,038	818
Return of investment from BBEP	—	31,435
Net cash used for investing activities	(340,082)	(1,943,520)
Financing activities:		
Issuance of debt	1,377,525	2,472,119
Repayment of debt	(1,507,137)	(781,988)
Debt issuance costs	(30,995)	(24,545)
Gas Purchase Commitment — net	54,488	—
Noncontrolling interest distributions	(7,344)	(6,343)
Other	(107)	(1,995)
Net cash provided by (used for) financing activities	(113,570)	1,657,248
Effect of exchange rate changes in cash	1,779	(2,609)
Net decrease in cash	(1,280)	(14,761)
Cash and cash equivalents at beginning of period	2,848	28,226
Cash and cash equivalents at end of period	\$ 1,568	\$ 13,465

The accompanying notes are an integral part of these condensed consolidated financial statements.

QUICKSILVER RESOURCES INC.
NOTES TO CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
Unaudited

1. ACCOUNTING POLICIES AND DISCLOSURES

The accompanying condensed consolidated interim financial statements have not been audited. In our management's opinion, the accompanying condensed consolidated interim financial statements contain all adjustments necessary to present fairly our financial position as of September 30, 2009 and our results of operations for the three and nine months ended September 30, 2009 and 2008 and cash flows for the nine months ended September 30, 2009 and 2008. All such adjustments are of a normal recurring nature. The results for interim periods are not necessarily indicative of annual results.

Preparing financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during each reporting period. We believe our estimates and assumptions are reasonable, but actual results could differ from our estimates.

Certain disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been condensed or omitted. Accordingly, these financial statements should be read in conjunction with our consolidated financial statements and notes thereto included in our 2008 Annual Report on Form 10-K, as amended.

Earnings per Share

The following is a reconciliation of the weighted average common shares used in the basic and diluted earnings (loss) per common share calculations for the periods presented. The basic and diluted earnings (loss) per common share for each of the periods presented includes unvested share-based payment awards that contain nonforfeitable rights to dividends. For the three months ended September 30, 2009 and 2008, approximately 9.8 million and 10.7 million potentially dilutive securities, respectively, were excluded from the diluted net loss per share calculation because they were antidilutive. Approximately 11.1 million potentially dilutive securities were excluded from the diluted net loss per share calculation for the nine months ended September 30, 2009. The excluded potentially dilutive securities include 9.8 million for the convertible debentures. No potentially dilutive securities were excluded from the diluted net income per share calculation for the nine months ended September 30, 2008.

	<u>Three Months Ended</u> <u>September 30,</u>		<u>Nine Months Ended</u> <u>September 30,</u>	
	<u>2009</u>	<u>2008</u>	<u>2009</u>	<u>2008</u>
	(In thousands, except per share data)		(In thousands, except per share data)	
Net income (loss) attributable to Quicksilver	\$ 730	\$ (3,755)	\$(590,011)	\$ 88,714
Impact of assumed conversions — interest on 1.875% convertible debentures, net of income taxes	<u>—</u>	<u>1,578</u>	<u>—</u>	<u>3,137</u>
Income (loss) available to stockholders assuming conversion of convertible debentures	<u>\$ 730</u>	<u>\$ (2,177)</u>	<u>\$(590,011)</u>	<u>\$ 91,851</u>
Weighted average common shares — basic	169,021	164,439	168,917	160,293
Effect of dilutive securities:				
Employee stock options	1,452	—	—	676
Employee stock unit awards	184	—	—	314
Contingently convertible debentures	<u>—</u>	<u>—</u>	<u>—</u>	<u>9,816</u>
Weighted average common shares — diluted	<u>170,657</u>	<u>164,439</u>	<u>168,917</u>	<u>171,099</u>
Earnings (loss) per common share — basic	\$ —	\$ (0.02)	\$ (3.49)	\$ 0.55
Earnings (loss) per common share — diluted	\$ —	\$ (0.02)	\$ (3.49)	\$ 0.55

Recently Issued Accounting Standards

Accounting standards-setting organizations frequently issue new or revised accounting rules. We regularly review all new pronouncements to determine their impact, if any, on our financial statements. Below we present a discussion of only those pronouncements that have an impact to our financial statements.

• Pronouncements Impacting Quicksilver That Have Been Implemented

In June 2009, the FASB issued guidance that identified the *FASB Accounting Standards Codification* as the single source of authoritative U.S. GAAP not promulgated by the SEC. The FASB also issued various technical corrections in Updates No. 2009-01 through No. 2009-03 and Update No. 2009-07. The FASC retains existing GAAP and had no effect on our financial statements upon its adoption by us on September 30, 2009, although all references to GAAP herein have been converted to the codified reference.

The FASB issued revised guidance for business combinations in December 2007, which retained fundamental requirements that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination. The acquirer is the entity that obtains control in the business combination and the guidance establishes the criteria to determine the acquisition date. An acquirer is also required to recognize the assets acquired and liabilities assumed measured at their fair values as of the acquisition date. In addition, acquisition costs are required to be recognized separately from the acquisition. Additional clarifications were issued on April 1, 2009 that address application issues regarding initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. We will apply this guidance, found in FASC Topic 805, *Business Combinations*, to any acquisition we enter into after January 1, 2009, but otherwise adoption had no effect on our financial statements.

The FASB issued new guidance in December 2007 which governs accounting and reporting standards for the noncontrolling interest in a subsidiary (previously referred to as “minority interest”) and for the deconsolidation of a subsidiary. The new guidance, found in FASC Section 810-10, *Consolidation*, amends prior standards to clarify that a noncontrolling interest should be reported as a component of consolidated equity. The consolidated income statement is now required to report consolidated net income at amounts that include the amounts attributable to both the parent and noncontrolling interest. Additionally, the guidance established a single method for accounting for changes in a parent’s ownership interest in a subsidiary that do not result in deconsolidation. We adopted the new accounting guidance on January 1, 2009, which resulted in the reclassification of the minority interest liability of \$29.9 million and deferred tax benefit of \$3.2 million, or \$26.7 million, to stockholders’ equity. In addition, our adoption resulted in reclassification of the \$79.3 million deferred gain related to the KGS IPO to “paid in capital in excess of par value” within stockholders’ equity. We have also retrospectively presented our consolidated balance sheet as of December 31, 2008 and our results of operations for 2008 to reflect a comparable presentation.

In February 2008, the FASB issued guidance which allowed for a one-year deferral of the effective date of the accounting guidance in FASC Topic 820, *Fair Value Measurements and Disclosures*, as it applies to non-financial assets and liabilities that are recognized or disclosed at fair value on a nonrecurring basis. Beginning January 1, 2009, we applied the accounting guidance for all fair value measurements to non-financial assets and liabilities.

The FASB issued accounting guidance in March 2008, also found in FASC Section 815-10, *Derivatives and Hedging*, requiring enhanced disclosures of the fair value and other aspects of all derivative and hedging instruments in tabular format and information about credit risk-related features in derivative agreements, counterparty credit risk, and its strategies and objectives for using derivative instruments. We adopted the guidance on January 1, 2009 and have provided the prescribed disclosures for all periods presented that may be found in Note 4.

In May 2008, the FASB issued guidance indicating that issuers of convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement) generally should separately account for the liability and equity components in a manner that will reflect the entity’s nonconvertible debt borrowing rate when interest cost is recognized in periods subsequent to issuance. We adopted the new guidance found at FASC Section 470-20-15, *Debt with Conversion and Other Options*, on January 1, 2009, which resulted in recognition of a \$26.8 million addition to “paid in capital in excess of par value,” additional deferred tax liability of \$5.8 million and decreases to other assets, long-term debt and retained earnings of \$2.4 million, \$19.0 million and \$16.0 million, respectively. We have also presented all comparable prior period information in conformity with this guidance.

The FASB issued additional guidance in June 2008 regarding unvested share-based payment awards that contain nonforfeitable rights to dividends. The guidance was effective and adopted by us on January 1, 2009. Under this guidance, found at FASC Subtopic 260-10, *Earnings per Share*, unvested share-based payment awards that contain nonforfeitable rights to dividends (whether paid or unpaid) are participating securities and should be included in the computation of basic earnings per share pursuant to the two-class method. Based upon the characteristics of our equity awards, approximately 2.5 million restricted shares have been identified as participating securities and are included in the basic earnings per share calculation for the three and nine months ended September 30, 2009. Basic earnings per share for the three and nine months ended September 30, 2008 have been retrospectively adjusted to reflect those restricted shares as participating securities.

On April 9, 2009, the FASB issued guidance, found at FASC Subtopic 825-10, *Financial Instruments*, requiring disclosures about fair value of financial instruments for interim reporting periods. We adopted the disclosure requirements with our quarterly report on Form 10-Q for the period ending March 31, 2009.

The FASB issued guidance in May 2009 for disclosure of events that occur after the balance sheet date but before financial statements are issued by public entities. It mirrors the longstanding existing guidance for subsequent events that was promulgated by the American Institute of Certified Public Accountants. We adopted the guidance found in FASC Subtopic 855-10, *Subsequent Events*, for the quarter ended June 30, 2009 when the guidance became effective without effect. We have carried out our evaluation for subsequent disclosure through November 9, 2009 except for our evaluation for impairment of our oil and gas properties, which was carried out through November 3, 2009.

The FASB issued Update No. 2009-05 in August 2009, which updated FASC Topic 820, *Fair Value Measurements and Disclosures*, for the fair value measurement of liabilities. We have adopted all guidance found in FASC Topic 820 for the quarter ended September 30, 2009.

The following table summarizes the impact of implementing the previously discussed accounting pronouncements on the 2008 periods presented in these financial statements:

	For the Three Months Ended September 30, 2008			For the Nine Months Ended September 30, 2008		
	As Originally Reported	As Adjusted	Effect of Change	As Originally Reported	As Adjusted	Effect of Change
	(In thousands, except for per share data)			(In thousands, except for per share data)		
Operating income	\$ 119,990	\$ 119,990	\$ —	\$ 297,816	\$ 297,816	\$ —
Loss from earnings of BBEP	(89,814)	(89,814)	—	(93,864)	(93,864)	—
Interest expense and other	(36,440)	(38,101)	(1,661)	(61,680)	(66,576)	(4,896)
Income before income tax	(6,264)	(7,925)	(1,661)	142,272	137,376	(4,896)
Income tax (expense) benefit	4,714	5,295	581	(47,754)	(46,041)	1,713
Minority interest expense	(1,125)	—	(1,125)	(2,621)	—	(2,621)
Net income attributable to noncontrolling interests	—	(1,125)	1,125	—	(2,621)	2,621
Net income attributable to Quicksilver	\$ (2,675)	\$ (3,755)	\$ (1,080)	\$ 91,897	\$ 88,714	\$ (3,183)
Earnings per share — basic	\$ (0.02)	\$ (0.02)	\$ —	\$ 0.57	\$ 0.55	\$ (0.02)
Earnings per share — diluted	\$ (0.02)	\$ (0.02)	\$ —	\$ 0.54	\$ 0.55	\$ 0.01
Basic weighted average shares outstanding	164,087	164,439	352	159,914	160,293	379
Diluted weighted average shares outstanding	164,087	164,439	352	171,759	171,099	(660)

• Pronouncements Not Yet Implemented

The SEC adopted revisions to its required oil and gas reporting disclosures in December 2008. The revisions affecting us include: 1) use of 12-month average of the first-day-of-the-month prices for determination of proved reserve values included in calculating full cost ceiling limitations and for annual proved reserve disclosures; 2) limitations on the types of technologies that may be relied upon to establish the levels of certainty required to classify reserves; and 3) ability to disclose “probable” and “possible” reserves as defined by the SEC. The SEC also updated the required disclosure requirements and eliminated use of price recoveries subsequent to period end for use in the ceiling test. We will adopt these changes for reporting our proved reserves

beginning with annual disclosures in our 2009 Annual Report on Form 10-K. We are still reviewing the implications of this adoption on our previous reserve disclosures.

2. ENI TRANSACTION

On June 19, 2009, we completed the Eni Transaction whereby we entered into a strategic alliance with Eni and sold a 27.5% interest in our Alliance Leasehold. The assets were sold to Eni for \$280 million in cash, inclusive of the Gas Purchase Commitment assumed, and subject to normal post-closing adjustments. We used the proceeds generated to repay a portion of the Senior Secured Second Lien Facility.

In connection with the sale, one of our wholly owned subsidiaries entered into a gas gathering agreement with Eni covering Eni's production from the Alliance Leasehold. Under the agreement, we will gather, treat and deliver Eni's Alliance Leasehold production. Eni also committed to pay approximately \$19.2 million by March 2010 to us (of which \$9.5 million has been paid through September 30, 2009) for construction and installation of the facilities required to gather Eni's production from future Alliance wells. We will be the sole owner of these facilities and, upon completion of the Gas Purchase Commitment, will recognize gathering revenue for the volumes of gas that are gathered.

Also as part of the sale, we entered into a joint development agreement with Eni. The joint development agreement includes a schedule of wells that we agreed to drill and complete with participation by Eni during the development period. In connection with the scheduled drilling of these wells, we have committed to drill and complete a minimum number of lateral feet each year. Eni agreed to pay us a turnkey drilling and completion cost of \$994 per linear foot attributable to Eni. The net linear footage requirements to be drilled and completed attributable to Eni are summarized below:

Year	Total Aggregate Linear Feet
2009	28,215
2010	58,448
2011	44,080
2012	26,974
2013	34,102

Under the joint development agreement, we may be subject to pay Eni for damages at the end of the development period should we fail to meet the linear footage requirements and certain production requirements have not been satisfied. We currently expect to satisfy these requirements and have recognized no liability for our non-performance.

3. ALLIANCE ACQUISITION

On August 8, 2008, we completed the Alliance Acquisition, whereby we acquired leasehold, royalty and midstream assets associated with the Barnett Shale formation in northern Tarrant and southern Denton counties of Texas. The purchase price was funded as follows:

(In thousands)	
Purchase Price:	
Cash paid	\$1,000,000
Cash received from post-closing settlement	(9,086)
Cash paid for acquisition-related expenses	1,368
Total cash	992,282
Issuance of 10,400,468 common shares	262,092
	\$1,254,374

The purchase price allocation is presented below:

(In thousands)	
Allocation of Purchase Price:	
Oil and gas properties — proved	\$ 788,457
Oil and gas properties — unproved	440,372
Midstream assets	27,652
Liabilities assumed	(1,035)
Asset retirement obligations	(1,072)
	<u>\$1,254,374</u>

The purchase price allocation was based on estimates of oil and gas reserves and other valuations and estimates by our management.

Pro Forma Information

The following table reflects Quicksilver's unaudited consolidated pro forma statements of income as though the Alliance Acquisition, associated borrowings and issuance of our common stock had taken place on January 1, 2008. The actual revenue and expenses for the acquisition are included in our 2008 consolidated results beginning on August 8, 2008 and for all of 2009. The following pro forma information is not necessarily indicative of the results of operations that would have been achieved if the acquisition had been effective on January 1, 2008.

	For the Three Months Ended September 30, 2008	For the Nine Months Ended September 30, 2008
	(In thousands, except for per share data)	
Revenues	\$ 249,956	\$ 667,762
Net income attributable to Quicksilver	\$ (112)	\$ 85,544
Earnings per share — basic	\$ —	\$ 0.51
Earnings per share — diluted	\$ —	\$ 0.50

4. DERIVATIVES AND FAIR VALUE MEASUREMENTS

We use derivatives to mitigate price risk associated with the sale of our natural gas, NGL and crude oil production. Prices for these products are capable of wide fluctuations that may negatively affect profitability and cash flow from operations but may also increase them. We mitigate the risk of adverse price movements with swaps and collars, which also limit future gains from favorable price movements. We also use derivatives, in the form of swaps, to monetize the fair value of our fixed-rate long-term debt in periods of low interest rates, thereby reducing our current levels of interest payments.

We enter into financial derivatives with counterparties who are lenders under our credit facility. The credit facility provides for collateralization of amounts outstanding from our derivative instruments in addition to amounts outstanding under the facility. Additionally, default on any of our obligations under derivative instruments with counterparty lenders could result in acceleration of the amounts outstanding under the credit facility. The credit facility and our internal credit policies require that any counterparties, including facility lenders, with whom we enter into commodity financial derivatives have credit ratings that meet or exceed BBB- or Baa3 from Standard and Poor's or Moody's, respectively. The fair value for each derivative takes into consideration credit risk, whether it be our counterparties' or our own. Derivatives are recorded in the balance sheet as current and non-current derivative assets and liabilities as determined by the expected timing of settlements.

Commodity Price Derivatives

As of September 30, 2009, we had price collars or fixed price swaps hedging 190 MMcfd of our anticipated natural gas production for the remainder of 2009. We have also hedged approximately 120 MMcfd of our anticipated 2010 U.S. natural gas production using natural gas price collars. In March 2009, we executed the early settlement of a price collar that hedged the sale of 40 MMcfd of our

forecasted 2010 natural gas production, whereby we received \$54.9 million. The settlement was recorded to AOCI and will be reclassified into natural gas revenue as we sell the associated hedged production volumes during 2010. Excluded from the amounts presented in the tables below are price collars and swaps entered into during October 2009.

Interest Rate Derivatives

In June 2009, we entered into interest rate swaps on our \$475 million Senior Notes due 2015 and our \$350 million Senior Subordinated Notes effectively converting the interest on those issues from a fixed to a floating rate indexed to a one-month LIBOR base rate. The maturity dates and all other significant terms are the same as those of the underlying debt. Under these swaps, we pay a variable interest rate and receive the fixed rate applicable to the underlying debt. The interest income or expense is accrued as earned and recorded as an adjustment to the interest expense accrued on the fixed-rate debt. The interest rate swaps are designated as fair value hedges of the underlying debt. The value of the contracts, excluding the net interest accrual, amounted to a net asset of \$16.0 million as of September 30, 2009. The offsetting fair value adjustment to the debt hedged resulted in an increase of long-term debt by \$16.0 million as of September 30, 2009. No ineffectiveness was recorded in connection with the fair value hedges. The average effective interest rates on the 2015 Senior Notes and Senior Subordinated Notes, since we entered into the hedges in June 2009, were approximately 5.12% and 3.74%, respectively.

Other Derivatives

Based on information available on June 19, 2009, we recognized a liability pursuant to the Gas Purchase Commitment based on the estimated production volumes attributable to Eni through December 31, 2010, which then totaled 22.2 Bcf. The Gas Purchase Commitment contains an embedded derivative that is adjusted to fair value throughout the period of the commitment, which expires on December 31, 2010. We recognized a \$1.2 million increase in the fair value of the embedded derivative liability between June 19 and September 30, 2009 and recorded a valuation loss in costs of purchased natural gas. At September 30, 2009, we have a remaining liability of \$55.7 million, including the \$1.2 million liability for the embedded derivative. The following summarizes activity to the Gas Purchase Commitment:

(In thousands)	
Initial valuation of liability ⁽¹⁾	\$58,294
Decrease due to gas volumes purchased	(3,806)
Embedded derivative increase (decrease) due to:	
Price changes	1,667
Volume changes	(479)
Total embedded derivative	1,188
Balance at September 30, 2009	<u>\$55,676</u>

⁽¹⁾ Initial valuation of the Gas Purchase Commitment was estimated using estimated Eni production volumes from June 19, 2009 through December 2010 and published future market prices and risk-adjusted interest rates as of June 19, 2009.

The estimated fair value of our derivatives at September 30, 2009 and December 31, 2008 were as follows:

	Asset Derivatives		Liability Derivatives	
	September 30, 2009	December 31, 2008	September 30, 2009	December 31, 2008
	(In thousands)		(In thousands)	
Derivatives designated as hedges:				
Commodity contracts reported in:				
Current derivative assets	\$ 145,180	\$ 179,079	\$ —	\$ 2,500
Noncurrent derivative assets	20,763	116,006	—	—
Current derivative liabilities	—	—	871	1,865
Interest rate contracts reported in:				
Current derivative assets	2,635	—	—	—
Noncurrent derivative assets	13,407	—	—	—
Current derivative liabilities	—	—	—	—
Noncurrent derivative liabilities	—	—	—	—
Total derivatives designated as hedges	<u>\$ 181,985</u>	<u>\$ 295,085</u>	<u>\$ 871</u>	<u>\$ 4,365</u>
Derivatives not designated as hedges:				
Gas Purchase Commitment reported in:				
Accrued liabilities	\$ —	\$ —	\$ 1,146	\$ —
Other liabilities	—	—	42	—
Michigan Sales Contract natural gas purchase derivatives ⁽¹⁾ reported in current derivative assets	—	—	—	4,839
Michigan Sales Contract ⁽¹⁾ reported in current derivative liabilities	—	—	—	8,063
Total derivatives not designated as hedges	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 1,188</u>	<u>\$ 12,902</u>
Total derivatives	<u>\$ 181,985</u>	<u>\$ 295,085</u>	<u>\$ 2,059</u>	<u>\$ 17,267</u>

⁽¹⁾ During 2009, our net cash payments were \$16.5 million, including derivative settlements, to complete our obligations under the Michigan Sales Contract

The following table shows the inputs used in our fair value calculations of our derivative instruments at September 30, 2009 and December 31, 2008:

	Fair Value Measurements as of September 30, 2009⁽¹⁾		
	Level 2	Other ⁽²⁾ (In thousands)	Balance Sheet Total
Derivative assets	<u>\$ 181,985</u>	<u>\$ —</u>	<u>\$ 181,985</u>
Derivative liabilities	<u>\$ 2,059</u>	<u>\$ —</u>	<u>\$ 2,059</u>

Fair Value Measurements as of December 31, 2008⁽¹⁾

	<u>Level 2</u>	<u>Other⁽²⁾</u>	<u>Balance Sheet Total</u>
		(In thousands)	
Derivative assets	\$ 295,085	\$ (7,339)	\$ 287,746
Derivative liabilities	\$ 17,267	\$ (7,339)	\$ 9,928

(1) No Level 1 or Level 3 measurements

(2) Represents amounts netted under master netting arrangements with counterparties

The decrease in carrying value of our commodity price derivatives since December 31, 2008 principally resulted from monthly settlements received during 2009 and the \$54.9 million early settlement of a natural gas collar that hedged 2010 natural gas production. These decreases were partially offset by the overall decline in market prices for natural gas relative to the prices in our open derivative instruments at September 30, 2009.

The changes in the carrying value of our derivatives for the three and nine months ended September 30, 2009 and 2008 are presented below:

	For the Three Months Ended September 30, 2009				
	<u>Michigan Contract</u>	<u>Gas Purchase Commitment</u>	<u>Fair Value Derivatives</u>	<u>Cash Flow Derivatives</u>	<u>Total</u>
			(In thousands)		
Derivative fair value at June 30, 2009	\$ —	\$ (3,818)	\$ (266)	\$ 257,548	\$ 253,464
Net settlements reported in revenue	—	—	—	(92,687)	(92,687)
Net settlements reported in interest expense	—	—	(6,537)	—	(6,537)
Change in fair value of Gas Purchase Commitment reported in costs of purchased gas	—	2,630	—	—	2,630
Change in fair value of effective interest swaps	—	—	22,845	—	22,845
Ineffectiveness reported in other revenue	—	—	—	77	77
Unrealized gains reported in OCI	—	—	—	134	134
Derivative fair value at September 30, 2009	\$ —	\$ (1,188)	\$ 16,042	\$ 165,072	\$ 179,926

	For the Three Months Ended September 30, 2008				
	<u>Michigan Contract</u>	<u>Gas Purchase Commitment</u>	<u>Fair Value Derivatives</u>	<u>Cash Flow Derivatives</u>	<u>Total</u>
			(In thousands)		
Derivative fair value at June 30, 2008	\$ (46,138)	\$ —	\$ —	\$ (372,842)	\$ (418,980)
Change in amounts due from Quicksilver	4,443	—	—	(612)	3,831
Net settlements	16,072	—	—	—	16,072
Net settlements reported in revenue	—	—	—	26,614	26,614
Ineffectiveness reported in other revenue	(357)	—	—	13,912	13,555
Unrealized gains reported in OCI	—	—	—	462,130	462,130
Derivative fair value at September 30, 2008	\$ (25,980)	\$ —	\$ —	\$ 129,202	\$ 103,222

	For the Nine Months Ended September 30, 2009				
	<u>Michigan Contract</u>	<u>Gas Purchase Commitment</u>	<u>Fair Value Derivatives</u> (In thousands)	<u>Cash Flow Derivatives</u>	<u>Total</u>
Derivative fair value at December 31, 2008	\$ (12,901)	\$ —	\$ —	\$ 290,719	\$ 277,818
Change in amounts due from Quicksilver	(3,518)	—	—	—	(3,518)
Net settlements	16,479	—	—	—	16,479
Net settlements reported in revenue	—	—	—	(234,812)	(234,812)
Net settlements reported in interest expense	—	—	(7,200)	—	(7,200)
Change in fair value of Gas Purchase Commitment reported in costs of purchased gas	—	(1,188)	—	—	(1,188)
Change in fair value of effective interest swaps	—	—	23,242	—	23,242
Ineffectiveness reported in other revenue	(60)	—	—	(1,589)	(1,649)
Cash settlement reported in OCI	—	—	—	(54,896)	(54,896)
Unrealized gains reported in OCI	—	—	—	165,650	165,650
Derivative fair value at September 30, 2009	<u>\$ —</u>	<u>\$ (1,188)</u>	<u>\$ 16,042</u>	<u>\$ 165,072</u>	<u>\$ 179,926</u>

	For the Nine Months Ended September 30, 2008				
	<u>Michigan Contract</u>	<u>Gas Purchase Commitment</u>	<u>Fair Value Derivatives</u> (In thousands)	<u>Cash Flow Derivatives</u>	<u>Total</u>
Derivative fair value at December 31, 2007	\$ (63,777)	\$ —	\$ —	\$ (5,503)	\$ (69,280)
Change in amounts due from Quicksilver	4,436	—	—	(1,663)	2,773
Net settlements	34,198	—	—	—	34,198
Net settlements reported in revenue	—	—	—	61,167	61,167
Ineffectiveness reported in other revenue	(837)	—	—	4,508	3,671
Unrealized gains reported in OCI	—	—	—	70,693	70,693
Derivative fair value at September 30, 2008	<u>\$ (25,980)</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 129,202</u>	<u>\$ 103,222</u>

Gains and losses from the effective portion of derivative assets and liabilities held in AOCI expected to be reclassified into earnings over the next twelve months would result in a gain of \$94.2 million net of income taxes. An additional \$27.4 million, net of income taxes, will be reclassified from AOCI from the realized gain on the natural gas collar settled in March 2009. Gains from the effective portion of non-current derivative assets and realized gains will be reclassified to earnings from AOCI over the three months ending December 31, 2010. Hedge derivative ineffectiveness resulted in losses of \$1.7 million (including an immaterial amount in the third quarter) and \$3.7 million (including a gain of \$13.6 million in the third quarter) recorded in other revenue for the nine months ended September 30, 2009 and 2008, respectively.

5. INVESTMENT IN BREITBURN ENERGY PARTNERS L.P.

We own approximately 21.3 million common units of BBEP, a publicly traded limited partnership, which we acquired in connection with the BreitBurn Transaction. On June 17, 2008, BBEP announced that it had repurchased and retired 14.4 million units, which represented approximately 22% of the units previously outstanding. The resulting reduction in the number of BBEP common units outstanding increased our ownership from approximately 32% to approximately 41%. At September 30, 2009, we owned approximately 40% of BBEP's outstanding common units.

During the first quarter of 2009, we evaluated our investment in BBEP for impairment in response to further decreases in prevailing commodity prices and BBEP's unit price since December 31, 2008. As a result of these decreases and the outlook for petroleum prices and broad limitations on available capital, we made the determination that the decline in value was other-than-temporary. Accordingly, our impairment analysis utilized the March 31, 2009 closing price of \$6.53 per BBEP unit, which resulted in an aggregate fair value of \$139.4 million for the portion of BBEP units owned by Quicksilver. The \$139.4 million aggregate fair value was compared to an aggregate carrying value of \$241.5 million. We recorded the difference of \$102.1 million as a pre-tax impairment charge during the first quarter of 2009. No subsequent impairment of our investment has occurred as the value derived

from the September 30, 2009 closing price of \$11.37 per BBEP unit exceeded our carrying value of approximately \$5.37 per unit. Additional impairment of our investment in BBEP units could occur during the remainder of 2009 depending upon the performance of BBEP's unit price, which itself is dependent upon numerous factors.

We account for our investment in BBEP units using the equity method, utilizing a one-quarter lag from BBEP's publicly available information. Summarized estimated financial information for BBEP is as follows:

	<u>For the Three Months Ended June 30,</u>		<u>For the Nine Months Ended June 30, 2009</u>	<u>For the Eight Months Ended June 30, 2008</u>
	<u>2009</u>	<u>2008</u>		
	(In thousands)			
Revenues ⁽¹⁾	\$ (36,994)	\$(212,677)	\$ 534,192	\$ (118,175)
Operating expenses ⁽²⁾	67,352	69,590	307,391	181,747
Operating income (loss)	(104,346)	(282,267)	226,801	(299,922)
Interest and other ⁽³⁾	4,988	4,994	37,458	16,274
Income tax (benefit) expense	(809)	(1,091)	336	(2,006)
Noncontrolling interests	(5)	70	15	155
Net income (loss) available to BBEP	<u>\$(108,520)</u>	<u>\$(286,240)</u>	<u>\$ 188,992</u>	<u>\$ (314,345)</u>
Net income (loss) available to common unitholders	<u>\$(108,520)</u>	<u>\$(284,494)</u>	<u>\$ 188,992</u>	<u>\$ (312,794)</u>

- (1) Unrealized losses on commodity derivatives of \$148.7 million and \$319.9 million were included for the three months ended June 30, 2009 and 2008, respectively. Unrealized gains of \$193.5 million and unrealized losses of \$392.2 million on commodity derivatives were included for the nine months ended June 30, 2009 and the eight months ended June 30, 2008, respectively. Realized gains on commodity derivatives of \$25.0 million and \$70.6 million for the early settlement of derivative positions were included for the three and nine months ended June 30, 2009, respectively.
- (2) An impairment of BBEP's oil and gas properties of \$86.4 million was included for the nine months ended June 30, 2009
- (3) The three months ended June 30, 2009 included \$0.3 million for unrealized gains on interest rate swaps and the nine months ended June 30, 2009 included \$17.9 million for unrealized losses on interest rate swaps

	<u>As of June 30, 2009</u>	<u>As of December 31, 2008</u>
		(In thousands)
Current assets	\$ 126,473	\$ 140,566
Property, plant and equipment	1,799,124	1,840,341
Other assets	123,248	235,927
Current liabilities	64,887	79,990
Long-term debt	640,000	736,000
Other non-current liabilities	73,986	47,413
Partners' equity	1,269,972	1,353,431

For the nine months ended September 30, 2009, we recognized income of \$77.4 million for our share of BBEP's income for the nine months ended June 30, 2009. For the comparable 2008 period, we recognized a loss of \$93.9 million for the eight months ended June 30, 2008.

Changes in the balance of our investment in BBEP for the first nine months of 2009 were as follows:

(In thousands)	
Balance at December 31, 2008	\$ 150,503
Equity income in BBEP	77,415
Distributions from BBEP	(11,101)
Non-cash impairment of BBEP	(102,084)
Balance at September 30, 2009	<u>\$ 114,733</u>

6. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consisted of the following:

	September 30, 2009	December 31, 2008
(In thousands)		
Oil and gas properties		
Subject to depletion	\$ 3,780,855	\$ 3,621,831
Unevaluated costs	497,301	543,533
Accumulated depletion	<u>(2,016,226)</u>	<u>(1,022,756)</u>
Net oil and gas properties	2,261,930	3,142,608
Other plant and equipment		
Pipelines and processing facilities	753,213	529,555
General properties	68,118	57,941
Construction in progress	6,269	134,557
Accumulated depreciation	<u>(95,730)</u>	<u>(66,946)</u>
Net other property and equipment	<u>731,870</u>	<u>655,107</u>
Property, plant and equipment, net of accumulated depletion and depreciation	<u>\$ 2,993,800</u>	<u>\$ 3,797,715</u>

Ceiling Test Analysis

Under the full cost method of accounting for our oil and gas properties, we must perform a quarterly ceiling test for each of our cost centers. In determining the ceiling limitation, the ceiling test incorporates pricing, costs and discount rates over which management has no influence. Additionally, the ceiling test requires us to evaluate the ceiling using only information for our exploration and production segment, thus we do not include the benefits associated with our ownership and consolidation of KGS.

The 2009 first quarter U.S. ceiling amount was computed using benchmark prices of \$3.63 per Mcf of natural gas, \$24.12 per barrel of NGL and \$49.66 per barrel of crude oil. When we determined the present value of our U.S. reserves, the carrying value of our U.S. oil and gas properties exceeded the ceiling limit by \$786.9 million (pre-tax). We computed the 2009 first quarter Canadian ceiling amount using an AECO benchmark price of \$2.92 per Mcf. Upon calculation of the present value of our Canadian reserves, the carrying value of our Canadian oil and gas properties exceeded the ceiling limit by \$109.6 million (pre-tax). We recorded a total impairment charge of \$896.5 million in the first quarter of 2009.

The second quarter 2009 ceiling test for our U.S. oil and gas properties resulted in no further recognition of impairment to those oil and gas properties due principally to price recoveries during the second quarter; however, the second quarter ceiling test for our Canadian oil and gas properties resulted in an additional charge for impairment. We computed the 2009 second quarter Canadian ceiling amount using an AECO benchmark price of \$2.87 per Mcf. The carrying value of our Canadian oil and gas reserves exceeded the present value of our Canadian proved reserves at June 30, 2009 by \$70.6 million (pre-tax), which we recorded as an impairment charge in the second quarter of 2009. The second quarter impairment charge primarily resulted from reductions in the capital forecast for the remainder of 2009 and 2010 for our Canadian oil and gas properties.

At September 30, 2009, the unamortized cost of our Canadian oil and gas properties exceeded the full cost ceiling limitation by approximately \$38.8 million (pre-tax). The full cost ceiling limitation included \$25.7 million (pre-tax) for hedge valuations. The

natural gas price for September 30, 2009 referenced an AECO price of \$3.41 per Mcf adjusted for appropriate price differentials. As permitted by full cost accounting rules, improvements in AECO spot natural gas prices subsequent to September 30, 2009 eliminated the necessity to record a charge for impairment. The third quarter 2009 ceiling test for our U.S. oil and gas properties resulted in no further recognition of impairment. Because of the volatility of oil and natural gas prices, no assurance can be given that we will not experience a charge for impairment in future periods.

The impairment charges recorded in the first and second quarters of 2009 are summarized below:

	<u>Net Capitalized Costs⁽¹⁾</u>	<u>Ceiling Limitation⁽²⁾</u> (In thousands)	<u>Pre-tax Charge for Impairment</u>
First Quarter			
United States	\$2,727,130	\$ 1,940,263	\$ 786,867
Canada	458,135	348,519	109,616
Total	<u>\$3,185,265</u>	<u>\$2,288,782</u>	<u>\$ 896,483</u>
Second Quarter			
Canada	\$ 400,696	\$ 330,053	\$ 70,643
Year to Date			
United States	\$2,727,130	\$ 1,940,263	\$ 786,867
Canada	858,831	678,572	180,259
Total	<u>\$3,585,961</u>	<u>\$2,618,835</u>	<u>\$ 967,126</u>

(1) Net capitalized costs before impairment includes all costs associated with development, exploration and acquisition of oil and gas properties net of accumulated depletion and impairment, reduced by the related deferred income tax liability

(2) The ceiling limitation is the sum of (i) estimated future net cash flows, discounted at 10% per annum, from proved reserves, based on unescalated period-end prices and costs, adjusted for financial derivatives that qualify as cash flow hedges of our oil and gas revenue, (ii) the costs of properties not being amortized, (iii) the lower of cost or market value of unproved properties not included in the costs being amortized, less (iv) income tax effects related to differences between book and tax bases of the oil and gas properties

7. LONG-TERM DEBT

Long-term debt consisted of the following:

	<u>September 30, 2009</u>	<u>December 31, 2008</u>
	(In thousands)	
Senior secured credit facility	\$ 480,873	\$ 827,868
Senior secured second lien facility, net of unamortized discount	—	641,555
Senior notes due 2015, net of unamortized discount	479,218	469,062
Senior notes due 2016, net of unamortized discount	580,830	—
Senior notes due 2019, net of unamortized discount	292,892	—
Senior subordinated notes due 2016	356,563	350,000
Convertible debentures, net of unamortized discount	134,356	129,240
KGS credit agreement	206,900	174,900
Total debt	<u>2,531,632</u>	<u>2,592,625</u>
Less current maturities	—	(6,579)
Long-term debt	<u>\$ 2,531,632</u>	<u>\$ 2,586,046</u>

Senior Secured Credit Facility

Upon completion of the Eni Transaction, our borrowing base was adjusted to \$1.125 billion. Approximately \$633 million was available under the Senior Secured Credit Facility at September 30, 2009 based upon the \$1.125 billion borrowing base. The October 2009 scheduled redetermination resulted in a revised borrowing base of \$1.0 billion.

Senior Secured Second Lien Facility and Senior Notes Due 2016

On June 25, 2009, we issued our senior notes due 2016 with a principal amount of \$600 million. The notes were issued at 96.717% of par, which resulted in proceeds of \$580.3 million. The notes bear interest at the rate of 11.75%. The proceeds from these notes and from the Eni Transaction were used to fully repay and terminate the remaining indebtedness under our Senior Secured Second Lien Facility, with the remaining proceeds used to reduce amounts outstanding under the Senior Secured Credit Facility. Upon termination of the Senior Secured Second Lien Facility, Quicksilver's and its domestic subsidiaries' guarantee obligations, which were secured by a second lien on substantially all the assets of Quicksilver and its domestic subsidiaries, terminated. Furthermore, the financial covenants regarding the present value of the cash flows of our oil and gas reserves under our Senior Secured Credit Facility were eliminated.

Senior Notes Due 2019

On August 14, 2009, we issued our senior notes due 2019 with a principal amount of \$300 million. The notes were issued at 97.612% of par and bear interest at the rate of 9.125%. The proceeds from these notes were used to reduce amounts outstanding under the Senior Secured Credit Facility.

Convertible Debentures

The convertible debentures are contingently convertible into shares of Quicksilver common stock at a rate of 65.4418 shares for each \$1,000 debenture, subject to adjustment. Upon conversion, we have the option to deliver any combination of Quicksilver common stock and cash. Should all debentures be converted to Quicksilver common stock, an additional 9,816,270 shares would become outstanding; however, as of October 1, 2009, the debentures were not convertible.

On January 1, 2009, Quicksilver adopted the FASB's new accounting guidance for contingent convertible securities as described in Note 1. The fair value of the equity component of our convertible debentures at the time of issuance was determined to be \$26.8 million, net of deferred tax liabilities based upon an interest rate of 6.75%. The remaining unamortized discount on the debentures at September 30, 2009 was \$15.6 million and \$20.8 million at December 31, 2008, resulting in a carrying value of \$134.4 million and \$129.2 million at September 30, 2009 and December 31, 2008, respectively. The remaining discount will be accreted to face value through October 2011. For the nine months ended September 30, 2009 and 2008, interest expense on our convertible debentures, recognized at an effective interest rate of 6.75%, was \$7.2 million and \$6.9 million, respectively, including contractual interest of \$2.1 million for each period.

KGS Credit Agreement

At September 30, 2009, KGS' borrowing capacity remained at the December 31, 2008 level of \$235 million, with approximately \$28 million of available capacity. In October 2009, KGS lenders increased their commitments to a total of \$320 million. The KGS Credit Agreement permits further expansion to as much as \$350 million, subject to consents and additional commitments.

Summary of All Outstanding Debt

For a more complete description of our long-term debt, see Note 14, *Long-Term Debt*, to the consolidated financial statements in our 2008 Annual Report on Form 10-K, as amended. The following table summarizes significant aspects of our long-term debt:

	Priority on Collateral and Structural Seniority ⁽⁷⁾						Recourse only to KGS assets
	Highest priority	Equal priority			Lowest priority		
	Senior Secured Credit Facility	2015 Senior Notes	2016 Senior Notes	2019 Senior Notes	Senior Subordinated Notes	Convertible Debentures	KGS Credit Agreement
Maturity date	February 9, 2012	June 27, 2015	January 1, 2016	September 1, 2019	March 16, 2016	November 1, 2024	August 10, 2012
Interest rate at September 30, 2009 ⁽¹⁾	3.067%	8.25%	11.75%	9.125%	7.125%	1.875%	1.50%
Base interest rate options ⁽²⁾	LIBOR, ABR or specified ⁽³⁾	N/A	N/A	N/A	N/A	N/A	LIBOR, ABR or specified ⁽⁴⁾
Financial covenants ⁽⁵⁾	- Minimum current ratio of 1.0 - Minimum EBITDA to interest expense ratio of 2.5	N/A	N/A	N/A	N/A	N/A	- Maximum debt to EBITDA ratio of 4.5 - Minimum EBITDA to interest expense ratio of 2.5
Significant non-financial covenants ⁽⁵⁾	- Incurrence of debt - Incurrence of liens - Payment of dividends - Equity purchases - Asset sales - Affiliate transactions - Limitations on derivatives	- Incurrence of debt - Incurrence of liens - Payment of dividends - Equity purchases - Affiliate transactions	- Incurrence of debt - Incurrence of liens - Payment of dividends - Equity purchases - Affiliate transactions	- Incurrence of debt - Incurrence of liens - Payment of dividends - Equity purchases - Asset sales - Affiliate transactions	- Incurrence of debt - Incurrence of liens - Payment of dividends - Equity purchases - Asset sales - Affiliate transactions	N/A	- Incurrence of debt - Incurrence of liens - Equity purchases - Asset sales - Limitations on derivatives
Estimated fair value ⁽⁶⁾	\$480.9 million	\$463.1 million	\$658.5 million	\$298.5 million	\$301.6 million	\$173.9 million	\$206.9 million

(1) Represents the weighted average borrowing rate payable to lenders and excludes effects of interest rate derivatives

(2) Interest rate options include a base rate plus a spread

(3) The Senior Secured Credit Facility was amended in August 2009 to add a floor to ABR of one-month LIBOR plus a 1%, increase in the ABR margin to a range of 1.375% to 2.375% and an increase in the Eurodollar and specified rate margins to a range of 2.25% to 3.25%

(4) The KGS Credit Agreement was amended in October 2009 to add a floor to ABR of one-month LIBOR plus a 1%, increase in the ABR margin to a range of 2.00% to 3.00% and an increase in the Eurodollar and specified rate margins to a range of 3.00% to 4.00%

(5) The covenant information presented in this table is qualified in all respects by reference to the full text of the covenants and related definitions contained in the documents governing the various components of our debt

(6) The estimated fair value is determined based on market quotations on the balance sheet date for fixed rate obligations. We consider debt with market-based interest rates to have a fair value equal to its carrying value.

(7) The Senior Secured Credit Facility is secured by a first perfected lien on substantially all the assets. The other debt presented is based upon structural seniority.

8. ASSET RETIREMENT OBLIGATIONS

The following table provides information about our estimated asset retirement obligations for the nine months ended September 30, 2009.

(In thousands)	
Beginning asset retirement obligations	\$35,193
Incremental liability incurred	6,000
Accretion expense	1,722
Change in estimates	157
Sale of properties	(380)
Asset retirement costs incurred	(153)
Gain on settlement of liability	208
Currency translation adjustment	2,595
Ending asset retirement obligations	45,342
Less current portion	(440)
Long-term asset retirement obligations	<u>\$44,902</u>

9. INCOME TAXES

The effective tax rate for the 2009 quarter was almost 88% primarily due to changes in our estimated annual effective tax rate for 2009, which had been forecasted as a 35% income tax benefit through June 30, 2009. We now expect a 34% income tax benefit based on changes to the expected earnings allocation between the U.S. and Canada. This change in the expected rate for 2009 required recognition during the third quarter of the cumulative amount to bring the year to date income tax provision to the 34% level. The 2009 quarter includes an estimated \$9.6 million of changes to the income tax provision for earnings recognized through the period ended June 30, 2009.

At September 30, 2009, our unrecognized tax benefits remain at \$9.3 million and we do not anticipate the total amount of unrecognized tax benefits will significantly increase or decrease within the next 12 months. We have not recognized any unrecognized tax benefits for state income taxes.

During March 2009, we filed the U.S. federal income tax return for 2008 reporting a taxable loss for the year. We also filed a net operating loss carryback from 2008 to 2007 to claim a federal tax refund of \$41.1 million. We received the refund in April 2009.

During October 2009, the Internal Revenue Service commenced an audit of our 2007 and 2008 consolidated U.S. federal income tax returns. Although no significant adjustments are expected, any required adjustments will be made upon completion of the audit.

10. COMMITMENTS AND CONTINGENCIES

For a more complete description of our commitments and contingencies see Note 17, *Commitments and Contingencies*, to the consolidated financial statements in our 2008 Annual Report on Form 10-K, as amended.

In October 2009, a jury awarded \$22 million to the plaintiffs in our litigation originally brought against us by the plaintiffs, Rod and Richard Thornton and Eagle Drilling, LLC. We are actively seeking an appeal in this matter.

In June 2009, the appellate court in the CMS litigation reversed the original district court judgment. Pursuant to a settlement agreement, we paid CMS \$5 million during July 2009, which we accrued during the quarter ended June 30, 2009.

Commitments

In connection with the Eni Transaction, we entered into the Gas Purchase Commitment. Note 4 contains further information regarding this commitment.

We had approximately \$11.4 million in letters of credit outstanding against the Senior Secured Credit Facility and approximately \$10.1 million of surety bonds outstanding at September 30, 2009 to fulfill contractual, legal or regulatory requirements. All letters of credit and surety bonds have an annual renewal option. Additionally, we had commitments outstanding of approximately \$13.9 million related to our 2009 and 2010 capital programs as of September 30, 2009.

11. STOCK-BASED COMPENSATION

On May 20, 2009, stockholders approved an amendment to the 2006 Equity Plan, which increased the number of shares available for issuance to 15 million. Note 20, *Stockholders' Equity*, in the consolidated financial statements in our 2008 Annual Report on Form 10-K, as amended, contains additional information about our equity-based compensation plans.

Quicksilver Stock Options

Options to purchase shares of common stock were granted in 2009 with an estimated fair value of \$8.7 million. We recognized expense of \$3.4 million for stock options in the first nine months of 2009. At September 30, 2009, we had unearned compensation cost of \$8.3 million remaining, which will be recognized in expense through January 2011.

We estimated the fair value of stock options granted in 2009 on the dates of grant using the Black-Scholes option pricing model with the following assumptions:

	Stock Options Issued
Wtd avg grant date fair value	\$ 6.21
Wtd avg grant date	Jan 2, 2009
Wtd avg risk-free interest rate	1.90%
Expected life (in years)	6.0
Wtd avg volatility	56.76%
Expected dividends	—

The following table summarizes stock option activity during the nine months ended September 30, 2009:

	Shares	Wtd Avg Exercise Price	Wtd Avg Remaining Contractual Life (In years)	Aggregate Intrinsic Value (In thousands)
Outstanding at December 31, 2008	1,103,336	\$ 14.20		
Granted	2,605,699	6.21		
Exercised	(147,510)	5.58		
Cancelled	(79,504)	9.01		
Outstanding at September 30, 2009	<u>3,482,021</u>	<u>\$ 8.70</u>	<u>7.6</u>	<u>\$ 24,668</u>
Exercisable at September 30, 2009	<u>803,128</u>	<u>\$ 10.25</u>	<u>2.4</u>	<u>\$ 5,046</u>
Vested at September 30, 2009 or expected to vest in the future	<u>3,303,418</u>	<u>\$ 7.18</u>		

Cash received from the exercise of stock options was \$0.8 million and \$1.2 million for the nine months ended September 30, 2009 and 2008, respectively.

Quicksilver Restricted Stock and Restricted Stock Units

The following table summarizes information regarding our restricted stock and RSU activity:

	Payable in stock		Payable in cash	
	Shares	Wtd Avg Grant Date Fair Value	Stock Units	Wtd Avg Grant Date Fair Value
Outstanding at December 31, 2008	1,336,111	\$24.01	—	\$ —
Granted	2,264,679	6.23	339,835	6.22
Vested	(715,431)	22.32	—	—
Cancelled	(156,900)	14.12	(5,795)	6.21
Outstanding at September 30, 2009	<u>2,728,459</u>	\$ 9.91	<u>334,040</u>	\$6.22

At January 1, 2009, we had total unvested compensation cost of \$17.6 million. During the first nine months of 2009, we recognized expense of \$12.4 million. Grants of restricted stock and stock-settled RSUs during the nine months ended September 30, 2009, had an estimated grant date fair value of \$16.2 million, which will be recognized as expense over the vesting period. Unrecognized compensation cost remaining at September 30, 2009 for restricted stock and stock-settled RSUs was \$19.3 million, which will be recognized through January 2011. The fair value of RSUs settled in cash was \$4.7 million at September 30, 2009. The total fair value of restricted shares and RSUs vested during the nine months ended September 30, 2009 was \$5.8 million.

KGS Phantom Units

On October 7, 2009, unitholders approved an amendment to the 2007 Equity Plan, which increased the number of units available for issuance to 750,000 as of November 4, 2009.

The following table summarizes information regarding KGS phantom unit activity:

	Payable in units		Payable in cash	
	Units	Wtd Avg Grant Date Fair Value	Units	Wtd Avg Grant Date Fair Value
Outstanding at December 31, 2008	139,918	\$25.15	60,319	\$21.63
Granted	405,428	10.06	920	13.40
Vested	(49,789)	25.25	(25,609)	13.53
Cancelled	(9,885)	15.90	(5,973)	21.36
Outstanding at September 30, 2009	<u>485,672</u>	\$12.73	<u>29,657</u>	\$28.42

At January 1, 2009, KGS had total unrecognized compensation cost of \$2.3 million related to unvested phantom unit awards. KGS recognized compensation expense of approximately \$1.9 million during the nine months ended September 30, 2009, including \$0.3 million related to Quicksilver equity grants issued to employees seconded to KGS. Grants of phantom units during the nine months ended September 30, 2009 had an estimated grant date fair value of \$4.1 million. KGS has unearned compensation expense of \$3.1 million at September 30, 2009 that will be recognized in expense through May 2012. Phantom units that vested during the nine months ended September 30, 2009 had a fair value of \$1.6 million on their vesting date.

12. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Note 21 to our 2008 Annual Report on Form 10-K, as amended, contains a more complete description of our guarantor, non-guarantor, restricted and unrestricted subsidiaries.

The following condensed consolidating financial information includes information about the Company and our restricted subsidiaries:

	September 30, 2009							
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Restricted Non-Guarantor Subsidiaries	Restricted Subsidiary Eliminations	Quicksilver and Restricted Subsidiaries	Unrestricted Non-Guarantor Subsidiaries	Consolidating Eliminations	Quicksilver Resources Inc. Consolidated
	(In thousands)							
ASSETS								
Current assets	\$ 362,105	\$ 198	\$ 48,680	\$ (119,055)	\$ 291,928	\$ 6,490	\$ (16,744)	\$ 281,674
Property and equipment	1,924,744	142,984	470,411	—	2,538,139	455,661	—	2,993,800
Investment in subsidiaries (equity method)	473,186	91,957	—	(358,453)	206,690	—	(91,957)	114,733
Other assets	275,033	67,238	1,643	—	343,914	1,635	(120,201)	225,348
Total assets	<u>\$ 3,035,068</u>	<u>\$ 302,377</u>	<u>\$ 520,734</u>	<u>\$ (477,508)</u>	<u>\$ 3,380,671</u>	<u>\$ 463,786</u>	<u>\$ (228,902)</u>	<u>\$ 3,615,555</u>
LIABILITIES AND STOCKHOLDERS' EQUITY								
Current liabilities	\$ 338,369	\$ 131,449	\$ 21,782	\$ (119,055)	\$ 372,545	\$ 10,241	\$ (16,744)	\$ 366,042
Long-term liabilities	2,115,343	11,458	299,969	—	2,426,770	336,556	(120,201)	2,643,125
Stockholders' equity	581,356	159,470	198,983	(358,453)	581,356	91,957	(91,957)	581,356
Noncontrolling interests	—	—	—	—	—	25,032	—	25,032
Total liabilities and stockholders' equity	<u>\$ 3,035,068</u>	<u>\$ 302,377</u>	<u>\$ 520,734</u>	<u>\$ (477,508)</u>	<u>\$ 3,380,671</u>	<u>\$ 463,786</u>	<u>\$ (228,902)</u>	<u>\$ 3,615,555</u>
December 31, 2008								
	Quicksilver Resources Inc.	Restricted Guarantor Subsidiaries	Restricted Non-Guarantor Subsidiaries	Restricted Subsidiary Eliminations	Quicksilver and Restricted Subsidiaries	Unrestricted Non-Guarantor Subsidiaries	Consolidating Eliminations	Quicksilver Resources Inc. Consolidated
	(In thousands)							
ASSETS								
Current assets	\$ 424,862	\$ 163	\$ 102,384	\$ (123,071)	\$ 404,338	\$ 2,613	\$ (13,615)	\$ 393,336
Property and equipment	2,756,915	1,774	550,906	—	3,309,595	488,120	—	3,797,715
Investment in subsidiaries (equity method)	513,706	79,316	—	(363,203)	229,819	—	(79,316)	150,503
Other assets	206,099	123,298	910	—	330,307	1,916	(175,569)	156,654
Total assets	<u>\$ 3,901,582</u>	<u>\$ 204,551</u>	<u>\$ 654,200</u>	<u>\$ (486,274)</u>	<u>\$ 4,274,059</u>	<u>\$ 492,649</u>	<u>\$ (268,500)</u>	<u>\$ 4,498,208</u>
LIABILITIES AND STOCKHOLDERS' EQUITY								
Current liabilities	\$ 357,077	\$ 122,677	\$ 44,907	\$ (123,071)	\$ 401,590	\$ 30,524	\$ (13,615)	\$ 418,499
Long-term liabilities	2,359,679	—	327,964	—	2,687,643	356,072	(175,569)	2,868,146
Stockholders' equity	1,184,826	81,874	281,329	(363,203)	1,184,826	79,316	(79,316)	1,184,826
Noncontrolling interests	—	—	—	—	—	26,737	—	26,737
Total liabilities and stockholders' equity	<u>\$ 3,901,582</u>	<u>\$ 204,551</u>	<u>\$ 654,200</u>	<u>\$ (486,274)</u>	<u>\$ 4,274,059</u>	<u>\$ 492,649</u>	<u>\$ (268,500)</u>	<u>\$ 4,498,208</u>
For the Three Months Ended September 30, 2009								
	Quicksilver Resources Inc.	Restricted Guarantor Subsidiaries	Restricted Non-Guarantor Subsidiaries	Restricted Subsidiary Eliminations	Quicksilver and Restricted Subsidiaries	Unrestricted Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
	(In thousands)							
Revenues	\$ 157,407	\$ (11)	\$ 47,648	\$ 91	\$ 205,135	\$ 24,298	\$ (22,776)	\$ 206,657
Operating expenses	90,053	2,190	20,224	91	112,558	13,172	(22,776)	102,954
Equity in net earnings of subsidiaries	23,685	7,224	—	(23,685)	7,224	—	(7,224)	—
Operating income (loss)	91,039	5,023	27,424	(23,685)	99,801	11,126	(7,224)	103,703
Income from earnings of BBEP	(43,685)	—	—	—	(43,685)	—	—	(43,685)
Interest expense and other	(38,525)	814	(2,315)	—	(40,026)	(2,238)	—	(42,264)
Income tax (expense) benefit	(8,099)	(2,043)	(5,218)	—	(15,360)	(235)	—	(15,595)
Net income (loss)	\$ 730	\$ 3,794	\$ 19,891	\$ (23,685)	\$ 730	\$ 8,653	\$ (7,224)	\$ 2,159
Net income attributable to noncontrolling interests	—	—	—	—	—	(1,429)	—	(1,429)
Net income attributable Quicksilver	<u>\$ 730</u>	<u>\$ 3,794</u>	<u>\$ 19,891</u>	<u>\$ (23,685)</u>	<u>\$ 730</u>	<u>\$ 7,224</u>	<u>\$ (7,224)</u>	<u>\$ 730</u>

For the Three Months Ended September 30, 2008

	<u>Quicksilver Resources Inc.</u>	<u>Restricted Guarantor Subsidiaries</u>	<u>Restricted Non-Guarantor Subsidiaries</u>	<u>Restricted Subsidiary Eliminations</u>	<u>Quicksilver and Restricted Subsidiaries</u>	<u>Unrestricted Non-Guarantor Subsidiaries</u>	<u>Eliminations</u>	<u>Quicksilver Resources Inc. Consolidated</u>
	(In thousands)							
Revenues	\$ 171,639	\$ —	\$ 61,266	\$ —	\$ 232,905	\$ 19,304	\$ (15,947)	\$ 236,262
Operating expenses	100,488	376	21,244	—	122,108	10,111	(15,947)	116,272
Equity in net earnings of subsidiaries	29,851	5,263	—	(29,851)	5,263	—	(5,263)	—
Operating income	101,002	4,887	40,022	(29,851)	116,060	9,193	(5,263)	119,990
Loss from earnings of BBEP	(89,814)	—	—	—	(89,814)	—	—	(89,814)
Interest expense and other	(31,948)	1,736	(5,190)	—	(35,402)	(2,699)	—	(38,101)
Income tax (expense) benefit	17,005	(2,317)	(9,287)	—	5,401	(106)	—	5,295
Net income	<u>\$ (3,755)</u>	<u>\$ 4,306</u>	<u>\$ 25,545</u>	<u>\$ (29,851)</u>	<u>\$ (3,755)</u>	<u>\$ 6,388</u>	<u>\$ (5,263)</u>	<u>\$ (2,630)</u>
Net income attributable to noncontrolling interests	—	—	—	—	—	(1,125)	—	(1,125)
Net income (loss) attributable to Quicksilver	<u>\$ (3,755)</u>	<u>\$ 4,306</u>	<u>\$ 25,545</u>	<u>\$ (29,851)</u>	<u>\$ (3,755)</u>	<u>\$ 5,263</u>	<u>\$ (5,263)</u>	<u>\$ (3,755)</u>

For the Nine Months Ended September 30, 2009

	<u>Quicksilver Resources Inc.</u>	<u>Guarantor Subsidiaries</u>	<u>Restricted Non-Guarantor Subsidiaries</u>	<u>Restricted Subsidiary Eliminations</u>	<u>Quicksilver and Restricted Subsidiaries</u>	<u>Unrestricted Non-Guarantor Subsidiaries</u>	<u>Eliminations</u>	<u>Quicksilver Resources Inc. Consolidated</u>
	(In thousands)							
Revenues	\$ 452,403	\$ 689	\$ 140,786	\$ (394)	\$ 593,484	\$ 72,993	\$ (67,847)	\$ 598,630
Operating expenses	1,094,552	4,547	240,063	(394)	1,338,768	39,125	(67,847)	1,310,046
Equity in net earnings of subsidiaries	(65,113)	21,088	—	65,113	21,088	—	(21,088)	—
Operating income (loss)	(707,262)	17,230	(99,277)	65,113	(724,196)	33,868	(21,088)	(711,416)
Income from earnings of BBEP	(24,669)	—	—	—	(24,669)	—	—	(24,669)
Interest expense and other	(139,682)	3,389	(6,424)	—	(142,717)	(7,923)	—	(150,640)
Income tax (expense) benefit	281,602	(7,217)	27,186	—	301,571	(446)	—	301,125
Net income (loss)	<u>\$ (590,011)</u>	<u>\$ 13,402</u>	<u>\$ (78,515)</u>	<u>\$ 65,113</u>	<u>\$ (590,011)</u>	<u>\$ 25,499</u>	<u>\$ (21,088)</u>	<u>\$ (585,600)</u>
Net income attributable to noncontrolling interests	—	—	—	—	—	(4,411)	—	(4,411)
Net income (loss) attributable to Quicksilver	<u>\$ (590,011)</u>	<u>\$ 13,402</u>	<u>\$ (78,515)</u>	<u>\$ 65,113</u>	<u>\$ (590,011)</u>	<u>\$ 21,088</u>	<u>\$ (21,088)</u>	<u>\$ (590,011)</u>

For the Nine Months Ended September 30, 2008

	<u>Quicksilver Resources Inc.</u>	<u>Guarantor Subsidiaries</u>	<u>Restricted Non-Guarantor Subsidiaries</u>	<u>Restricted Subsidiary Eliminations</u>	<u>Quicksilver and Restricted Subsidiaries</u>	<u>Unrestricted Non-Guarantor Subsidiaries</u>	<u>Eliminations</u>	<u>Quicksilver Resources Inc. Consolidated</u>
	(In thousands)							
Revenues	\$ 437,512	\$ —	\$ 145,238	\$ —	\$ 582,750	\$ 52,694	\$ (43,664)	\$ 591,780
Operating expenses	240,274	1,389	65,790	—	307,453	30,175	(43,664)	293,964
Equity in net earnings of subsidiaries	59,469	12,257	—	(59,469)	12,257	—	(12,257)	—
Operating income	256,707	10,868	79,448	(59,469)	287,554	22,519	(12,257)	297,816
Loss from earnings of BBEP	(93,864)	—	—	—	(93,864)	—	—	(93,864)
Interest expense and other	(50,601)	4,664	(13,107)	—	(59,044)	(7,532)	—	(66,576)
Income tax (expense) benefit	(23,528)	(5,436)	(16,968)	—	(45,932)	(109)	—	(46,041)
Net income	<u>\$ 88,714</u>	<u>\$ 10,096</u>	<u>\$ 49,373</u>	<u>\$ (59,469)</u>	<u>\$ 88,714</u>	<u>\$ 14,878</u>	<u>\$ (12,257)</u>	<u>\$ 91,335</u>
Net income attributable to noncontrolling interests	—	—	—	—	—	(2,621)	—	(2,621)
Net income attributable to Quicksilver	<u>\$ 88,714</u>	<u>\$ 10,096</u>	<u>\$ 49,373</u>	<u>\$ (59,469)</u>	<u>\$ 88,714</u>	<u>\$ 12,257</u>	<u>\$ (12,257)</u>	<u>\$ 88,714</u>

For the Nine Months Ended September 30, 2009								
	Quicksilver Resources Inc.	Restricted Guarantor Subsidiaries	Restricted Non-Guarantor Subsidiaries	Restricted Subsidiary Eliminations	Quicksilver and Restricted Subsidiaries	Unrestricted Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
(In thousands)								
Net cash flow provided by operating activities	\$ 260,402	\$ 47,666	\$ 121,102	\$ —	\$ 429,170	\$ 51,268	\$ (29,845)	\$ 450,593
Purchases of property, plant and equipment	(387,938)	(47,666)	(79,745)	—	(515,349)	(50,067)	4,296	(561,120)
Assets purchased under Repurchase Obligation	—	—	—	—	—	(5,645)	5,645	—
Proceeds from sales of property, plant and equipment	220,270	—	768	—	221,038	—	—	221,038
Net cash flow used for investing activities	(167,668)	(47,666)	(78,977)	—	(294,311)	(55,712)	9,941	(340,082)
Issuance of debt	1,278,138	—	52,887	—	1,331,025	46,500	—	1,377,525
Repayments of debt	(1,396,105)	—	(96,532)	—	(1,492,637)	(14,500)	—	(1,507,137)
Debt issuance costs	(29,870)	—	(1,125)	—	(30,995)	—	—	(30,995)
Gas Purchase Commitment — net	54,488	—	—	—	54,488	—	—	54,488
Distributions to parent	—	—	—	—	—	(19,904)	19,904	—
Distributions to noncontrolling interests	—	—	—	—	—	(7,344)	—	(7,344)
Other	(44)	—	—	—	(44)	(63)	—	(107)
Net cash flow provided by (used for) financing activities	(93,393)	—	(44,770)	—	(138,163)	4,689	19,904	(113,570)
Effect of exchange rates on cash	—	—	1,779	—	1,779	—	—	1,779
Net decrease in cash and equivalents	(659)	—	(866)	—	(1,525)	245	—	(1,280)
Cash and equivalents at beginning of period	1,679	—	866	—	2,545	303	—	2,848
Cash and equivalents at end of period	\$ 1,020	\$ —	\$ —	\$ —	\$ 1,020	\$ 548	\$ —	\$ 1,568

For the Nine Months Ended September 30, 2008								
	Quicksilver Resources Inc.	Restricted Guarantor Subsidiaries	Restricted Non-Guarantor Subsidiaries	Restricted Subsidiary Eliminations	Quicksilver and Restricted Subsidiaries	Unrestricted Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
(In thousands)								
Net cash flow provided by operations	\$ 138,736	\$ 2,483	\$ 113,616	\$ —	\$ 254,835	\$ 36,365	\$ (17,080)	\$ 274,120
Purchases of property, plant and equipment	(1,744,219)	(2,483)	(116,871)	—	(1,863,573)	(112,200)	—	(1,975,773)
Return of investment from BBEP	31,435	—	—	—	31,435	—	—	31,435
Proceeds from sales of property, plant and equipment	1,025	—	618	—	1,643	—	(825)	818
Net cash flow used for investing activities	(1,711,759)	(2,483)	(116,253)	—	(1,830,495)	(112,200)	(825)	(1,943,520)
Issuance of debt	2,169,611	—	203,208	—	2,372,819	99,300	—	2,472,119
Repayments of debt	(583,782)	—	(198,206)	—	(781,988)	—	—	(781,988)
Debt issuance costs	(24,545)	—	—	—	(24,545)	—	—	(24,545)
Payments to parent	—	—	—	—	—	(825)	825	—
Distributions to parent	—	—	—	—	—	(17,080)	17,080	—
Distributions to noncontrolling interests	—	—	—	—	—	(6,343)	—	(6,343)
Other	(1,995)	—	—	—	(1,995)	—	—	(1,995)
Net cash flow provided by (used for) financing activities	1,559,289	—	5,002	—	1,564,291	75,052	17,905	1,657,248
Effect of exchange rates on cash	(155)	—	(2,454)	—	(2,609)	—	—	(2,609)
Net decrease in cash and equivalents	(13,889)	—	(89)	—	(13,978)	(783)	—	(14,761)
Cash and equivalents at beginning of period	27,012	—	89	—	27,101	1,125	—	28,226
Cash and equivalents at end of period	\$ 13,123	\$ —	\$ —	\$ —	\$ 13,123	\$ 342	\$ —	\$ 13,465

13. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid (received) for interest and income taxes is as follows:

Interest	Nine Months Ended September 30,	
	2009	2008
(In thousands)		
	\$111,549	\$58,762

Income taxes

(41,267) 49,775

Other non-cash transactions include:

	Nine Months Ended September 30,	
	2009	2008
	(In thousands)	
Working capital related to acquisition of property, plant and equipment	\$126,520	\$191,959
Issuance of common stock as consideration for the Alliance Acquisition	—	262,092

14. RELATED-PARTY TRANSACTIONS

As of September 30, 2009, members of the Darden family and entities controlled by them beneficially owned approximately 30% of our outstanding common stock. Thomas F. Darden, Glenn Darden and Anne Darden Self are officers and directors of Quicksilver.

Quicksilver and its associated entities paid \$0.6 million and \$1.6 million in the first nine months of 2009 and 2008, respectively, for rent on buildings owned by entities affiliated with Mercury. Rental rates have been determined based on comparable rates charged by third parties.

We paid \$0.2 million and \$0.7 million during the first nine months of 2009 and 2008, respectively, for use of an airplane owned by an entity controlled by members of the Darden family. Usage rates are determined based on comparable rates charged by third parties.

We paid \$0.2 million in the first nine months of 2009 for delay rentals under leases for over 5,000 acres held by a related party entity. The lease terms were determined based on comparable prices and terms granted to third parties with respect to similar leases in the area.

Payments received from Mercury for sublease rentals, employee insurance coverage and administrative services during the first nine months of 2009 and 2008 totaled \$0.2 million and \$0.1 million, respectively.

15. SEGMENT INFORMATION

We operate in two geographic segments, the United States and Canada, where we are engaged in the exploration and production segment of the oil and gas industry. Additionally, we operate in the midstream segment, where we provide natural gas processing and gathering services in the United States, predominantly through KGS. Revenue earned by KGS for the processing and gathering of Quicksilver gas are eliminated on a consolidated basis as are the costs of these services recognized by Quicksilver's producing properties. We evaluate performance based on operating income and property and equipment costs incurred.

	Exploration & Production		Processing & Gathering	Corporate and Other	Elimination	Quicksilver Consolidated
	United States	Canada				
	(in thousands)					
For the Three Months Ended						
September 30, :						
2009						
Revenues	\$ 157,407	\$ 47,648	\$ 24,287	\$ —	\$ (22,685)	\$ 206,657
Depletion, depreciation and accretion	27,957	9,321	6,836	434	—	44,548
Operating income	82,747	28,354	10,718	(18,116)	—	103,703
Property and equipment costs incurred	80,852	13,925	43,946	362	—	139,085
2008						
Revenues	\$ 171,421	\$ 61,484	\$ 19,304	\$ —	\$ (15,947)	\$ 236,262
Depletion, depreciation and accretion	36,178	11,337	3,990	272	—	51,777
Operating income	94,650	40,927	8,817	(24,404)	—	119,990
Property and equipment costs incurred	1,484,080	21,208	97,525	215	—	1,603,028

	<u>Exploration & Production</u>		<u>Processing &</u>	<u>Corporate</u>		<u>Quicksilver</u>
	<u>United States</u>	<u>Canada</u>	<u>Gathering</u>	<u>and Other</u>	<u>Elimination</u>	<u>Consolidated</u>
	(in thousands)					
For the Nine Months Ended						
September 30, :						
2009						
Revenues	\$ 452,403	\$ 140,786	\$ 73,682	\$ —	\$ (68,241)	\$ 598,630
Depletion, depreciation and accretion	106,338	29,284	18,346	1,242	—	155,210
Operating income	(589,707)	(96,487)	35,472	(60,694)	—	(711,416)
Property and equipment costs incurred	308,905	70,440	92,226	2,018	—	473,589
2008						
Revenues	\$ 436,925	\$ 145,825	\$ 52,694	\$ —	\$ (43,664)	\$ 591,780
Depletion, depreciation and accretion	79,731	34,353	10,874	798	—	125,756
Operating income	247,311	81,862	21,130	(52,487)	—	297,816
Property and equipment costs incurred	1,938,667	108,482	204,330	769	—	2,252,248
Property, Plant and Equipment-net						
September 30, 2009	\$ 1,912,941	\$ 470,411	\$ 598,645	\$ 11,803	\$ —	\$ 2,993,800
December 31, 2008	2,723,103	550,413	519,447	4,752	—	3,797,715

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

The following discussion and analysis of our consolidated financial condition and results of operations should be read in conjunction with our condensed consolidated financial statements, and notes thereto, and the other financial data included elsewhere in this quarterly report. The following discussion should also be read in conjunction with our audited consolidated financial statements, and notes thereto, and "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in our 2008 Annual Report on Form 10-K, as amended.

EXECUTIVE OVERVIEW

We are an independent energy company engaged primarily in exploration, development and production of unconventional natural gas onshore in North America. We own producing oil and natural gas properties in the United States, principally in Texas, and in Alberta, Canada, where we had total estimated aggregate proved reserves of approximately 2.2 Tcfe at December 31, 2008. We also have properties in the Horn River Basin of Northeast British Columbia, the Greater Green River Basin of Colorado and the Delaware Basin of West Texas where we are exploring for additional reserves, but have recognized only immaterial proved reserves based upon exploration to date. In addition, we own approximately 73% of KGS, a publicly traded midstream master limited partnership controlled and consolidated by us, and we own approximately 40% of the limited partner units of BBEP, a publicly traded oil and natural gas exploration and production master limited partnership, which we account for using the equity method.

2009 HIGHLIGHTS

Eni Transaction

On June 19, 2009, we completed the Eni Transaction whereby we entered into a strategic alliance with Eni and sold a 27.5% interest in our Alliance Leasehold. The total proceeds for the Eni Transaction were \$280 million in cash, inclusive of the Gas Purchase Commitment, and subject to normal post-closing adjustments. We used the proceeds from the transaction to repay a portion of the Senior Secured Second Lien Facility. Notes 2 and 4 in the condensed consolidated financial statements contains further information regarding the Eni Transaction and the Gas Purchase Commitment.

Long-Term Debt

Upon completion of the Eni Transaction, the borrowing base under the Senior Secured Credit Facility was adjusted to \$1.125 billion. The October 2009 redetermination resulted in a revised borrowing base of \$1.0 billion. The credit facility provides us an option to increase the commitment by up to \$250 million, with a maximum of \$1.45 billion with lenders consents and additional commitments. We can also extend the facility, which matures on February 9, 2012, up to two additional years with lender approval. Note 7 to the condensed consolidated financial statements contains additional information about our long-term debt.

On June 25, 2009, we issued Senior Notes due 2016 with a principal amount of \$600 million for proceeds of \$580.3 million. The notes bear interest at the rate of 11.75%. The proceeds of these notes, in addition to proceeds from the Eni Transaction, were used to repay and terminate the remaining indebtedness under our Senior Secured Second Lien Facility and to make repayments under the Senior Secured Credit Facility.

On August 14, 2009, we issued Senior Notes due 2019 with a principal amount of \$300 million for proceeds of \$292.8 million. The notes bear interest at the rate of 9.125%. The proceeds of these notes were used to make repayments under the Senior Secured Credit Facility.

Increase in Production

Daily production increased 34% during the nine months ended September 30, 2009 from the corresponding period in 2008. The production increase is discussed further in *Results of Operations* below.

Horn River Basin Discovery

During the first nine months of 2009, we spent \$44 million for exploration and facilities in the Horn River Basin where we have drilled and cased two wells, one of which was placed into service in the third quarter of 2009 with an initial production rate of 13 Mcfd. Our capital expenditures include costs related to infrastructure development, such as construction of roads and production laterals.

We also entered into a nine-year agreement with a third party that began in May 2009 for the firm transportation of natural gas out of the Horn River Basin with initial volumes of 3 MMcfd and increasing to 100 MMcfd in May 2013. We expect that the second well will be completed and commence production during the late fourth quarter of 2009 or early first quarter of 2010.

BBEP Update

In April 2009, BBEP announced that it was suspending its distributions to remain in compliance with certain provisions of its credit facility and to redirect cash flow to reduce its debt. BBEP management stated that the future resumption of distributions may be at levels below the recent distribution rate, but it cannot forecast or predict when distributions will resume. In February 2009, we received a quarterly distribution of \$11.1 million for the quarter ended December 31, 2008. During the nine months ended September 30, 2009, we recognized \$77.4 million of equity earnings in BBEP and an impairment of \$102.1 million.

Litigation Update

In October 2009, a jury awarded \$22 million to the plaintiffs in our litigation originally brought against us by the plaintiffs Rod and Richard Thornton and Eagle Drilling, LLC. We are actively seeking an appeal in this matter.

In June 2009, the appellate court in the CMS litigation reversed the original district court judgment. Pursuant to a settlement agreement, we paid CMS \$5 million during July 2009, which we accrued during the quarter ended June 30, 2009.

2009 — 2010 OUTLOOK

Commodity prices, drilling and well completion costs and access to capital and services are the most significant drivers of our business. As of the date of this report, the credit markets remain tight and natural gas prices, both in the near-term and intermediate future, remain at low levels due to the global recession and the level of natural gas supply relative to its demand. As a result, we continue to focus on ways to optimize our 2009 capital program and prepare for our 2010 program. We currently expect that the 2009 capital program will total approximately \$550 million, net of midstream capital contributed by Eni and working capital changes. Our focus remains on the continued development of our properties in the Barnett Shale and exploration in the Horn River and Greater Green River Basins. For the remainder of 2009, we expect to spend approximately \$63 million for exploration and development activities, \$26 million for midstream facilities (including approximately \$7 million to be funded directly by KGS) and approximately \$7 million for other property and equipment. On a regional basis, approximately \$52 million is forecasted in Texas to drill approximately 32 net wells on operated properties, to complete and tie-in approximately 14 of those net wells and to further develop our midstream infrastructure. Canadian spending for the remainder of 2009 is forecasted to be approximately \$6 million chiefly to explore the Horn River Basin and, to a lesser extent, limit decreases to current production levels. The remaining capital budget is spread among our other operating areas. We expect the final 2009 capital program to be less than the cash flows generated by our internal funding sources.

Our remaining 2009 program described above is dynamic and there are a number of factors that could affect our decision to invest capital. Commodity prices, well costs, hedging programs and program performance are a few factors that individually or in combination could change the scale or relative allocation of our remaining capital program for 2009. We are currently developing our capital budget for 2010 and have yet to determine the exact allocation geographically or by expenditure type. However, we do expect capital expenditures in 2010 to be less than cash flows generated by our internal funding sources.

RESULTS OF OPERATIONS — Three Months Ended September 30, 2009 and 2008

The following discussion compares the results of operations for the three months ended September 30, 2009 and 2008, or the 2009 quarter and 2008 quarter, respectively.

Natural Gas, NGL and Crude Oil Revenue

Production Revenue:

	Natural Gas		NGL		Oil and Condensate		Total	
	2009	2008	2009	2008	2009	2008	2009	2008
	(In millions)							
Texas	\$ 45.7	\$117.4	\$ 36.1	\$ 61.6	\$ 3.3	\$ 9.1	\$ 85.1	\$188.1
Other U.S.	0.1	0.2	0.2	0.4	2.2	4.7	2.5	5.3
Hedging	63.2	(15.1)	—	(4.9)	—	(3.4)	63.2	(23.4)
Total U.S.	109.0	102.5	36.3	57.1	5.5	10.4	150.8	170.0
Canada	18.0	51.6	—	—	—	—	18.0	51.6
Hedging	29.5	(3.4)	—	—	—	—	29.5	(3.4)
Total Canada	47.5	48.2	—	—	—	—	47.5	48.2
Total Company	<u>\$156.5</u>	<u>\$150.7</u>	<u>\$ 36.3</u>	<u>\$ 57.1</u>	<u>\$ 5.5</u>	<u>\$ 10.4</u>	<u>\$198.3</u>	<u>\$218.2</u>

Average Daily Production Volumes:

	Natural Gas		NGL		Oil and Condensate		Equivalent Total	
	2009	2008	2009	2008	2009	2008	2009	2008
	(MMcfd)		(Bbl/d)		(Bbl/d)		(MMcfd)	
Texas	153.0	137.1	13,973	11,485	565	865	240.2	211.2
Other U.S.	0.4	0.2	48	49	416	469	3.2	3.3
Total U.S.	153.4	137.3	14,021	11,534	981	1,334	243.4	214.5
Canada	67.8	62.5	3	—	—	—	67.8	62.5
Total Company	<u>221.2</u>	<u>199.8</u>	<u>14,024</u>	<u>11,534</u>	<u>981</u>	<u>1,334</u>	<u>311.2</u>	<u>277.0</u>

Average Realized Prices:

	Natural Gas		NGL		Oil and Condensate		Equivalent Total	
	2009	2008	2009	2008	2009	2008	2009	2008
	(per Mcf)		(per Bbl)		(per Bbl)		(per Mcfe)	
Texas	\$ 3.25	\$ 9.31	\$ 28.11	\$58.30	\$62.46	\$114.11	\$ 3.85	\$ 9.68
Other U.S.	3.22	3.77	34.43	88.26	57.96	107.59	8.52	16.69
Hedging — U.S.	4.48	(1.19)	—	(4.61)	—	(27.01)	2.82	(1.18)
Total U.S.	7.73	8.11	28.15	53.82	60.55	84.80	6.73	8.61
Canada	2.89	8.97	116.68	—	—	—	2.89	8.97
Hedging — Canada	4.73	(0.58)	—	—	—	—	4.73	(0.58)
Total Canada	7.61	8.39	116.68	—	—	—	7.61	8.39
Total Company	<u>\$ 7.69</u>	<u>\$ 8.20</u>	<u>\$ 28.15</u>	<u>\$53.82</u>	<u>\$60.55</u>	<u>\$ 84.80</u>	<u>\$ 6.93</u>	<u>\$ 8.56</u>

The following table summarizes the changes in our production revenues during the 2009 quarter compared with the 2008 quarter:

	<u>Natural Gas</u>	<u>NGL</u>	<u>Oil</u>	<u>Total</u>
	(In thousands)			
Revenue for the quarter ended September 30, 2008	\$ 150,697	\$ 57,108	\$ 10,409	\$ 218,214
Volume variance	16,100	12,326	(2,757)	25,669
Hedge settlement variance	111,179	4,944	3,395	119,518
Price variance	(121,476)	(38,055)	(5,583)	(165,114)
Revenue for the quarter ended September 30, 2009	<u>\$ 156,500</u>	<u>\$ 36,323</u>	<u>\$ 5,464</u>	<u>\$ 198,287</u>

Natural gas revenue increased as a result of increases in production and the effect of hedge settlements which were nearly offset by a decrease in prices for the 2009 quarter as compared to the 2008 quarter. The 16.1 MMcfd increase in U.S. natural gas volumes was due to wells placed into service in the Fort Worth Basin subsequent to September 30, 2008. Natural production declines from existing Fort Worth Basin wells partially offset the volume increases for the 2009 quarter. Canadian natural gas production increased 5.3 MMcfd from new wells placed into service subsequent to September 30, 2008, which includes the Horn River well placed into service during the 2009 quarter.

The decrease in NGL revenue was because of a 52% decrease in Fort Worth Basin prices for the 2009 quarter compared to the 2008 quarter. Partially offsetting the price decrease were a production increase from the Fort Worth Basin and the absence of outlays for hedge settlements. The 22% increase in Fort Worth Basin production was due to new wells placed into production subsequent to September 30, 2008, lower field pressures and improved NGL recoveries from the Corvette Plant, which was placed into service by KGS during the first quarter of 2009.

Oil and condensate revenue for the 2009 quarter decreased due to both a 45% decrease in prices for the 2009 quarter as compared to the 2008 quarter and a 353 Bbld decrease in production for the 2009 quarter. An absence of outlays for hedge settlements partially offset these decreases.

Utilization of our hedging program may result in natural gas, NGL and crude oil realized prices varying from market prices that we receive from the sale of natural gas, NGL and crude oil. Our revenue from natural gas, NGL and crude oil production was \$92.8 million higher and \$26.8 million lower because of our hedging programs for 2009 quarter and 2008 quarter, respectively.

We expect our average production for the fourth quarter of 2009 to range between 330 MMcfd to 340 MMcfd.

Sales of Purchased Natural Gas and Costs of Purchased Natural Gas

	Three Months Ended	
	September 30,	
	<u>2009</u>	<u>2008</u>
	(In thousands)	
Sales of purchased natural gas	\$ 5,964	\$ —
Costs of purchased natural gas sold	(5,594)	—
Gain on valuation of Gas Purchase Commitment	2,630	—
Costs of purchased natural gas	(2,964)	—
Net sales and purchases of natural gas	<u>\$ 3,000</u>	<u>\$ —</u>

Our marketing activities related to the purchase and sale of natural gas have increased in Texas because of natural gas sales and purchases made under the Gas Purchase Commitment. The Gas Purchase Commitment is more fully described in Note 4 in the condensed consolidated financial statements.

Other Revenue

Other revenue of \$2.4 million for the 2009 period decreased \$15.6 million from the 2008 quarter. The decrease was primarily because of the absence of \$13.5 million in gains from Canadian hedge ineffectiveness recognized in the 2008 quarter. The 2008 quarter gains were the result of the recovery of losses from Canadian hedge derivative ineffectiveness recognized in the 2008 second quarter. Additionally, KGS third-party processing and transportation revenue for the 2009 quarter decreased \$1.9 million as compared to the 2008 quarter.

Oil and Gas Production Expense

	Three Months Ended September 30,			
	2009		2008	
	(In thousands, except per unit amounts)			
		Per Mcf		Per Mcf
Texas				
Cash expense	\$18,051	\$ 0.82	\$21,644	\$ 1.11
Equity compensation	270	0.01	301	0.02
	<u>\$18,321</u>	<u>\$ 0.83</u>	<u>\$21,945</u>	<u>\$ 1.13</u>
Other U.S.				
Cash expense	\$ 1,633	\$ 5.53	\$ 1,639	\$ 5.31
Equity compensation	49	0.17	42	0.14
	<u>\$ 1,682</u>	<u>\$ 5.70</u>	<u>\$ 1,681</u>	<u>\$ 5.45</u>
Total U.S.				
Cash expense	\$19,684	\$ 0.88	\$23,283	\$ 1.18
Equity compensation	319	0.01	343	0.02
	<u>\$20,003</u>	<u>\$ 0.89</u>	<u>\$23,626</u>	<u>\$ 1.20</u>
Canada				
Cash expense	\$ 8,594	\$ 1.38	\$ 8,837	\$ 1.54
Equity compensation	467	0.07	605	0.10
	<u>\$ 9,061</u>	<u>\$ 1.45</u>	<u>\$ 9,442</u>	<u>\$ 1.64</u>
Total Company				
Cash expense	\$28,278	\$ 0.99	\$32,120	\$ 1.26
Equity compensation	786	0.03	948	0.04
	<u>\$29,064</u>	<u>\$ 1.02</u>	<u>\$33,068</u>	<u>\$ 1.30</u>

U.S. production expense decreased \$3.6 million because of cost containment efforts in the Fort Worth Basin during the 2009 quarter when compared to the 2008 quarter despite higher production levels. Our daily production from the Fort Worth Basin increased approximately 14% for the 2009 quarter compared to the 2008 quarter while Fort Worth Basin production expense per Mcfe for the 2009 quarter decreased 27% from the 2008 quarter. Fort Worth Basin production expense of \$0.83 per Mcfe for the 2009 quarter also reflected a 23% decrease from \$1.08 per Mcfe for the fourth quarter of 2008 and a 6% decrease from the \$0.88 per Mcfe for the second quarter of 2009. These decreases resulted from lower saltwater disposal costs, vendor price reductions, and our ongoing stringent efforts to contain costs through vendor bidding processes, bulk purchasing and additional automation of well operations.

Canadian production expense for the 2009 quarter was down \$0.4 million, or \$0.19 per Mcfe, as compared to the 2008 quarter. Decreases in Canadian production expense were primarily the result of changes in U.S.-Canadian exchange rates for the 2009 quarter when compared to the 2008 quarter. Canadian production expense on a Canadian dollar basis increased approximately 2% primarily due to higher Canadian production levels.

Production and Ad Valorem Taxes

	Three Months Ended September 30,			
	2009		2008	
	(In thousands, except per unit amounts)			
		Per Mcf		Per Mcf
Production and ad valorem taxes				
U.S.	\$5,718	\$ 0.26	\$5,166	\$ 0.26
Canada	912	0.15	(222)	(0.04)
Total production and ad valorem taxes	\$6,630	\$ 0.23	\$4,944	\$ 0.19

Ad valorem taxes in the Fort Worth Basin increased approximately \$1.3 million from the 2008 quarter to the 2009 quarter because of the addition of wells and midstream facilities placed into service over the past twelve months. Partially offsetting this increase was a \$0.7 million decrease in U.S. production taxes from the 2008 quarter. Lower sales prices received for production in the 2009 quarter as compared to the 2008 quarter resulted in lower production taxes. Lower Canadian taxes for the 2008 quarter were the result of recoupment of 2006 and 2007 taxes.

Other Operating Costs

Other operating costs increased \$1.2 million from the 2008 quarter primarily due to additional KGS operating expenses associated with the operation of its Corvette Plant that commenced operations in the first quarter of 2009. These KGS expenses are associated with its third-party gathering and processing revenues.

Depletion, Depreciation and Accretion

	Three Months Ended September 30,			
	2009		2008	
	(In thousands, except per unit amounts)			
		Per Mcf		Per Mcf
Depletion				
U.S.	\$26,365	\$ 1.18	\$34,348	\$ 1.74
Canada	7,985	1.28	10,120	1.76
Total depletion	34,350	1.20	44,468	1.74
Depreciation of other fixed assets				
U.S.	\$ 8,576	\$ 0.38	\$ 5,928	\$ 0.30
Canada	1,039	0.17	1,006	0.17
Total depreciation	9,615	0.34	6,934	0.27
Accretion	583	0.02	375	0.02
Total depletion, depreciation and accretion	\$44,548	\$ 1.56	\$51,777	\$ 2.03

Lower depletion for the 2009 quarter when compared with the 2008 quarter was due to a decrease in depletion rates. Our U.S. depletion expense decreased \$8.0 million due primarily to a 32% decrease in our U.S. depletion rate that was partially offset by a 13% increase in U.S. production volumes. Lower Canadian depletion expense for the 2009 quarter was the result of a 27% decrease in the Canadian depletion rate partially offset by the 8% increase in Canadian production volumes, as compared to the 2008 quarter. Both the U.S. and Canadian depletion rates have decreased because of impairment charges. U.S. impairment charges were recognized in the fourth quarter of 2008 and the first quarter of 2009. Canadian impairment charges were recognized in the first and second quarters of 2009. The \$2.6 million increase in U.S. depreciation for the 2009 quarter as compared to the 2008 quarter was primarily associated with additions of Fort Worth Basin field compression and the KGS gathering system in addition to KGS' Corvette Plant that was placed into service in the first quarter of 2009.

General and Administrative Expense

	Three Months Ended September 30,			
	2009		2008	
	(In thousands, except per unit amounts)			
		Per Mcf		Per Mcf
General and administrative expense				
Cash expense	\$12,968	\$ 0.46	\$12,674	\$ 0.49
Litigation settlement	1,000	0.03	9,633	0.38
Equity compensation	3,714	0.13	3,298	0.13
Total general and administrative expense	\$17,682	\$ 0.62	\$25,605	\$ 1.00

General and administrative expense decreased \$7.9 million because of the absence of a \$9.6 million charge for a legal settlement incurred for the 2008 quarter partially offset by a \$1.0 million charge in the 2009 quarter for the Eagle litigation. Accrued bonuses for the 2009 quarter were \$1.1 million lower, but were partially offset by a \$0.5 million increase stock-based compensation expense when compared to the 2008 quarter. Additional expenses for legal and accounting fees increased general and administrative expense by approximately \$0.9 million for the 2009 quarter as compared to the 2008 quarter.

BBEP-Related Income

During the 2009 quarter, we recognized a loss of \$43.7 million for equity earnings from our investment in BBEP based upon its reported earnings for the quarter ended June 30, 2009 as compared to a loss of \$89.8 million that we recognized for the 2008 quarter. BBEP continues to experience significant volatility in its net earnings due to changes in value of its derivative instruments for which it does not employ hedge accounting. Note 5 to the condensed consolidated financial statements contains additional information regarding our investment in BBEP.

Interest Expense

	Three Months Ended September 30,	
	2009	2008
	(in thousands)	
Interest costs	\$ 38,676	\$ 35,209
Add: Non-cash interest ⁽¹⁾	4,705	3,553
Less: Interest capitalized	(1,762)	(2,774)
Interest expense	\$ 41,619	\$ 35,988

⁽¹⁾ Amortization of deferred financing costs and original issue discount

Interest costs for the 2009 quarter were higher than the 2008 quarter primarily because of higher outstanding debt balances partially offset by slightly lower interest rates. Additionally, proceeds from our interest rate swaps, initiated in June 2009, reduced interest expense \$6.5 million.

Income Tax Expense

	Three Months Ended	
	September 30,	
	2009	2008
Income tax (benefit) expense (in thousands)	\$15,595	\$(5,295)
Effective tax rate	87.8%	66.8%

Our provision for income taxes for the 2009 quarter changed from the 2008 quarter due to higher income before taxes for the 2009 quarter as compared to the 2008 quarter. The effective tax rate for the 2009 quarter was almost 88% primarily due to changes in our estimated annual effective tax rate for 2009, which had been forecasted as a 35% income tax benefit through June 30, 2009. We now expect a 34% income tax benefit based on changes to the expected earnings allocation between the U.S. and Canada. This change in the expected rate for 2009 required third quarter recognition of the cumulative amount to bring the year to date income tax provision to the 34% level. The 2009 quarter includes an estimated \$9.6 million change to the income tax provision for earnings recognized through the period ended June 30, 2009.

RESULTS OF OPERATIONS — Nine Months Ended September 30, 2009 and 2008

The following discussion compares the results of operations for the nine months ended September 30, 2009 and 2008, or the 2009 period and 2008 period, respectively.

Natural Gas, NGL and Crude Oil Revenue

Production Revenue:

	Natural Gas		NGL		Oil and Condensate		Total	
	2009	2008	2009	2008	2009	2008	2009	2008
	(In millions)							
Texas	\$170.5	\$272.8	\$ 94.2	\$171.5	\$ 10.5	\$ 25.8	\$275.2	\$470.1
Other U.S.	0.3	0.4	0.1	1.0	5.5	13.2	5.9	14.6
Hedging	159.3	(28.5)	—	(13.4)	—	(8.6)	159.3	(50.5)
Total U.S.	330.1	244.7	94.3	159.1	16.0	30.4	440.4	434.2
Canada	65.0	151.1	0.1	—	—	—	65.1	151.1
Hedging	75.6	(10.6)	—	—	—	—	75.6	(10.6)
Total Canada	140.6	140.5	0.1	—	—	—	140.7	140.5
Total Company	<u>\$470.7</u>	<u>\$385.2</u>	<u>\$ 94.4</u>	<u>\$159.1</u>	<u>\$ 16.0</u>	<u>\$ 30.4</u>	<u>\$581.1</u>	<u>\$574.7</u>

Average Daily Production Volumes:

	Natural Gas		NGL		Oil and Condensate		Equivalent Total	
	2009	2008	2009	2008	2009	2008	2009	2008
	(MMcfd)		(Bbl)		(Bbl)		(MMcfd)	
Texas	166.3	104.6	14,038	10,976	794	864	255.3	175.6
Other U.S.	0.3	0.3	31	42	440	462	3.2	3.4
Total U.S.	166.6	104.9	14,069	11,018	1,234	1,326	258.5	179.0
Canada	66.1	62.5	5	—	2	—	66.1	62.5
Total Company	<u>232.7</u>	<u>167.4</u>	<u>14,074</u>	<u>11,018</u>	<u>1,236</u>	<u>1,326</u>	<u>324.6</u>	<u>241.5</u>

Average Realized Prices:

	Natural Gas		NGL		Oil and Condensate		Equivalent Total	
	2009	2008	2009	2008	2009	2008	2009	2008
	(per Mcf)		(per Bbl)		(per Bbl)		(per Mcfe)	
Texas	\$3.76	\$ 9.52	\$24.57	\$57.03	\$48.33	\$109.30	\$3.95	\$ 9.77
Other U.S.	0.56	4.45	26.08	86.32	45.82	103.65	6.98	16.11
Hedging — U.S.	3.50	(0.99)	—	(4.46)	—	(23.62)	2.26	(1.03)
Total U.S.	7.26	8.51	24.56	52.69	47.44	83.70	6.24	8.85
Canada	3.61	8.83	70.67	—	47.25	—	3.61	8.83
Hedging — Canada	4.19	(0.62)	—	—	—	—	4.19	(0.62)
Total Canada	7.80	8.21	70.67	—	47.25	—	7.80	8.21
Total Company	\$7.41	\$ 8.40	\$24.57	\$52.69	\$47.44	\$ 83.70	\$6.56	\$ 8.69

The following table summarizes the changes in our production revenues during the nine months ended September 30, 2009 compared with the comparable 2008 period:

	<u>Natural Gas</u>	<u>NGL</u>	<u>Oil</u>	<u>Total</u>
	(In thousands)			
Revenue for the nine months ended September 30, 2008	\$ 385,244	\$ 159,061	\$ 30,412	\$ 574,717
Volume variance	148,407	43,375	(2,159)	189,623
Hedge settlement variance	273,967	13,448	8,583	295,998
Price variance	(336,894)	(121,463)	(20,825)	(479,182)
Revenue for the nine months ended September 30, 2009	<u>\$ 470,724</u>	<u>\$ 94,421</u>	<u>\$ 16,011</u>	<u>\$ 581,156</u>

Natural gas revenue for the 2009 period increased from the 2008 period because of increases in production and the effect of hedge settlements partially offset by the decrease in prices. The 61.7 MMcfd increase in U.S. natural gas volumes is due to new wells purchased or placed into service principally in the Fort Worth Basin subsequent to September 30, 2008. These increases were partially offset by lower volumes resulting from the sale of 27.5% revenue interest in our Alliance properties in June and natural production declines from existing Fort Worth Basin wells. Canadian natural gas production increased 3.6 MMcfd production from new wells placed into service subsequent to September 30, 2008, which includes the Horn River well placed into service during the third quarter of 2009.

The decrease in NGL revenue was primarily due to a 57% decrease in Texas prices for the 2009 period as compared to the 2008 period. Partially offsetting the price decrease were increases in production and the absence of outlays for hedge settlements. Fort Worth Basin production increased 28% due to new wells placed into production subsequent to September 30, 2008, lower field pressures and improved NGL recoveries from the Corvette Plant, which was placed into service by KGS during the first quarter of 2009.

Oil and condensate revenue for the 2009 period decreased because of a 56% decrease in prices and a 7% decrease in oil and condensate production for the 2009 period as compared to the 2008 period. An increase in oil and condensate revenue from the absence of outlays for hedge settlements partially offset these decreases.

Utilization of our hedging program may result in natural gas, NGL and crude oil realized prices varying from market prices that we receive from the sale of natural gas, NGL and crude oil. Our revenue from natural gas, NGL and crude oil production was \$234.8 million higher and \$61.1 million lower because of our hedging programs for 2009 period and 2008 period, respectively.

Sales of Purchased Natural Gas and Costs of Purchased Natural Gas

	Nine Months Ended September 30,	
	2009	2008
	(In thousands)	
Sales of purchased natural gas	\$ 11,181	\$ —
Costs of purchased natural gas sold	(10,358)	—
Loss on valuation of Gas Purchase Commitment	(1,188)	—
Costs of purchased natural gas	(11,546)	—
Net sales and purchases of natural gas	<u>\$ (365)</u>	<u>\$ —</u>

Our marketing activities related to the purchase and sale of natural gas have increased in Texas because of natural gas sales and purchases made under the Gas Purchase Commitment. The Gas Purchase Commitment is more fully described in Note 4 in the condensed consolidated financial statements.

Other Revenue

Other revenue of \$6.3 million for the 2009 period was \$10.8 million lower than for the 2008 period. Gains attributable to partial ineffectiveness of derivatives hedging our Canadian production were \$5.3 million less for the 2009 period when compared to the 2008 period. Additionally, KGS third-party revenue for the 2009 period was \$4.0 million less for the 2009 period when compared to the 2008 period. Lastly, the absence of transition services revenue earned in the 2008 period further decreased other revenue for the 2009 period by \$0.8 million.

Oil and Gas Production Expense

	Nine Months Ended September 30,			
	2009		2008	
	(In thousands, except per unit amounts)			
		Per Mcf		Per Mcf
Texas				
Cash expense	\$61,112	\$ 0.88	\$65,129	\$ 1.35
Equity compensation	785	0.01	925	0.02
	<u>\$61,897</u>	<u>\$ 0.89</u>	<u>\$66,054</u>	<u>\$ 1.37</u>
Other U.S.				
Cash expense	\$ 4,913	\$ 5.70	\$ 4,273	\$ 4.64
Equity compensation	147	0.17	133	0.15
	<u>\$ 5,060</u>	<u>\$ 5.87</u>	<u>\$ 4,406</u>	<u>\$ 4.79</u>
Total U.S.				
Cash expense	\$66,025	\$ 0.94	\$69,402	\$ 1.42
Equity compensation	932	0.01	1,058	0.02
	<u>\$66,957</u>	<u>\$ 0.95</u>	<u>\$70,460</u>	<u>\$ 1.44</u>
Canada				
Cash expense	\$24,399	\$ 1.35	\$26,440	\$ 1.54
Equity compensation	1,582	0.09	1,543	0.09
	<u>\$25,981</u>	<u>\$ 1.44</u>	<u>\$27,983</u>	<u>\$ 1.63</u>
Total Company				
Cash expense	\$90,424	\$ 1.02	\$95,842	\$ 1.45
Equity compensation	2,514	0.03	2,601	0.04
	<u>\$92,938</u>	<u>\$ 1.05</u>	<u>\$98,443</u>	<u>\$ 1.49</u>

U.S. production expense was \$3.5 million lower for the 2009 period despite a 44% production increase from the 2008 period. Cost containment efforts in the Fort Worth Basin during the 2009 period resulted in a production expense decrease of \$4.2 million when comparing the 2009 period to the 2008 period. Fort Worth Basin production expense of \$0.89 per Mcfe for the 2009 period also reflected a 35% decrease from a rate of \$1.37 per Mcfe for 2008. These decreases resulted from lower saltwater disposal costs, price reductions, and our stringent efforts to contain costs through vendor bidding processes, bulk purchasing and additional reliance on automation of well operations.

Canadian production expense for the 2009 period decreased \$2.0 million, or \$0.19 per Mcfe, from the 2008 period. Decreased Canadian production expense was primarily the result of changes in U.S.-Canadian exchange rates during the 2009 period when compared to the 2008 period. Canadian production expense on a Canadian dollar basis increased approximately C\$1.8 million or 7% due primarily to the Canadian production increase.

Production and Ad Valorem Taxes

	Nine Months Ended September 30,			
	2009		2008	
	(In thousands, except per unit amounts)			
		Per Mcf		Per Mcf
Production and ad valorem taxes				
U.S.	\$16,688	\$ 0.24	\$ 9,057	\$ 0.18
Canada	1,749	0.10	1,627	0.10
Total production and ad valorem taxes	<u>\$18,437</u>	<u>\$ 0.21</u>	<u>\$10,684</u>	<u>\$ 0.16</u>

Production and ad valorem taxes reflect the addition of wells and midstream facilities in the Fort Worth Basin over the past twelve months, which increased production and ad valorem taxes for Texas approximately \$8.3 million during the 2009 period as compared to the 2008 period.

Other Operating Costs

The \$2.7 million increase in other operating costs for the 2009 period when compared to the 2008 period was primarily the result of additional KGS operating expenses associated with the operation of its Corvette Plant that began operations in the first quarter of 2009. These KGS expenses are associated with its third-party gathering and processing revenues.

Depletion, Depreciation and Accretion

	<u>Nine Months Ended September 30,</u>			
	<u>2009</u>		<u>2008</u>	
	(In thousands, except per unit amounts)			
		Per Mcf		Per Mcf
Depletion				
U.S.	\$101,045	\$ 1.43	\$ 75,649	\$ 1.54
Canada	<u>25,494</u>	1.41	<u>30,967</u>	1.81
Total depletion	126,539	1.43	106,616	1.61
Depreciation of other fixed assets:				
U.S.	\$ 24,092	\$ 0.34	\$ 15,293	\$ 0.31
Canada	<u>2,856</u>	0.16	<u>2,751</u>	0.16
Total depreciation	26,948	0.30	18,044	0.27
Accretion	<u>1,723</u>	0.02	<u>1,096</u>	0.02
Total depletion, depreciation and accretion	<u>\$155,210</u>	\$ 1.75	<u>\$125,756</u>	\$ 1.90

Higher depletion for the 2009 period was due to production increases partially offset by lower depletion rates. Our U.S. depletion expense increased due primarily to a 44% increase in U.S. sales volumes. Both our U.S. and Canadian depletion rates were impacted by impairment charges. U.S. impairment charges were recognized in the fourth quarter of 2008 and the first quarter of 2009. Canadian impairment charges were recognized in the first and second quarters of 2009. Changes in the U.S.-Canadian dollar exchange rate also contributed to lower Canadian depletion expense and the Canadian depletion rate on a Mcfe-basis. The change in the exchange rate decreased depletion \$3.8 million when comparing the 2009 period to the 2008 period. The \$8.8 million increase in U.S. depreciation for the 2009 period as compared to the 2008 period was primarily associated with additions of Fort Worth Basin field compression and KGS' gathering system in addition to KGS' Corvette Plant that was placed into service in the first quarter of 2009.

Impairment of Oil and Gas Properties

We recognized a non-cash pre-tax charge of \$896.5 million (\$593.7 million after tax) for impairment related to both our U.S. and Canadian oil and gas properties in March 2009. Benchmark natural gas prices at March 31, 2009 for the U.S. and Canada decreased \$2.08 per Mcf and \$2.52 per Mcf, respectively, from December 31, 2008 and resulted in significant decreases to the estimated future net cash flows from our proved oil and gas reserves.

We recognized an additional second quarter non-cash pre-tax charge of \$70.6 million (\$52.9 million after tax) for impairment of our Canadian oil and gas properties. The impairment charge primarily resulted from reductions in the expected capital during the remainder of 2009 and in 2010 for our Canadian oil and gas properties. Additionally, the Canadian AECO benchmark natural gas prices at June 30, 2009 decreased \$0.05 per Mcf from March 31, 2009.

As required under full cost accounting rules, we perform quarterly ceiling tests. Net capitalized costs include the book value of our oil and gas properties net of accumulated depletion and impairment, reduced by the related deferred tax liability. Net capitalized costs are compared to the period-end ceiling limitation, which is the sum of (i) estimated future net cash flows, discounted at 10% per annum, from proved reserves, based on unescalated period-end prices and costs, adjusted for financial derivatives that qualify as cash flow hedges of our oil and gas revenue, (ii) the costs of properties not being amortized, (iii) the lower of cost or market value of

unproved properties not included in the costs being amortized, less (iv) income tax effects related to differences between book and tax bases of the oil and gas properties. Note 6 to our condensed consolidated financial statements contains additional information about the ceiling test calculation.

General and Administrative Expense

	Nine Months Ended September 30,			
	2009		2008	
	(In thousands, except per unit amounts)			
		Per Mcf		Per Mcf
General and administrative expense				
Cash expense	\$40,483	\$ 0.45	\$37,175	\$ 0.55
Litigation settlement	6,000	0.07	9,633	0.15
Equity compensation	12,969	0.15	9,594	0.15
Total general and administrative expense	\$59,452	\$ 0.67	\$56,402	\$ 0.85

General and administrative expense for the 2009 period increased \$3.0 million from the 2008 period. The 2009 period expense increased \$5.0 million for final settlement of the CMS Litigation and \$1.0 million for the Eagle litigation judgment. Legal and accounting fees increased general and administrative expense by approximately \$4.5 million for the 2009 period as compared to the 2008 period and included approximately \$0.8 million for the Eni Transaction and \$3.7 million related to our litigation with BBEP and various other corporate matters. Vesting of stock-based compensation in the 2009 period increased \$3.4 million when compared to the 2008 period. These items were partially offset by the absence of a \$9.6 million charge for a legal settlement in 2008 and expense decreases of \$1.3 million resulting from cost reduction efforts.

BBEP-Related Income and Expense

During the 2009 period, we recognized \$77.4 million for equity earnings from our investment in BBEP for the nine months ended June 30, 2009 as compared to a loss of \$93.9 million based upon their reported earnings for the eight months ended June 30, 2008. A portion of the increase in equity earnings is the result of an increase in our proportionate ownership of BBEP from 32% to 41% as a result of BBEP's purchase and retirement of units in June 2008. The remaining increase is primarily due to a significant reduction in unrealized losses from derivative instruments that BBEP experienced in the 2008 eight-month period. BBEP continues to experience significant volatility in its net earnings due to changes in value of its derivative instruments for which it does not employ hedge accounting.

During the first quarter of 2009, we evaluated our investment in BBEP for impairment in response to further decreases in prevailing commodity prices and BBEP's unit price since December 31, 2008. As a result of these decreases and the outlook for petroleum prices and broad limitations on available capital, we made the determination that the decline in value was other-than-temporary. Accordingly, our impairment analysis, which utilized the March 31, 2009 closing price of \$6.53 per BBEP unit, resulted in an aggregate fair value of \$139.4 million for the portion of BBEP units that we owned. The \$139.4 million aggregate fair value was compared to the \$241.5 million carrying value of our investment in BBEP. We recorded the difference of \$102.1 million as an impairment charge during the first quarter of 2009. A similar analysis was performed as of September 30, 2009, which resulted in no further impairment. Note 5 to our condensed consolidated financial statements contains additional information regarding our investment in BBEP for more information.

Interest Expense

	Nine Months Ended September 30,	
	2009	2008
	(in thousands)	
Interest costs	\$113,972	\$63,837
Add:		
Non-cash interest ⁽¹⁾	13,431	8,085
Loss on early debt extinguishment	27,122	—
Less: Interest capitalized	(4,624)	(6,401)
Interest expense	<u>\$149,901</u>	<u>\$65,521</u>

(1) Amortization of deferred financing costs and original issue discount

Interest costs for the 2009 period were higher than the 2008 period primarily because of higher outstanding debt balances, which included the issuance of our Senior Notes due 2015 in June 2008 and our Senior Secured Second Lien Facility in August of 2008, as well as additional borrowings outstanding under our Senior Secured Credit Facility. We recognized additional interest expense of \$27.1 million for the remaining unamortized original issue discount and deferred financing costs upon the early repayment of the Senior Secured Second Lien Facility in June 2009. Interest rate swaps entered into in June 2009 partially offset increased interest expense by \$7.2 million for the 2009 period. We expect interest expense to increase during future quarters based on increases to base borrowing rates under our Senior Secured Credit Facility and higher interest rates incurred for our Senior Notes due 2016 and 2019.

Income Tax Expense

	Nine Months Ended September 30,	
	2009	2008
Income tax (benefit) expense (in thousands)	\$(301,125)	\$46,041
Effective tax rate	34.0%	33.5%

Our income tax provision for the 2009 period changed from the 2008 period due to a \$1.0 billion reduction of pre-tax earnings that resulted primarily from the impairment charges for our oil and gas properties recognized during 2009. The effective tax rate for the 2009 period was affected by the resulting taxable net loss in both the U.S. and Canada that were taxed at approximately 35% and approximately 25%, respectively. We expect our effective income tax rate to be approximately 34% for all of 2009.

Quicksilver Resources Inc. and its Restricted Subsidiaries

Note 21 to our consolidated financial statements included in our 2008 Annual Report on Form 10-K, as amended, contains information about the Company and its restricted and unrestricted subsidiaries.

The combined results of operations for the Company and its restricted subsidiaries are substantially similar to our consolidated results of operations, which are discussed above under *Results of Operations*. The combined financial position of the Company and its restricted subsidiaries and our consolidated financial position are materially the same except for the property, plant and equipment purchased by the unrestricted subsidiaries since the KGS initial public offering, the borrowings under the KGS credit facility and the equity of the unrestricted subsidiaries. The other balance sheet items are discussed below in "Financial Position." The combined operating cash flows, financing cash flows and investing cash flows for the Company and its restricted subsidiaries are substantially similar to our consolidated operating cash flows, financing cash flows and investing cash flows, which are discussed below in *Liquidity, Capital Resources and Financial Condition*.

LIQUIDITY, CAPITAL RESOURCES AND FINANCIAL CONDITION

Cash Flow Activity

Our financial condition and results of operations, including our liquidity and profitability, are significantly affected by the prices that we realize for our natural gas, NGL and oil production and the volumes of natural gas, NGL and oil that we produce.

The natural gas, NGLs and oil that we produce are commodity products for which established trading markets exist. Accordingly, product pricing is determined by the relationship between supply and demand for these products. Product supply is affected primarily by fluctuations in production volumes, and product demand is affected by the state of the economy in general, the availability and price of alternative fuels and a variety of other factors. Prices for our products historically have been volatile, and we have no meaningful influence over the timing and extent of price changes for our products. Although we have mitigated our near term exposure to such price declines through derivative financial instruments covering substantial portions of our expected near-term production, we cannot confidently predict whether or when market prices for natural gas, NGL and oil will increase or decrease.

The volumes that we produce may be significantly affected by the rates at which we acquire leaseholds and other mineral interests and explore, exploit and develop our leasehold and other mineral interests through drilling and production activities. These activities require substantial capital expenditures, and our ability to fund these activities through cash flow from our operations, borrowings and other sources may be significantly affected by instability in the credit and financial markets, resulting in our and other industry participants' planned lowering of capital expenditures and drilling activities year-over-year.

	Nine Months Ended September 30,	
	2009	2008
	(In thousands)	
Net cash provided by operating activities	\$ 450,593	\$ 274,120
Net cash used for investing activities	(340,082)	(1,943,520)
Net cash provided by financing activities	(113,570)	1,657,248
Effect of exchange rate changes in cash	1,779	(2,609)

Operating Cash Flows

Net cash provided by operations for the 2009 period increased \$176.5 million from the comparable 2008 period because of increases from working capital including \$54.9 million received from the March 2009 early settlement of a derivative hedging 40 MMcfd of 2010 natural gas production and receipt of a \$41.1 million U.S. federal income tax refund. Cash provided by operations increased because of significantly higher production and lower production expense partially offset by lower average realized natural gas, NGL and crude oil prices. Additionally, the cash distributions we receive on our BBEP units decreased \$20.3 million from the 2008 period to \$11.1 million as BBEP ceased making distributions during the second quarter of 2009.

For the nine months ended September 30, 2009, price collars and swaps covered approximately 190 MMcfd of our natural gas production and resulted in higher realized revenues from our production of \$234.8 million. These price collars and swaps remain in place to hedge our anticipated natural gas production for the remainder of 2009. As of September 30, 2009, we also had approximately 120 MMcfd of our anticipated 2010 U.S. natural gas production hedged using natural gas price collars. We recorded the receipt of the \$54.9 million settlement of the previously discussed 40 MMcfd contract in AOCI. As natural gas is produced and sold during 2010, we will reclassify the proportionate amount of the settlement into natural gas revenue. In October 2009, we entered into additional price collars and swaps as summarized below:

Product	Type	Contract Period	Volume	Weighted Avg Price Per Mcf of Bbl
Gas	Collar	Jan 2010-Dec 2011	40 MMcfd	\$6.00-7.00
Gas	Collar	Jan 2010-Dec 2012	20 MMcfd	6.50-7.15
Gas	Collar	Jan 2010-Dec 2012	20 MMcfd	6.50-7.18
Gas	Collar	Jan 2011-Dec 2011	40 MMcfd	6.25-7.50
Gas	Collar	Jan 2012-Dec 2012	20 MMcfd	6.50-8.01
NGL	Swap	Jan 2010-Dec 2010	2,000 Bbld	\$ 32.65
NGL	Swap	Jan 2010-Dec 2010	3,000 Bbld	32.98
NGL	Swap	Jan 2010-Dec 2010	1,000 Bbld	33.63
NGL	Swap	Jan 2010-Dec 2010	1,000 Bbld	34.15
NGL	Swap	Jan 2010-Dec 2010	3,000 Bbld	34.22
NGL	Swap	Jan 2011-Dec 2011	3,000 Bbld	36.06
Gas	Basis	Jan 2010-Dec 2010	20 MMcfd	(1)
Gas	Basis	Jan 2010-Dec 2010	20 MMcfd	(1)

(1) Basis swaps for 40 MMcfd hedge the AECO basis adjustment at a deduction of \$0.45 per Mcf from NYMEX for 2010.

Investing Cash Flows

Our expenditures for property and equipment (payments for property and equipment plus non-cash changes in working capital associated with property and equipment) during the first nine months of 2009 totaled \$473.6 million. These investing cash flows were partially offset by the proceeds from the Eni Transaction. Our expenditures for property and equipment consisted of the following.

	Nine Months Ended September 30, 2009 (In thousands)
Exploration and development:	
Texas	\$ 281,674
Other U.S.	23,582
Total U.S.	305,256
Canada	70,116
Total exploration and development	375,372
Midstream — Texas	92,226
Corporate and field office	5,991
Total plant and equipment costs incurred	<u>\$ 473,589</u>

Our decision to reduce our exploration and development activity in response to lower natural gas prices caused a large reduction in capital expenditures in the nine months ended September 30, 2009 as compared to the 2008 period. We currently expect our 2009 capital expenditures to total approximately \$550 million, net of midstream capital contributed by Eni and working capital changes.

Financing Cash Flows

On June 25, 2009, we issued our senior notes due 2016 with a principal amount of \$600 million. The notes were issued at 96.717% of par, which resulted in proceeds of \$580.3 million. The notes bear interest at the rate of 11.75% but yield 12.50% after the effects of the original issue discount. The proceeds from both these notes and the Eni Transaction were used to repay and terminate the remaining indebtedness under our Senior Secured Second Lien Facility and to repay a portion of the outstanding borrowings under the Senior Secured Credit Facility.

On August 14, 2009, we issued Senior Notes due 2019 with a principal amount of \$300 million for proceeds of \$292.8 million. The notes bear interest at the rate of 9.125%. The proceeds of these notes were used to make repayments under the Senior Secured Credit Facility.

After completion of the Eni Transaction on June 19, 2009, our borrowing base was adjusted to \$1.125 billion. As of September 30, 2009, approximately \$633 million was available for borrowing under our Senior Secured Credit Facility. The October 2009 redetermination resulted in a revised borrowing base of \$1.0 billion.

KGS' \$235 million Credit Agreement had \$207 million of borrowings outstanding at September 30, 2009 and approximately \$28 million of available capacity. In October 2009, KGS lenders increased their commitments to a total of \$320 million. The KGS Credit Agreement permits further expansion to as much as \$350 million, subject to consents and additional commitments.

Notes 2 and 4 to the condensed consolidated financial statements contain additional information about the Eni Transaction and the related Gas Purchase Commitment. Based upon estimates of production volumes attributable to Eni as of June 19, 2009, we recognized a liability of approximately \$58.3 million for the Gas Purchase Commitment and reported a portion of the net proceeds for that liability as a component of cash flows from financing activities. Our payments to Eni for its natural gas production that reduce the liability for the Gas Purchase Commitment will be included in financing cash flows when made.

Financial Position

The following summarizes the significant changes to our balance sheet as of September 30, 2009, as compared to our December 31, 2008 balance sheet:

- Our current and non-current derivative assets and liabilities decreased \$96.7 million on a net basis. Our net open derivative position decreased \$234.8 million because of monthly settlements during the 2009 period and \$54.9 million received for early settlement of a derivative hedging a portion of our 2010 production. The valuation of our remaining open derivative positions partially offset these decreases as a result of natural gas price decreases during the 2009 period. The Michigan Sales Contract was completed in March 2009, which increased our derivative assets by \$4.8 million and decreased our derivative liabilities by \$8.1 million. Our current deferred income tax liability increased \$11.0 million because of changes in the allocation between the U.S. and Canada of open derivative positions and the difference in statutory tax rates between them.
- Our net property, plant and equipment balance decreased \$803.9 million over the nine-month period ended September 30, 2009. During 2009, we recorded charges for impairment of our oil gas properties of \$967.1 million and 2009 DD&A expense of \$155.2 million. Our property, plant and equipment balances were also decreased by proceeds of \$219.8 million for the Eni Transaction. These decreases were partially offset by \$473.6 million of costs incurred for property, plant and equipment.
- Our deferred income tax liability has decreased \$197.8 million and a deferred tax asset of \$143.5 million was reclassified in connection with the impairments of both our investment in BBEP and our U.S. oil and gas properties.

Contractual Obligations and Commercial Commitments

Except as discussed in Note 4 for the Gas Purchase Commitment, there have been no significant changes to our contractual obligations and commercial commitments as disclosed in Item 7 in our 2008 Annual Report on Form 10-K, as amended.

Critical Accounting Estimates

Management's discussion and analysis of financial condition and results of operations are based on our condensed consolidated interim financial statements and related footnotes contained within this report. Our more critical accounting estimates used in the preparation of the consolidated financial statements were discussed in our 2008 Annual Report on Form 10-K, as amended. These critical estimates, for which no significant changes occurred during the three months ended September 30, 2009, include estimates and assumptions for:

- | | |
|---------------------------------|--------------------------------|
| * full cost ceiling calculation | * oil and gas reserves |
| * derivative instruments | * asset retirement obligations |
| * stock-based compensation | * income taxes |

The process of preparing financial statements in conformity with GAAP requires the use of estimates and assumptions to determine certain of the assets, liabilities, revenues and expenses. These estimates and assumptions are based upon what we believe is the best information available at the time of the estimates or assumptions. The estimates and assumptions could change materially as conditions within and beyond our control change. Accordingly, actual results could differ materially from those estimates.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements within the meaning of Item 303(a)(4) of SEC Regulation S-K.

Recently Issued Accounting Standards

The information regarding recent accounting pronouncements is included in Note 1 to our condensed consolidated financial statements included in Item 1 of this quarterly report.

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

We have established policies and procedures for managing risk within our organization, including internal controls. The level of risk assumed by us is based on our objectives and capacity to manage risk.

Our primary risk exposure is related to fluctuations in natural gas, oil and NGL commodity prices. We have mitigated the risk of adverse price movements with swaps and collars; however, we have also limited future gains from favorable price movements.

Commodity Price Risk

We enter into financial derivative contracts to mitigate our exposure to commodity price risk associated with anticipated future natural gas, NGL and crude oil production. Our financial derivative contracts result in more predictability of our natural gas, NGL and crude oil revenues. As of September 30, 2009, approximately 150 MMcfd and 40 MMcfd of natural gas price collars and swaps, respectively, are in place to hedge a portion of our anticipated production for the remainder of 2009. Also 120 MMcfd of 2010 natural gas production has been hedged using price collars. Excluded from the amounts presented in the table below are price collars and swaps entered into during October 2009 as described in Item 2.

Utilization of our hedging program may result in natural gas, NGL and crude oil realized prices varying from market prices that we receive from the sale of natural gas, NGL and crude oil. Our revenue from natural gas, NGL and crude oil production was \$234.8 million higher and \$61.1 million lower because of our hedging programs for the nine months ended 2009 and 2008, respectively. Other revenue was \$1.7 million lower and \$3.7 million higher as a result of derivative and hedging ineffectiveness for the nine months ended September 30, 2009 and 2008, respectively.

The following table summarizes our commodity derivative positions as of September 30, 2009:

<u>Product</u>	<u>Type</u>	<u>Remaining Contract Period</u>	<u>Volume</u>	<u>Weighted Avg Price Per Mcf</u>	<u>Fair Value</u> (In thousands)
Gas	Swap	Oct 2009-Dec 2009	10 MMcfd	\$ 8.45	\$ 3,410
Gas	Swap	Oct 2009-Dec 2009	10 MMcfd	8.45	3,410
Gas	Swap	Oct 2009-Dec 2009	20 MMcfd	8.46	6,830
Gas	Collar	Oct 2009-Dec 2009	20 MMcfd	7.50-9.34	5,024
Gas	Collar	Oct 2009-Dec 2009	20 MMcfd	7.75-10.20	5,553
Gas	Collar	Oct 2009-Dec 2009	10 MMcfd	7.75-10.26	2,784
Gas	Collar	Oct 2009-Dec 2009	20 MMcfd	8.25-9.60	6,378
Gas	Collar	Oct 2009-Dec 2009	10 MMcfd	8.25-10.45	3,232
Gas	Collar	Oct 2009-Dec 2009	10 MMcfd	8.25-10.45	3,232
Gas	Collar	Oct 2009-Dec 2009	10 MMcfd	8.25-10.45	3,232
Gas	Collar	Oct 2009-Dec 2009	10 MMcfd	8.50-13.15	3,420
Gas	Collar	Oct 2009-Dec 2009	30 MMcfd	11.00-13.50	17,197
Gas	Collar	Oct 2009-Dec 2009	10 MMcfd	11.50-14.48	6,165
Gas	Collar	Jan 2010-Dec 2010	20 MMcfd	8.00-11.00	15,044
Gas	Collar	Jan 2010-Dec 2010	20 MMcfd	8.00-11.00	15,044
Gas	Collar	Jan 2010-Dec 2010	20 MMcfd	8.00-12.20	15,336
Gas	Collar	Jan 2010-Dec 2010	20 MMcfd	8.00-12.20	15,336
Gas	Collar	Jan 2010-Dec 2010	10 MMcfd	8.50-12.05	9,173
Gas	Collar	Jan 2010-Dec 2010	20 MMcfd	8.50-12.05	18,347
Gas	Collar	Jan 2010-Dec 2010	10 MMcfd	8.50-12.08	9,227
Gas	Basis	Oct 2009-Dec 2009	20 MMcfd	(1)	(871)
Gas	Basis	Oct 2009-Dec 2009	10 MMcfd	(1)	(435)
Gas	Basis	Oct 2009-Dec 2009	15 MMcfd	(1)	(495)
Gas	Basis	Oct 2009-Dec 2009	15 MMcfd	(1)	(501)
Total					<u>\$165,072</u>

(1) Basis swaps for 60 MMcfd hedge the AECO basis adjustment at a weighted average deduction of \$0.84 per Mcf from NYMEX for the remainder of 2009.

In March 2009, we completed the early settlement of a natural gas collar that hedged 40 MMcfd through December 2010. Proceeds of approximately \$54.9 million were received and will be recognized in revenue and earnings as the associated hedged production volumes are sold.

In March 2009, we satisfied our obligation to deliver 25 MMcfd of natural gas under the Michigan Sales Contract. Our total 2009 net cash payments for settlement of the obligation were \$16.5 million.

Based on information available on June 19, 2009, we recognized a liability pursuant to the Gas Purchase Commitment which is more fully described in Note 4 to the condensed consolidated financial statements. The following summarizes activity to the Gas Purchase Commitment since June 19, 2009:

(In thousands)	
Initial valuation of liability ⁽¹⁾	\$58,294
Decrease due to gas volumes purchased	(3,806)
Embedded derivative increase (decrease) due to:	
Price changes	1,667
Volume changes	(479)
Total embedded derivative	1,188
Balance at September 30, 2009	<u>\$55,676</u>

The fair value of all derivative instruments included in these disclosures was estimated using commodity prices quoted in active markets for the periods covered by the derivatives and the value confirmed by counterparties. Estimates were determined by applying the net differential between the prices in each derivative and market prices for future periods, as adjusted for estimated basis differential, to the volumes stipulated in each contract to arrive at an estimated future value. This estimated future value was discounted on each contract at rates commensurate with federal treasury instruments with similar contractual lives.

Interest Rate Risk

In June 2009, we entered into interest rate swaps on our \$475 million Senior Notes due 2015 and our \$350 million Senior Subordinated Notes effectively converting the interest on those issues from a fixed to a floating rate indexed to a one-month LIBOR base rate. The maturity dates and all other significant terms are the same as those of the underlying debt. Under these swaps, we pay a variable interest rate and receive the fixed rate applicable to the underlying debt. The interest income or expense is accrued as earned and recorded as an adjustment to the interest expense accrued on the fixed-rate debt. The interest swaps are designated as fair value hedges of the underlying debt. The value of the contracts, excluding the net interest accrual, amounted to a net asset of \$16.0 million as of September 30, 2009. The offsetting fair value adjustment to the debt hedged resulted in an increase of long-term debt by \$16.0 million as of September 30, 2009. For the three and nine months ended September 30, 2009, interest expense was reduced \$6.5 million and \$7.2 million, respectively, as a result of the swaps.

ITEM 4. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Securities Exchange Act Rule 13a-15. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of September 30, 2009, our disclosure controls and procedures were effective to provide reasonable assurance that material information required to be disclosed by us (including our consolidated subsidiaries) in reports that we file or submit under the Securities Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting during the quarter ended September 30, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

In October 2009, a jury awarded \$22 million to the plaintiffs in our litigation originally brought against us by the plaintiffs, Rod and Richard Thornton and Eagle Drilling, LLC in the District Court of Cleveland County, Oklahoma. We are actively seeking an appeal in this matter.

There have been no other material changes in legal proceedings from those described in Part I, Item 3. Legal Proceedings included in our 2008 Annual Report on Form 10-K, as amended and in Part II, Item 1. Legal Proceedings, included in our Quarterly Report on Form 10-Q for the period ended June 30, 2009.

ITEM 1A. Risk Factors

The following risk factors update the risk factors set forth in Part I, Item IA, “Risk Factors” of our 2008 Annual Report on Form 10-K, as amended. You should carefully consider the following risk factors together with all of the other information included in this quarterly report and the other information that we file with the SEC, including the financial statements and related notes, when deciding to invest in us. You should be aware that the occurrence of any of the events described in this Risk Factors section and elsewhere in this quarterly report could have a material adverse effect on our business, financial position, results of operations and cash flows.

Natural gas, NGL and crude oil prices fluctuate widely, and low prices could have a material adverse impact on our business, financial condition, results of operations and cash flows.

Our revenue, profitability and future growth depend in part on prevailing natural gas, NGL and crude oil prices. These prices also affect the amount of cash flow available to service our debt, pay for our capital expenditures and fund our other liquidity needs, as well as our ability to borrow, raise additional capital and comply with the terms of our debt agreements. Among other things, the amount we can borrow under our Senior Secured Credit Facility is subject to periodic redetermination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas, NGLs and crude oil that we can economically produce.

While prices for natural gas and crude oil may be favorable at any point in time, they fluctuate widely, particularly as evidenced by price movements in the latter half of 2008 and the first nine months of 2009. Among the factors that can cause these fluctuations are:

- domestic and foreign demand for natural gas and crude oil;
- the level of domestic and foreign natural gas and crude oil supplies;
- the price and availability of alternative fuels;
- weather conditions;
- domestic and foreign governmental regulations;
- impact of trade organizations, such as OPEC;
- political conditions in oil and natural gas producing regions; and
- worldwide economic conditions.

Due to the volatility of natural gas and crude oil prices and the inability to control the factors that influence them, we cannot predict future pricing levels.

If natural gas, NGL or crude oil prices decrease, our exploration and development efforts are unsuccessful or our costs increase substantially, we may be required to recognize impairment of our oil and gas properties, which could have a material adverse effect on our financial condition, our results of operations and our ability to borrow under and comply with our debt agreements.

We employ the full cost method of accounting for our oil and gas properties, whereby all costs associated with acquiring, exploring for, and developing natural gas and crude oil reserves are capitalized and accumulated in separate country cost centers. These capitalized costs are amortized based on production from the reserves for each country cost center. Each capitalized cost pool cannot exceed the net present value of the underlying natural gas, NGL and crude oil reserves. Impairment to the carrying value of our oil and gas properties was recognized in the fourth quarter of 2008 and the first and second quarters of 2009 and could occur again in the future if natural gas, NGL or crude oil prices at a reporting period end result in decreased value of our reserves. Increased operating and capitalized costs without incremental increases in natural gas and crude oil reserves could also trigger impairment based on decreased value of our reserves. In the event of impairment of our oil and gas properties, we reduce their carrying value and recognize expense, which could be material and could adversely affect our financial condition and results of operations and our ability to borrow under and comply with the terms of our debt agreements.

Reserve estimates depend on many assumptions that may turn out to be inaccurate and any material inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves.

The process of estimating natural gas, NGL and crude oil reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves disclosed in our filings with the SEC.

In order to prepare these estimates, we and independent reserve engineers engaged by us must project production rates and timing of development expenditures. We and the engineers must also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions with respect to natural gas and crude oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, natural gas, NGL and crude oil prices and revenue, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and crude oil reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves disclosed in our Annual Report on Form 10-K, as amended. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing petroleum prices and other factors, which may be beyond our control.

At December 31, 2008, approximately 37% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires additional capital expenditures and successful drilling and completion operations. Our reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our reserves and the costs associated with them in accordance with industry standards, there is risk that the estimated costs are inaccurate, that development will not occur as scheduled or that actual results will not be as estimated.

The present value of future net cash flows disclosed in Item 8 of our Annual Report on Form 10-K, as amended, is not necessarily the fair value of our estimated proved natural gas and crude oil reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are based on prices and costs as of period end. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by natural gas, NGL and crude oil purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of natural gas and crude oil properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and natural gas industry in general will affect the appropriateness of the 10% discount factor in arriving at the reserves' actual fair value.

Our production is concentrated in a small number of geographic areas.

Approximately 75% of our 2008 production was from Texas and approximately 24% was from Alberta, Canada. Because of our concentration in these geographic areas, any regional events that increase costs, reduce availability of equipment or supplies, reduce demand or limit production, including weather and natural disasters, may impact us more than if our operations were more geographically diversified.

Our Canadian operations present unique risks and uncertainties, different from or in addition to those we face in our domestic operations.

In addition to the various risks associated with our U.S. operations, risks associated with our operations in Canada, where we have substantial operations, include, among other things, risks related to increases in taxes and governmental royalties, changes in laws and policies governing operations of foreign-based companies, currency restrictions and exchange rate fluctuations. Laws and policies of the United States affecting foreign trade and taxation may also adversely affect our Canadian operations.

We may have difficulty financing our planned growth.

We have experienced capital expenditure and working capital needs, particularly as a result of our property acquisition and drilling activities. Our capital program may require additional financing above the level of cash generated by our operations to fund our growth. If revenue decreases as a result of lower petroleum prices or otherwise, our ability to expend the capital necessary to replace our reserves or to maintain production of current levels may be limited, resulting in a decrease in production over time. If our cash flow from operations is not sufficient to satisfy our capital expenditure requirements, we cannot be certain that additional financing

will be available to us on acceptable terms or at all. If additional capital resources are unavailable, we may curtail our activities or be forced to sell some of our assets on an untimely or unfavorable basis.

We are vulnerable to operational hazards, transportation dependencies, regulatory risks and other uninsured risks associated with our activities.

The oil and natural gas business involves operating hazards such as well blowouts, explosions, uncontrollable flows of crude oil, natural gas or well fluids, fires, formations with abnormal pressures, treatment plant “downtime”, pipeline ruptures or spills, pollution, releases of toxic gas and other environmental hazards and risks, any of which could cause us to experience substantial losses. Also, the availability of a ready market for our natural gas and crude oil production depends on the proximity of reserves to, and the capacity of, natural gas and crude oil gathering systems, treatment plants, pipelines and trucking or terminal facilities.

U.S. and Canadian federal, state, local and provincial regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand and general economic conditions could adversely affect our ability to produce and market our natural gas, NGLs and crude oil. In addition, we may be liable for environmental damage caused by previous owners of properties purchased or leased by us.

As a result of operating hazards, regulatory risks and other uninsured risks, we could incur substantial liabilities to third parties or governmental entities. We maintain insurance against some, but not all, of such risks and losses in accordance with customary industry practice. Generally, environmental risks are not fully insurable. The occurrence of an event that is not covered, or not fully covered, by insurance could have a material adverse effect on our business, financial condition and results of operations.

The failure to replace our reserves could adversely affect our production and cash flows.

Our future success depends upon our ability to find, develop or acquire additional reserves that are economically recoverable. Our proved reserves will generally decline as reserves are produced, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves. In order to increase reserves and production, we must continue our development drilling and recompletion programs or undertake other replacement activities. Our current strategy is to maintain our focus on low-cost operations while increasing our reserve base and production through exploration and development of our existing properties. Our planned exploration or development projects or any acquisition activities that we may undertake might not result in meaningful additional reserves and we might not have continuing success drilling productive wells. Furthermore, while our revenue may increase if prevailing petroleum prices increase materially, our finding costs also could increase.

We have risk through our investment in BBEP.

We own a 40% limited partner interest in BBEP, but have no management oversight over BBEP, its financial condition, its operating results or its financial reporting process and are subject to the risks associated with BBEP’s business and operations. Moreover, the management of BBEP has discretion over the amount, if any, that they distribute to unitholders, and on April 17, 2009 BBEP announced that it was suspending such distributions.

The nature of our ownership interest in a publicly traded entity subjects us to market risks associated with most ownership interests traded on a public exchange. Sales of substantial amounts of BBEP limited partner units, or a perception that such sales could occur, and various other factors, including BBEP suspending distributions on its units, could adversely affect the market price of BBEP limited partner units. Impairment to the carrying value of BBEP limited partnership units was recognized in both the fourth quarter of 2008 and the first quarter of 2009, and could occur again in the future if the market price for BBEP units declines further. In the event of impairment of our BBEP units, we reduce the carrying value of our BBEP units and recognize expense for impairment, which could be material and could adversely affect our financial condition and results of operations and our ability to borrow under and comply with the provisions of our debt agreements.

We have risk through our ownership of KGS.

Through our ownership interest in KGS, we share in KGS’ results of operations and may be entitled to distributions from KGS. Accordingly, we have diminished control over assets owned by KGS and assets, which KGS has a right to acquire. We are also subject to the risks associated with KGS’ business and operations, including, but not limited to:

- changes in general economic conditions;
- fluctuations in natural gas prices;
- failure or delays in us and third parties achieving expected production from natural gas projects;
- competitive conditions in the midstream industry;
- actions taken on non-performance by third parties, including suppliers, contractors, operators, processors, transporters and customers;
- changes in the availability and cost of capital;
- operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- construction costs or capital expenditures exceeding estimated or budgeted amounts;
- the effects of existing and future laws and governmental regulations;
- the effects of future litigation; and
- other factors discussed in KGS' Annual Report on Form 10-K and as are or may be detailed from time to time in KGS' public announcements and other filings with the SEC.

We cannot control the operations of gas processing and transportation facilities we do not own or operate.

We deliver our Canadian production to market primarily by either the TransCanada or ATCO systems. We have no influence over the operation of these facilities and must depend upon their owners to minimize any loss of processing and transportation capacity.

The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent on a relatively small group of key management personnel, including our executive officers. There is a risk that the services of all of these individuals may not be available to us in the future. Because competition for experienced personnel in our industry can be intense, we may be unable to find acceptable replacements with comparable skills and experience and their loss could have an adverse effect on us.

Competition in our industry is intense, and we are smaller and have a more limited operating history than many of our competitors.

We compete with major and independent oil and natural gas companies for property acquisitions. We also compete for the equipment and labor required to develop and operate our properties. Many of our competitors have substantially greater financial and other resources than we do. In addition, larger competitors may be able to absorb the burden of any changes in federal, state, provincial and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for exploratory prospects and productive natural gas and crude oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for natural gas and crude oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to complete transactions in this highly competitive environment. Furthermore, the oil and natural gas industry competes with other industries in supplying the energy and fuel needs of industrial, commercial and other consumers.

Hedging our production may result in losses or limit our ability to benefit from price increases.

To reduce our exposure to petroleum price fluctuations, we have entered into financial hedging arrangements which may limit the benefit we would receive from increases in petroleum prices. These hedging arrangements also expose us to risk of financial losses in some circumstances, including the following:

- our production could be materially less than expected; or
- the other parties to the hedging contracts could fail to perform their contractual obligations.

The result of natural gas market prices exceeding collar ceilings requires us to make monthly cash payments. If we choose not to engage in hedging arrangements in the future, we could be more affected by changes in natural gas, NGL and crude oil prices than our competitors who engage in hedging arrangements.

Delays in obtaining oil field equipment and increases in drilling and other service costs could adversely affect our ability to pursue our drilling program and our results of operations.

As natural gas, NGL and crude oil prices increase, demand and costs for drilling equipment, crews and associated supplies, equipment and services can increase significantly. We cannot be certain that in a higher petroleum price environment we would be able to obtain necessary drilling equipment and supplies in a timely manner or on satisfactory terms, and we could experience shortages of, or material increases in the cost of, drilling equipment, crews and associated supplies, equipment and services. Any such delays and price increases could adversely affect our ability to pursue our drilling program and our results of operations.

Our activities are regulated by complex laws and regulations, including those relating to environmental matters, that can adversely affect the cost, manner or feasibility of doing business.

Our operations are subject to various U.S. and Canadian federal, state, provincial and local government laws and regulations that could change in response to economic or political conditions. Matters that are typically regulated include:

- discharge permits for drilling operations;
- water obtained for drilling purposes;
- drilling permits and bonds;
- reports concerning operations;
- spacing of wells;
- disposal wells;
- unitization and pooling of properties;
- environmental protection; and
- taxation.

From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of natural gas and crude oil wells below actual production capacity to conserve supplies of natural gas and crude oil. We also are subject to changing and extensive tax laws, the effects of which cannot be predicted

The development, production, handling, storage, transportation and disposal of natural gas and crude oil, by-products and other substances and materials produced or used in connection with our operations are also subject to laws and regulations primarily relating to protection of human health and the environment. The discharge of natural gas, crude oil or pollutants into the air, soil or water may give rise to significant liabilities on our part to the government and third parties and may result in the assessment of civil or criminal penalties or require us to incur substantial costs of remediation.

Legal and tax requirements frequently are changed and subject to interpretation, and we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. Environmental laws and regulations, in particular, are subject to reinterpretation, change frequently and have tended to become more stringent over time. For example, uncertainty exists with respect to the regulation of hydraulic fracturing. Legislation has been introduced in the U.S. Congress that would subject hydraulic fracturing to regulation under the U.S. Safe Drinking Water Act, and certain states are also evaluating whether additional regulation of hydraulic fracturing is appropriate. Greenhouse gas regulation is also the subject of significant uncertainty. In addition to various other foreign, federal, regional, state and provincial greenhouse gas legislation and regulations that are currently in effect or under development, the U.S. Congress is currently considering legislation that would significantly curtail national greenhouse gas emissions. The U.S. Environmental Protection Agency has also taken steps to declare that certain greenhouse gas emissions are contributing to air pollution which is an endangerment to human health, and may regulate greenhouse gas emissions under the U.S. federal Clean Air Act.

We cannot assure you that existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations, will not materially adversely affect our business, results of operations and financial condition.

The risks associated with our debt could adversely affect our business, financial condition and results of operations and the value of our securities.

Subject to the limits contained in our various debt agreements, we may incur additional debt. Our ability to incur additional debt and to comply with the terms of our debt agreements is affected by a variety of factors, including natural gas, NGL and crude oil prices and their effects on our financial condition, results of operations and cash flows. Among other things, our ability to borrow under our Senior Secured Credit Facility is subject to the quantity and value of our proved reserves and other assets, including our investment in BBEP. If we incur additional debt or fail to increase the quantity and value of our proved reserves, the risks that we now face as a result of our indebtedness could intensify.

We have demands on our cash resources in addition to interest expense, including operating expenses, principal payments under our debt and funding of our capital expenditures. Our level of debt, the value of our oil and gas properties and other assets, the demands on our cash resources, and the provisions of our debt agreements could have important effects on our business and on the value of our securities. For example, they could:

- make it more difficult for us to satisfy our obligations with respect to our debt;
- require us to dedicate a substantial portion of our cash flow from operations to payments on our debt, thereby reducing the amount of our cash flow available for working capital, capital expenditures, acquisitions and other general corporate purposes;
- require us to make principal payments if the quantity and value of our proved reserves are insufficient to support our level of borrowings;
- limit our flexibility in planning for, or reacting to, changes in the oil and natural gas industry;
- place us at a competitive disadvantage compared to our competitors who may have lower debt service obligations and greater financing flexibility than we do;
- limit our financial flexibility, including our ability to borrow additional funds;
- increase our interest expense on our variable rate borrowings if interest rates increase;
- limit our ability to make capital expenditures to develop our properties;
- increase our vulnerability to exchange risk associated with Canadian dollar denominated indebtedness;
- increase our vulnerability to general adverse economic and industry conditions; and
- result in a default or event of default under our debt agreements, which, if not cured or waived, could adversely affect our financial condition, results of operations and cash flows.

Our ability to pay principal and interest on our debt, to otherwise comply with the provisions of our debt agreements and to refinance our debt may be affected by economic and capital markets conditions and other factors that may be beyond our control. If we are unable to service our debt and fund our other liquidity needs, we will be forced to adopt alternative strategies that may include:

- reducing or delaying capital expenditures;
- seeking additional debt financing or equity capital;
- selling assets;
- restructuring or refinancing debt; or
- reorganizing our capital structure.

We cannot assure you that we would be able to implement any of these strategies on satisfactory terms, if at all, and our inability to do so could cause the holders of our securities to experience a partial or total loss of their investment in us.

Our debt agreements restrict our ability to engage in certain activities.

Our debt agreements restrict our ability to, among other things:

- incur additional debt;
- pay dividends on, or redeem or repurchase capital stock;
- make certain investments;
- incur or permit certain liens to exist;
- enter into certain types of transactions with affiliates;
- merge, consolidate or amalgamate with another company;
- transfer or otherwise dispose of assets, including capital stock of subsidiaries; and
- redeem subordinated debt.

Our debt agreements, among other things, also require the maintenance of financial covenants that are more fully described in Note 7 to the condensed consolidated financial statements in Item 1 of this quarterly report. Our ability to comply with these covenants and other provisions of our debt agreements may be affected by events beyond our control, and we may be unable to comply with all aspects of our debt agreements in the future. In addition, our ability to borrow under our Senior Secured Credit Facility is dependent upon the quantity and value of our proved reserves and other assets, including our investment in BBEP.

The provisions of our debt agreements may affect the manner in which we obtain future financing, pursue attractive business opportunities and plan for and react to changes in business conditions. In addition, failure to comply with the provisions of our debt agreements could result in an event of default which could enable the applicable creditors, subject to the terms and conditions of the applicable agreement, to declare the outstanding principal of that debt, together with accrued interest, to be immediately due and

payable. Moreover, any of our debt agreements that contain a cross-default or cross-acceleration provision could also be subject to acceleration. If we were unable to repay the accelerated amounts, the creditors could proceed against the collateral granted to them to secure such debt. If the payment of our debt is accelerated, there can be no assurance that our assets would be sufficient to repay such debt in full, and the holders of our securities could experience a partial or total loss of their investment.

Parties with whom we do business may become unable or unwilling to timely perform their obligations to us.

We enter into contracts and transactions with various third parties, including contractors, suppliers, customers, lenders and counterparties to hedging arrangements, under which such third parties incur performance or payment obligations to us. Any delay or failure on the part of one or more of such third parties to perform their obligations to us could, depending upon the nature and magnitude of such failure or failures, have a material adverse effect on our business, financial condition and results of operations.

A small number of existing stockholders exercise significant control over our company, which could limit your ability to influence the outcome of stockholder votes.

Members of the Darden family, together with entities controlled by them, beneficially owned approximately 30% of our common stock as of September 30, 2009. As a result, they are generally able to significantly affect the outcome of stockholder votes, including votes concerning the election of directors, the adoption or amendment of provisions in our charter or bylaws and the approval of mergers and other significant corporate transactions.

A large number of our outstanding shares and shares to be issued upon conversion of our outstanding convertible debentures or exercise of our outstanding options may be sold into the market in the future, which could cause the market price of our common stock to drop significantly, even if our business is performing well.

Our shares that are eligible for future sale may adversely affect the price of our common stock. There were more than 169 million shares of our common stock outstanding at September 30, 2009. In addition, when the conditions permitting conversion of our convertible debentures are satisfied, the holders could elect to convert such debentures. Based on the applicable conversion rate at September 30, 2009, the holders' election to convert such debentures could result in an aggregate of 9,816,270 shares of our common stock being issued. We also had options outstanding to purchase 3,482,021 shares of our common stock at September 30, 2009.

Sales of substantial amounts of common stock, or a perception that such sales could occur, and the existence of conversion and option rights to acquire shares of common stock at prices that may be below the then current market price of the common stock, could adversely affect the market price of our common stock and could impair our ability to raise capital through the sale of our equity securities.

Our amended and restated certificate of incorporation, restated bylaws and stockholder rights plan contain provisions that could discourage an acquisition or change of control without our board of directors' approval.

Our amended and restated certificate of incorporation and restated bylaws contain provisions that could discourage an acquisition or change of control without our board of directors' approval. In this regard:

- our board of directors is authorized to issue preferred stock without stockholder approval;
- our board of directors is classified; and
- advance notice is required for director nominations by stockholders and actions to be taken at annual meetings at the request of stockholders.

In addition, we have adopted a stockholder rights plan, which could also impede a merger, consolidation, takeover or other business combination involving us, even if that change of control might be beneficial to stockholders, thus increasing the likelihood that incumbent directors will retain their positions. In certain circumstances, the fact that corporate devices are in place that will inhibit or discourage takeover attempts could reduce the market value of our common stock.

We have identified material weaknesses in our internal controls that, if not properly corrected, could result in material misstatements in our financial statements.

We and our auditors identified two material weaknesses in our system of internal control over financial reporting as of March 31, 2009. A material weakness is a deficiency, or combination of deficiencies in internal controls over financial reporting that results in a

reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

The first material weakness related to the preparation of combined financial information within our condensed consolidating financial information. The condensed consolidating information previously reported contained errors that included “combining adjustments” for non-guarantor subsidiaries being reported within “consolidating eliminations” and in the amounts reported for equity earnings of wholly owned subsidiaries. These errors did not affect the amounts previously reported in our consolidated financial statements. To remedy this material weakness, we have revised our process to better structure the preparation and allow for further review of our consolidating financial information.

The second material weakness related to the monitoring of our financial reporting requirements, particularly with respect to the form and content of our condensed consolidating financial information and the financial information about the Company and our restricted subsidiaries. To remedy this material weakness we have enhanced our process for documenting and satisfying the full extent of our financial reporting requirements.

Although there can be no assurances, we believe these enhancements and improvements, when repeated in future periods, will remediate the material weaknesses described above. If we are not able to remedy the material weaknesses in a timely manner, we may be unable to provide our security holders with the required financial information in a timely and reliable manner and we may incorrectly report financial information, either of which could subject us to litigation and regulatory enforcement actions.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities

The following table summarizes our repurchases of Quicksilver common stock during the quarter ended September 30, 2009.

Period	Total Number of Shares Purchased ⁽¹⁾	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan ⁽²⁾	Maximum Number of Shares that May Yet Be Purchased Under the Plan ⁽²⁾
July 2009	25,063	\$ 9.18	—	—
August 2009	198	\$12.02	—	—
September 2009	882	\$10.57	—	—
Total	26,143	\$ 9.25	—	—

(1) Represents shares of common stock surrendered by employees to satisfy our income tax withholding obligations arising upon the vesting of restricted stock issued under our Amended and Restated 1999 Stock Option and Retention Stock Plan or Amended and Restated 2006 Equity Plan.

(2) We do not currently have in place any publicly announced, specific plans or programs to purchase equity securities.

ITEM 3. Defaults Upon Senior Securities

None.

ITEM 4. Submission of Matters to a Vote of Security Holders

None.

ITEM 5. Other Information

None.

ITEM 6. Exhibits:

<u>Exhibit No.</u>	<u>Description</u>
4.1	First Supplemental Indenture, dated July 31, 2009, between Quicksilver Resources Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed as Exhibit 4.2 to the Company's Form 10-Q filed August 10, 2009 and included herein by reference).
4.2	Eighth Supplemental Indenture, dated as of August 14, 2009, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (filed as Exhibit 4.1 to the Company's Form 8-K filed August 17, 2009 and included herein by reference).
* 31.1	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
* 31.2	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
* 32.1	Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Dated: November 9, 2009

Quicksilver Resources Inc.

By: /s/ Philip Cook
Philip Cook
Senior Vice President - Chief Financial Officer

EXHIBIT INDEX

<u>Exhibit No.</u>	<u>Description</u>
4.1	First Supplemental Indenture, dated July 31, 2009, between Quicksilver Resources Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed as Exhibit 4.2 to the Company's Form 10-Q filed August 10, 2009 and included herein by reference).
4.2	Eighth Supplemental Indenture, dated as of August 14, 2009, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (filed as Exhibit 4.1 to the Company's Form 8-K filed August 17, 2009 and included herein by reference).
* 31.1	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
* 31.2	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
* 32.1	Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

CERTIFICATION

I, Glenn Darden, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Quicksilver Resources Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2009

/s/ Glenn Darden

Glenn Darden

President and Chief Executive Officer

CERTIFICATION

I, Philip Cook, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Quicksilver Resources Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2009

/s/ Philip Cook

Philip Cook

Senior Vice President — Chief Financial Officer

**CERTIFICATION PURSUANT TO 18 U.S.C. § 1350, AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

Pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, in connection with the Quarterly Report on Form 10-Q of Quicksilver Resources Inc. (the "Company") for the quarter ended September 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, Philip Cook, Senior Vice President — Chief Financial Officer of the Company, and Glenn Darden, President and Chief Executive Officer of the Company, each certifies that, to his knowledge:

- (1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of the dates and for the periods expressed in the Report.

Date: November 9, 2009

By: /s/ Philip Cook
Philip Cook
Senior Vice President — Chief Financial Officer

By: /s/ Glenn Darden
Glenn Darden
President and Chief Executive Officer