CIMAREX ENERGY CO
Form 10-Q
November 03, 2009
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

x Quarterly Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934

o Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the Quarterly Period ended September 30, 2009

Commission File No. 001-31446

CIMAREX ENERGY CO.

1700 Lincoln Street, Suite 1800

Denver, Colorado 80203-4518

(303) 295-3995

Incorporated in the State of Delaware	Employer Identification No. 45-0466694

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

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

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

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The number of shares of Cimarex Energy Co. common stock outstanding as of September 30, 2009 was 83,511,991.

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GLOSSARY

Bbl/d Barrels (of oil) per day

Bbls Barrels (of oil)

Bcf Billion cubic feet

Bcfe Billion cubic feet equivalent

MBbls Thousand barrels

Mcf Thousand cubic feet (of natural gas)

Mcfe Thousand cubic feet equivalent

MMBbls Million barrels

MMBtu Million British Thermal Units

MMcf Million cubic feet

MMcf/d Million cubic feet per day

MMcfe Million cubic feet equivalent

MMcfe/d Million cubic feet equivalent per day

Net Acres Gross acreage multiplied by working interest percentage

Net Production Gross production multiplied by net revenue interest

NGL Natural gas liquids

Tcf Trillion cubic feet

Tcfe Trillion cubic feet equivalent

One barrel of oil is the energy equivalent of six Mcf of natural gas

CAUTIONARY INFORMATION ABOUT FORWARD-LOOKING STATEMENTS

Throughout this Form 10-Q, we make statements that may be deemed forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities and Exchange Act of 1934. These forward-looking statements include, among others, statements concerning our outlook with regard to timing and amount of future production of oil and gas, price realizations, amounts, nature and timing of capital expenditures for exploration and development, plans for funding operations and capital expenditures, drilling of wells, operating costs and other expenses, marketing of oil and gas and other statements of expectations, beliefs, future plans and strategies, anticipated events or trends, and similar expressions concerning matters that are not historical facts. The forward-looking statements in this report are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in or implied by the statements.

These risks and uncertainties include, but are not limited to, fluctuations in the price we receive for our oil and gas production, reductions in the quantity of oil and gas sold due to decreased industry-wide demand and/or curtailments in production from specific properties due to mechanical, marketing or other problems, operating and capital expenditures that are either significantly higher or lower than anticipated because the actual cost of identified projects varied from original estimates and/or from the number of exploration and development opportunities being greater or fewer than currently anticipated, and increased financing costs due to a significant increase in interest rates. In addition, exploration and development opportunities that we pursue may not result in productive oil and gas properties. There are also numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and the timing of development expenditures. These and other risks and uncertainties affecting us are discussed in greater detail in this report and in our other filings with the Securities and Exchange Commission.

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PART I

ITEM 1 - Financial Statements

CIMAREX ENERGY CO.

Consolidated Balance Sheets

	September 30, 2009 (Unaudited)	December 31, 2008
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 2,962	$ 1,213
Restricted cash	593	502
Short-term investments		2,502
Receivables, net	173,914	259,082
Oil and gas well equipment and supplies	166,021	186,062
Deferred income taxes	8,566	2,435
Derivative instruments	3,150	
Other current assets	26,303	63,148
Total current assets	381,509	514,944
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	7,476,167	7,052,464
Unproved properties and properties under development, not being amortized	385,321	465,638
	7,861,488	7,518,102
Less accumulated depreciation, depletion and amortization	(5,696,671)	(4,709,597)
Net oil and gas properties	2,164,817	2,808,505
Fixed assets, net	122,984	119,616
Goodwill	691,432	691,432
Other assets, net	35,420	30,436
	$ 3,396,162	$ 4,164,933
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 19,646	$ 101,157
Accrued liabilities	202,544	263,994
Derivative instruments	12,645	
Revenue payable	90,027	104,438
Total current liabilities	324,862	469,589
Long-term debt	523,753	587,630
Deferred income taxes	327,653	500,945
Other liabilities	286,711	255,122
Stockholders equity:		
Preferred stock, $0.01 par value, 15,000,000 shares authorized, no shares issued		
Common stock, $0.01 par value, 200,000,000 shares authorized, 83,511,991 and 84,144,024 shares issued, respectively	835	841
Treasury stock, at cost, zero and 885,392 shares held, respectively		(33,344)
Paid-in capital	1,853,876	1,874,834

Retained earnings		78,546		510,271
Accumulated other comprehensive loss		(74)		(955)
		1,933,183		2,351,647
	$	3,396,162	$	4,164,933

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Consolidated Statements of Operations

(Unaudited)

	For the Three Months Ended September 30, 2009	For the Three Months Ended September 30, 2008	For the Nine Months Ended September 30, 2009	For the Nine Months Ended September 30, 2008
	(In thousands, except per share data)			
Revenues:				
Gas sales	$ 107,275	$ 313,523	$ 324,438	$ 912,443
Oil sales	131,073	238,918	324,507	683,109
Gas gathering, processing and other	10,732	24,163	31,165	73,734
Gas marketing, net	54	654	888	2,225
	249,134	577,258	680,998	1,671,511
Costs and expenses:				
Impairment of oil and gas properties		657,146	791,137	657,146
Depreciation, depletion and amortization	59,240	147,432	205,791	406,189
Asset retirement obligation	4,024	1,978	8,665	5,434
Production	42,682	55,362	139,127	156,506
Transportation	8,760	10,621	25,233	29,551
Gas gathering and processing	4,830	12,591	14,347	35,787
Taxes other than income	19,728	39,097	50,525	109,453
General and administrative	12,522	12,377	29,803	37,837
Stock compensation, net	2,477	2,791	6,831	7,432
Loss on derivative instruments, net	17,357		17,613	
Other operating, net	2,911	11,871	19,094	12,992
	174,531	951,266	1,308,166	1,458,327
Operating income (loss)	74,603	(374,008)	(627,168)	213,184
Other (income) and expense:				
Interest expense	10,623	8,066	30,144	24,785
Capitalized interest	(5,295)	(5,671)	(16,230)	(14,930)
Other, net	3,737	(8,086)	11,627	(16,610)
Income (loss) before income tax	65,538	(368,317)	(652,709)	219,939
Income tax expense (benefit)	26,833	(135,894)	(236,121)	73,811
Net income (loss)	$ 38,705	$ (232,423)	$ (416,588)	$ 146,128
Earnings (loss) per share to common stockholders:				
Basic				
Distributed	$ 0.06	$ 0.06	$ 0.18	$ 0.18
Undistributed	0.40	(2.91)	(5.28)	1.56
	$ 0.46	$ (2.85)	$ (5.10)	$ 1.74
Diluted				
Distributed	$ 0.06	$ 0.06	$ 0.18	$ 0.18
Undistributed	0.40	(2.91)	(5.28)	1.53
	$ 0.46	$ (2.85)	$ (5.10)	$ 1.71

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	For the Nine Months Ended September 30, 2009	2008
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$ (416,588)	$ 146,128
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Impairments	804,815	657,146
Depreciation, depletion and amortization	205,791	406,189
Asset retirement obligation	8,665	5,434
Deferred income taxes	(220,592)	(38,840)
Stock compensation, net	6,831	7,432
Derivative instruments, net	21,157	
Changes in non-current assets and liabilities	48,673	(94)
Other, net	13,682	1,019
Changes in operating assets and liabilities:		
(Increase) decrease in receivables, net	84,044	(20,762)
(Increase) decrease in other current assets	17,404	(59,669)
Increase (decrease) in accounts payable and accrued liabilities	(108,236)	36,726
Net cash provided by operating activities	465,646	1,140,709
Cash flows from investing activities:		
Oil and gas expenditures	(390,108)	(1,026,719)
Sales of oil and gas and other assets	38,556	434
Sales of short-term investments	3,328	9,288
Other expenditures	(21,131)	(43,253)
Net cash used by investing activities	(369,355)	(1,060,250)
Cash flows from financing activities:		
Net increase (decrease) in bank debt	(64,000)	
Financing costs incurred	(17,995)	(50)
Dividends paid	(15,123)	(15,007)
Issuance of common stock and other	2,576	12,931
Net cash used in financing activities	(94,542)	(2,126)
Net change in cash and cash equivalents	1,749	78,333
Cash and cash equivalents at beginning of period	1,213	123,050
Cash and cash equivalents at end of period	$ 2,962	$ 201,383

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

September 30, 2009

(Unaudited)

1. Basis of Presentation

The accompanying unaudited financial statements have been prepared by Cimarex Energy Co. pursuant to rules and regulations of the Securities and Exchange Commission (SEC). Accordingly, certain disclosures required by accounting principles generally accepted in the United States and normally included in annual reports on Form 10-K have been omitted. Although management believes that our disclosures in these interim financial statements are adequate, they should be read in conjunction with the financial statements, summary of significant accounting policies, and footnotes included in our 2008 Annual Report on Form 10-K, as amended by the Current Report on Form 8-K filed July 17, 2009 with the SEC.

In the opinion of management, the accompanying financial statements reflect all adjustments necessary to present fairly our financial position, results of operations, and cash flows for the periods shown.

Full Cost Accounting Method and Ceiling Limitation

We use the full cost method of accounting for our oil and gas operations. All costs associated with property acquisition, exploration, and development activities are capitalized. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities, and other costs incurred for the purpose of finding oil and gas reserves. Salaries and benefits paid to employees directly involved in the exploration and development of properties, as well as other internal costs that can be directly identified with acquisition, exploration, and development activities, are also capitalized. Under the full cost method of accounting, no gain or loss is recognized upon the disposition of oil and gas properties unless such disposition would significantly alter the relationship between capitalized costs and proved reserves.

At the end of each quarter we make a full cost ceiling limitation calculation whereby net capitalized costs related to proved properties less associated deferred income taxes may not exceed the amount of the present value discounted at ten percent of estimated future net revenues from proved reserves less estimated future production and development costs and related income tax expense. Future net revenues used in the calculation of the full cost ceiling limitation are determined based on current oil and gas prices and are adjusted for designated cash flow hedges, if any. Changes in proved reserve estimates (whether based upon quantity revisions or oil and gas prices) will cause corresponding changes to the full cost ceiling limitation. If net capitalized costs subject to amortization exceed this limit, the excess would be charged to expense. However, if commodity prices increase after period end and before issuance of the financial statements, these higher commodity prices may be used to determine if the capital costs are in fact impaired as of the end of the period. Any recorded impairment of oil and gas properties is not reversible at a later date.

Due to the significant decrease in natural gas prices during the first quarter of 2009, our March 31, 2009 ceiling limitation calculation resulted in excess capitalized costs of $791 million ($502 million, net of tax) for which we recorded a non-cash impairment of oil and gas properties. During the second and third quarters of 2009, gas prices remained relatively constant, while oil prices increased significantly. Therefore, we have not had any further ceiling impairments in 2009. Our quarterly and annual ceiling tests are primarily impacted by period end commodity prices, reserve quantities added and produced, overall exploration and development costs and depletion expense. Holding all factors constant other than commodity prices, a 10% decline in commodity prices as of September 30, 2009 would not have resulted in a ceiling test impairment. Decreases in commodity prices can also impact our goodwill impairment analysis. Changes in actual reserve quantities added and produced along with our actual overall exploration and development costs wi ll determine the Company s actual ceiling test calculation and impairment analyses.

Depletion of proved oil and gas properties is computed on the units-of-production method, whereby capitalized costs, as adjusted for future development costs, asset retirement obligations, and impairments are amortized over the total estimated proved reserves. The costs of wells in progress, certain unevaluated properties, and oil and gas well equipment yet to be installed on wells are not being amortized. On a quarterly

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2009

(Unaudited)

basis, we evaluate such costs for inclusion in the costs to be amortized resulting from the determination of proved reserves, impairments, or reductions in value. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

Goodwill

At September 30, 2009, we had $691.4 million of goodwill recorded in conjunction with past business combinations. Goodwill is subject to annual reviews for impairment, however, we continuously monitor the economic environment throughout the year to determine if additional impairment assessments are necessary. These assessments are based on a two-step accounting test. The first step is to compare the estimated fair value of the Company with the recorded net book value (including goodwill), after giving effect to any period impairment of oil and gas properties resulting from the ceiling limitation calculation. At September 30, 2009, the estimated fair value was higher than the recorded net book value. Therefore, no impairment was deemed to exist and no further testing was required.

If the estimated fair value is below the recorded net book value, a second step must be performed to determine the goodwill impairment required, if any. In this second step, the estimated fair value from the first step is used as the purchase price in a hypothetical acquisition of the Company. Purchase business combination accounting rules are followed to determine a hypothetical purchase price allocation to the Company s assets and liabilities. The residual amount of goodwill that results from this hypothetical purchase price allocation is compared to the recorded amount of goodwill and the recorded amount is written down to the hypothetical amount, if lower.

There have recently been severe disruptions in the credit markets and reductions in global economic activity which continue to impact stock markets and oil and gas commodity prices. Management must apply judgment in determining the estimated fair value of the Company for purposes of performing the goodwill impairment test. To estimate the fair value of the Company, we use all available information to make fair value determinations, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the assets. Because of the significant volatility in the stock market, we do not consider the market value of our shares to be an accurate reflection of our net assets for impairment purposes. As of September 30, 2009, the market price per share of our common stock exceeded the book value by more than $20 per share.

Use of Estimates

We make certain estimates and assumptions to prepare our financial statements in conformity with accounting principles generally accepted in the United States of America. Those estimates and assumptions affect the reported amounts of assets, liabilities, revenues, and expenses during the reporting period and in disclosures of commitments and contingencies. We analyze our estimates, including those related to oil and gas revenues, reserves and properties, as well as goodwill and contingencies, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions.

The more significant areas requiring the use of management s estimates and judgments relate to the estimation of proved oil and gas reserves, the use of these oil and gas reserves in calculating depletion, depreciation, and amortization, the use of the estimates of future net revenues in computing ceiling test limitations, the assessment of goodwill and estimates of future abandonment obligations used in recording asset retirement obligations. Estimates and judgments are also required in determining reserves for bad debt, impairments of undeveloped properties and other assets, purchase price allocation, valuation of deferred tax assets, fair value measurements and commitments and contingencies.

Accounting Changes

Certain amounts in prior years financial statements have been reclassified to conform to the 2009 financial statement presentation. In addition, effective January 1, 2009, we adopted new rules promulgated by

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Notes to Consolidated Financial Statements (Continued)

September 30, 2009

(Unaudited)

the Financial Accounting Standards Board (FASB) pertaining to the accounting treatment for certain convertible debt instruments (see Note 6) and to the calculation of earnings per share (see Note 9). Accordingly, prior periods have been adjusted retrospectively to conform to the applicable accounting pronouncements.

Recent Accounting Developments

In June 2009, the FASB approved the FASB Accounting Standards Codification (ASC), which after its launch on July 1, 2009 became the single source of authoritative, nongovernmental U.S. Generally Accepted Accounting Principles (GAAP). The Codification reorganizes all previous U.S. GAAP pronouncements into roughly 90 accounting topics and displays all topics using a consistent structure. All existing standards that were used to create the Codification are now superseded, replacing the previous references to specific Statements of Financial Accounting Standards with numbers used in the Codification s structural organization.

In May 2009, the FASB established general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Although there is new terminology, the standard is based on the same principles as those that currently exist. This guidance, which includes a new required disclosure of the date through which an entity has evaluated subsequent events, is effective for interim or annual periods ending after June 15, 2009. Our adoption of these provisions beginning with the period ending June 30, 2009 did not have an impact on our financial position or results of operations.

In December 2008, the SEC issued revised reporting requirements for oil and gas reserves that a company holds. Included in the new rule entitled *Modernization of Oil and Gas Reporting Requirements,* are the following changes: 1) permitting use of new technologies to determine proved reserves, if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes; 2) enabling companies to additionally disclose their probable and possible reserves to investors, in addition to their proved reserves; 3) allowing previously excluded resources, such as oil sands, to be classified as oil and gas reserves rather than mining reserves; 4) requiring companies to report the independence and qualifications of a preparer or auditor, based on current Society of Petroleum Engineers criteria; 5) requiring the filing of reports for companies that rely on a third party to prepare reserve estimates or conduct a reserve audit; and 6) requiring companies to report oil and gas reserves using an average price based upon the prior 12-month period, rather than year-end prices. The new requirements are effective for registration statements filed on or after January 1, 2010, and for annual reports on Form 10K for fiscal years ending on or after December 31, 2009. Early adoption is not permitted.

In September 2009, the FASB issued an exposure draft of proposed Accounting Standards Update (ASU) entitled *Oil and Gas Reserve Estimation and Disclosures.* This proposed ASU would amend the FASB accounting standards to align the reserve calculation and disclosure requirements with the requirements in the new SEC Rule, *Modernization of Oil and Gas Reporting Requirements*. As proposed, the ASU would be effective for reporting periods ending on or after December 31, 2009. Public comment is sought on the proposed ASU by October 15, 2009.

Subsequent Events

As of November 2nd, 2009, the day prior to issuing these financial statements, we completed our evaluation of potential subsequent events for disclosure and none were identified.

2. Derivative Instruments/Hedging

We periodically enter into derivative instruments to mitigate a portion of our potential exposure to a decline in commodity prices and the corresponding negative impact on cash flow available for reinvestment. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes.

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Notes to Consolidated Financial Statements (Continued)

September 30, 2009

(Unaudited)

On January 1, 2009, we adopted provisions set forth by the FASB which requires qualitative and quantitative disclosures about objectives and strategies for using derivatives, how such derivatives are accounted for and how the derivative instruments affect an entity s financial position, results of operations, and cash flows.

At September 30, 2009, we had the following outstanding contracts relative to our future production. We have elected not to account for these derivatives as cash flow hedges.

Natural Gas Contracts

Period	Type	Volume/Day		Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling	Weighted Average Price Swap	Fair Value (000 s)
Oct 09 - Dec 09	Collar	143,370	MMBtu	PEPL	$ 3.00	$ 5.00		$ (4,762)
Jan 10 - Dec 10	Collar	100,000	MMBtu	PEPL	$ 5.00	$ 6.62		$ (4,556)
Jan 10 - Dec 10	Swap	40,000	MMBtu	PEPL			$ 5.18	$ (8,787)
Jan 10 - Dec 10	Collar	20,000	MMBtu	HSC	$ 5.00	$ 6.85		$ (2,347)

Oil Contracts

Period	Type	Volume/Day		Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value (000 s)
Jan 10 - Dec 10	Collar	10,000	Bbls	WTI	$ 60.03	$ 92.07	$ 1,612
Jan 10 - Dec 10	Put/Floor	1,000	Bbls	WTI	$ 60.00		$ 1,621

(1) PEPL refers to Panhandle Eastern Pipe Line Company price and HSC refers to Houston Ship Channel price, both as quoted in Platt s Inside FERC on the first business day of each month. WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

The gas contracts that expire in 2009 represent approximately 47% of our total projected gas production (approximately 32% of our equivalent oil and gas production) for the remainder of 2009. We do not anticipate entering into further contracts related to our 2009 or 2010 production.

Under a collar agreement, we receive the difference between the published index price and a floor price if the index price is below the floor. We pay the difference between the ceiling price and the index price only if the index price is above the contracted ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices. Under a floor contract, if the settlement price for a settlement period is below the floor price, we receive the difference between the settlement price and the floor price. We are not required to make any payments in connection with the settlement of a floor contract. For a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price. We are required to make a payment to the counterparty if the settlement price for the settlement period is greater than the swap price.

Our derivative contracts are carried at their fair value on our balance sheet. We estimate the fair value using internal risk adjusted discounted cash flow calculations. Cash flows are based on the stated contract prices and current and projected published forward commodity price curves, adjusted for volatility. Due to the volatility of commodity prices, the estimated fair values of our derivative instruments are subject to fluctuation from period to period, which could result in significant differences between the current estimated fair value and the ultimate settlement price. The following table presents the estimated fair values of our derivative assets and liabilities as of September 30, 2009. At December 31, 2008, we had no derivative instruments outstanding.

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2009

(Unaudited)

	Balance Sheet Location	Asset		Liability	
		(In thousands)			
Derivatives not designated as hedging instruments:					
Natural gas contracts	Current assets Derivative instruments	$		$	
Oil contracts	Current assets Derivative instruments	$	3,150	$	
Oil contracts	Noncurrent assets Other assets, net	$	393	$	
Natural gas contracts	Current liabilities Derivative instruments	$		$	12,645
Natural gas contracts	Noncurrent liabilities Other liabilities	$		$	7,807
Oil contracts	Noncurrent liabilities Other liabilities	$		$	310

Because we have elected not to account for our current derivative contracts as cash flow hedges, we recognize all realized and unrealized changes in fair value in earnings. The derivative contracts that were outstanding in 2008 were treated as cash flow hedges. Accordingly, the realized gains or losses upon settlement of the 2008 contracts were reflected in gas revenue as an adjustment to the realized sales price. In 2008, unrealized gains and losses were recorded in accumulated other comprehensive income (which is included in shareholders equity). Cash settlements of our derivative contracts are included in cash flows from operating activities in our statements of cash flows.

The following table summarizes the realized and unrealized gains and losses from cash settlements and changes in fair value of our derivative contracts as presented in our accompanying financial statements.

	Three Months Ended September 30,				Nine Months Ended September 30,			
		2009		2008		2009		2008
	(In thousands)							
Derivatives not designated as hedging instruments:								
Cash settlements gains:								
Natural gas contracts	$	176	$		$	3,544	$	
Oil contracts								
Total cash settlements gains		176				3,544		
Unrealized gains (losses) on fair value change:								
Natural gas contracts		(20,289)				(22,602)		
Oil contracts		2,756				1,445		
Total net unrealized losses on fair value change		(17,533)				(21,157)		

Loss on derivative instruments, net	$ (17,357)	$	$ (17,613)	$
Derivatives designated as cash flow hedges:				
Natural gas contracts gains (losses)				
Cash payments included in gas sales	$	$ (1,064)	$	$ (72)
Unrealized gains (losses) on fair value change included in other comprehensive income (loss)	$	$ 22,095	$	$ (5,004)

We are exposed to financial risks associated with these contracts from non-performance by our counterparties. Counterparty risk is also a component of our estimated fair value calculations. We have mitigated our exposure to any single counterparty by contracting with eight financial institutions, each of which has a high credit rating and is a member of our bank credit facility. Our member banks have a secured interest in our oil and gas properties, and therefore do not require us to post collateral for our hedge liability positions.

3. Fair Value Measurements

Our short-term investments are reported at fair value in the accompanying balance sheets. The FASB has established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs are the highest priority and consist of unadjusted quoted prices in active markets for identical assets and liabilities. Level 2 inputs are inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for an asset or liability.

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2009

(Unaudited)

The following tables provide fair value measurement information for certain assets and liabilities as of September 30, 2009 and December 31, 2008.

September 30, 2009:		Carrying Amount		Fair Value
		(In thousands)		
Financial Assets (Liabilities):				
Derivative instruments	$	3,543	$	3,543
Derivative instruments	$	(20,761)	$	(20,761)
7.125% Notes due 2017	$	(350,000)	$	(338,625)
Bank debt	$	(156,000)	$	(156,000)
Floating rate convertible notes due 2023	$	(17,753)	$	(19,450)

December 31, 2008:		Carrying Amount		Fair Value
		(In thousands)		
Financial Assets (Liabilities):				
Short-term investments	$	2,502	$	2,502
7.125% Notes due 2017	$	(350,000)	$	(267,750)
Bank debt	$	(220,000)	$	(220,000)
Floating rate convertible notes due 2023	$	(17,630)	$	(19,450)

Assessing the significance of a particular input to the fair value measurement requires judgment, considering factors specific to the asset or liability. The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Short-term Investments (Level 2)

In the fourth quarter of 2007, we invested $16 million in an asset-backed securities fund, which was liquidated in the third quarter of 2009. The investments were classified as available-for-sale, and at the end of each period, changes in the fair value of the investments were recorded in other comprehensive income. The fair values of these investments were based on a net asset valuation provided by the fund manager. During the nine months ended September 30, 2009, we liquidated the remaining investments for $3.3 million, with a realized gain of $280 thousand, which was included in earnings for the period.

Bank Debt and Notes

Debt

The fair value of our bank debt is estimated to approximate the carrying amount because we recently entered into a new revolving credit facility. Interest on the facility is a floating rate based on either (a) a London Interbank Offered Rate (LIBOR) plus 2 to 3 percent, based on borrowing base usage, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50 percent, or (iii) adjusted LIBOR, in each case, plus an additional 1.125 to 2.125 percent, based on borrowing base usage. Each of the floating rate interest options resets periodically.

Notes

The fair values for our 7.125% fixed rate notes were based on their last traded value before period end.

There is not an observable market for our convertible notes. The fair value of the notes is estimated to approximate the face value of the notes because the notes bear interest at LIBOR and reset quarterly. The conversion rate of $28.59 attributable to the conversion feature at September 30, 2009 and December 31, 2008 exceeded requirements for the closing price of our common stock; therefore, no value was attributed to the conversion feature at either date.

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Derivative Instruments (Level 2)

The fair values of our derivative instruments at September 30, 2009 were estimated using internal discounted cash flow calculations. Cash flows are based on the stated contract prices and current and published forward commodity price curves, adjusted for volatility. The cash flows are also risk adjusted relative to non-performance for both our counterparties and our liability positions. At December 31, 2008, we had no derivative instruments outstanding.

Other Financial Instruments

The carrying amounts of our cash, cash equivalents, restricted cash, accounts receivable, accounts payable, and accrued liabilities approximate fair value because of the short-term maturities of these assets and liabilities. At September 30, 2009 and December 31, 2008, the aggregate allowance for doubtful accounts for trade, oil and gas sales, and gas gathering, processing, and marketing receivables was $6.7 million and $5.8 million, respectively.

Most of our accounts receivable balances are uncollateralized and result from transactions with other companies in the oil and gas industry. Concentration of customers may impact our overall credit risk because our customers may be similarly affected by changes in economic or other conditions within the industry.

4. Capital Stock

A summary of our common stock activity for the nine months ended September 30, 2009, follows:

		Number of Shares (in thousands)	
	Issued	**Treasury**	**Outstanding**
December 31, 2008	84,144	(885)	83,259
Restricted shares issued under compensation plans, net of cancellations	159		159
Option exercises, net of cancellations	94		94

Treasury shares cancelled	(885)	885	
September 30, 2009	83,512		83,512

Stock-based Compensation

Our 2002 Stock Incentive Plan was approved by stockholders in May 2003 and is effective until October 1, 2012. The plan provides for grants of stock options, restricted stock and restricted stock units to non-employee directors, officers and other eligible employees. A total of 12.7 million shares of common stock may be issued under the Plan.

Restricted Stock and Units

During the nine months ended September 30, 2009, we issued a total of 366,090 restricted shares to non-employee directors, officers, and other employees. Included in that amount are 228,000 shares issued to certain executives that are subject to market condition-based vesting determined by our stock price performance relative to a defined peer group s stock price performance. After three years of continued service, an executive will be entitled to vest in 50% to 100% of the award. The material terms of performance goals applicable to these awards were approved by stockholders in May 2006. The other shares granted in 2009 have service-based vesting schedules of three to five years.

The following table presents restricted stock as of September 30, 2009, and changes during the year:

Outstanding as of January 1, 2009	1,672,245
Vested	(166,725)
Granted	366,090
Canceled	(151,360)
Outstanding as of September 30, 2009	1,720,250

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The following table presents restricted units as of September 30, 2009 and changes during the year:

Outstanding as of January 1, 2009	655,205
Converted to Stock	(5,362)
Granted	
Canceled	
Outstanding as of September 30, 2009	649,843
Vested included in outstanding	605,559

Vesting of restricted stock and units granted in years before 2006 is exclusively related to continued service of the grantee for one to five years. In certain cases, a three-year required holding period following vesting also applies. A restricted unit represents a right to an unrestricted share of common stock upon completion of defined vesting and holding periods. The restricted stock and stock unit agreements provide that grantees are entitled to receive dividends on unvested shares.

Compensation expense for service-based vesting restricted shares or units is based upon amortization of the grant-date market value of the award. The fair value of the market condition-based restricted stock awards is based on the grant-date market value of the award utilizing a Monte Carlo simulation model to estimate the percentage of awards that will vest at the end of a three-year period. Compensation expense related to the restricted stock and unit awards is recognized ratably over the applicable vesting period. Compensation expense (including capitalized amounts) was $3.7 million and $4.0 million, respectively, for the quarters ended September 30, 2009 and 2008. Compensation expense (including capitalized amounts) for the nine months ended September 30, 2009 and 2008, totaled $9.6 million and $11.7 million, respectively,

Unamortized compensation costs related to unvested restricted shares and units at September 30, 2009 and 2008 was $30.3 million and $38.3 million, respectively.

Stock Options

Options granted under our plan expire ten years from the grant date and have service-based vesting schedules of three to five years. The plan provides that all grants have an exercise price of the average of the high and low prices of our common stock as reported by the New York Stock Exchange on the date of grant.

There were 228,175 stock options granted to employees during the nine months ended September 30, 2009. There were 483,500 stock options granted to employees during the nine months ended September 30, 2008.

Information about outstanding stock options is summarized below:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Term	Aggregate Intrinsic Value (000)
Outstanding as of January 1, 2009	1,532,016	$ 29.95		
Exercised	(105,970)	15.64		
Granted	228,175	27.74		
Canceled	(45,900)	55.48		
Outstanding as of September 30, 2009	1,608,321	$ 29.85	5.6 Years	$ 27,205
Exercisable as of September 30, 2009	1,041,159	$ 22.75	3.7 Years	$ 23,293

There were 105,970 and 404,449 stock options exercised during the nine months ended September 30, 2009 and September 30, 2008, respectively. Cash received from option exercises during the nine months ended September 30, 2009 and September 30, 2008 was $1.7 million and $6.3 million, respectively, and the related tax benefits realized from option exercises totaled $918 thousand and $6.7 million, respectively, and were recorded to paid-in capital. The total intrinsic value of stock options exercised during the three and nine months ended September 30, 2009 was $2.4 million and $2.5 million, respectively. The total intrinsic value of

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stock options exercised during the three and nine months ended September 30, 2008 was zero and $18.7 million, respectively.

We estimate the fair value of options as of the date of grant using the Black-Scholes option-pricing model. Expected volatilities are based on the historical volatility of our common stock. We also use historical data to estimate the probability of option exercise, expected years until exercise and potential forfeitures. The risk-free interest rate we use is the five-year U.S. Treasury bond in effect at the date of the grant. The following summary reflects the status of non-vested stock options as of September 30, 2009 and changes during the year:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Exercise Price
Non-vested as of January 1, 2009	529,620	$ 18.96	$ 54.15
Vested	(144,733)	19.35	56.17
Granted	228,175	11.11	27.74
Forfeited	(45,900)	19.07	55.48
Non-vested as of September 30, 2009	567,162	$ 15.70	$ 42.90

We recognize compensation cost related to stock options ratably over the vesting period. Historical amounts may not be representative of future amounts as additional options may be granted. Compensation cost (including capitalized amounts) for the quarters ended September 30, 2009 and 2008, totaled $988 thousand and $692 thousand, respectively. For the nine months ended September 30, 2009 and 2008, compensation cost (including capitalized amounts) totaled $2.4 million and $910 thousand, respectively. The increase in costs for the 2009 periods is primarily a result of 476 thousand options granted in the third quarter of 2008, when the average price of our common stock was approximately $56.00 per share.

As of September 30, 2009, there was $7.9 million of unrecognized compensation cost related to non-vested stock options granted under our stock incentive plan. We expect to recognize that cost pro rata over a weighted-average period of 2.1 years.

Stockholder Rights Plan

We have a stockholder rights plan. The plan is designed to improve the ability of our board to protect the interests of our stockholders in the event of an unsolicited takeover attempt. For every outstanding share of Cimarex common stock, there exists one purchase right (the Right). Each Right represents a right to purchase one one-hundredth of a share of Series A Junior Participating Preferred Stock, at a purchase price of $60.00 per share, subject to adjustment in certain cases, to prevent dilution. The Rights will become exercisable only in the event a person or group acquires beneficial ownership of 15% or more of our common stock, or a person or group commences a tender offer or exchange offer that, if successfully consummated, would result in such person or group beneficially owning 15% or more of our common stock. In general, in either of these events, each holder of a right, other than the person or group initiating the acquisition or tender offer, will have the right to receive Cimarex common stock with a value equal to two times the exercise price of the right.

We generally will be entitled to redeem the Rights under certain circumstances at $0.01 per Right at any time before the close of business on the tenth business day after there has been a public announcement of the acquisition of beneficial ownership by any person or group of 15% or more of our common stock. The Rights may not be exercised until our Board s right to redeem the stock has expired. Unless redeemed earlier, the Rights expire on February 23, 2012.

Dividends and Stock Repurchases

In September 2009, the Board of Directors declared a cash dividend of $0.06 per share on our common stock. The dividend is payable December 1, 2009 to stockholders of record on November 13, 2009. The Board of Directors declared our first quarterly cash dividend of $0.04 per share in December 2005. A dividend has been declared in every quarter since then. Future dividend payments will depend on the Company s level of earnings, financial requirements, and other factors considered relevant by the Board of Directors.

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In December 2005, the Board of Directors authorized the repurchase of up to four million shares of our common stock. The authorization is currently set to expire on December 31, 2009. Through December 31, 2007, we had repurchased and cancelled a total of 1,364,300 shares at an overall average price of $39.05. Purchases may be made in both the open market and through negotiated transactions, and purchases may be increased, decreased or discontinued at any time without prior notice. There were no shares repurchased in the third quarter of 2009, or since the quarter ended September 30, 2007.

Issuer Purchases of Equity Securities for the Quarter Ended September 30, 2009

	Total Number of Shares Purchased	**Average Price Paid per Share**	**Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**	**Maximum Number of shares that may yet be Purchased Under the Plans or Programs**
July, 2009	None	NA	None	2,635,700
August, 2009	None	NA	None	2,635,700
September, 2009	None	NA	None	2,635,700

5. Asset Retirement Obligations

We recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred, if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. Oil and gas producing companies incur this liability which includes costs related to the plugging of wells, the removal of facilities and equipment, and site restorations, upon acquiring or drilling a successful well. Subsequent to initial measurement, the asset retirement liability is required to be accreted each period. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement capitalized cost. Capitalized costs are depleted as a component of the full cost pool.

The following table reflects the components of the change in the carrying amount of the asset retirement obligation for the nine months ended September 30, 2009 (in thousands):

Asset retirement obligation at January 1, 2009	$	139,948
Liabilities incurred		2,978

Liability settlements and disposals		(6,648)
Accretion expense		5,823
Revisions of estimated liabilities		13,714
Asset retirement obligation at September 30, 2009		155,815
Less current obligation		(21,306)
Long-term asset retirement obligation	$	134,509

6. Long-Term Debt

Debt at September 30, 2009 and December 31, 2008 consisted of the following (in thousands):

		September 30, 2009		December 31, 2008
Bank debt	$	156,000	$	220,000
7.125% Notes due 2017		350,000		350,000
Floating rate convertible notes due 2023 (face value $19,450)		17,753		17,630
Total long-term debt	$	523,753	$	587,630

Bank Debt

In April 2009, we entered into a new three-year senior secured revolving credit facility (credit facility). The new credit facility increases bank commitments from $500 million to $800 million, with a

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borrowing base of $1 billion. The credit facility is provided by a syndicate of banks led by JP Morgan Chase Bank, N.A., matures on April 14, 2012 and is secured by mortgages on certain of our oil and gas properties and the stock of certain wholly-owned operating subsidiaries.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves, and is subject to potential special and regular semi-annual redeterminations.

The credit facility contains covenants and restrictive provisions which may limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility requires us to maintain a current ratio greater than 1 to 1 and a leverage ratio not to exceed 3.5 to 1. As of September 30, 2009, we were in compliance with all of the financial and non-financial covenants.

At Cimarex s option, borrowings under the credit facility may bear interest at either (a) a London Interbank Offered Rate (LIBOR) plus 2 to 3 percent, based on borrowing base usage, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50 percent, or (iii) adjusted LIBOR, in each case, plus an additional 1.125 to 2.125 percent, based on borrowing base usage.

At September 30, 2009, there was $156 million of borrowings outstanding under the credit facility at a weighted average interest rate of approximately 3.1%. We also had letters of credit outstanding of $17.7 million leaving an unused borrowing availability of $626.3 million.

7.125% Notes due 2017

In May, 2007, we issued $350 million of 7.125% senior unsecured notes that mature May 1, 2017 at par. Interest on the notes is payable May 1 and November 1 of each year. The notes are governed by an indenture containing covenants that could limit our ability to incur additional indebtedness; pay dividends or repurchase our common stock; make investments and other restricted payments; incur liens; enter into sale/leaseback transactions; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets.

The notes are redeemable at our option, in whole or in part, at any time on and after May 1, 2012 at the following redemption prices (expressed as percentages of the principal amount) plus accrued interest, if any, thereon to the date of redemption.

Year	Percentage
2012	103.6%
2013	102.4%
2014	101.2%
2015 and thereafter	100.0%

At any time prior to May 1, 2010, we may redeem up to 35% of the original principal amount of the notes with the proceeds of certain equity offerings of our shares of common stock at a redemption price of 107.125% of the principal amount of the notes, together with accrued and unpaid interest, if any, to the date of redemption. At any time prior to May 1, 2012, we may also redeem all, but not part, of the notes at a price of 100% of the principal amount of the notes plus accrued and unpaid interest plus a make-whole premium.

If a specified change of control occurs, subject to certain conditions, we must make an offer to purchase the notes at a purchase price of 101% of the principal amount of the notes, plus accrued and unpaid interest to the date of the purchase.

Floating rate convertible notes due 2023

The floating rate convertible senior notes mature on December 15, 2023. The notes are senior unsecured obligations and bear interest at the three month LIBOR, reset quarterly. On September 30, 2009, the interest rate approximated 0.3%.

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In December 2008, holders of $105.5 million of the original $125 million issuance amount elected to submit their notes for repurchase. We repurchased the $105.5 million in notes with borrowings under our credit facility. Holders of the remaining $19.5 million of notes have optional repurchase dates of December 15, 2013, and 2018.

In addition to the repurchase rights, holders of the convertible notes may surrender their notes for conversion into a combination of cash and shares of our common stock upon the occurrence of certain circumstances, including if the price of our common stock has been trading above 110% of the conversion price of $28.59 per share for a defined period of time. As of September 30, 2009 and December 31, 2008, the notes were not convertible. However, based on the price of our common stock during September 2009, the notes became convertible effective October 1, 2009.

At our option, we may offer to redeem the notes at any time at par. In addition, if a change of control occurs, subject to certain conditions, we must make an offer to purchase the notes at a purchase price of 101% of the principal amount.

In May 2008, the FASB issued new guidance that changed the accounting for the components of convertible debt that can be settled wholly or partly in cash upon conversion. The new requirements are required to be applied to both new instruments and retrospectively to previously issued convertible instruments. The debt and equity components of the instruments are accounted for separately. The value assigned to the debt component is the estimated value of similar debt without a conversion feature as of the issuance date, with the remaining proceeds allocated to the equity component and recorded as additional paid-in capital. The debt component is recorded at a discount and is subsequently accreted to its par value, thereby reflecting an overall market rate of interest in the income statement. The effective interest rate for the quarters ended September 30, 2009 and 2008 was 1.5% and 4%, respectively. The effective interest rate for the nine months ended September 30, 2009 and 2008 was 2.3% and 4.7%, respectively.

We adopted this guidance on January 1, 2009. The following table reflects a comparison of certain financial statement line items affected by the retrospective application of this guidance.

Summary of the Retrospective Application of Changes (amounts in thousands):

	Three Months Ended September 30, 2008		Nine Months Ended September 30, 2008	
	After	**As Previously Reported**	**After**	**As Previously Reported**

	Adoption		Adoption	
Changes to the Consolidated Statements of Operations:				
Interest expense	$ 8,066	$ 7,795	$ 24,785	$ 23,963
Amortization of fair value of debt	$	$ (191)	$	$ (572)
Income before income tax expense (benefit)	$ (368,317)	$ (367,855)	$ 219,939	$ 221,133
Income tax expense (benefit)	$ (135,894)	$ (135,726)	$ 73,811	$ 74,319
Net income (loss)	$ (232,423)	$ (232,129)	$ 146,128	$ 147,014

	At December 31, 2008	
	After Adoption	As Previously Reported
Changes to the Consolidated Balance Sheets:		
Long-term debt	$ 587,630	$ 591,223
Deferred income taxes	$ 500,945	$ 499,634
Paid-in capital	$ 1,874,834	$ 1,855,825
Retained earnings	$ 510,271	$ 526,998

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7. Income Taxes

The components of our provision for income taxes are as follows (in thousands):

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Current provision (benefits)	$ 13,305	$ 27,068	$ (15,529)	$ 112,651
Deferred tax (benefit)	13,528	(162,962)	(220,592)	(38,840)
	$ 26,833	$ (135,894)	$ (236,121)	$ 73,811

We account for uncertainty in our income tax provisions in accordance with rules promulgated by the FASB. At September 30, 2009 we have no unrecognized tax benefits that would impact our effective rate and we have made no provisions for interest or penalties related to uncertain tax positions. The tax years 2005 2008 remain open to examination by the Internal Revenue Service of the United States. We file tax returns with various state taxing authorities which remain open for tax years 2004 2008 for examination.

Our provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes, non-deductible expenses, and special deductions. The effective income tax rates for the nine months ended September 30, 2009 and September 30, 2008 was 36.2% and 33.6%, respectively.

8. Supplemental Disclosure of Cash Flow Information (in thousands):

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Cash paid during the period for:				
Interest expense (net of amounts capitalized)	$ (2,499)	$ (4,390)	$ 3,916	$ 2,263
Interest capitalized	5,295	5,671	16,230	14,930
Income taxes		1,457	1,670	128,318
Cash received for income taxes	49,936	2,121	91,918	4,185

9. Earnings (Loss) per Share and Comprehensive Income

Earnings (Loss) per Share

In 2008, the FASB issued new guidance which holds that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are participating securities (as defined as securities that may participate in undistributed earnings with common stock, whether that participation is conditioned upon the occurrence of a specified event or not, regardless of the form of participation), and therefore should be included in computing earnings per share using the two-class earnings allocation method. The two-class method is an earnings allocation formula that determines earnings per share for each class of common stock and participating security according to dividends declared (or accumulated) and participation rights in undistributed earnings. The guidance became effective for financial statements issued in fiscal years beginning after December 15, 2008, and for interim periods within those years. The requirements are to be applied by recasting previously reported earnings per share data. Under this guidance, our unvested share based payment awards, consisting of restricted stock and restricted stock units, qualify as participating securities. We adopted this guidance in the first quarter of 2009.

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The calculations of basic and diluted net earnings (loss) per common share under the two-class method are presented below (in thousands, except per share data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Net income (loss)	$ 38,705	$ (232,423)	$ (416,588)	$ 146,128
Less distributed earnings (dividends declared during the period)	(5,050)	(5,035)	(15,127)	(15,073)
Undistributed earnings (loss) for the period	$ 33,655	$ (237,458)	$ (431,715)	$ 131,055
Allocation of undistributed earnings(loss):				
Basic allocation to unrestricted common stockholders	$ 32,707	$ (237,458)	$ (431,715)	$ 127,384
Basic allocation to participating securities	$ 948	$ (2)	$ (2)	$ 3,671
Diluted allocation to unrestricted common stockholders	$ 32,712	$ (237,458)	$ (431,715)	$ 127,457
Diluted allocation to participating securities	$ 943	$ (2)	$ (2)	$ 3,598
Basic Shares Outstanding				
Unrestricted outstanding common shares	81,792	81,576	81,792	81,576
Add Participating securities:				
Restricted stock outstanding	1,720	1,696	1,720	1,696
Restricted stock units outstanding	650	655	650	655
Total participating securities	2,370	2,351	2,370	2,351
Total Basic Shares Outstanding	84,162	83,927	84,162	83,927
Fully Diluted Shares				
Unrestricted outstanding common shares	81,792	81,576	81,792	81,576
Incremental shares from assumed exercise of stock options	385	(1)	(1)	574
Incremental shares from assumed conversion of the convertible senior notes	(3)	(1)	(1)	1,125
Fully diluted common stock	82,177	81,576	81,792	83,275
Participating securities	2,370(2)	2,351(2)	2,370(2)	2,351
Total Fully Diluted Shares	84,547	83,927	84,162	85,626
Basic earnings (loss) per share				
Unrestricted common stockholders:				
Distributed earnings	$ 0.06	$ 0.06	$ 0.18	$ 0.18
Undistributed earnings (loss)	0.40	(2.91)	(5.28)	1.56
	$ 0.46	$ (2.85)	$ (5.10)	$ 1.74
Participating securities:				
Distributed earnings	$ 0.06	$ 0.06	$ 0.18	$ 0.18
Undistributed earnings (loss)	0.40	0.00	0.00	1.56
	$ 0.46	$ 0.06	$ 0.18	$ 1.74

Fully diluted earnings (loss) per share								
Unrestricted common stockholders:								
Distributed earnings	$	0.06	$	0.06	$	0.18	$	0.18
Undistributed earnings (loss)		0.40		(2.91)		(5.28)		1.53
	$	0.46	$	(2.85)	$	(5.10)	$	1.71
Participating securities:								
Distributed earnings	$	0.06	$	0.06	$	0.18	$	0.18
Undistributed earnings (loss)		0.40		0.00		0.00		1.53
	$	0.46	$	0.06	$	0.18	$	1.71

(1) No potential common shares or securities are included in the diluted share computation when a loss from continuing operations exists.

(2) Participating securities are included in distributed earnings and not in undistributed earnings when a loss from continuing operations exists.

(3) Based on the price of our common stock during June 2009, the notes were not convertible during the third quarter of 2009. However, the notes became convertible on October 1, 2009, based on the price of our common stock during September 2009.

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The following table presents the amounts of outstanding stock options, restricted stock and units as follows:

	September 30, 2009	September 30, 2008
Stock options	1,608,321	1,566,516
Restricted stock	1,720,250	1,695,523
Restricted units	649,843	655,205

All stock options and restricted units and shares were considered potentially dilutive securities for each of the periods presented except for those determined to be anti-dilutive as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
Stock options	762,429	1,566,516	1,608,321	121,394
Restricted stock		1,695,523	1,720,250	
Restricted stock units		655,205	649,843	
Convertible notes		1,125,000		
	762,429	5,042,244	3,978,414	121,394

Comprehensive Income (Loss)

Comprehensive income is a term used to refer to net income (loss) plus other comprehensive income (loss). Other comprehensive income (loss) is comprised of revenues, expenses, gains and losses that under generally accepted accounting principles are reported as separate components of stockholders equity instead of net income (loss).

The components of comprehensive income (loss) are as follows (in thousands):

	Three Months Ended September 30,	Nine Months Ended September 30,

	2009	2008	2009	2008
Net Income (loss)	$ 38,705	$ (232,423)	$ (416,588)	$ 146,128
Other comprehensive income (loss):				
Cash flow hedges				
Increase (decrease) in fair value		22,095		(5,004)
Settlements reflected in gas sales		1,064		72
Sub-total		23,159		(4,932)
Related income tax effect		(8,282)		1,885
Total cash flow hedges		14,877		(3,047)
Change in fair value of short-term investments and other, net of tax	366	(213)	882	(413)
Total comprehensive income (loss)	$ 39,071	$ (217,759)	$ (415,706)	$ 142,668

10. Commitments and Contingencies

Litigation

In January 2009, the Tulsa County District Court issued a judgment in the H.B. Krug, et al versus Helmerich & Payne, Inc. (H&P) case. This lawsuit was originally filed in 1998 and addressed H&P s conduct pertaining to a 1989 take-or-pay settlement, along with potential drainage issues and other related matters. Damages of $6.9 million, plus $119.5 million for disgorgement of H&P s estimated potential compounded profit since 1989 resulting from the noted damages, were awarded to plaintiff royalty owners for

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(Unaudited)

a total of $126.4 million. This amount was subsequently adjusted by the court to a total of $119.6 million. Pursuant to the 2002 spin-off transaction to shareholders of H&P by which Cimarex became a publicly traded entity, Cimarex assumed the assets and liabilities of H&P s exploration and production business. In 2008 we had accrued litigation expense of $119.6 million for this lawsuit. During the nine months ended September 30, 2009, we have accrued an additional $7.6 million. We have appealed the District Court s judgments, but do not expect this matter to be resolved in 2009.

In the normal course of business, we have other various litigation related matters. We assess the probability of estimable amounts related to litigation matters in accordance with guidance established by the FASB and adjust our accruals accordingly. Though some of the related claims may be significant, the resolution of them we believe, individually or in the aggregate, would not have a material adverse effect on our financial condition or results of operations.

Other

We have a large development project in Sublette County, Wyoming where we are developing the deep Madison gas formation and constructing a gas processing plant. At September 30, 2009, we had commitments of $163.1 million relating to construction of the gas processing plant of which $102.6 million is subject to a construction contract. The total cost of the project will approximate $354 million. Pursuant to the terms of our operating agreement with our partners in this project, we will be reimbursed by them for 42.5% of the costs. The gas processing plant is subject to a delivery commitment agreement over a 20 year period, commencing December, 2011. If no deliveries were made, the maximum amount that would be payable under the agreement would be approximately $43 million.

We have drilling commitments of approximately $69.1 million consisting of obligations to complete drilling wells in progress at September 30, 2009. We also have minimum expenditure contractual commitments of $46.8 million to secure the use of drilling rigs.

At September 30, 2009, we had firm sales contracts to deliver approximately 5.6 Bcf of natural gas over the next six months. If this gas is not delivered, our financial commitment would be approximately $19.6 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no significant financial commitment will be due based on our reserves and current production levels.

In connection with a gas gathering and processing agreement, we have commitments to deliver 58.5 Bcf of gas over the next five years. If no gas was delivered, the maximum amount that would be payable under these commitments would be approximately $43.5 million.

We have other various delivery commitments in the normal course of business, none of which are individually material. In aggregate, these commitments have a maximum amount that would be payable, if no gas is delivered, of approximately $5 million.

All of the noted commitments were routine and were made in the normal course of our business.

11. Property Sales

Various interests in oil and gas properties were sold during the first nine months of 2009 for $28.3 million. These were recorded as a reduction to oil and gas properties. In October 2009, we completed the sale of our interest in a Texas secondary recovery oil field for approximately $81 million.

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

BUSINESS OVERVIEW

We are an independent oil and gas exploration and production company with operations entirely located in the United States. We have determined that our business is comprised of only one segment because our gathering, processing and marketing activities are ancillary to our production operations and are not separately managed.

The downward pressure in natural gas prices that began in the last half of 2008 has continued during the first nine months of 2009. Our average realized natural gas price for the first nine months of 2009 decreased 61% from the same period of 2008. Additionally, although oil prices have improved since the end of 2008, the September 2009 price of West Texas Intermediate oil is down 33% from September 2008.

As a result, our earnings for the first nine months of 2009 were negatively impacted. During the third quarter, we generated net income of $38.7 million, or $0.46 per diluted share, and for the first nine months of the year we reported a net loss of $416.6 million, or $5.10 per share. The year to date loss in 2009 was primarily the result of a first quarter noncash impairment of our oil and gas properties of $501.8 million, net of income taxes. Substantially all of this noncash charge was the result of the continuing drop in commodity prices in the first quarter.

In response to the lower oil and gas prices we significantly reduced our planned 2009 capital expenditures from our record high in 2008. Total planned capital expenditures for 2009 are approximately $525 million, down from 2008 capital expenditures of $1.4 billion. We have also entered into derivative contracts to reduce a portion of our potential exposure to continued weakness in commodity prices. During the third quarter we continued to enter into Calendar 2010 hedges. To date we have hedged an average of 11,000 barrels of oil per day and 160,000 MMBtu of gas per day. These contracts cover a portion of our anticipated production through December 2010.

In October our bank group, as part of the regularly scheduled fall review, reaffirmed our $1.0 billion borrowing base related to our credit facility maturing in April 2012. Bank group commitments of $800 million also remain unchanged. As of September 30, 2009, we had borrowings outstanding of $156 million, which is $183 million less than the second quarter balance of $339 million. The reduction in borrowings was funded from non-core property sales, tax refunds, lower capital spending relative to cash flow and a net positive working capital change.

Also in October, we completed the sale of our interest in a Texas secondary recovery oil field for approximately $81 million. Including this sale, year-to-date proved property sales total $106.3 million, with associated proved reserves of 28 Bcfe and 8 MMcfe/d of production.

Third quarter 2009 summary financial and operating results:

- Oil and gas sales declined 57% to $238.3 million from $552.4 million a year earlier.
- Average realized gas price fell 61% to $3.80 per Mcf versus $9.76 per Mcf.
- Average realized oil price dropped 45% to $63.49 per barrel from $114.87 per barrel.
- Oil and gas production volumes averaged 441.5 MMcfe/d, down from 484.9 MMcfe/d for third quarter 2008.

- Net income of $38.7 million, or $0.46 per diluted share, versus a loss of $232.4 million, or $2.85 per share.

- Cash flow from operating activities was $271.3 million, down from $443.2 million.

- Debt totaled $523.8 million at September 30, 2009, down from $587.6 million at year end 2008.

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Oil and Gas Prices

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2009		2008		2009		2008	
Gas Prices:								
Average Henry Hub price ($/Mcf)	$	3.39	$	10.25	$	3.93	$	9.74
Average realized sales price excluding hedge effect ($/Mcf)	$	3.80	$	9.76	$	3.70	$	9.58
Effect of hedges ($/Mcf)	$		$	(.03)	$		$	
Oil Prices:								
Average WTI Cushing price ($/Bbl)	$	68.33	$	117.95	$	57.01	$	113.28
Average realized sales price ($/Bbl)	$	63.49	$	114.87	$	50.80	$	110.26

On an energy equivalent basis, 70% of our 2009 aggregate production was natural gas. A $0.10 per Mcf change in our average realized gas sales price would have resulted in approximately an $8.8 million change in our gas revenues. Similarly 30% of our production was crude oil. A $1.00 per barrel change in our average realized crude oil sales price would have resulted in approximately a $6.4 million change in our oil revenues.

Hedging

To mitigate a portion of our exposure to a decrease in funds from operations stemming from falling oil and gas prices we periodically use derivative contracts to provide downside risk protection on a portion of our production.

During the first nine months of 2008 we had 40,000 MMBtu per day of Mid-Continent gas production hedged through the use of collars accounted for as cash flow hedges. As of December 31, 2008 all of our cash flow effective hedge contracts had expired.

In March 2009 we entered into derivative gas contracts covering the period April 2009 through December 2009. The collars set a floor of $3.00 and ceiling of $5.00 and cover approximately 148,000 MMBtu per day of our Mid-Continent gas production during the contract period. As of September 30, 2009 the remaining contracts will cover approximately 47% of our estimated October through December 2009 gas volumes.

During the second and third quarters of 2009 we entered into derivative contracts for a portion of our 2010 production. We do not anticipate entering into further contracts related to our 2009 or 2010 production.

At September 30, 2009, we had the following outstanding contracts:

Natural Gas Contracts

Period		Type	Volume/Day		Index(1)	Weighted Average Price Floor		Ceiling		Swap	
Oct 09	Dec 09	Collar	143,370	MMBtu	PEPL	$	3.00	$	5.00		
Jan 10	Dec 10	Collar	100,000	MMBtu	PEPL	$	5.00	$	6.62		
Jan 10	Dec 10	Swap	40,000	MMBtu	PEPL					$	5.18
Jan 10	Dec 10	Collar	20,000	MMBtu	HSC	$	5.00	$	6.85		

Oil Contracts

Period		Type	Volume/Day		Index(1)	Weighted Average Price Floor		Ceiling	
Jan 10	Dec 10	Collar	10,000	Bbls	WTI	$	60.03	$	92.07
Jan 10	Dec 10	Put/Floor	1,000	Bbls	WTI	$	60.00		

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(1) PEPL refers to Panhandle Eastern Pipe Line Company price and HSC refers to Houston Ship Channel price, both as quoted in Platt s Inside FERC on the first business day of each month. WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

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We did not choose to apply hedge accounting treatment to any of the contracts we have entered into in the current year. As such, settlements on these contracts will not impact our realized commodity prices during the periods they cover. Instead, any settlements on these contracts will be shown as a component of operating costs and expenses as a realized (gain) loss on derivative instruments. See Note 2 to the Consolidated Financial Statements and Item 3 of this report for additional information regarding our derivative instruments.

Production and other operating expenses

The costs associated with finding and producing oil and gas are substantial. Some of these costs vary with oil and gas prices, some trend with production volume and some are a function of the number of wells we own. At the end of 2008, we owned interests in 12,980 wells.

Production expense generally consists of the cost of power and fuel, direct labor, third-party field services, compression, water disposal, and certain maintenance activity necessary to produce oil and gas from existing wells.

Transportation expense is comprised of costs paid to move oil and gas from the wellhead to a specified sales point. In some cases we receive a payment from purchasers which is net of transportation costs, and in other instances we separately pay for transportation. If costs are netted in the proceeds received, both the gross revenues and gross costs are shown in sales and expenses, respectively.

Depreciation, depletion and amortization (DD&A) of our producing properties is computed using the units-of-production method. Because the economic life of each producing well depends upon the assumed price for future sales of production, fluctuations in oil and gas prices may impact the level of proved reserves used in the calculation. Higher prices generally have the effect of increasing reserves, which reduces depletion expense, while lower prices generally have the effect of decreasing reserves, which increases depletion expense. In addition, changes in estimates of reserve quantities and estimates of future development costs or reclassifications from unproved properties to proved properties will impact depletion expense.

General and administrative expenses consist primarily of salaries and related benefits, office rent, legal fees, consultants, systems costs and other administrative costs incurred in our offices and not directly associated with exploration, development or production activities. While we expect these costs to increase with our growth, we also expect such increases to be proportionately smaller than our production growth.

Production taxes are assessed by state and local taxing authorities pertaining to production, revenues or the value of properties. These typically include production severance, ad valorem and excise taxes.

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RESULTS OF OPERATIONS

Three months and nine months ended September 30, 2009 vs. September 30, 2008

Net income for the third quarter of 2009 was $38.7 million, or $0.46 per diluted share. This compares to a net loss of $232.4 million, or $2.85 per share for the same period in 2008. For the nine months ended September 30, 2009, we recognized a net loss of $416.6 million, or $5.10 per share, compared to net income of $146.1 million, or $1.71 per diluted share, for the first nine months of 2008. The change in net income for both the quarter and nine months ended is primarily the result of non-cash full cost ceiling write-downs that were recorded in the third quarter of 2008 and the first quarter of 2009. These impairments are discussed further in the operating costs and expenses section below.

Oil and Gas Sales (In thousands or as indicated)	2009	2008	Percent Change Between 2009/2008	Price/Volume Analysis Price	Volume	Variance
For the Three Months Ended September 30,						
Gas sales	$ 107,275	$ 313,523	(66)%	$ (168,245)	$ (38,003)	$ (206,248)
Oil sales	131,073	238,918	(45)%	(106,048)	(1,797)	(107,845)
Total oil and gas sales	$ 238,348	$ 552,441		$ (274,293)	$ (39,800)	$ (314,093)
For the Nine Months Ended September 30,						
Gas sales	$ 324,438	$ 912,443	(64)%	$ (515,117)	$ (72,888)	$ (588,005)
Oil sales	324,507	683,109	(52)%	(379,830)	21,228	(358,602)
Total oil and gas sales	$ 648,945	$ 1,595,552		$ (894,947)	$ (51,660)	$ (946,607)

	For the Three Months Ended September 30, 2009	2008	Percent Change Between 2009/2008	For the Nine Months Ended September 30, 2009	2008	Percent Change Between 2009/2008
Total gas volume MMcf	28,229	32,136	(12)%	87,605	95,218	(8)%
Gas volume MMcf per day	306.8	349.3		320.9	347.5	
Average gas price per Mcf	$ 3.80	$ 9.76	(61)%	$ 3.70	$ 9.58	(61)%
Effect of hedges per Mcf	$	$ (.03)		$		
Total oil volume thousand barrels	2,064	2,080	(1)%	6,388	6,196	3%
Oil volume barrels per day	22,439	22,607		23,400	22,611	
Average oil price per barrel	$ 63.49	$ 114.87	(45)%	$ 50.80	$ 110.26	(54)%

Oil and gas sales for the third quarter of 2009 totaled $238.3 million, compared to $552.4 million in 2008. Of the $314.1 million decrease in sales between the two periods, $39.8 million related to lower production volumes and $274.3 million resulted from lower prices. For the nine months ended September 30, 2009, oil and gas sales decreased by $946.6 million, from $1.6 billion to $649.0 million during the first nine months of 2009. Decreased commodity prices resulted in a $895.0 million decrease in oil and gas sales and lower production volumes resulted in a $51.7 million decrease between the two nine-month periods.

When compared to the third quarter of 2008, our third quarter 2009 oil production decreased by one percent to an average of 22,439 barrels per day. This change resulted in $1.8 million decrease in revenues. Third quarter gas volumes averaged 306.8 MMcf per day in 2009 compared to 349.3 MMcf per day in the third quarter of 2008, resulting in a decrease in revenues of $38.0 million. For the first nine months of 2009, gas volumes averaged 320.9 MMcf per day and oil volumes equaled 23,400 barrels per day, compared to the first nine months of 2008 volumes of 347.5 MMcf per day and 22,611 barrels per day. The lower gas volumes decreased sales between the two periods by $72.9 million, and the higher oil volumes resulted in $21.2 million of additional revenues. The expected decrease in natural gas volumes during the quarter and the first nine months of the current year is due to our significantly reduced drilling program from prior year. Most of our gas wells produce from resevoirs characterized by high initial production which decline rapidly and stabilize within three to five years. During the current year we have drilled 76% fewer wells as compared to the same period of 2008.

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Total 2009 oil and gas production volumes were 461.3 MMcfe per day, down 21.9 MMcfe per day from 2008. The expected decrease in production volumes between the periods is a result of reduced drilling. Our 2009 operated rig count is 11 rigs as compared to 42 in the comparable period of 2008.

Average realized gas prices decreased by 61% to $3.80 per Mcf for the three months ended September 30, 2009, compared to $9.76 per Mcf for the third quarter of 2008. This price decrease lowered gas sales by $168.2 million between the two periods. For the nine months ended September 30, 2009, realized gas prices decreased 61% to $3.70 per Mcf from $9.58 per Mcf. This price change decreased sales by $515.1 million. Included in our first nine months of 2008 realized gas price is $72 thousand of net cash payments from cash flow designated hedges.

Realized oil prices averaged $63.49 per barrel during the third quarter of 2009, compared to $114.87 per barrel for the same period in 2008. The decrease in oil sales resulting from this 45% decrease in oil prices totaled $106.0 million. For the nine months ended September 30, 2009, realized oil prices decreased 54% to $50.80 per barrel, from $110.26 per barrel, in the first nine months of 2008. This oil price decrease lowered sales $379.8 million.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Gas Gathering, Processing, Marketing and Other (in thousands):				
Gas gathering, processing and other revenues	$ 10,732	$ 24,163	$ 31,165	$ 73,734
Gas gathering and processing costs	(4,830)	(12,591)	(14,347)	(35,787)
Gas gathering, processing and other margin	$ 5,902	$ 11,572	$ 16,818	$ 37,947
Gas marketing revenues, net of related costs	$ 54	$ 654	$ 888	$ 2,225

We sometimes transport, process and market third-party gas that is associated with our gas. In the third quarter of 2009, third-party gas gathering, processing and other contributed $5.9 million of pre-tax cash operating margin (revenues less direct cash expenses) versus $11.6 million in 2008. For the nine months ended September 30, 2009 and 2008, such revenues less direct cash expenses totaled $16.8 million and $37.9 million, respectively. Our gas marketing margin (revenues less purchases) was $54 thousand in the third quarter of 2009 compared to $0.7 million in the third quarter of 2008. Gas marketing margin decreased to $0.9 million from $2.2 million for the first nine months of 2009 and 2008, respectively. Changes in net margins from gas gathering, processing, marketing and other activities are the direct result of volumes and overall market conditions.

	For the Three Months Ended September 30,		Variance Between	For the Nine Months Ended September 30,		Variance Between
	2009	2008	2009/2008	2009	2008	2009/2008
Operating costs and expenses (in thousands):						
Impairment of oil and gas properties	$	$ 657,146	$ (657,146)	$ 791,137	$ 657,146	$ 133,991
	59,240	147,432	(88,192)	205,791	406,189	(200,398)

Depreciation, depletion and amortization						
Asset retirement obligation	4,024	1,978	2,046	8,665	5,434	3,231
Production	42,682	55,362	(12,680)	139,127	156,506	(17,379)
Transportation	8,760	10,621	(1,861)	25,233	29,551	(4,318)
Taxes other than income	19,728	39,097	(19,369)	50,525	109,453	(58,928)
General and administrative	12,522	12,377	145	29,803	37,837	(8,034)
Stock compensation	2,477	2,791	(314)	6,831	7,432	(601)
Loss on derivative instruments, net	17,357		17,357	17,613		17,613
Other operating, net	2,911	11,871	(8,960)	19,094	12,992	6,102
	$ 169,701	$ 938,675	$ (768,974)	$ 1,293,819	$ 1,422,540	$ (128,721)

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Total operating costs and expenses (not including gas gathering, marketing and processing costs, or income tax expense) decreased to $169.7 million in the third quarter of 2009 compared to $938.7 million in the third quarter of 2008. For the first nine months of 2009 these operating costs and expenses decreased $128.7 million from $1.423 billion in 2008 to $1.294 billion.

The significant decrease in the current quarter as compared to third quarter 2008 is primarily due to an oil and gas impairment that was recorded in the prior year. At September 30, 2008 gas prices fell sharply in the Permian and Mid-Continent regions where we produce over 80% of our gas. As a result, we recorded a non-cash impairment of oil and gas properties in the amount of $657.1 million ($417.4 million, net of tax). A similar impairment was recorded in the first quarter of 2009 due to a continued decline in natural gas prices. This current year non-cash impairment of oil and gas properties was in the amount of $791.1 million ($501.8 million, net of tax).Volatility of oil and gas prices could require us to record a ceiling test write-down in future periods. The full cost method of accounting is discussed in detail under Note 1 to the Consolidated Financial Statements.

DD&A decreased from $147.4 million in the third quarter of 2008 to $59.2 million in the same period of 2009. On a unit of production basis, third quarter DD&A was $3.30 per Mcfe in 2008 compared to $1.46 per Mcfe for 2009. For the first nine months of 2009 and 2008, DD&A totaled $205.8 million and $406.2 million, respectively. On a unit of production basis, DD&A was $1.63 per Mcfe for the first nine months in 2009 compared to $3.07 per Mcfe for 2008. The significant decrease in DD&A in the third quarter and first nine months of 2009 is due to $3.0 billion of impairments to the carrying value of our oil and gas properties recorded during the last half of 2008 and the first quarter of 2009.

Asset retirement obligation expense was $4.0 million in the third quarter of 2009 compared to $2.0 million for 2008. The asset retirement obligation expense increased from $5.4 million for the first nine months of 2008 to $8.7 million for the same period in 2009. The increase in the current year is due to plugging and abandonment costs being greater than our original asset retirement obligation estimates. This was primarily the result of hurricane damage to our offshore properties which caused additional expenses to be incurred during site restoration.

Production costs decreased $12.7 million from $55.4 million ($1.24 per Mcfe) in the third quarter of 2008 to $42.7 million ($1.05 per Mcfe) in the third quarter of 2009. Production costs decreased by $17.4 million from $156.5 million ($1.18 per Mcfe) during the first nine months of 2008 to $139.1 million ($1.11 per Mcfe) during the same period in 2009. Our production costs consist of workover expense and lease operating expenses. We have seen a decrease in costs between quarters and the nine month periods in both of these areas. A reduction in large scale workover projects caused a $5.0 million decrease in workover expense from prior year. A decrease in lease operating expense in the current year is attributable to the sale of producing properties in the last half of 2008 and early 2009 and a significant decline in service costs in comparison to their peak in mid 2008.

Transportation costs decreased from $10.6 million in the third quarter of 2008 to $8.8 million in the third quarter of 2009. Transportation costs for the first nine months of 2009 were $25.2 million compared to $29.6 million for the same period in 2008. The decrease is the result of lower sales volumes and a decreasing fuel cost component.

Taxes other than income in the third quarter of 2009 were $19.4 million lower, decreasing from $39.1 million in third quarter 2008 to $19.7 million. Taxes other than income were $50.5 million during the first nine months of 2009 versus $109.5 million in 2008. The decrease between periods resulted from decreases in oil and gas sales stemming from significantly lower commodity prices and lower production volumes.

General and administrative (G&A) expenses increased $0.1 million from $12.4 million in the third quarter of 2008 to $12.5 million in the third quarter of 2009. G&A expense for the first nine months of 2009 equaled $29.8 million compared to $37.8 million for the same period of 2008. The decrease between the nine month periods is primarily the result of lower employee-benefit costs incurred during the first and second quarters of 2009. We recorded lower bonus and profit sharing expenses resulting from significant decreases in commodity prices from the prior year.

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A component of our operating costs and expense for the third quarter and first nine months of 2009 is (gain) loss on our derivative instruments. We recorded a net unrealized loss of $17.4 million and $17.6 million for the third quarter and first nine months of 2009, respectively. The year to date recorded loss is comprised of $21.1 million of unrealized losses which is partially offset by $3.5 million of realized gains on contract settlements during the first nine months of the year. See Note 2 to the Consolidated Financial Statements of this report for detailed information regarding our derivative instruments.

Other operating, net decreased from $11.9 million for the third quarter of 2008 to $2.9 million in the same period of 2009. For the first nine months of 2009, Other operating, net increased by $6.1 million from $13.0 million in 2008 to $19.1 million in 2009. The change between the periods is due to the timing of recordings related to the resolution of and accruals related to various legal matters most of which pertain to contract settlements and title and royalty issues.

Other Income and Expense

Interest expense was $5.3 million higher in the first nine months of the year, increasing from $24.8 million in 2008 to $30.1 million in 2009. Interest expense for the third quarter increased from $8.1 million in 2008 to $10.6 million in 2009. This change resulted primarily from a $6.2 million increase in interest expense on bank debt as we had no borrowings on our credit facility during the first nine months of 2008 and an average outstanding balance of more than $250 million during 2009. Also, in comparison to prior year, we recognized an additional $2.8 million of deferred financing costs. These higher costs are the result of the new credit facility we entered into in April 2009. Partially offsetting these increases is a $3.7 million decrease in interest expense on our convertible notes due to the December 2008 repurchases of $105.5 million of the outstanding $125 million (face value) notes. We repurchased the notes with borrowings under our credit facility.

Other, net changed from $8.1 million of income in the third quarter of 2008 to $3.7 million of expense in the third quarter of 2009. Other, net for the nine months ended September 30, 2009 was $11.6 million of expense and income of $16.6 million during the same period of 2008. Components consist of miscellaneous income and expense items that will vary from period to period, including income and loss in equity investees, gain or loss on sale of oil and gas well equipment and interest income. The change from 2008 to 2009 is primarily the result of oil and gas well equipment impairments due to decreased value of drill pipe resulting from a significant slowing of drilling activity across the industry. An impairment of $13.7 million has been recognized in the current year versus $12.5 million of gain on sale of oil and gas well equipment in the prior year.

Income Tax

For third quarter 2009, a net income tax expense of $26.8 million, of which $13.3 million is current, was recognized versus $135.9 million of income tax benefit for the third quarter of 2008. Income tax equaled a combined federal and state effective income tax rate of 40.9% and 36.9% in the third quarters of 2009 and 2008, respectively. The effective tax rate for the third quarter of 2009 differs from the statutory rate primarily due to state income taxes, non-deductible expenses, and adjustments for the non-realization of special deductions. An income tax benefit for the first nine months of 2009 equaled $236.1 million, of which $15.5 million is a current benefit, compared to $73.8 million of income tax expense for the same period of 2008, equating to combined Federal and state effective income tax rates of 36.2% and 33.6%, respectively. The effective tax rate for the first nine months of 2009 differs from the statutory rate primarily due to state income taxes, and non-deductible expenses.

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LIQUIDITY AND CAPITAL RESOURCES

Overview

The ongoing economic downturn, credit crisis and slowing demand have continued to negatively impact commodity prices. Sustained low oil and gas prices may reduce the amount of oil and gas that we can economically produce, and can also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. These conditions may also impact third parties with whom we do business which could lead to losses associated with uncollectible receivables.

We have and will continue to focus on maintaining liquidity, promoting operational efficiency, and expanding long-term reserves through focused drilling projects and potential acquisitions. Historically our exploration and development expenditures have generally been funded by cash flow provided by operating activities (operating cash flow). With our intent to continue to operate within operating cash flows, we have significantly scaled back our planned 2009 drilling program in comparison to 2008 and are focusing on our highest rate of return projects.

We continue to search for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable. In order to ready ourselves for such an opportunity and to prepare ourselves for the potential of further declines in commodity prices, in April 2009, we entered into a new three-year senior secured revolving credit facility. The new facility increases bank commitments from $500 million to a fully-subscribed $800 million. The borrowing base remains unchanged at $1 billion. In addition to our increased credit facility, we may consider a high-yield bond offering in the future to raise additional capital, if appropriate.

We believe that our operating cash flow and other capital resources will be adequate to continue to meet our needs for our planned capital expenditures, working capital, debt servicing and dividend payments for 2009 and beyond.

Analysis of Cash Flow Changes

Cash flow provided by operating activities for the first nine months of 2009 was $465.6 million, compared to $1.1 billion for the nine months ended September 30, 2008. The decrease in the first nine months of 2009 resulted primarily from significantly lower gas and oil prices and decreased production.

Cash flow used in investing activities for the first nine months of 2009 was $369.4 million, compared to $1.1 billion for the nine months ended September 30, 2008. Changes in the cash flow used in investing activities are generally the result of changes in our exploration and development programs, acquisitions and property sales. The decrease from the first nine months of 2008 to 2009 was mostly caused by decreased oil and gas expenditures resulting from a planned decrease in activity in our drilling and exploitation programs.

Net cash flow used by financing activities in the first nine months of 2009 was $94.5 million versus $2.1 million in the same period of 2008. In 2009, we had net payments on our credit facility of $64.0 million while we had no activity in 2008. In addition, we incurred $18.0 million of financing costs in the current year for our new three-year senior secured revolving credit facility.

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Capital Expenditures

The following table sets forth certain historical information regarding capitalized expenditures by us in our oil and gas acquisition, exploration, and development activities (in thousands):

	For Three Months Ended September 30, 2009	For Three Months Ended September 30, 2008	For Nine Months Ended September 30, 2009	For Nine Months Ended September 30, 2008
Acquisitions:				
Proved	$ 350	$ 120	$ 474	$ 1,489
Unproved	(10,315)(1)		(10,315)(1)	
	(9,965)	120	(9,841)	1,489
Exploration and development:				
Land and seismic	7,036	52,485	34,072	109,611
Exploration and development	119,144	366,456	332,844	976,183
	126,180	418,941	366,916	1,085,794
Property sales	(9,877)		(28,305)	
	$ 106,338	$ 419,061	$ 328,770	$ 1 ,087,283

(1) The negative balance reflects purchase price adjustments related to an acreage acquisition in fourth quarter 2008.

Our exploration and development expenditures decreased 66 percent in the first nine months of 2009 compared to the first nine months of 2008. The decrease in 2009 resulted from a planned decrease in our exploration activity in response to the current economic environment and our continued efforts to operate within our cash flow provided by operating activities. Overall, we drilled a total of 94 gross (56 net) wells during the first nine months of 2009 versus 376 gross (232 net) wells in the same period of 2008.

Our planned capital program for 2009 is approximately $525 million with the expectation of continued low oil and gas prices. Although our 2009 capital budget is set at a level that we believe corresponds with our anticipated 2009 cash flows, the timing of capital expenditures and the receipt of cash flows do not necessarily match. We anticipate borrowing and repaying funds under our credit arrangements throughout the year. If we start to see a significant change in commodity prices from our current forecasts, we have the operational flexibility to react quickly with our capital expenditures to changes in our cash flows from operations.

We have made, and will continue to make, expenditures to comply with environmental and safety regulations and requirements. These costs are considered a normal recurring cost of our ongoing operations and not an extraordinary cost of compliance. We do not anticipate that we will be required to expend amounts that will have a material adverse effect on our financial position or operations, nor are we aware of any pending regulatory changes that would have a material impact.

Financial Condition

During the first nine months of 2009 our total assets, net oil and gas assets, net income and stockholders equity were reduced by a non-cash impairment of oil and gas properties in the amount of $791.1 million ($501.8 million after tax). Total assets decreased by $0.8 billion in the first nine months of 2009 from $4.2 billion at the beginning of the year to $3.4 billion by September 30, 2009. Our net oil and gas assets decreased by $643.7 million and our cash position increased by $1.7 million for the same period. As of September 30, 2009, stockholders equity totaled $1.9 billion, down from $2.4 billion at December 31, 2008. The decrease resulted primarily from a current year 2009 net loss of $416.6 million.

Dividends

In December 2005, the Board of Directors declared the Company s first quarterly cash dividend of $.04 per share on our common stock. A dividend has been authorized in every quarter since then. On

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December 12, 2007 the Board of Directors increased the regular cash dividend on our common stock from $0.04 to $0.06 per share.

Common Stock Repurchase Program

In December 2005, the Board of Directors authorized the repurchase of up to four million shares of common stock. During 2007 we repurchased a total of 1,114,200 shares at an average purchase price of $37.93. Cumulative purchases through December 31, 2007 total 1,364,300 shares at an average price of $39.05. No purchases have been made since the quarter ended September 30, 2007.

Working Capital

Working capital increased $11.3 million from year-end 2008 to $56.6 million at third quarter-end 2009. Working capital increased primarily because of the following:

- A $144.7 million decrease in current liabilities during the year is due to decrease in payables attributable to lower commodity prices, less production, and a significant decrease in exploration and development activities.

These working capital increases were mostly offset by:

- A $133.4 million decrease in current assets during the first nine months due to a decrease in receivables caused by lower average commodity prices and reduced drilling activity. Additionally, we have seen a decrease in prepaid expenses due to timing and a decrease in oil and gas well equipment and supplies primarily due to drill pipe impairments.

Our receivables are a major component of our working capital and are made up of a diverse group of companies including major energy companies, pipeline companies, local distribution companies and end-users in various industries. The collection of receivables during the period presented has been timely. Historically, losses associated with uncollectible receivables have not been significant.

Financing

Debt at September 30, 2009 and December 31, 2008 consisted of the following (in thousands):

	September 30, 2009	December 31, 2008
Bank debt	$ 156,000	$ 220,000
7.125% Notes due 2017	350,000	350,000
Floating rate convertible notes due 2023 (face value $19,450)	17,753	17,630
Total long-term debt	$ 523,753	$ 587,630

Bank Debt

In April 2009, we entered into a new three-year senior secured revolving credit facility (credit facility). The new credit facility increases bank commitments from $500 million to $800 million, with a borrowing base of $1 billion. The credit facility is provided by a syndicate of banks led by JP Morgan Chase Bank, N.A., matures on April 14, 2012 and is secured by mortgages on certain of our oil and gas properties and the stock of certain wholly-owned operating subsidiaries.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves, and is subject to potential special and regular semi-annual redeterminations.

The credit facility contains covenants and restrictive provisions which may limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility requires us to maintain a current ratio greater than 1 to 1 and a leverage ratio not to exceed 3.5 to 1. As of September 30, 2009, we were in compliance with all of the financial and non-financial covenants.

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At Cimarex s option, borrowings under the credit facility may bear interest at either (a) a London Interbank Offered Rate (LIBOR) plus 2 to 3 percent, based on borrowing base usage, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50 percent, or (iii) adjusted LIBOR, in each case, plus an additional 1.125 to 2.125 percent, based on borrowing base usage.

At September 30, 2009, there was $156 million of borrowings outstanding under the credit facility at a weighted average interest rate of approximately 3.1%. We also had letters of credit outstanding of $17.7 million leaving an unused borrowing availability of $626.3 million.

7.125% Notes due 2017

In May, 2007, we issued $350 million of 7.125% senior unsecured notes that mature May 1, 2017 at par. Interest on the notes is payable May 1 and November 1 of each year. The notes are governed by an indenture containing covenants that could limit our ability to incur additional indebtedness; pay dividends or repurchase our common stock; make investments and other restricted payments; incur liens; enter into sale/leaseback transactions; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets.

The notes are redeemable at our option, in whole or in part, at any time on and after May 1, 2012 at the following redemption prices (expressed as percentages of the principal amount) plus accrued interest, if any, thereon to the date of redemption.

Year	**Percentage**
2012	103.6%
2013	102.4%
2014	101.2%
2015 and thereafter	100.0%

At any time prior to May 1, 2010, we may redeem up to 35% of the original principal amount of the notes with the proceeds of certain equity offerings of our shares of common stock at a redemption price of 107.125% of the principal amount of the notes, together with accrued and unpaid interest, if any, to the date of redemption. At any time prior to May 1, 2012, we may also redeem all, but not part, of the notes at a price of 100% of the principal amount of the notes plus accrued and unpaid interest plus a make-whole premium.

If a specified change of control occurs, subject to certain conditions, we must make an offer to purchase the notes at a purchase price of 101% of the principal amount of the notes, plus accrued and unpaid interest to the date of the purchase.

Floating rate convertible notes due 2023

The floating rate convertible senior notes mature on December 15, 2023. The notes are senior unsecured obligations and bear interest at the three month LIBOR, reset quarterly. On September 30, 2009, the interest rate approximated 0.3%.

In December 2008, holders of $105.5 million of the original $125 million issuance amount elected to submit their notes for repurchase. We repurchased the $105.5 million in notes with borrowings under our credit facility. Holders of the remaining $19.5 million of notes have optional repurchase dates as of December 15, 2013, and 2018.

In addition to the repurchase rights, holders of the convertible notes may surrender their notes for conversion into a combination of cash and shares of our common stock upon the occurrence of certain circumstances, including if the price of our common stock has been trading above 110% of the conversion price of $28.59 per share for a defined period of time. As of September 30, 2009, and December 31, 2008, the notes were not convertible. However, based on the price of our common stock during September 2009, the notes became convertible effective October 1, 2009.

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At our option, we may offer to redeem the notes at any time at par. In addition, if a change of control occurs, subject to certain conditions, we must make an offer to purchase the notes at a purchase price of 101% of the principal amount of the notes.

In May 2008, the FASB issued new guidance that changed the accounting for the components of convertible debt that can be settled wholly or partly in cash upon conversion. The new requirements are required to be applied to both new instruments and retrospectively to previously issued convertible instruments. The debt and equity components of the instruments are accounted for separately. The value assigned to the debt component is the estimated value of similar debt without a conversion feature as of the issuance date, with the remaining proceeds allocated to the equity component and recorded as additional paid-in capital. The debt component is recorded at a discount and is subsequently accreted to its par value, thereby reflecting an overall market rate of interest in the income statement. The effective interest rate for the quarters ended September 30, 2009 and 2008 was 1.5% and 4%, respectively. The effective interest rate for the nine months ended September 30, 2009 and 2008 was 2.3% and 4.7%, respectively. (See Note 6 for additional information).

Contractual Obligations and Material Commitments

At September 30, 2009, we had contractual obligations and material commitments as follows:

		Payments Due by Period			
Contractual obligations	**Total**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**More than 5 Years**
			(In thousands)		
Long-term debt (1)	$ 525,450	$	$ 156,000	$	$ 369,450
Fixed-Rate interest payments (1)	199,500	24,938	49,875	49,875	74,812
Operating leases	24,819	5,841	10,883	7,643	452
Drilling commitments (2)	115,879	115,879			
Gas processing facility (3)	102,583	43,701	34,186	24,696	
Asset retirement obligation	155,815	21,306	(4)	(4)	(4)
Derivative instruments	20,761	12,645	8,116		
Other liabilities (5)	48,741	10,243	20,029	10,029	8,440

(1) These amounts do not include interest on the $156 million of bank debt outstanding at September 30, 2009. The weighted average interest rate at September 30, 2009 was approximately 3.1%. See item 3: Interest Rate Risk for more information regarding fixed and variable rate debt.

(2) We have drilling commitments of approximately $69.1 million consisting of obligations to complete drilling wells in progress at September 30, 2009. We also have minimum expenditure commitments of $46.8 million to secure the use of drilling rigs.

(3) We have a large development project in Sublette County, Wyoming where we are developing the deep Madison gas formation and constructing a gas processing plant. At September 30, 2009, we had commitments of $163.1 million relating to construction of the gas processing plant of which $102.6 million is subject to a construction contract. The total cost of the project will approximate $354 million. Pursuant to the terms of our operating agreement with our partners in this project, we will be reimbursed by them for 42.5% of the costs. The gas processing plant is subject to a delivery commitment agreement over a 20 year period, commencing December, 2011. If no deliveries were made, the maximum amount that would be payable under the agreement would be approximately $43 million.

(4) We have excluded the long term asset retirement obligations because we are not able to precisely predict the timing of these amounts.

(5) Other liabilities include the fair value of our liabilities associated with our benefit obligations and other miscellaneous commitments.

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At September 30, 2009, we had firm sales contracts to deliver approximately 5.6 Bcf of natural gas over the next six months. If this gas is not delivered, our financial commitment would be approximately $19.6 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no significant financial commitment will be due based on our reserves and current production levels.

In connection with a gas gathering and processing agreement, we have commitments to deliver 58.5 Bcf of gas over the next five years. If no gas was delivered, the maximum amount that would be payable under these commitments would be approximately $43.5 million.

We have other various delivery commitments in the normal course of business, none of which are individually material. In aggregate, these commitments have a maximum amount that would be payable, if no gas is delivered, of approximately $5 million.

All of the noted commitments were routine and were made in the normal course of our business.

Based on current commodity prices and anticipated levels of production, we believe that the estimated net cash generated from operations, coupled with the cash on hand and amounts available under our existing bank credit facility will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operations and exploration and development activities.

2009 Outlook

Our exploration and development expenditures program for 2009 is projected to range from $500 million to $550 million. Though there are a variety of factors that could curtail, delay or even cancel some of our planned operations, we believe our projected program is likely to occur. The majority of projects are in hand, drilling rigs are being scheduled, and the historical results of our drilling efforts warrant pursuit of the projects. A majority of the expenditures will be in the Mid-Continent area, primarily in our Western Oklahoma Anadarko-Woodford shale Cana play. In addition we plan to continue to drill in our Permian Basin and Gulf Coast areas.

Production estimates for 2009 range from 455 to 460 MMcfe per day. Revenues from production will be dependent not only on the level of oil and gas actually produced, but also the prices that will be realized. During 2008, our realized prices averaged $8.43 per Mcf of gas and $96.03 per barrel of oil. Prices can be very volatile and the possibility of 2009 realized prices being different than they were in 2008 is high.

Costs of operations on a per Mcfe basis for fourth quarter of 2009 are currently estimated as follows:

	2009
Production expense	$1.10 - $1.20
Transportation expense	0.19 - 0.24
DD&A and Asset retirement obligation	1.40 - 1.70

General and Administrative	0.24 - 0.30
Production taxes (% of oil and gas revenue)	7.5% - 8.5%

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We consider accounting policies related to oil and gas reserves, full cost accounting, goodwill, derivatives, contingencies and asset retirement obligations to be critical policies and estimates. These critical policies and estimates are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our 2008 annual report on Form 10-K, as amended by the Current Report on Form 8-K filed July 17, 2009 with the SEC.

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Accounting Changes

Certain amounts in prior years financial statements have been reclassified to conform to the 2009 financial statement presentation. In addition, effective January 1, 2009, we adopted new rules promulgated by the Financial Accounting Standards Board (FASB) pertaining to the accounting treatment for certain convertible debt instruments (see Note 6) and to the calculation of earnings per share (see Note 9). Accordingly, prior periods have been adjusted retrospectively to conform to the applicable accounting pronouncements.

Recent Accounting Developments

In December 2008, the SEC adopted revisions to its required oil and gas reporting disclosures. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. In the three decades that have passed since adoption of these disclosure items, there have been significant changes in the oil and gas industry. The amendments are designed to modernize and update the oil and gas disclosure requirements to align them with current practices and changes in technology. In addition, the amendments concurrently align the SEC s full cost accounting rules with the revised disclosures. The revised disclosure requirements must be incorporated in registration statements filed on or after January 1, 2010, and annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. A company may not apply the new rules to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required.

The following amendments have the greatest likelihood of affecting our reserve disclosures:

- *Pricing mechanism for oil and gas reserves estimation* The SEC s current rules require proved reserve estimates to be calculated using prices as of the end of the period and held constant over the life of the reserves. Price changes can be made only to the extent provided by contractual arrangements. The revised rules require reserve estimates to be calculated using a 12-month average price. The 12-month average price will also be used for purposes of calculating the full cost ceiling limitations. Price changes can still be incorporated to the extent defined by contractual arrangements. The use of a 12-month average price rather than a single-day price is expected to reduce the impact on reserve estimates and the full cost ceiling limitations due to short-term volatility and seasonality of prices.

- *Reasonable certainty* The SEC s current definition of proved oil and gas reserves incorporate certain specific concepts such as lowest known hydrocarbons, which limits the ability to claim proved reserves in the absence of information on fluid contacts in a well penetration, notwithstanding the existence of other engineering and geoscientific evidence. The revised rules amend the definition to permit the use of new reliable technologies to establish the reasonable certainty of proved reserves. This revision also includes provisions for establishing levels of lowest known hydrocarbons and highest known oil through reliable technology other than well penetrations.

The revised rules also amend the definition of proved oil and gas reserves to include reserves located beyond development spacing areas that are immediately adjacent to developed spacing areas if economic producibility can be established with reasonable certainty. These revisions are designed to permit the use of alternative technologies to establish proved reserves in lieu of requiring companies to use specific tests. In addition, they establish a uniform standard of reasonable certainty that applies to all proved reserves, regardless of location or distance from producing wells. Because the revised rules generally expand the definition of proved reserves, proved reserve estimates could increase upon adoption of the revised rules. However, we are not able to estimate the magnitude of the potential change at this time.

- *Unproved reserves* The SEC s current rules prohibit disclosure of reserve estimates other than proved in documents filed with the SEC. The revised rules permit disclosure of probable and

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possible reserves and provide definitions of probable reserves and possible reserves. Disclosure of probable and possible reserves is optional. However, such disclosures must meet specific requirements. Disclosures of probable or possible reserves must provide the same level of geographic detail as proved reserves. Probable and possible reserve disclosures must also provide the relative uncertainty associated with these classifications of reserves estimations. We have not yet determined whether we will disclose our probable and possible reserves in documents filed with the SEC.

In June 2009, the FASB approved the FASB Accounting Standards Codification (ASC), which after its launch on July 1, 2009 became the single source of authoritative, nongovernmental U.S. Generally Accepted Accounting Principles (GAAP). The Codification reorganizes all previous U.S. GAAP pronouncements into roughly 90 accounting topics and displays all topics using a consistent structure. All existing standards that were used to create the Codification are now superseded, replacing the previous references to specific Statements of Financial Accounting Standards with numbers used in the Codification s structural organization.

In September 2009, the FASB issued an exposure draft of proposed Accounting Standards Update (ASU) entitled Oil and Gas Reserve Estimation and Disclosures. This proposed ASU would amend the FASB accounting standards to align the reserve calculation and disclosure requirements with the requirements in the new SEC Rule, *Modernization of Oil and Gas Reporting Requirements*. As proposed, the ASU would be effective for reporting periods ending on or after December 31, 2009. Public comment is sought on the proposed ASU by October 15, 2009.

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ITEM 3. QUALITATIVE AND QUANTITATIVE DISCLOSURES ABOUT MARKET RISK

The term   market risk   refers to the risk of loss arising from adverse changes in oil and gas prices, interest rates and value of our short-term investments. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses.

Price Fluctuations

Our major market risk is pricing applicable to our oil and gas production. The prices we receive for our production are based on prevailing market conditions and are influenced by many factors that are beyond our control. Pricing for oil and gas production has been volatile and unpredictable.

We periodically hedge a portion of our price risk associated with our future oil and gas production.

The following table details the contracts we have in place as of September 30, 2009:

Natural Gas Contracts

					Weighted Average Price			Fair Value
Period	**Type**	**Volume/Day**		**Index(1)**	**Floor**	**Ceiling**	**Swap**	**(000 s)**
Oct 09 Dec 09	Collar	143,370	MMBtu	PEPL	$ 3.00	$ 5.00		$ (4,762)
Jan 10 - Dec 10	Collar	100,000	MMBtu	PEPL	$ 5.00	$ 6.62		