PETROHAWK ENERGY CORP
Form 10-Q
November 05, 2009
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY 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 number 001-33334

PETROHAWK ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**86-0876964**
(State or other jurisdiction of	**(I.R.S. Employer**

incorporation or organization)	**Identification Number)**

1000 Louisiana, Suite 5600, Houston, Texas 77002

(Address of principal executive offices including ZIP code)

(832) 204-2700

(Registrant s telephone number)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $.001 per share	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: None

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 ¨

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 ¨

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 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	¨
Non-accelerated filer ¨	(Do not check if a smaller reporting company)	Smaller reporting company	¨

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

As of October 30, 2009 the Registrant had 300,847,010 shares of Common Stock, $.001 par value, outstanding.

Table of Contents

TABLE OF CONTENTS

Table of Contents

Special note regarding forward-looking statements

This report on Form 10-Q contains forward-looking statements within the meaning of the federal securities laws. All statements, other than statements of historical facts, concerning, among other things, planned capital expenditures, potential increases in oil and natural gas production, the number of anticipated wells to be drilled in the future, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as may, expect, estimate, project, plan, believe, intend, achievable, will, continue, potential, should, could and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. The actual results could differ materially from those anticipated in these forward-looking statements. One should consider carefully the statements under the Risk Factors section of this report and other sections of this report, as well as those described in our Form 10-K, as amended for the year ended December 31, 2008, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements, including, but not limited to, the following factors:

- our ability to successfully develop our large inventory of undeveloped acreage primarily held in resource-style areas in Louisiana, Arkansas and Texas, including our resource-style plays such as the Haynesville, Fayetteville and Eagle Ford Shales;
- the volatility in commodity prices for oil and natural gas, including continued declines in prices;
- the possibility that the industry may be subject to future regulatory or legislative actions (including any additional taxes and changes in environmental regulation);
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;
- the possibility that production decline rates in some of our resource-style plays are greater than we expect;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fully develop our undeveloped acreage positions;
- our ability to replace oil and natural gas reserves;
- environmental risks;
- drilling and operating risks;
- exploration and development risks;
- competition, including competition for acreage in resource-style areas;

management s ability to execute our plans to meet our goals;

our ability to retain key members of senior management and key technical employees;

our ability to obtain goods and services, such as drilling rigs and tubulars, and access to adequate gathering systems and pipeline take-away capacity, to support our drilling program;

our ability to secure firm transportation for natural gas we produce and to sell natural gas at market prices;

general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business, may be less favorable than expected, including the possibility that the current economic recession and credit crisis in the United States will be severe and prolonged, which could adversely affect the demand for oil and natural gas and make it difficult to access financial markets;

Table of Contents

- continued hostilities in the Middle East and other sustained military campaigns or acts of terrorism or sabotage; and

- other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors that may negatively impact our business, operations or pricing.

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Condensed Consolidated Financial Statements (unaudited)

PETROHAWK ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (Unaudited)

(In thousands, except per share amounts)

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Operating revenues:				
Oil and natural gas	$ 174,783	$ 304,960	$ 512,528	$ 824,531
Marketing	63,155		216,165	
Total operating revenues	237,938	304,960	728,693	824,531
Operating expenses:				
Marketing	66,586		211,722	
Production:				
Lease operating	20,788	12,324	55,903	37,621
Workover and other	865	1,696	1,793	3,482
Taxes other than income	15,204	12,185	39,921	37,185
Gathering, transportation and other	22,743	12,489	65,870	32,956
General and administrative	24,550	18,996	68,181	52,364
Depletion, depreciation and amortization	91,692	99,400	290,383	269,221
Full cost ceiling impairment			1,732,486	
Total operating expenses	242,428	157,090	2,466,259	432,829
(Loss) income from operations	(4,490)	147,870	(1,737,566)	391,702
Other (expenses) income:				
Net (loss) gain on derivative contracts	(1,568)	388,216	196,360	(32,130)
Interest expense and other	(58,981)	(40,018)	(170,929)	(102,709)
Total other (expenses) income	(60,549)	348,198	25,431	(134,839)
(Loss) income before income taxes	(65,039)	496,068	(1,712,135)	256,863
Income tax benefit (provision)	24,862	(190,603)	650,201	(99,776)
Net (loss) income available to common stockholders	$ (40,177)	$ 305,465	$ (1,061,934)	$ 157,087
Net (loss) income per share of common stock:				
Basic	$ (0.14)	$ 1.30	$ (3.88)	$ 0.75
Diluted	$ (0.14)	$ 1.28	$ (3.88)	$ 0.74
Weighted average shares outstanding:				
Basic	287,913	235,235	273,477	208,549

Diluted	287,913	239,479	273,477	212,503

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

PETROHAWK ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)

(In thousands, except share and per share amounts)

	September 30, 2009	December 31, 2008
Current assets:		
Cash	$ 1,692	$ 6,883
Marketable securities	150,028	123,009
Accounts receivable	181,915	277,349
Receivables from derivative contracts	150,346	201,128
Prepaids and other	42,079	40,063
Total current assets	526,060	648,432
Oil and natural gas properties (full cost method):		
Evaluated	5,947,489	4,894,357
Unevaluated	2,332,134	2,287,968
Gross oil and natural gas properties	8,279,623	7,182,325
Less - accumulated depletion	(4,122,596)	(2,111,038)
Net oil and natural gas properties	4,157,027	5,071,287
Other operating property and equipment:		
Gas gathering system and equipment	448,596	190,054
Other operating assets	24,301	20,271
Gross other operating property and equipment	472,897	210,325
Less - accumulated depreciation	(21,347)	(11,106)
Net other operating property and equipment	451,550	199,219
Other noncurrent assets:		
Goodwill	932,802	933,058
Other intangible assets	103,266	
Deferred income taxes	173,037	
Debt issuance costs, net of amortization	36,586	30,477
Receivables from derivative contracts	24,589	23,399
Other	2,551	1,457
Total assets	$ 6,407,468	$ 6,907,329
Current liabilities:		
Accounts payable and accrued liabilities	$ 610,496	$ 639,432
Deferred income taxes	42,976	77,454
Liabilities from derivative contracts	363	
Long-term debt	39,821	9,426
Total current liabilities	693,656	726,312

Long-term debt	2,394,270	2,283,874
Other noncurrent liabilities:		
Liabilities from derivative contracts	1,237	
Asset retirement obligations	31,660	28,644
Deferred income taxes		460,913
Other	4,235	2,676
Commitments and contingencies (Note 7)		
Stockholders equity:		
Common stock: 500,000,000 and 300,000,000 shares of $.001 par value authorized at September 30, 2009 and December 31, 2008, respectively; 300,846,264 and 252,364,143 shares issued and outstanding at September 30, 2009 and December 31, 2008, respectively	301	252
Additional paid-in capital	4,594,885	3,655,500
Accumulated deficit	(1,312,776)	(250,842)
Total stockholders equity	3,282,410	3,404,910
Total liabilities and stockholders equity	$ 6,407,468	$ 6,907,329

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

6

Table of Contents

PETROHAWK ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)

(In thousands)

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Cash flows from operating activities:		
Net (loss) income	$ (1,061,934)	$ 157,087
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Depletion, depreciation and amortization	290,383	269,221
Full cost ceiling impairment	1,732,486	
Income tax (benefit) provision	(650,201)	99,776
Stock-based compensation	10,762	9,068
Net unrealized loss (gain) on derivative contracts	96,752	(57,337)
Other	15,926	2,292
Change in assets and liabilities:		
Accounts receivable	91,571	(82,561)
Prepaids and other	(2,016)	1,948
Accounts payable and accrued liabilities	(49,448)	123,369
Other	469	2,921
Net cash provided by operating activities	474,750	525,784
Cash flows from investing activities:		
Oil and natural gas capital expenditures	(1,164,392)	(2,545,944)
Proceeds received from sale of oil and natural gas properties	724	107,324
Marketable securities purchased	(1,282,601)	(2,151,077)
Marketable securities redeemed	1,255,582	1,898,358
Decrease in restricted cash		269,837
Other operating property and equipment expenditures	(225,322)	(75,525)
Other intangible assets acquired	(105,108)	
Other	37,600	
Net cash used in investing activities	(1,483,517)	(2,497,027)
Cash flows from financing activities:		
Proceeds from exercise of options and warrants	2,667	10,770
Proceeds from issuance of common stock	956,500	1,831,951
Offering costs	(30,727)	(73,754)
Proceeds from borrowings	937,674	1,964,000
Repayment of borrowings	(849,513)	(1,736,266)
Debt issue costs	(13,025)	(23,391)
Net cash provided by financing activities	1,003,576	1,973,310
Net (decrease) increase in cash	(5,191)	2,067
Cash at beginning of period	6,883	1,812
Cash at end of period	$ 1,692	$ 3,879

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

Table of Contents

PETROHAWK ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1. FINANCIAL STATEMENT PRESENTATION

During interim periods, Petrohawk Energy Corporation (referred to as Petrohawk or the Company) follows the accounting policies disclosed in its 2008 Annual Report on Form 10-K, as amended, and filed with the Securities and Exchange Commission (SEC). Please refer to the footnotes in the 2008 Form 10-K when reviewing interim financial results.

These unaudited condensed consolidated financial statements reflect, in the opinion of the Company s management, all adjustments, consisting only of normal and recurring adjustments, necessary to present fairly the financial position as of, and results of operations for, the periods presented. Condensed consolidated interim period results are not necessarily indicative of results of operations or cash flows for the full year and accordingly, certain information normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States has been condensed or omitted. Certain prior year amounts have been reclassified to conform to the current year presentation. We have evaluated events or transactions through November 4, 2009 in conjunction with the preparation of these condensed consolidated financial statements.

Marketable Securities

The Company invests a portion of its cash in money market mutual funds which are highly liquid marketable securities. The Company accounts for marketable securities in accordance with Financial Accounting Standards Board s (FASB) Accounting Standards Codification (ASC) 320, *Investments Debt and Equity Securities* and classifies marketable securities as trading, available-for-sale, or held-to-maturity. The appropriate classification of its marketable securities is determined at the time of purchase and reevaluated at each balance sheet date.

At September 30, 2009 and December 31, 2008, the Company held approximately $150.0 million and $123.0 million, respectively of marketable securities which have been classified and accounted for as trading securities. Trading securities are recorded at fair value with realized gains and losses reported in *Interest expense and other* in the condensed consolidated statements of operations.

Oil and Natural Gas Properties

The Company accounts for its oil and natural gas producing activities using the full cost method of accounting as prescribed by the SEC. Accordingly, all costs incurred in the acquisition, exploration, and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of proved oil and natural gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%, net of tax considerations. Under ASC 932, *Extractive Activities-Oil and Gas*, the Company may utilize the prices in effect on a date subsequent to the end of a reporting period when the full cost ceiling limitation was exceeded at the end of a reporting period and subsequent pricing exceeds pricing at the end of the reporting period. This option will no longer be available to the Company starting December 31, 2009 due to adoption of the new oil and gas reporting requirements as described below under *Recently Issued Accounting Pronouncements*.

Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The Company reviews its unevaluated properties at the end of each quarter to determine whether the costs incurred should be transferred to the full cost pool and thereby subject to amortization.

Marketing Revenue and Expense

During the fourth quarter of 2008, a subsidiary of the Company began purchasing and selling third party natural gas produced from wells it operates. The revenues and expenses related to these marketing activities are reported on a gross basis as part of operating revenues and operating expenses. Marketing revenues are recorded at the time natural gas is physically delivered to third parties at a fixed or index price. Marketing expenses attributable to gas purchases are recorded as the Company takes physical title to natural gas and transports the purchased volumes to the point of sale.

Risk Management Activities

The Company follows ASC 815, *Derivatives and Hedging*. From time to time, the Company may hedge a portion of its forecasted oil and natural gas production. Derivative contracts entered into by the Company have consisted of transactions in which the Company hedges the variability of cash flow related to a forecasted transaction. The Company has elected to not designate any of its positions for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in *Net (loss) gain on derivative contracts* on the condensed consolidated statements of operations.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in an acquisition. ASC 350, *Intangibles - Goodwill and Other (ASC 350)* requires that intangible assets with indefinite lives, including goodwill, be evaluated on an annual basis for impairment or more frequently if an event occurs or circumstances change that could potentially result in impairment. The goodwill impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. If the fair value of the reporting unit is less than the book value (including goodwill), then goodwill is reduced to its implied fair value and the amount of the write-down is charged against earnings. The assumptions used by the Company in calculating its reporting unit fair value at the time of the test include the Company s market capitalization and discounted future cash flows based on estimated reserves and production, future costs and future oil and natural gas prices. Adverse changes to any of these factors could lead to an impairment of all or a portion of the Company s goodwill in future periods.

As a result of full cost ceiling impairments recorded by the Company for the year ended December 31, 2008 and the quarter ended March 31, 2009, the Company reviewed its goodwill for impairment as of March 31, 2009 and December 31, 2008. The Company completed its annual goodwill impairment test during the third quarter of 2009. Based on these reviews, no goodwill impairments were deemed necessary.

Other Intangible Assets

The Company treats the costs associated with acquired transportation contracts as intangible assets. The initial amount recorded represents the fair value of the contract at the time of acquisition, which is amortized under a straight-line method over the life of the contract. Any unamortized balance of the Company s intangible assets will be subject to impairment testing pursuant to the *Impairment or Disposal of Long-Lived Assets Subsections* of ASC Subtopic 360-10.

On July 31, 2009, the Company purchased all outstanding membership interests in Kaiser Trading, LLC (Kaiser) for approximately $105 million. Kaiser s only assets were transportation-related contracts including a firm transportation contract, interruptible gas transportation service agreement, parking and lending services agreement, and a pooling services agreement. The initial firm transportation contract runs through 2013 and at no additional cost, the Company has the contractual right to extend firm supply through 2019. The purchase price has been allocated to the transportation contract which will be amortized on a straight line basis over the life of the extended agreement. Amortization expense was $1.8 million for the period from acquisition through September 30, 2009 and was allocated between *Marketing expenses* and *Gathering, transportation and other* on the condensed consolidated statements of operations based on the usage of the contract. The estimated amortization expense for 2009 will be approximately $4.6 million and approximately $11.1 million per year for the remainder of the contract.

Intangible assets subject to amortization at September 30, 2009 are as follows:

	Gross Carrying Amount	Accumulated Amortization (In thousands)	Net Carrying Amount
Balance at September 30, 2009:			
Transportation contracts	$ 105,108	$ (1,842)	$ 103,266
	$ 105,108	$ (1,842)	$ 103,266

Recently Issued Accounting Pronouncements

In August 2009, the FASB issued Update No. 2009-05, *Fair Value Measurements and Disclosures* (ASU 2009-05). ASU 2009-05 amends Subtopic 820-10, *Fair Value Measurements and Disclosures*, to provide guidance on the fair value measurement of liabilities. ASU 2009-05 provides clarification for circumstances in which a quoted price in an active market for the identical liability is not available. ASU 2009-05 is effective for interim and annual periods beginning after August 26, 2009. The Company is currently assessing the impact that the adoption of ASU 2009-05 will have on the Company s disclosures, operating results, financial position and cash flows.

In June 2009, the FASB issued Update No. 2009-01, *Generally Accepted Accounting Principles* (ASU 2009-01). ASU 2009-01 establishes The FASB Accounting Standards Codification, or Codification, which became the source of authoritative GAAP recognized by the FASB to be applied by nongovernmental entities. On the effective date, the Codification superseded all then-existing non-SEC accounting and reporting standards. All other nongrandfathered non-SEC accounting literature not included in the Codification will become nonauthoritative. ASU 2009-01 is effective for interim and annual periods ending after September 15, 2009. The Company adopted the provisions of ASU 2009-01 for the period ended September 30, 2009. There was no impact on the Company s operating results, financial position or cash flows.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events* (ASC 855) to establish 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. ASC 855 is effective for interim and annual reporting periods ending after June 15, 2009. The Company adopted the provisions of ASC 855 for the period ended June 30, 2009. There was no impact on the Company s operating results, financial position or cash flows.

In April 2009, the FASB issued FASB Staff Position (FSP) No. FAS 107-1 and Accounting Principles Board (APB) 28-1, *Interim Disclosures about Fair Value of Financial Instruments* (ASC 825-10-65) to change the reporting requirements on certain fair value disclosures of financial instruments to include interim reporting periods. The Company adopted ASC 825-10-65 in the second quarter of 2009. There was no impact on the Company s operating results, financial position or cash flows; however additional disclosures were added to the accompanying notes to the condensed consolidated financial statements for the Company s fair value of financial instruments. See Note 5 *Fair Value Measurements* for more details.

In April 2009, the FASB *issued FSP No. FAS 115-2 and FAS 124-2, Recognition and Presentation of Other-Than-Temporary Impairments*, (ASC 320-10-65), to expand other-than-temporary impairment guidance for debt

Table of Contents

securities to enhance the application of the guidance and improve the presentation and disclosure of other-than temporary impairments on debt and equity securities within the financial statements. The adoption of ASC 320-10-65 in the second quarter of 2009 did not have a significant impact on the Company s operating results, financial position or cash flows.

In April 2009, the FASB issued FSP No. FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly*, (ASC 820-10-65) to provide additional guidance for estimating fair value when the volume and level of activity for an asset or liability has significantly decreased. In addition, ASC 820-10-65 includes guidance on identifying circumstances that indicate a transaction is not orderly. The adoption of ASC 820-10-65 in the second quarter of 2009 did not have a significant impact on the Company s operating results, financial position or cash flows.

In December 2008, the SEC issued Release No. 33-8995, Modernization of Oil and Gas Reporting, which amends the oil and gas disclosures for oil and gas producers contained in Regulations S-K and S-X, as well as adding a section to Regulation S-K (Subpart 1200) to codify the revised disclosure requirements in Securities Act Industry Guide 2, which is being phased out. The goal of Release No. 33-8995 is to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. Energy companies affected by Release No. 33-8995 will be required to price proved oil and gas reserves using the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. SEC Release No. 33-8995 is effective beginning January 1, 2010. The Company is currently evaluating what impact Release No. 33-8995 may have on its financial position, results of operations or cash flows.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133* (ASC 815-10-65). ASC 815-10-65 requires entities that utilize derivative contracts to provide qualitative disclosures about their objectives and strategies for using such instruments, as well as any details of credit-risk-related contingent features contained within derivatives. ASC 815-10-65 also requires entities to disclose additional information about the amounts and location of derivatives located within the financial statements, how the provisions of ASC 815 have been applied, and the impact that hedges have on an entity s operating results, financial position or cash flows. The Company adopted ASC 815-10-65 on January 1, 2009. There was no impact on the Company s operating results, financial position or cash flows; however additional disclosures were added to the accompanying notes to the condensed consolidated financial statements for the Company s derivative contracts. See Note 8 *Derivatives* for more details.

In December 2007, the FASB issued SFAS No. 141 (Revised 2007), *Business Combinations* (ASC 805), and SFAS No. 160, *Accounting and Reporting of Noncontrolling Interest in Consolidated Financial Statements, an amendment of ARB No. 51* (ASC 810-10-65). ASC 805 and ASC 810-10-65 significantly change the accounting for and reporting of business combination transactions and noncontrolling (minority) interests within the financial statements. ASC 805 provides additional definitions, such as the definition of the acquirer in a purchase and improvements in the application of how the acquisition method is applied. ASC 810-10-65 changes the accounting and reporting for minority interests, which are re-characterized as non-controlling interests, and classified as a component of equity. The Company adopted ASC 805 and ASC 810-10-65 on January 1, 2009. There was no impact on the Company s operating results, financial position or cash flows; however if the Company enters into future business combinations, certain transaction related expenses may be recorded within the Company s operating results which could reduce its current period net income or increase its net loss. Additionally, valuation of certain assets may be different than under the old accounting standards.

Effective January 1, 2009, the Company adopted FSP No. FAS 157-2, *Effective Date of FASB Statement No. 157* (ASC 820-10-55). ASC 820-10-55 delayed the effective date of ASC 820 for all non-financial assets and non-financial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until the beginning of the first quarter of fiscal 2009. These include goodwill and other non-amortizable intangible assets as well as asset retirement obligations. The adoption of ASC 820-10-55 did not have a significant impact on the Company s operating results, financial position or cash flows. See Note 6 *Asset Retirement Obligations* for more details.

In June 2008, the FASB issued FSP No. Emerging Issues Task Force (EITF) 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* (ASC 260). ASC 260 clarifies that share-based payment awards that entitle their holders to receive non-forfeitable dividends or dividend equivalents before vesting should be considered participating securities. The adoption of ASC 260 on January 1, 2009 did not have a significant impact on the Company s operating results, financial position or cash flows.

2. ACQUISITIONS AND DIVESTITURES

Acquisitions

Fayetteville Shale

On January 7, 2008, the Company entered into an agreement to purchase additional properties located in the Fayetteville Shale for $231.3 million after customary closing adjustments. The transaction closed on February 8, 2008. The acquired properties include interests primarily in Van Buren and Cleburne Counties, Arkansas that are substantially undeveloped.

Elm Grove Field

On January 22, 2008, the Company completed an acquisition of interests in the Elm Grove Field, located primarily in Bossier and Caddo Parishes of North Louisiana, for approximately $169 million.

Divestitures

Gulf Coast Properties

On November 30, 2007, the Company completed the sale of its Gulf Coast properties for $825 million, consisting of $700 million in cash and a $125 million note that the purchaser could redeem at any time prior to one year from November 30, 2007 for $100 million plus accrued and unpaid interest. If the redemption occurred prior to April 29, 2008, accrued interest would be waived. On April 28, 2008, the purchaser redeemed the note for $100 million.

3. OIL AND NATURAL GAS PROPERTIES

The Company uses the full cost method of accounting for its investment in oil and natural gas properties. Under this method of accounting, all costs of acquisition, exploration and development of oil and natural gas reserves (including such costs as leasehold acquisition costs, geological expenditures, dry hole costs, tangible and intangible development costs and direct internal costs) are capitalized as the cost of oil and natural gas properties when incurred. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depletion exceed the discounted future net revenues of proved oil and natural gas reserves net of deferred taxes, such excess capitalized costs are charged to expense. Full cost companies use the prices in effect at the end of each accounting quarter to calculate the ceiling test value of their reserves. Subsequent commodity price increases may be utilized to calculate the ceiling value and reserves. However, this option will no longer be available to the Company starting December 31, 2009 due to adoption of the new oil and natural gas reporting requirements.

Table of Contents

The Company assesses all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value. The Company assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

At September 30, 2009, the ceiling test value of the Company s reserves was calculated based on the September 30, 2009 West Texas Intermediate (WTI) posted price of $70.61 per barrel, adjusted by lease for quality, transportation fees, and regional price differentials, and the September 30, 2009 Henry Hub spot market price of $3.30 per million British thermal units (Mmbtu), adjusted by lease for energy content, transportation fees, and regional price differentials. At September 30, 2009, the Company s net book value of oil and natural gas properties exceeded the ceiling amount by approximately $880 million before tax, $546 million after tax. However, subsequent to September 30, 2009, the market price for Henry Hub gas and West Texas Intermediate oil increased significantly. As a consequence, prior to October 28, 2009, the Company elected to use prices on October 28, 2009, which were a WTI price of $77.20 per barrel and a Henry Hub spot market price of $4.51 per Mmbtu, adjusted for certain items as previously discussed. Utilizing these prices, the Company s net book value of oil and natural gas properties at September 30, 2009, would not have exceeded the ceiling amount. As a result of the increase in the ceiling amount using the subsequent prices, the Company did not record a write-down of its oil and natural gas property costs. Changes in production rates, levels of reserves, future development costs, and other factors will determine the Company s actual ceiling test calculation and impairment analyses in future periods.

At March 31, 2009 the ceiling test value of the Company s reserves was calculated based on the March 31, 2009 WTI posted price of $49.66 per barrel, adjusted by lease for quality, transportation fees, and regional price differentials, and the March 31, 2009 Henry Hub spot market price of $3.63 per Mmbtu, adjusted by lease for energy content, transportation fees, and regional price differentials. Using these prices, the Company s net book value of oil and natural gas properties exceeded the ceiling amount by approximately $1.7 billion before tax, $1.1 billion after tax. Accordingly, the Company recorded an approximate $1.7 billion full cost ceiling impairment at March 31, 2009, before tax.

At December 31, 2008, the ceiling test value of the Company s reserves was calculated based on the December 31, 2008 WTI posted price of $41.00 per barrel, adjusted by lease for quality, transportation fees, and regional price differentials, and the December 31, 2008, Henry Hub spot market price of $5.71 per Mmbtu, adjusted by lease for energy content, transportation fees, and regional price differentials. At December 31, 2008, the Company s net book value of oil and natural gas properties exceeded the ceiling amount by approximately $1.0 billion before tax, and $574 million after tax. Accordingly, the Company recorded approximately $1.0 billion in full cost ceiling impairments at December 31, 2008, before tax.

Table of Contents

4. LONG-TERM DEBT

Long-term debt as of September 30, 2009 and December 31, 2008 consisted of the following:

	September 30, 2009(1)	December 31, 2008(1)
	(In thousands)	
Senior revolving credit facility	$	$ 450,000
10.5% $600 million senior notes (2)	552,337	
7.875% $800 million senior notes	800,000	800,000
9.125% $775 million senior notes (3)	764,456	763,773
7.125% $275 million senior notes (4)	265,804	264,080
9.875% senior notes	224	254
Deferred premiums on derivatives	11,449	5,767
	$ 2,394,270	$ 2,283,874

(1) Amount excludes $39.8 million and $9.4 million of long-term debt which has been classified as current at September 30, 2009 and December 31, 2008, respectively. These amounts represent deferred premiums on derivatives contracts that are expected to be settled in the next 12 months.

(2) Amount includes a $47.7 million discount at September 30, 2009 recorded by the Company in conjunction with the issuance of the notes. See 10.5% Senior Notes below for more details.

(3) This amount is comprised of the $650.0 million and $125.0 million private placements consummated in July 2006. These amounts include a $5.1 million and $5.9 million discount at September 30, 2009 and December 31, 2008, respectively, recorded by the Company in conjunction with the issuance of the $650.0 million notes. Additionally, these amounts include a $0.8 and $1.0 million premium at September 30, 2009 and December 31, 2008, recorded by the Company in conjunction with the issuance of the $125.0 million notes. See 9.125% Senior Notes below for more details.

(4) Amount includes a $6.6 million and $8.3 million discount at September 30, 2009 and December 31, 2008, respectively, recorded by the Company in conjunction with the assumption of the notes. See 7.125% Senior Notes below for more details.

Senior Revolving Credit Facility

The Company entered into the Third Amended and Restated Senior Revolving Credit Agreement, dated as of September 10, 2008 (the Senior Credit Agreement), between the Company, each of the lenders from time to time party thereto (the Lenders), BNP Paribas, as administrative agent for the Lenders, Bank of America, N.A. and BMO Capital Markets Financing, Inc. as co-syndication agents for the Lenders, and JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A. and Fortis Capital Corp. as co-documentation agents for the Lenders, which amends and restates its $1 billion senior revolving credit agreement dated July 12, 2006. The Senior Credit Agreement provides for a $1.5 billion facility with a borrowing base of $1.1 billion that will be redetermined on a semi-annual basis, with the Company and the Lenders each having the right to one annual interim unscheduled redetermination, and adjusted based on the Company s oil and natural gas properties, reserves, other indebtedness and other relevant factors. The Company s borrowing base is subject to a reduction equal to the product of $0.25 multiplied by the stated principal amount (without regard to any initial issue discount) of any notes that the Company may issue. On January 27, 2009, the Company completed a private placement offering to eligible purchasers of an aggregate principal amount of $600 million 10.5% senior notes due August 1, 2014. In conjunction with the closing of this offering, the Company s borrowing base was reduced to $950 million.

Amounts outstanding under the Senior Credit Agreement will bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.25% to 2.00% for Eurodollar loans or at specified margins over the Alternate Base Rate (ABR) of 0.00% to 0.50% for ABR loans. Such margins will fluctuate based on the utilization of the facility. Borrowings under the Senior Credit Agreement may be secured by first priority liens on

Table of Contents

substantially all of the Company s assets, including pursuant to the terms of the Third Amended and Restated Guarantee and Collateral Agreement, substantially all of the assets of, and all equity interests in, the Company s subsidiaries. Amounts drawn down on the facility will mature on July 1, 2013.

The Senior Credit Agreement contains financial and other covenants, including minimum working capital levels (the ratio of current assets plus the unused commitment under the Senior Credit Agreement to current liabilities) of not less than 1.0 to 1.0 and minimum coverage of interest expenses of not less than 2.5 to 1.0. In addition, the Company is subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. At September 30, 2009, the Company was in compliance with all of its debt covenants under the Senior Credit Agreement.

On October 14, 2009, the Company entered into the Fourth Amended and Restated Senior Revolving Credit Agreement (the Fourth Amendment), which amends and restates its Senior Credit Agreement. The Fourth Amendment is a $2.0 billion facility with a borrowing base of $1.5 billion, $1.2 billion of which relates to the Company s oil and natural gas properties and up to $300 million (currently limited as described below) of which relates to the Company s midstream assets. The portion of the borrowing base which relates to the Company s oil and natural gas properties will be redetermined on a semi-annual basis (with the Company and the Lenders each having the right to one annual interim unscheduled redetermination) and adjusted based on the Company s oil and natural gas properties, reserves, other indebtedness and other relevant factors. The component of the borrowing base related to the Company s midstream assets is limited to the lesser of $300 million or 3.5 times midstream EBITDA, and is determined quarterly. The initial available borrowing base aggregates $1.38 billion as the midstream component is currently $182 million. Amounts outstanding under the Fourth Amendment will bear interest at specified margins over LIBOR of 2.25% to 3.25% for Eurodollar loans or at specified margins over the ABR of 0.75% to 1.75% for ABR loans. Such margins will fluctuate based on the utilization of the facility. Borrowings under the Fourth Amendment will be secured by first priority liens on substantially all of the Company s assets, including pursuant to the terms of the Fourth Amended and Restated Guarantee and Collateral Agreement, all of the assets of, and equity interests in, the Company s subsidiaries. Amounts drawn down on the facility will mature on July 1, 2013. On October 30, 2009, in conjunction with the closing of the sale of the Company s Permian Basin properties, the oil and natural gas properties portion of the borrowing base under the Fourth Amendment was reduced by $200 million to $1 billion, resulting in a new aggregate borrowing base of $1.18 billion, including the Company s midstream assets allocation. Please refer to Note 12, *Subsequent Events*, for further information.

10.5% Senior Notes

On January 27, 2009, the Company completed a private placement offering to eligible purchasers of an aggregate principal amount of $600 million principal amount of its 10.5% senior notes due August 1, 2014 (the 2014 Notes). The 2014 Notes were issued under and are governed by an indenture dated January 27, 2009, between the Company, U.S. Bank Trust National Association, as trustee, and the Company s subsidiaries named therein as guarantors (the 2014 Indenture). The 2014 Notes were priced at 91.279% of the face value to yield 12.7% to maturity. Net proceeds from the offering were used to repay all outstanding borrowings on the Company s Senior Credit Agreement.

The 2014 Notes bear interest at a rate of 10.5% per annum, payable semi-annually on February 1 and August 1 of each year, commencing August 1, 2009. The 2014 notes will mature on August 1, 2014. The 2014 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness. The 2014 Notes are jointly and severally guaranteed on a senior unsecured basis by the Company s subsidiaries. Petrohawk Energy Corporation, the issuer of the 2014 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

On or before February 1, 2012, the Company may redeem up to 35% of the aggregate principal amount of the 2014 Notes with the net cash proceeds of certain equity offerings at a redemption price of 110.5% of the principal amount plus accrued interest and unpaid interest to the redemption date provided that at least 65% in aggregate principal amount of the 2014 Notes originally issued under the 2014 Indenture remain outstanding immediately after the redemption. In addition, at any time prior to February 1, 2012, the Company may redeem some or all of the 2014 Notes for the principal amount thereof, plus accrued and unpaid interest plus a make

Table of Contents

whole premium equal to the excess, if any of (a) the present value at such time of (i) the redemption price of such note at February 1, 2012, (ii) plus required interest payments due on the notes, computed using a discount rate based upon the yield of U.S. Treasury securities with a constant maturity most nearly equal to the period from the redemption date to February 1, 2012 plus 50 basis points, over (b) the principal amount of such note.

On or after February 1, 2012, the Company may redeem some or all of the 2014 Notes at any time or from time to time at the redemption prices (expressed as a percentage of principal amount) set forth in the following table plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the 12-month period beginning February 1 of the years indicated below:

Year	Percentage
2012	110.500
2013	105.250
2014	100.000

The Company may be required to offer to repurchase the 2014 Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined in the 2014 Indenture. The 2014 Indenture contains covenants that, among other things, restrict or limit the ability of the Company and its subsidiaries to: borrow money; pay dividends on stock; purchase or redeem stock or subordinated indebtedness; make investments; create liens; enter into transactions with affiliates; sell assets; and merge with or into other companies or transfer all or substantially all of the Company s assets. At September 30, 2009, the Company was in compliance with all of its debt covenants relating to the 2014 Notes.

In conjunction with the issuance of the $600 million 2014 Notes, the Company recorded a discount of $52.3 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized discount was $47.7 million at September 30, 2009.

7.875% Senior Notes

On May 13, 2008 and June 19, 2008, the Company issued $500 million principal amount and $300 million principal amount, respectively, of its 7.875% senior notes due 2015 (the 2015 Notes). The 2015 Notes were issued under and are governed by an indenture dated May 13, 2008, between the Company, U.S. Bank Trust National Association, as trustee, and the Company s subsidiaries named therein as guarantors.

The 2015 Notes bear interest at a rate of 7.875% per annum, payable semi-annually on June 1 and December 1 of each year, commencing December 1, 2008. The 2015 Notes will mature on June 1, 2015. The 2015 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness. The 2015 Notes are jointly and severally guaranteed on a senior unsecured basis by the Company s subsidiaries. Petrohawk Energy Corporation, the issuer of the 2015 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries. At September 30, 2009, the Company is in compliance with all of its debt covenants relating to the 2015 Notes.

9.125% Senior Notes

In July 2006, the Company consummated its private placement of 9.125% Senior Notes, also referred to as the 2013 Notes, pursuant to an Indenture dated as of July 12, 2006 (2013 Indenture) and the First Supplemental Indenture to the 2013 Notes (the 2013 First Supplemental Indenture), among the Company, the Company s subsidiaries named therein as guarantors, and U.S. Bank National Association, as trustee. The 2013 Notes were issued at 98.735% of the face amount.

The 2013 Notes bear interest at the rate of 9.125% per annum, payable semi-annually on January 15 and July 15 of each year, commencing January 15, 2007. The 2013 Notes mature on July 15, 2013. The 2013 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior

Table of Contents

indebtedness, including the 2012 Notes. The 2013 Notes rank effectively subordinate to the Company s secured debt to the extent of the collateral, including secured debt under the Senior Credit Agreement, and senior to any future subordinated indebtedness. The 2013 Notes are jointly and severally guaranteed on a senior unsecured basis by the Company s subsidiaries, including, pursuant to the 2013 First Supplemental Indenture, the KCS Energy, Inc. (KCS) subsidiaries acquired in the Company s merger with KCS. Petrohawk Energy Corporation, the issuer of the 2013 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries. At September 30, 2009, the Company was in compliance with all of its debt covenants relating to the 2013 Notes.

In conjunction with the issuance of the $650 million 2013 Notes, the Company recorded a discount of $8.2 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized discount was $5.1 million at September 30, 2009. In conjunction with the issuance of the $125 million 2013 Notes, the Company recorded a premium of $1.4 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized premium was $0.8 million at September 30, 2009.

7.125% Senior Notes

On July 12, 2006, the date of the Company s merger with KCS, the Company assumed (pursuant to the Second Supplemental Indenture relating to the 7.125% Senior Notes, also referred to as the 2012 Notes), and subsidiaries of the Company guaranteed (pursuant to the Third Supplemental Indenture relating to such notes), all the obligations (approximately $275 million) of KCS under the 2012 Notes and the Indenture dated April 1, 2004 (the 2012 Indenture) among KCS, U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein, which governs the terms of the 2012 Notes. The 2012 Notes are guaranteed on an unsubordinated, unsecured basis by all of the Company s current subsidiaries, including the subsidiaries of KCS that the Company acquired in the merger. Interest on the 2012 Notes is payable semi-annually, on each April 1 and October 1. The 2012 Notes are jointly and severally guaranteed on a senior unsecured basis by the Company s subsidiaries. Petrohawk Energy Corporation, the issuer of the Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries. At September 30, 2009, the Company was in compliance with all of its debt covenants under the 7.125% Senior Notes.

In conjunction with the assumption of the 7.125% Senior Notes from KCS, the Company recorded a discount of $13.6 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized discount is $6.6 million at September 30, 2009.

9.875% Senior Notes

On April 8, 2004, Mission Resources Corporation (Mission) issued $130.0 million of its 9.875% senior notes due 2011 (the 2011 Notes). The Company assumed these notes upon the closing of the Company s merger with Mission. In conjunction with the Company s merger with KCS, the Company redeemed substantially all of its 2011 Notes for face value plus a premium of $14.9 million and accrued interest of $3.5 million. There were approximately $0.2 million of the notes which were not redeemed and are still outstanding as of September 30, 2009. In connection with the extinguishment of substantially all of the 2011 Notes, the Company requested and received from the noteholders consent to eliminate the debt covenants associated with the 2011 Notes.

Debt Issuance Costs

The Company capitalizes certain direct costs associated with the issuance of long-term debt. The Company capitalized $23.8 million of debt issue costs in connection with the Company s issuance of 2015 Notes in May and June 2008 and in connection with the Company s amended and restated senior revolving credit facility in September 2008. The Company capitalized $13.2 million with its issuance of the 2014 Notes in January 2009. In the first quarter of 2009, the Company wrote off $0.9 million of debt issuance costs as a result of the 2014 Notes issuance and from the reduction of our Senior Credit Agreement s borrowing base to $950 million. At September 30, 2009 and December 31, 2008, the Company had approximately $36.6 million and $30.5 million, respectively of debt issuance costs remaining that are being amortized over the lives of the respective debt.

5. FAIR VALUE MEASUREMENTS

Effective January 1, 2008, the Company adopted ASC 820. ASC 820 defines fair value, establishes a framework for measuring fair value and expands the related disclosure requirements. Pursuant to ASC 820, the Company s determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company s condensed consolidated balance sheets, but also the impact of the Company s nonperformance risk on its liabilities.

ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs. ASC 820 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

The three levels of the fair value hierarchy defined by ASC 820 are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, marketable securities and listed equities.

Level 2 Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category generally include non-exchange-traded derivatives such as commodity swaps, interest rate swaps, options and collars.

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value.

Table of Contents

The following tables set forth by level within the fair value hierarchy the Company s financial assets and liabilities that were accounted for at fair value as of September 30, 2009 and December 31, 2008. As required by ASC 820, a financial instrument s level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	September 30, 2009			
	Level 1	Level 2 (In thousands)	Level 3	Total
Assets:				
Marketable securities	$ 150,028	$	$	$ 150,028
Receivables from derivative contracts		174,935		174,935
	$ 150,028	$ 174,935	$	$ 324,963
Liabilities:				
Liabilities from derivative contracts	$	$ 1,600	$	$ 1,600
	$	$ 1,600	$	$ 1,600

	December 31, 2008			
	Level 1	Level 2 (In thousands)	Level 3	Total
Assets:				
Marketable securities	$ 123,009	$	$	$ 123,009
Receivables from derivative contracts		224,527		224,527
	$ 123,009	$ 224,527	$	$ 347,536
Liabilities:				
Liabilities from derivative contracts	$	$	$	$
	$	$	$	$

Marketable securities listed above are carried at fair value. The Company is able to value its marketable securities based on quoted fair values for identical instruments, which resulted in the Company reporting its marketable securities as Level 1.

Derivatives listed above include collars, swaps, basis swaps and puts that are carried at fair value. The Company records the net change in the fair value of these positions in *Net (loss) gain on derivative contracts* in the Company s condensed consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curve for commodity prices based on quoted markets prices and implied volatility factors related to changes in the forward curves.

As of September 30, 2009 and December 31, 2008, the Company s derivative contracts were with major financial institutions with investment grade credit ratings which are believed to have a minimal credit risk. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above; however, the Company does not anticipate such nonperformance. Each of the counterparties to the Company s derivative contracts is a lender in the Company s Senior Credit Agreement. The Company did not post collateral under any of these contracts as they are secured under the Senior Credit Agreement.

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of ASC 825-10-65. The estimated fair value amounts have been determined at discrete points in

time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of the Company s Senior Credit Agreement approximates carrying value because the facility s interest rate approximates current market rates. The following table presents the estimated fair values of the Company s fixed interest rate debt instruments as of September 30, 2009 and December 31, 2008 (excluding premiums and discounts):

	September 30, 2009		December 31, 2008	
Debt	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
		(In thousands)		
10.5% $600 million senior notes	$ 600,000	$ 643,500	$	$
7.875% $800 million senior notes	800,000	800,800	800,000	591,040
9.125% $775 million senior notes	768,725	787,943	768,725	595,762
7.125% $275 million senior notes	272,375	271,694	272,375	223,348
9.875% senior notes	224	228	254	213
	$ 2,441,324	$ 2,504,165	$ 1,841,354	$ 1,410,363

6. ASSET RETIREMENT OBLIGATIONS

The Company records an asset retirement obligation (ARO) when the total depth of a drilled well is reached and the Company can reasonably estimate the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon costs. For gas gathering systems, the Company records an ARO when the system is placed in service and the Company can reasonably estimate the fair value of an obligation to perform site reclamation and other necessary work. The Company records the ARO liability on the condensed consolidated balance sheets and capitalizes the cost in *Oil and natural gas properties evaluated* or *Other operating property and equipment - gas gathering system and equipment* during the period in which the obligation is incurred. In general, the amount of an ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date and adjusted for the Company s credit risk. This amount is then discounted back to the date that the abandonment obligation was incurred using an assumed cost of funds for the Company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds. The Company records the accretion of its ARO liabilities in *Depletion, depreciation and amortization* expense in the condensed consolidated statements of operations. The additional capitalized costs are depreciated on a unit-of-production basis or straight-line basis.

The Company recorded the following activity related to its ARO liability for the nine months ended September 30, 2009 (in thousands):

Liability for asset retirement obligation as of December 31, 2008	$ 28,644
Liabilities settled and divested	(351)
Additions	2,246
Acquisitions	14
Accretion expense	1,070
Revisions in estimated cash flows	37
Liability for asset retirement obligation as of September 30, 2009	$ 31,660

7. COMMITMENTS AND CONTINGENCIES

From time to time, the Company may be a plaintiff or defendant in a pending or threatened legal proceeding arising in the normal course of its business. All known liabilities are accrued based on the Company s best estimate of the potential loss. While the outcome and impact of currently pending legal proceedings cannot be

20

Table of Contents

predicted with certainty, the Company s management and legal counsel believe that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on the Company s condensed consolidated operating results, financial position or cash flows. Please refer to Part II. Other Information, Item 1. *Legal Proceedings* for further information on pending cases.

As of September 30, 2009, the Company had drilling rigs under contract with a total commitment of $316.0 million over approximately four years. At December 31, 2008, the Company had drilling rigs under contract with a total commitment of $433.0 million over four years.

The Company has various other contractual commitments pertaining to exploration, development and production activities. The Company has work related commitments for, among other things, pipeline and well equipment, obtaining and processing seismic data and natural gas pipeline transportation. At September 30, 2009 and December 31, 2008, these work related commitments totaled $1.1 billion over 16 years and $507.8 million over 20 years, respectively.

8. DERIVATIVES

The Company is exposed to certain risks relating to its ongoing business operations, such as commodity price risk and interest rate risk. Derivative contracts are utilized to economically hedge its exposure to price fluctuations and reduce the variability in the Company s cash flows associated with anticipated sales on future oil and natural gas production. The Company generally hedges a substantial, but varying, portion of anticipated oil and natural gas production for the next 12-36 months. Derivatives are carried at fair value on the condensed consolidated balance sheets, with the changes in the fair value included in the condensed consolidated statements of operations for the period in which the change occurs. Generally, the Company enters into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates (such as those on the Company s Senior Credit Agreement) to fixed interest rates.

It is the Company s policy to enter into derivative contracts, including interest rate swaps, only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Each of the counterparties to the Company s derivative contracts is a lender in the Company s Senior Credit Agreement. The Company did not post collateral under any of these contracts as they are secured under the Company s Senior Credit Agreement.

At September 30, 2009 the Company has entered into commodity collars, swaps, put options and basis swaps. The Company has elected to not designate any of its derivative contracts for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in *Net (loss) gain on derivatives contracts* on the condensed consolidated statements of operations.

During the second quarter of 2009, the Company entered into five interest rate swaps to convert a portion of its long-term debt from a fixed interest rate to a variable interest rate. During the third quarter of 2009, the Company made the decision to settle all of its outstanding interest rate swap positions which resulted in a gain of approximately $5.2 million. This gain is included in *Net (loss) gain on derivatives contracts* on the condensed consolidated statements of operations.

During the first quarter of 2009, the Company entered into three interest rate swap derivative contracts. In conjunction with the issuance of the 2014 Notes in January 2009, the Company repaid all outstanding borrowings under its Senior Credit Agreement. As a result, the Company made the decision to settle all of its outstanding interest rate swap derivative contracts which resulted in a minimal gain during the first quarter of 2009. This gain is included in *Net (loss) gain on derivative contracts* on the condensed consolidated statements of operations.

During the first quarter of 2008, the Company entered into two interest rate swap derivative contracts. In conjunction with the Company s debt and equity raises during the second quarter of 2008, the Company repaid

Table of Contents

all outstanding borrowings under its Senior Credit Agreement. As a result, the Company made the decision to settle all of its outstanding interest rate swap derivative contracts which resulted in a gain of $1.5 million during the second quarter of 2008 which is included in *Net (loss) gain on derivative contracts* on the condensed consolidated statements of operations.

At September 30, 2009, the Company had 95 open commodity derivative contracts summarized in the tables below: 74 natural gas collar arrangements, two natural gas swap arrangements, two natural gas basis swap arrangement, 13 natural gas put options and four crude oil price swap arrangements. Derivative commodity contracts settle based on NYMEX West Texas Intermediate and Henry Hub prices which may differ from the actual price received by the Company for the sale of its oil and natural gas production. The Company s basis swaps hedge the basis differential between NYMEX Henry Hub price and the Houston Ship Channel price.

At December 31, 2008, the Company had 69 open commodity derivative contracts summarized in the tables below: 52 natural gas collar arrangements, two natural gas swap arrangements, one natural gas basis swap arrangement, 10 natural gas put options and four crude oil price swap arrangements.

All derivative contracts are recorded at fair market value in accordance with ASC 815 and ASC 820 and included in the condensed consolidated balance sheets as assets or liabilities. The following table summarizes the location and fair value amounts of all derivative contracts in the condensed consolidated balance sheets as of September 30, 2009 and December 31, 2008:

Derivatives not	**Asset derivative contracts**			**Liability derivative contracts**		
designated as hedging contracts under ASC 815	**Balance sheet location**	**September 30, 2009**	**December 31, 2008**	**Balance sheet location**	**September 30, 2009**	**December 31, 2008**
		(In thousands)			**(In thousands)**	
Commodity contracts	Current assets - receivables from derivative contracts	$ 150,346	$ 201,128	Current liabilities - liabilities from derivative contracts	$ (363)	$
Commodity contracts	Other noncurrent assets - receivables from derivative contracts	24,589	23,399	Other noncurrent liabilities - liabilities from derivative contracts	(1,237)	
Total derivatives not designated as hedging contracts under ASC 815		$ 174,935	$ 224,527		$ (1,600)	$

22

Table of Contents

The following table summarizes the location and amounts of the Company s realized and unrealized gains and losses on derivative contracts in the Company s condensed consolidated statements of operations:

Derivatives not designated as hedging contracts under ASC 815	Location of gain or (loss) recognized in income on derivative contracts	Amount of gain or (loss) recognized in income on derivative contracts three months ended September 30, 2009	2008	Amount of gain or (loss) recognized in income on derivative contracts nine months ended September 30, 2009	2008
		(In thousands)			
Commodity contracts:					
Unrealized (loss) gain on commodity contracts	Other (expenses) income - net (loss) gain on derivative contracts	$ (112,891)	$ 423,917	$ (96,752)	$ 57,337
Realized gain (loss) on commodity contracts	Other (expenses) income - net (loss) gain on derivative contracts	108,358	(35,701)	287,579	(90,967)
Total net (loss) gain on commodity contracts		$ (4,533)	$ 388,216	$ 190,827	$ (33,630)
Interest rate swaps:					
Unrealized loss on interest rate swaps	Other (expenses) income - net (loss) gain on derivative contracts	$ (2,280)	$	$	$
Realized gain on interest rate swaps	Other (expenses) income - net (loss) gain on derivative contracts	5,245		5,533	1,500
Total net gain on interest rate swaps		$ 2,965	$	$ 5,533	$ 1,500
Total net (loss) gain on derivative contracts	Other (expenses) income - net (loss) gain on derivative contracts	$ (1,568)	$ 388,216	$ 196,360	$ (32,130)

At September 30, 2009 and December 31, 2008, the Company had the following open derivative contracts:

				September 30, 2009			
				Floors		Ceilings	
Period	Instrument	Commodity	Volume in Mmbtu s / Bbl s	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
October 2009 - December 2009 [1]	Collars	Natural gas	18,400,000	$ 4.50 - $9.00	$ 7.60	$ 6.69 - $16.45	$ 12.22
October 2009 - December 2009	Swaps	Natural gas	460,000	8.43	8.43		
October 2009 - December 2009	Floor	Natural gas	13,800,000	4.50 - 10.00	6.21		
October 2009 - December 2009	Swaps	Oil	69,000	76.85 -77.30	77.00		
January 2010 - December 2010	Collars	Natural gas	138,700,000	5.00 - 7.00	5.97	9.00 - 10.00	9.21
January 2010 - December 2010	Swaps	Natural gas	1,825,000	8.22	8.22		
January 2010 - December 2010	Floor	Natural gas	7,240,000	4.49 - 4.55	4.54		
January 2010 - December 2010	Swaps	Oil	273,750	75.15 - 75.55	75.28		
January 2011 - December 2011	Collars	Natural gas	125,925,000	5.50 - 6.00	5.57	9.00 - 10.30	10.00

(1) Includes a natural gas collar with a second put option sold at $3.00 for 920,000 Mmbtus during the fourth quarter.

Period	Instrument	Commodity	September 30, 2009

			Volume in Mmbtu s	Price Range	Weighted Average Price
October 2009 - December 2009	Basis swaps	Natural gas	1,840,000	$ 0.33 - $0.34	$ 0.34

Table of Contents

				December 31, 2008			
				Floors		Ceilings	
Period	Instrument	Commodity	Volume in Mmbtu's / Bbl's	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
January 2009 - December 2009	Collars	Natural gas	75,730,000	$ 7.00 - $10.00	$ 7.57	$ 9.60 - $16.45	$ 11.79
January 2009 - December 2009	Swaps	Natural gas	1,825,000	8.43	8.43		
January 2009 - December 2009	Floor	Natural gas	14,600,000	10.00	10.00		
January 2009 - December 2009	Swaps	Oil	273,750	76.85 - 77.30	77.00		
January 2010 - December 2010	Collars	Natural gas	29,200,000	7.00	7.00	10.00	10.00
January 2010 - December 2010	Swaps	Natural gas	1,825,000	8.22	8.22		
January 2010 - December 2010	Swaps	Oil	273,750	75.15 - 75.55	75.28		

			December 31, 2008		
Period	Instrument	Commodity	Volume in Mmbtu s	Price / Price Range	Weighted Average Price
January 2009 - December 2009	Basis swaps	Natural gas	3,650,000	$ 0.33	$ 0.33

9. STOCKHOLDERS EQUITY

At the Company s annual meeting on June 18, 2009, its shareholders voted on three proposals related to its common stock and stock plans. The Company s Certificate of Incorporation was amended to increase the number of shares of common stock available for issuance from 300 million shares to 500 million shares. In addition, amendments to the Company s 2004 Employee Incentive Plan and the 2004 Non-Employee Director Incentive Plan were approved to increase the number of shares of common stock that may be issued under the plans by 5.3 million shares and 0.5 million shares, respectively.

On August 11, 2009, the Company sold an aggregate of 25.0 million shares of its common stock in an underwritten public offering. The gross proceeds from the sale were approximately $572 million, before deducting underwriting discounts and commissions and estimated expenses of $22 million.

On March 4, 2009, the Company sold an aggregate of 22.0 million shares of its common stock in an underwritten public offering. The gross proceeds from the sale were approximately $385 million, before deducting underwriting discounts and commissions and estimated expenses of $9 million.

On August 15, 2008, the Company sold an aggregate of 28.8 million shares of its common stock in an underwritten public offering. The gross proceeds from the sale were approximately $763 million, before deducting underwriting discounts and commissions and estimated expenses of $29 million.

On May 13, 2008, the Company sold an aggregate of 25.0 million shares of its common stock in an underwritten public offering. Pursuant to the underwriting agreement, the Company granted the underwriters a 30-day option to purchase up to an additional 3.75 million shares of common stock at the public offering price less underwriting discounts and commissions. The underwriters exercised in full their option to purchase additional shares of common stock which closed on May 23, 2008. The gross proceeds from these sales were approximately $759 million, before deducting underwriting discounts and commissions and estimated expenses of $32 million.

On February 1, 2008, the Company sold an aggregate of 20.7 million shares of its common stock in an underwritten public offering. The gross proceeds from the sale were approximately $311 million, before deducting underwriting discounts and commissions and estimated expenses of $14 million.

Warrants, Options and Stock Appreciation Rights

During the nine months ended September 30, 2009, the Company granted stock options covering 1.6 million shares of common stock to employees of the Company. The stock options have exercise prices ranging from

Table of Contents

$15.23 to $26.12 with a weighted average price of $15.47. These awards vest over a three year period at a rate of one-third on the annual anniversary date of the grant and expire ten years from the grant date. At September 30, 2009, the unrecognized compensation expense related to non-vested stock appreciation rights and stock options totaled $8.6 million and will be recognized on a straight line basis over the weighted average remaining vesting period of 1.2 years.

During the nine months ended September 30, 2008, the Company granted stock options covering 1.1 million shares of common stock to employees of the Company. The stock options have exercise prices ranging from $15.97 to $47.16 with a weighted average price of $19.03. These awards vest over a three year period at a rate of one-third on the annual anniversary date of the grant and expire ten years from the grant date.

During the nine months ended September 30, 2009, there were 0.6 million warrants exercised at a price of $3.30 per share which represented the remaining outstanding warrants granted in conjunction with the recapitalization of the Company by PHAWK, LLC in the second quarter of 2004.

Restricted Stock

During the nine months ended September 30, 2009, the Company granted 0.7 million shares of restricted stock to employees of the Company and non-employee directors. These restricted shares were granted at prices ranging from $15.23 to $26.12 with a weighted average price of $15.81. Employee shares vest over a three-year period at a rate of one-third on the annual anniversary date of the grant and the non-employee directors shares vest six-months from the date of grant. At September 30, 2009, the unrecognized compensation expense related to non-vested restricted stock totaled $10.0 million and was to be recognized on a straight line basis over the weighted average remaining vesting period of 1.2 years.

During the nine months ended September 30, 2008, the Company granted 0.5 million shares of restricted stock to employees of the Company. These restricted shares were granted at prices ranging from $15.97 to $48.30 with a weighted average price of $19.04. Employee shares vest over a three-year period at a rate of one-third on the annual anniversary date of the grant and the non-employee directors shares vest six-months from the date of grant.

Performance Shares

At December 31, 2008, the performance period related to the plan assumed in the merger between KCS and Petrohawk was completed. The required objectives were met and therefore a total of 0.2 million shares were issued on February 16, 2009. The shares are now held as restricted stock until the restriction lapses on December 31, 2009. The Company recognized $0.4 million in compensation cost for the nine months ended September 30, 2008.

Table of Contents

Assumptions

The assumptions used in calculating the fair value of the Company s stock-based compensation are disclosed in the following table:

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Weighted average value per option granted during the period	$ 7.23	$ 5.57
Assumptions (1)(2)(3):		
Stock price volatility	70.0%	40.0%
Risk free rate of return	1.49%	2.00%
Expected term	3.0 years	3.0 years

(1) The Company s estimated future forfeiture rate is approximately 5% based on the Company s historical forfeiture rate.
(2) Calculated using the Black-Scholes fair value based method.
(3) The Company does not pay dividends on its common stock.

10. EARNINGS PER SHARE OF COMMON STOCK

The following represents the calculation of earnings per share of common stock:

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(In thousands, except per share amounts)			
Basic				
Net (loss) income	$ (40,177)	$ 305,465	$ (1,061,934)	$ 157,087
Weighted average basic number of shares outstanding	287,913	235,235	273,477	208,549
Basic net (loss) income per share of common stock	$ (0.14)	$ 1.30	$ (3.88)	$ 0.75
Diluted				
Net (loss) income	$ (40,177)	$ 305,465	$ (1,061,934)	$ 157,087
Weighted average basic number of shares outstanding	287,913	235,235	273,477	208,549
Common stock equivalent shares representing shares issuable upon exercise of stock options and stock appreciation rights	Anti-dilutive	2,453	Anti-dilutive	2,190
Common stock equivalent shares representing shares issuable upon exercise of warrants		1,020	Anti-dilutive	993
Common stock equivalent shares representing shares included upon vesting of restricted shares	Anti-dilutive	771	Anti-dilutive	771
Weighted average diluted number of shares outstanding	287,913	239,479	273,477	212,503
Diluted net (loss) income per share of common stock	$ (0.14)	$ 1.28	$ (3.88)	$ 0.74

Common stock equivalents, including stock options, SARS and warrants, totaling 4.8 million and 4.6 million shares were not included in the computations of diluted earnings per share because the effect would have been anti-dilutive due to the net loss for the three and nine months ended September 30, 2009. Common

stock equivalents, including stock options, SARS and warrants, totaling 27,000 and 75,000 shares were not included in the computation of diluted earnings per share as the effect would have been anti-dilutive for the three and nine months ended September 30, 2008 because the grant prices were greater than the average market price of the common shares.

11. ADDITIONAL FINANCIAL STATEMENT INFORMATION

Certain balance sheet amounts are comprised of the following:

	September 30, 2009	December 31, 2008
	(In thousands)	
Accounts receivable:		
Oil and gas revenues	$ 56,680	$ 98,536
Marketing revenues	18,651	36,476
Joint interest accounts	87,706	96,485
Income taxes receivable	12,729	35,535
Other	6,149	10,317
	$ 181,915	$ 277,349
Prepaids and other:		
Prepaid insurance	$ 3,888	$ 2,315
Prepaid drilling costs	35,468	35,739
Other	2,723	2,009
	$ 42,079	$ 40,063
Accounts payable and accrued liabilities:		
Trade payables	$ 53,015	$ 82,028
Revenues and royalties payable	133,162	145,828
Accrued capital costs	231,880	264,888
Accrued interest expense	55,889	42,548
Prepayment liabilities	29,413	59,234
Accrued lease operating expenses	9,316	7,017
Accrued ad valorem taxes payable	9,050	4,029
Accrued employee compensation	15,750	11,723
Income taxes payable	5,226	4,022
Advances on assets disposed	37,600	
Other	30,195	18,115
	$ 610,496	$ 639,432

12. SUBSEQUENT EVENTS

On October 14, 2009, the Company entered into the Fourth Amended and Restated Senior Revolving Credit Agreement (the Fourth Amendment), which amends and restates its Third Amended and Restated Senior Revolving Credit Agreement dated September 10, 2008. The Fourth Amendment is a $2.0 billion facility with a borrowing base of $1.5 billion, $1.2 billion of which relates to the Company s oil and natural gas properties and up to $300 million (currently limited as described below) of which relates to the Company s midstream assets. The portion of the borrowing base which relates to the Company s oil and natural gas properties will be redetermined on a semi-annual basis (with the Company and the Lenders each having the right to one annual interim unscheduled redetermination) and adjusted based on the Company s oil and natural gas properties, reserves, other indebtedness and other relevant factors. The component of the borrowing base related to the Company s midstream assets is limited to the lesser of $300 million or 3.5 times midstream EBITDA, and is

Table of Contents

determined quarterly. The initial available borrowing base aggregates $1.38 billion as the midstream component is currently $182 million. Amounts outstanding under the Fourth Amendment will bear interest at specified margins over LIBOR of 2.25% to 3.25% for Eurodollar loans or at specified margins over ABR of 0.75% to 1.75% for ABR loans. Such margins will fluctuate based on the utilization of the facility. Borrowings under the Fourth Amendment will be secured by first priority liens on substantially all of the Company s assets, including pursuant to the terms of the Fourth Amended and Restated Guarantee and Collateral Agreement, all of the assets of, and equity interests in, the Company s subsidiaries. Amounts drawn down on the facility will mature on July 1, 2013.

On October 30, 2009, the Company closed its previously announced sale of its Permian Basin properties to a privately-owned company for $376 million in cash, before customary closing adjustments, $37.6 million of which was received by the Company as a deposit during the third quarter. The effective date of the sale was July 1, 2009. Proceeds from the sale will be recorded as a reduction to the carrying value of the Company s full cost pool. Upon closing of this sale, the oil and natural gas properties portion of the borrowing base under the Fourth Amendment was reduced by $200 million to $1 billion, resulting in a new aggregate borrowing base of $1.18 billion, including the Company s midstream assets allocation. In conjunction with the closing of this sale, the Company deposited the remaining proceeds with a qualified intermediary to facilitate potential like-kind exchange transactions.

Table of Contents

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

The following discussion of operations for the three and nine months ended September 30, 2009 and 2008 should be read in conjunction with our condensed consolidated financial statements and the notes thereto included in this Form 10-Q and with the consolidated financial statements, notes and management s discussion and analysis included in our Annual Report on Form 10-K, as amended, for the year ended December 31, 2008.

Overview

We are an independent energy company engaged in the exploration, development and production of predominately natural gas properties located onshore in the United States. Our properties are primarily located in Louisiana, Texas, Arkansas and Oklahoma. We organize our operations into two principal regions: the Mid-Continent, which includes our Louisiana and Arkansas properties; and the Western, which includes our Texas and Oklahoma properties.

Historically, we have grown through acquisitions of proved reserves and undeveloped acreage, with a focus on properties within our core operating areas which we believe have significant development and exploration opportunities and where we can apply our technical experience and economies of scale to increase production and proved reserves while lowering lease operating costs. Beginning in 2008 and continuing in 2009, we have significantly expanded our leasehold position in natural gas shale plays, particularly in the Haynesville Shale play in northern Louisiana and East Texas and the Eagle Ford Shale play in South Texas. The vast majority of our acreage in these plays is currently undeveloped. Typically, the leases we own require that production in paying quantities be established on units under the lease within the lease term (generally three to five years) or the lease will expire, although a significant percentage of the leases in the Haynesville Shale play are currently held by production from other producing zones. Lease expirations will be an important factor determining our capital expenditures focus over the next several years.

Average daily production increased 64% in the first nine months of 2009 which averaged 469 million cubic feet of natural gas equivalent per day (Mmcfe/d) compared to average production of 286 Mmcfe/d during the first nine months of 2008. The increase in production compared to prior year is driven by our drilling successes in the Haynesville, Fayetteville and Eagle Ford Shales. Overall, we drilled or participated in the drilling of 467 gross wells (123.3 net wells) of which 466 gross (123.1 net) were successful resulting in a success rate of 99.8%.

Our financial results depend upon many factors, but are largely driven by the volume of our oil and natural gas production and the price that we receive for that production. Our production volumes will decline as reserves are depleted unless we expend capital in successful development and exploration activities or acquire properties with existing production. The amount we realize for our production depends predominantly upon commodity prices and our related commodity price hedging activities, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Accordingly, finding and developing oil and natural gas reserves at economical costs is critical to our long-term success.

We have focused our 2009 capital budget on the development of non-proved locations in our Haynesville, Fayetteville and Eagle Ford Shale plays. We believe these projects also offer the potential for high internal rates of return and reserve growth. We recently increased our capital budget for drilling, completions, seismic and workovers $100 million to $1.1 billion from $1.0 billion of our total $1.3 billion capital budget for 2009, exclusive of acquisitions. We plan to capitalize on additional drilling and seismic opportunities in the Haynesville and Eagle Ford Shales during the fourth quarter of 2009 with our increased budget. We expect to spend approximately $1.45 billion in 2010 on drilling and completion activities and an additional $250 million on infrastructure expansion. We also expect to spend an additional $100 million to $300 million on ongoing leasing activities. Our future drilling plans and infrastructure are subject to change based upon various factors, some of which are beyond our control, including drilling results, natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and

Table of Contents

pipeline transportation constraints and regulatory approvals. To the extent these factors lead to reductions in our plans and associated capital budgets in future periods, our financial position, cash flows and operating results could be adversely impacted.

One consequence of continued low natural gas prices is the possibility that we may be required to recognize additional non-cash impairment expense under the full cost method of accounting, which we use to account for our oil and natural gas exploration and development activities. We recorded full cost ceiling impairments before income taxes of approximately $1.7 billion and $1.0 billion at March 31, 2009 and December 31, 2008, respectively, primarily due to the decrease in the Henry Hub spot market price to $3.63 from $5.71 per million British thermal units (Mmbtu). No impairment was required at June 30, 2009 as the Henry Hub spot market price increased to $3.89. At September 30, 2009, our net book value of oil and gas properties exceeded our ceiling amount by approximately $880 million before tax, $546 million after tax based on the September 30, 2009 WTI posted price of $70.61 per barrel and the Henry Hub spot market price of $3.30 per Mmbtu. However, subsequent to September 30, 2009, the market price for Henry Hub gas and WTI oil increased significantly. As a consequence, prior to October 28, 2009, we elected to use prices on October 28, 2009, which were a WTI posted price of $77.20 per barrel and a Henry Hub spot market price of $4.51 per Mmbtu, adjusted for certain items as previously discussed. Utilizing these prices, our net book value of oil and natural gas properties at September 30, 2009, did not exceed the ceiling amount. As a result of the increase in the ceiling amount using the subsequent prices, we did not record a write-down of our oil and natural gas property costs. If natural gas prices decline, we may be required to take additional impairment charges in the future. If the September 30, 2009 WTI posted price and Henry Hub spot market price had been 10% lower while all other factors remained constant, our ceiling amount related to its net book value of oil and natural gas properties would have been reduced by approximately $206 million resulting in an additional ceiling test impairment of approximately $332 million, before income taxes had we not elected to use subsequent prices as of October 28, 2009. Changes in production rates, levels of reserves, future development costs, and other factors will determine our actual ceiling test calculation and impairment analyses in future periods.

On October 14, 2009, we entered into the Fourth Amended and Restated Senior Revolving Credit Agreement (the Fourth Amendment), which amends and restates our Third Amended and Restated Senior Revolving Credit Agreement dated September 10, 2008. The Fourth Amendment is a $2.0 billion facility with an initial borrowing base of $1.5 billion, $1.2 billion of which relates to our oil and natural gas properties and up to $300 million (currently limited as described below) of which relates to our midstream assets. The portion of the borrowing base which relates to our oil and natural gas properties will be redetermined on a semi-annual basis (with us and the Lenders each having the right to one annual interim unscheduled redetermination) and adjusted based on our oil and natural gas properties, reserves, other indebtedness and other relevant factors. The component of the borrowing base related to our midstream assets is limited to the lesser of $300 million or 3.5 times midstream EBITDA, and is determined quarterly. The initial available borrowing base aggregates $1.38 billion as the midstream component is currently $182 million. Amounts outstanding under the Fourth Amendment will bear interest at specified margins over LIBOR of 2.25% to 3.25% for Eurodollar loans or at specified margins over ABR of 0.75% to 1.75% for ABR loans. Such margins will fluctuate based on the utilization of the facility. Borrowings under the Fourth Amendment will be secured by first priority liens on substantially all of our assets, including pursuant to the terms of the Fourth Amended and Restated Guarantee and Collateral Agreement, all of the assets of, and equity interests in, our subsidiaries. Amounts drawn down on the facility will mature on July 1, 2013.

On October 30, 2009, we closed our previously announced sale of our Permian Basin properties to a privately-owned company for $376 million in cash, before customary closing adjustments, $37.6 million of which we received as a deposit during the third quarter. The effective date of the sale was July 1, 2009. Proceeds from the sale will be recorded as a reduction to the carrying value of our full cost pool. Upon closing of this sale, the oil and gas properties portion of the borrowing base under the Fourth Amendment was reduced by $200 million to $1 billion, resulting in a new aggregate borrowing base of $1.18 billion, including our midstream assets allocation. In conjunction with the closing of this sale, we deposited the remaining proceeds with a qualified intermediary to facilitate potential like-kind exchange transactions.

Capital Resources and Liquidity

Our primary sources of capital resources and liquidity are internally generated cash flows from operations, availability under our Senior Credit Agreement, and access to capital markets, to the extent available. The capital markets have been adversely impacted by the current financial crisis, concerns about overall deflation and its effect on commodity prices, the possibility of a deepening world recession that could extend for a long period into the future, and a generally higher cost of capital. Continued volatility in the capital markets could adversely impact our access to capital, which could reduce our ability to execute our development and acquisition plans, our ability to replace our reserves, and eventually, our production levels. We continue to monitor our liquidity and the capital markets. We continuously evaluate our development plans in light of a variety of factors, including, but not limited to, our cash flows, capital resources and drilling success. Our weighting in this regard and the effect this may have on our development of proved undeveloped reserves can, and likely will, change.

Our future capital resources and liquidity may depend, in part, on our success in developing the leasehold interests that we acquired. Cash is required to fund capital expenditures necessary to offset inherent declines in production and proven reserves, which is typical in the capital-intensive oil and natural gas industry. Future success in growing reserves and production will be highly dependent on our capital resources and our success in finding additional reserves. During 2008 and to date in 2009, we have raised $1.3 billion of debt (net of discounts and expenses) and $2.7 billion of equity capital (net of discounts and expenses). We expect to fund our future capital requirements through internally generated cash flows, borrowings under our Senior Credit Agreement, which gives us $950 million of borrowing capacity as of September 30, 2009 (updated to $1.18 billion after entering into the Fourth Amendment to the Credit Agreement and closing on the sale of our Permian Basin properties), pursuing asset monetization transactions when we consider market conditions favorable, and accessing the capital markets, if necessary. Our ability to utilize the full amount of our borrowing capacity is influenced by a variety of factors, including semi-annual redeterminations of our borrowing base, which may also be redetermined periodically at the discretion of the banks, and covenants under our Senior Credit Agreement and our senior unsecured debt indentures. Our senior indenture covenants limit the aggregate debt we may incur based upon the ratio of our adjusted consolidated earnings before interest, income taxes, depreciation, depletion and amortization and certain other non-cash charges (EBITDA), to our adjusted consolidated interest expense for the preceding four fiscal quarters and which may limit borrowings to a fixed percentage of our adjusted consolidated net tangible assets. Our borrowing base, EBITDA and consolidated net tangible assets are significantly influenced by, among other things, oil and natural gas prices. We strive to maintain financial flexibility while continuing our rapid growth and may access the capital markets to, among other things, maintain substantial borrowing capacity under our Senior Credit Agreement, facilitate drilling on our large undeveloped acreage position and permit us to selectively expand our acreage position and infrastructure projects. Our ability to complete future debt and equity offerings is limited by general market conditions.

Our long-term cash flows are subject to a number of variables including our level of production and commodity prices, as well as various economic conditions that have historically affected the oil and natural gas industry. If oil and natural gas prices remain at their current levels for a prolonged period of time or if natural gas prices continue to decline, our ability to fund our capital expenditures, reduce debt, meet our financial obligations and become profitable may be materially impacted.

Cash Flow

Our primary sources of cash for the nine months ended September 30, 2009 and 2008 were from operating and financing activities. Proceeds from the sale of common stock, the issuance of new senior debt and cash received from operations were offset by repayments of our Senior Credit Agreement and cash used in investing activities to fund our drilling program and acquisition activities. Operating cash flow fluctuations were substantially driven by changes in commodity prices and changes in our production volumes. Working capital was substantially influenced by these variables. Fluctuation in cash flow may result in an increase or decrease in our future capital expenditures. Prices for oil and natural gas have historically been subject to seasonal influences

Table of Contents

typically characterized by peak demand and higher prices in the winter heating season; however, the impact of other risks and uncertainties have influenced prices throughout recent years. See *Results of Operations* below for a review of the impact of prices and volumes on revenues.

Net (decrease) increase in cash is summarized as follows:

	Nine Months Ended September 30,	
	2009	2008
	(In thousands)	
Cash flows provided by operating activities	$ 474,750	$ 525,784
Cash flows used in investing activities	(1,483,517)	(2,497,027)
Cash flows provided by financing activities	1,003,576	1,973,310
Net (decrease) increase in cash	$ (5,191)	$ 2,067

Operating Activities. Net cash provided by operating activities for the nine months ended September 30, 2009 and 2008 were $474.8 million and $525.8 million, respectively.

Net cash provided by operating activities decreased in 2009 primarily due to the 63% decrease in our average realized natural gas equivalent price compared to the same period in the prior year partially offset by a 64% increase in our average daily production volumes due to our recent drilling success in the Haynesville, Fayetteville and Eagle Ford Shales. Our natural gas equivalent price decreased $6.62 per thousand cubic feet of natural gas equivalent (Mcfe) to $3.83 per Mcfe from $10.45 per Mcfe in the prior year. Production for the first nine months of 2009 averaged 469 Mmcfe/d compared to 286 Mmcfe/d during the same period of 2008. As a result of our 2009 capital budget program, we expect to continue to increase our production volumes throughout 2009 and 2010. However, we are unable to predict future production levels or future commodity prices with certainty, and, therefore, we cannot provide any assurance about future levels of net cash provided by operating activities.

Investing Activities. The primary driver of cash used in investing activities is capital spending, inclusive of acquisitions and net of dispositions. Cash used in investing activities was $1.5 billion and $2.5 billion for the nine months ended September 30, 2009 and 2008, respectively.

During the first nine months of 2009, we spent $1.2 billion on oil and natural gas capital expenditures. To date in 2009, we participated in the drilling of 467 gross wells (123.3 net wells). We spent an additional $225.3 million on other operating property and equipment expenditures, primarily to fund the completion of gathering systems in the Fayetteville Shale in Arkansas and the development of our gathering systems in the Haynesville Shale in Louisiana and the Eagle Ford Shale in Texas.

During the first nine months of 2009, we used excess funds to purchase a net $27.0 million of marketable securities. These marketable securities have been classified and accounted for as trading securities and were used primarily to fund a portion of our 2009 capital program.

On July 31, 2009, we purchased all outstanding membership interests in Kaiser Trading, LLC (Kaiser) for approximately $105 million. Kaiser s only assets were transportation-related contracts including a firm transportation contract, interruptible gas transportation service agreement, parking and lending services agreement, and a pooling services agreement. The initial firm transportation contract runs-through 2013 and at no additional cost, we have the contractual right to extend firm supply through 2019. The purchase price has been allocated to transportation contract which will be amortized on a straight line basis over the life of the extended agreement.

On September 18, 2009, we entered into a definitive agreement to sell our Permian Basin properties to a privately-owned company for $376 million in cash, before customary closing adjustments. In conjunction with

Table of Contents

the signing of the agreement, we received a $37.6 million deposit. The deal closed on October 30, 2009. The effective date of the sale was July 1, 2009. Proceeds from the sale will be recorded as a reduction to the carrying value of our full cost pool. In conjunction with the closing of this sale, we deposited the remaining proceeds with a qualified intermediary to facilitate potential like-kind exchange transactions.

During the first nine months of 2008, we spent $2.5 billion on oil and natural gas capital expenditures. Our acquisitions were partially funded by the remaining restricted cash that we had deposited with a qualified intermediary following the sale of our Gulf Coast properties to facilitate like-kind exchange transactions. Our program to acquire additional interests and acreage in our key areas, including the Fayetteville Shale in Arkansas; Elm Grove, and Terryville fields in Louisiana, the Haynesville Shale in Louisiana and the Eagle Ford Shale in Texas is ongoing on a selective basis. In addition, we participated in the drilling of 523 gross wells in 2008 (194.6 net wells). We spent an additional $75.5 million on other operating property and equipment during the first nine months of 2008 as well, primarily to fund the development of gathering systems in the Fayetteville Shale in Arkansas.

On November 30, 2007, we closed the sale of our Gulf Coast properties for $825 million, before customary closing adjustments, consisting of $700 million in cash and a $125 million note from the purchaser (the Note). The Note matured five years and ninety-one days from the closing date and bore interest at 12% per annum payable in kind at the purchaser s option. The economic effective date for the sale was July 1, 2007. Proceeds from the sale were recorded as a reduction to the carrying value of our full cost pool. In conjunction with the closing of this sale, we deposited $650 million with a qualified intermediary to facilitate potential like-kind exchange transactions. At December 31, 2007, we had $269.8 million remaining for use in future acquisitions, all of which was utilized for property acquisitions during the first quarter of 2008. On April 28, 2008, the purchaser redeemed the Note for $100 million.

During the first nine months of 2008, we used excess funds from our debt and equity offerings discussed below to purchase a net $252.7 million of marketable securities. These marketable securities were classified and accounted for as trading securities and were used primarily to fund our leasing and acquisition activities in the Haynesville Shale.

Financing Activities. Net cash flows provided by financing activities were $1.0 billion and $2.0 billion for the nine months ended September 30, 2009 and 2008, respectively. Cash flows provided by financing activities in the first nine months of 2009 were the result of the issuance of new senior notes and the sale of our common stock.

On August 11, 2009, we sold an aggregate of 25.0 million shares of our common stock in an underwritten public offering. The net proceeds from the sale were approximately $550 million, after deducting underwriting discounts and commissions and expenses.

On March 4, 2009, we sold an aggregate of 22.0 million shares of our common stock in an underwritten public offering. The net proceeds from this offering were approximately $376 million, after deducting underwriting discounts and commissions and expenses.

On January 27, 2009, we completed a private placement offering to eligible purchasers of an aggregate principal amount of $600 million 10.5% senior notes due August 1, 2014. The net proceeds from the sale of the 2014 Notes were approximately $535.4 million, after deducting the initial purchasers discounts and offering expenses and commissions.

On August 15, 2008, we sold an aggregate of 28.8 million shares of our common stock in an underwritten public offering. The net proceeds from the sale were approximately $734 million, after deducting underwriting discounts and commissions and expenses.

On June 19, 2008, we issued an additional $300 million aggregate principal amount of 2015 Notes in a private placement under the Securities Act of 1933, as amended. The net proceeds from the sale of the 2015 Notes were approximately $294 million, after deducting the initial purchaser s discount and offering expenses.

On May 13, 2008, we issued $500 million aggregate principal amount of the 2015 Notes in a private placement under the Securities Act of 1933, as amended. The net proceeds from the sale of the 2015 Notes were approximately $490 million, after deducting the initial purchasers discounts and offering expenses, including commissions.

On May 13, 2008, we sold an aggregate of 25.0 million shares of our common stock in an underwritten public offering. Pursuant to the underwriting agreement, we granted the underwriters a 30-day option to purchase up to an additional 3.75 million shares of common stock at the public offering price less underwriting discounts and commissions. The underwriters exercised in full their option to purchase additional shares of common stock which closed on May 23, 2008. The net proceeds from these sales were approximately $727 million, after deducting underwriting discounts and commissions and expenses.

On February 1, 2008, we sold an aggregate of 20.7 million shares of our common stock in an underwritten public offering. The net proceeds from the sale were approximately $297 million, after deducting underwriting discounts and commissions and expenses.

Capital financing and excess cash flow from operations are used to repay borrowings under our Senior Credit Agreement to the extent available. During the first nine months of 2009, we had net borrowings of $88.2 million after the application of a portion of the net proceeds from our issuance of the 2014 Notes and the sale of our common stock as discussed above. During the first nine months of 2008, we had net borrowings of $227.7 million.

Contractual Obligations

We have no material changes in our long-term commitments associated with our capital expenditure plans or operating agreements other than those described below. Our level of capital expenditures will vary in future periods depending on the success we experience in our acquisition, development and exploration activities, oil and natural gas price conditions and other related economic factors. We have no sources of liquidity or financing are provided by off-balance sheet arrangements or transactions with unconsolidated, limited-purpose entities.

As of September 30, 2009, we had drilling rigs under contract with a total commitment of $316.0 million over approximately four years. At December 31, 2008, we had drilling rigs under contract with a total commitment of $433.0 million over four years.

We have various other contractual commitments pertaining to exploration, development and production activities. We have work related commitments for, among other things, pipeline and well equipment, obtaining and processing seismic data and natural gas pipeline transportation. At September 30, 2009 and December 31, 2008, these work related commitments totaled $1.1 billion over 16 years and $507.8 million over 20 years, respectively.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operation are based upon the condensed consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. There have been no changes to our critical accounting policies from those described in our annual report on Form 10-K, as amended, for the year ended December 31, 2008.

Table of Contents

Results of Operations

Quarters ended September 30, 2009 and 2008

We reported a net loss of $40.2 million for the three months ended September 30, 2009 compared to net income of $305.4 million for the comparable period in 2008, resulting in a net change of $345.6 million. This change was primarily attributable to a $1.6 million net loss on derivative contracts for the three months ended September 30, 2009 versus a net gain of $388.2 million for the 2008 period. Also contributing to the change were lower revenues partially offset by lower income tax expense.

	Three Months Ended September 30,		
In thousands (except per unit and per Mcfe amounts)	**2009**	**2008**	**Change**
Net (loss) income available to common stockholders	$ (40,177)	$ 305,465	$ (345,642)
Operating revenues:			
Oil and natural gas	174,783	304,960	(130,177)
Marketing	63,155		63,155
Expenses:			
Marketing	66,586		66,586
Production:			
Lease operating	20,788	12,324	8,464
Workover and other	865	1,696	(831)
Taxes other than income	15,204	12,185	3,019
Gathering, transportation and other	22,743	12,489	10,254
General and administrative:			
General and administrative	20,405	15,607	4,798
Stock-based compensation	4,145	3,389	756
Depletion, depreciation and amortization:			
Depletion Full cost	87,324	98,293	(10,969)
Depreciation Other	3,998	787	3,211
Accretion expense	370	320	50
Net (loss) gain on derivative contracts	(1,568)	388,216	(389,784)
Interest expense and other	(58,981)	(40,018)	(18,963)
Income tax benefit (provision)	24,862	(190,603)	215,465
Production:			
Natural Gas Mmcf [(1)]	44,850	26,701	18,149
Crude Oil Mbbl	383	378	5
Natural Gas Equivalent Mmcfe	47,148	28,972	18,176
Average Daily Production Mmcfe	512	315	197
Average price per unit [(2)]:			
Gas price per Mcf [(1)]	$ 3.15	$ 9.68	$ (6.53)
Oil price per Bbl	64.64	117.14	(52.50)
Equivalent per Mcfe	3.52	10.45	(6.93)
Average cost per Mcfe:			
Production:			
Lease operating	0.44	0.43	0.01
Workover and other	0.02	0.06	(0.04)
Taxes other than income	0.32	0.42	(0.10)
Gathering, transportation and other	0.48	0.43	0.05
General and administrative:			
General and administrative	0.43	0.54	(0.11)
Stock-based compensation	0.09	0.12	(0.03)
Depletion	1.85	3.39	(1.54)

(1) Approximately 1% and 2% of natural gas production represents natural gas liquids (calculated with a 6:1 equivalent ratio) with an average price of $30.98 per barrel (Bbl) and $67.32 per Bbl for the three months ended September 30, 2009 and 2008, respectively.
(2) Average prices per unit exclude the impact of cash paid/received on settled contracts as we did not elect to apply hedge accounting.

For the three months ended September 30, 2009, oil and natural gas revenues decreased $130.2 million from the same period in 2008, to $174.8 million. The decrease was primarily due to the decrease of $6.93 per Mcfe in our realized average price to $3.52 per Mcfe from $10.45 per Mcfe in the prior year. This decrease per Mcfe led to a decrease in oil and natural gas revenues of $327 million. The effect of lower prices was partially offset by an increase in production of 18,176 Mmcfe, or 63% over the three months ended September 30, 2008, due to our recent drilling successes in resource-style plays in Louisiana, Arkansas and Texas. Increased production contributed to approximately $197 million in revenues for the three months ended September 30, 2009.

We had marketing revenues of $63.2 million and marketing expenses of $66.6 million for the three months ended September 30, 2009, resulting in a net loss of $3.4 million. During the fourth quarter of 2008, we began purchasing and selling third party natural gas produced from wells we operate. We report the revenues and expenses related to these marketing activities on a gross basis as part of our operating revenues and operating expenses. Marketing revenues are recorded at the time natural gas is physically delivered to third parties at a fixed or index price. Marketing expenses attributable to gas purchases are recorded as we take physical title to the natural gas and transport the purchased volumes to the point of sale. We recorded a net loss for the three months ended September 30, 2009 which is attributable to decreased margins associated with lower prices in the current period.

Lease operating expenses increased $8.5 million for the three months ended September 30, 2009 primarily due to our increased production in the current year. On a per unit basis, lease operating expenses increased $0.01 per Mcfe to $0.44 per Mcfe in 2009 from $0.43 per Mcfe in 2008.

Taxes other than income increased $3.0 million for the three months ended September 30, 2009 as compared to the same period in 2008. The largest components of taxes other than income are production and severance taxes which are generally assessed as either a fixed rate based on production or as a percentage of gross oil and natural gas sales. On a per unit basis, taxes other than income decreased $0.10 per Mcfe to $0.32 per Mcfe compared to $0.42 per Mcfe in 2008. This decrease on a per unit basis is primarily attributable to the decrease in oil and natural gas prices.

Gathering, transportation and other expense increased $10.3 million, or $0.05 per Mcfe, for the three months ended September 30, 2009 as compared to the same period in 2008. This increase was primarily due to the costs associated with the increases in production in the Haynesville Shale play as well as an increase in production in the Fayetteville Shale which has higher gathering, transportation and other costs.

General and administrative expense for the three months ended September 30, 2009 increased $4.8 million as compared to the same period in 2008. The increase was primarily attributable to the Company s $2.1 million increase in professional fees associated with increased legal and engineering services. General and administrative expense per Mcfe decreased $0.11 per Mcfe to $0.43 per Mcfe as production increases have more than offset our administrative expense increase.

Depletion for oil and natural gas properties is calculated using the unit of production method, which essentially depletes the capitalized costs associated with the evaluated properties plus future development costs based on the ratio of production volume for the current period to total remaining reserve volume for the evaluated properties. Depletion expense decreased $11.0 million for the three months ended September 30, 2009 from the same period in 2008, to $87.3 million. On a per unit basis, depletion expense decreased $1.54 per Mcfe to $1.85 per Mcfe. This decrease on a per unit basis is primarily due to the ceiling test impairment write-down of $1.7 billion we recorded at March 31, 2009 and $1.0 billion that we recorded at December 31, 2008.

Other depreciation expense increased $3.2 million to $4.0 million for the three months ended September 30, 2009 compared to $0.8 million in the prior year. This increase is primarily due to the construction of our gas gathering systems in the Fayetteville Shale in Arkansas and the Haynesville Shale in North Louisiana.

Table of Contents

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Consistent with the prior year, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the condensed consolidated statement of operations. At September 30, 2009, we had a $174.9 million derivative asset, $150.3 million of which was classified as current, and a $1.6 million derivative liability, $0.4 million of which was classified as current. The Company recorded a net derivative loss of $1.6 million ($115.2 million net unrealized loss and $113.6 million net gain for cash received on settled contracts) for the three months ended September 30, 2009 compared to a net derivative gain of $388.2 million ($423.9 million net unrealized gain and a $35.7 million loss for cash paid on settled contracts) in the same period in 2008.

Interest expense and other increased $19.0 million for the three months ended September 30, 2009 compared to the same period in 2008. Interest expense increased $15.6 million due to the issuance of new long-term debt ($600 million 10.5% senior notes due August 1, 2014 (the 2014 Notes)). In conjunction with the issuance of the 2014 Notes, the Company capitalized $13.2 million in debt issue costs resulting in a $0.6 million amortization expense of the debt issue costs in the current period. The amortization of the discount recorded in conjunction with the issuance of the 2014 Notes increased interest expense approximately $1.8 million during the three months ended September 30, 2009 as compared to the prior year. Interest income decreased $1.0 million for the three months ended September 30, 2009 due to a reduction of marketable securities as compared to the same period in the prior year.

Income tax expense for the three months ended September 30, 2009 decreased $215.5 million from the same period in 2008. The decrease in income tax expense from prior year was primarily due to our pre-tax loss of $65.0 million for the three months ended September 30, 2009 compared to our pre-tax gain of $496.1 million in 2008. The effective tax rates for the three months ended September 30, 2009 and 2008 were 38.2% and 38.4%, respectively.

Table of Contents

Nine Months ended September 30, 2009 and 2008

We reported a net loss of $1.1 billion for the nine months ended September 30, 2009 compared to net income of $157.1 million for the comparable period in 2008, resulting in a net change of $1.2 billion. This change was primarily attributable to our full cost ceiling impairment of $1.7 billion as well as lower revenues partially offset by a $196.4 million net gain on derivative contracts for the nine months ended September 30, 2009 versus a net loss of $32.1 million for the 2008 period and lower income tax expense.

	Nine Months Ended September 30,		
In thousands (except per unit and per Mcfe amounts)	**2009**	**2008**	**Change**
Net (loss) income available to common stockholders	$ (1,061,934)	$ 157,087	$ (1,219,021)
Operating revenues:			
Oil and natural gas	512,528	824,531	(312,003)
Marketing	216,165		216,165
Expenses:			
Marketing	211,722		211,722
Production:			
Lease operating	55,903	37,621	18,282
Workover and other	1,793	3,482	(1,689)
Taxes other than income	39,921	37,185	2,736
Gathering, transportation and other	65,870	32,956	32,914
General and administrative:			
General and administrative	57,419	43,296	14,123
Stock-based compensation	10,762	9,068	1,694
Depletion, depreciation and amortization:			
Depletion Full cost	279,072	265,963	13,109
Depreciation Other	10,241	2,346	7,895
Accretion expense	1,070	912	158
Full cost ceiling impairment	1,732,486		1,732,486
Net gain (loss) on derivative contracts	196,360	(32,130)	228,490
Interest expense and other	(170,929)	(102,709)	(68,220)
Income tax benefit (provision)	650,201	(99,776)	749,977
Production:			
Natural gas Mmcf[1]	120,926	71,637	49,289
Crude oil MBbl	1,204	1,128	76
Natural gas equivalent Mmcfe	128,150	78,405	49,745
Daily production Mmcfe	469	286	183
Average price per unit [2]:			
Natural gas price Mcf[1]	$ 3.54	$ 9.71	$ (6.17)
Crude oil price Bbl	51.82	110.17	(58.35)
Equivalent Mcfe	3.83	10.45	(6.62)
Average cost per Mcfe:			
Production:			
Lease operating	0.44	0.48	(0.04)
Workover and other	0.01	0.04	(0.03)
Taxes other than income	0.31	0.47	(0.16)
Gathering, transportation and other	0.51	0.42	0.09
General and administrative:			
General and administrative	0.45	0.55	(0.10)
Stock-based compensation	0.08	0.12	(0.04)
Depletion	2.18	3.39	(1.21)

(1)

Approximately 1% and 2% of natural gas production represents natural gas liquids (calculated with a 6:1 equivalent ratio) with an average price of $27.04 per Bbl and $64.70 per Bbl for the nine months ended September 30, 2009 and 2008, respectively.

(2) Average price per unit exclude the impact of cash paid/received on settled contracts as we did not elect to apply hedge accounting.

For the nine months ended September 30, 2009, oil and natural gas revenues decreased $312.0 million from the same period in 2008, to $512.5 million. The decrease was primarily due to the decrease of $6.62 per Mcfe in our realized average price to $3.83 per Mcfe from $10.45 per Mcfe in the prior year. This decrease per Mcfe led to a decrease in oil and natural gas revenues of $848 million. The effect of lower prices was partially offset by an increase in production of 49,745 Mmcfe or 63% over the nine months ended September 30, 2008 due to our recent drilling successes in resource-style plays in Louisiana, Arkansas and Texas. Increased production contributed approximately $536 million in revenues for the nine months ended September 30, 2009.

We had marketing revenues of $216.2 million and marketing expenses of $211.7 million for the nine months ended September 30, 2009, resulting in a net margin of $4.5 million. During the fourth quarter of 2008, we began purchasing and selling third party natural gas produced from wells we operate. We report the revenues and expenses related to these marketing activities on a gross basis as part of our operating revenues and operating expenses. Marketing revenues are recorded at the time natural gas is physically delivered to third parties at a fixed or index price. Marketing expenses attributable to gas purchases are recorded as we take physical title to the natural gas and transport the purchased volumes to the point of sale.

Lease operating expenses increased $18.3 million for the nine months ended September 30, 2009 as compared to the same period in 2008. This increase was primarily due to our increased production in the current year. On a per unit basis, lease operating expenses decreased $0.04 per Mcfe to $0.44 per Mcfe in 2009 from $0.48 per Mcfe in 2008. This decrease on a per unit basis is primarily due to the increase in production from our resource-style plays over the first nine months of 2009 as compared to the prior year which typically have a lower per unit operating cost.

Taxes other than income increased $2.7 million for the nine months ended September 30, 2009 as compared to the same period in 2008. The largest components of taxes other than income are production and severance taxes which are generally assessed as either a fixed rate based on production or as a percentage of gross oil and natural gas sales. On a per unit basis, taxes other than income decreased $0.16 per Mcfe to $0.31 per Mcfe compared to $0.47 per Mcfe in 2008. This decrease on a per unit basis is primarily attributable to the decrease in oil and natural gas prices.

Gathering, transportation and other expense increased $32.9 million, or $0.09 per Mcfe, for the nine months ended September 30, 2009 as compared to the same period in 2008. This increase was primarily due to costs associated with increases in production in the Haynesville Shale play as well as an increase in production in the Fayetteville Shale which has higher gathering, transportation and other costs.

General and administrative expense for the nine months ended September 30, 2009 increased $14.1 million as compared to the same period in 2008. This increase was primarily attributable to a $7.3 million increase in employee expense, including salary, medical and incentives, associated with the continued building of our work force associated with the recent growth in our Company. Professional fees increased $4.9 million due to increased legal, engineering and contract services as compared to the same period in 2008. General and administrative expense per Mcfe decreased $0.10 per Mcfe to $0.45 per Mcfe in 2009 as production increases have more than offset our administrative expense increases.

Depletion for oil and natural gas properties is calculated using the unit of production method, which essentially depletes the capitalized costs associated with the evaluated properties plus future development costs based on the ratio of production volume for the current period to total remaining reserve volume for the evaluated properties. Depletion expense increased $13.1 million for the nine months ended September 30, 2009 from the same period in 2008, to $279.1 million. This increase was primarily attributable to the 49,745 Mcfe increase in production. On a per unit basis, depletion expense decreased $1.21 per Mcfe to $2.18 per Mcfe. This decrease on a per unit basis is primarily due to the ceiling test impairment write-down of $1.7 billion we recorded at March 31, 2009 and $1.0 billion that we recorded at December 31, 2008.

Table of Contents

Other depreciation expense increased $7.9 million to $10.2 million for the nine months ended September 30, 2009. This increase is primarily due to the construction of our gas gathering systems in the Fayetteville Shale in Arkansas and the Haynesville Shale in North Louisiana.

We recorded a full cost ceiling impairment of approximately $1.7 billion for the nine months ended September 30, 2009. A variety of economic and other factors have recently caused significant declines in oil and natural gas prices. We utilize the full cost method of accounting to account for our oil and natural gas exploration and development activities. Under this method of accounting, we are required on a quarterly basis to determine whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the ceiling , based upon the expected after tax present value (discounted at 10%) of the future net cash flows from our proved reserves, calculated using prevailing oil and natural gas prices on the last day of the period, or a subsequent higher price under certain circumstances. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non-cash impairment expense. At March 31, 2009, our ceiling was calculated using prices of $49.66 per barrel of oil and $3.63 per Mmbtu. Accordingly, at March 31, 2009, our costs exceeded our ceiling limitation by approximately $1.7 billion, resulting in an approximate $1.7 billion write-down of our oil and natural gas properties. At September 30, 2009, our net book value of oil and gas properties exceeded our ceiling amount by approximately $880 million before tax, $546 million after tax. However, subsequent to September 30, 2009, the market price for Henry Hub gas and WTI oil increased significantly. As a consequence, prior to October 28, 2009, we elected to use prices on October 28, 2009, which were a WTI posted price of $77.20 per barrel and a Henry Hub spot market price of $4.51 per Mmbtu, adjusted for certain items as previously discussed. Utilizing these prices, our net book value of oil and natural gas properties at September 30, 2009, would not have exceeded the ceiling amount. As a result of the increase in the ceiling amount using the subsequent prices, we did not record a write-down of our oil and natural gas property costs.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Consistent with the prior year, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the condensed consolidated statement of operations. At September 30, 2009, we had a $174.9 million derivative asset, $150.3 million of which was classified as current, and a $1.6 million derivative liability, $0.4 million of which was classified as current. The Company recorded a net derivative gain of $196.4 million ($96.7 million net unrealized loss and $293.1 million gain for cash received on settled contracts) for the nine months ended September 30, 2009 compared to a net derivative loss of $32.1 million ($57.3 million net unrealized gain and a $89.4 million loss for cash paid on settled contracts) in the same period in 2008.

Interest expense and other increased $68.2 million for the nine months ended September 30, 2009 compared to the same period in 2008. Interest expense increased $68.5 million due to the issuance of new long-term debt ($25.8 million for the $800 million 7.875% senior notes due 2015 and $42.7 million for the $600 million 10.5% senior notes due August 1, 2014 (the 2014 Notes)). In conjunction with the new notes, amortization of debt issue costs and amortization of the discount recorded on the 2014 Notes accounted for $7.7 million of the increase in interest expense. This was partially offset by a $9.3 million reduction in interest expense associated with the decrease in our outstanding balance on our Senior Credit Agreement compared to the prior year. In the nine months ended September 30, 2009, interest expense included a $3.3 million credit for the capitalization of the interest associated with the ongoing construction of our gas gathering systems. The remaining insignificant difference relates to a number of factors including a decrease in interest income from proceeds on marketable securities.

We had an income tax benefit of $650.2 million for the nine months ended September 30, 2009 compared to income tax expense of $99.8 million in the prior year. The change of $750.0 million was primarily due to our pre-tax loss of $1.7 billion for the nine months ended September 30, 2009 compared to our pre-tax income of $256.9 million in 2008. The effective tax rates for the nine months ended September 30, 2009 and 2008 were 38.0% and 38.8%, respectively.

Table of Contents

Recently Issued Accounting Pronouncements

We discuss recently adopted and issued accounting standards in Item 1. *Condensed Consolidated Financial Statements* Note 1, *Financial Statement Presentation*.

Item 3. Quantitative and Qualitative Disclosures About Market Risk
Derivative Instruments and Hedging Activity

We are exposed to various risks including energy commodity price risk. When oil and natural gas prices decline significantly our ability to finance our capital budget and operations could be adversely impacted. We expect energy prices to remain volatile and unpredictable, therefore we have designed a risk management policy which provides for the use of derivative instruments to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the affect it could have on our operations. The types of derivative instruments that we typically utilize include collars, swaps, basis swaps and puts. The total volumes which we hedge through the use of our derivative instruments varies from period to period, however, generally our objective is to hedge approximately 65% to 70% of our current and anticipated production for the next 12 to 36 months. Our hedge policies and objectives may change significantly as commodities prices or price futures change.

We are exposed to market risk on our open derivative contracts of non-performance by our counterparties. We do not expect such non-performance because our contracts are with major financial institutions with investment grade credit ratings. Each of the counterparties to our derivative contracts is a lender in our Senior Credit Agreement. We did not post collateral under any of these contracts as they are secured under the Senior Credit Agreement. Please refer to Item 1. *Condensed Consolidated Financial Statements* Note 8, *Derivatives* for additional information.

We have also been exposed to interest rate risk on our variable interest rate debt. If interest rates increase, our interest expense would increase and our available cash flow would decrease. Periodically, we may look to utilize interest rate swaps to reduce the exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. At September 30, 2009, we did not have any open positions that converted our variable interest rate debt to fixed interest rates. We continue to monitor our risk exposure as we incur future indebtedness at variable interest rates and will look to continue our risk management policy as situations present themselves.

We accounts for our derivative activities under the provisions of ASC 815, *Derivatives and Hedging*. ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. See Item 1. *Condensed Consolidated Financial Statements* Note 8, *Derivatives* for more details.

Interest Sensitivity

Historically, we have been exposed to interest rate risk exposure primarily from fluctuations in short-term rates, which are LIBOR and ABR based. These fluctuations can cause reductions of earnings or cash flows due to increases in the interest rates that we have historically paid on these obligations. At September 30, 2009, total debt excluding related discounts and premiums was $2.4 billion which bears interest at a weighted average fixed interest rate of 8.8% per year. At September 30, 2009, we did not have any amounts drawn under our Senior Credit Agreement. We do not currently have any long-term debt that bears interest at floating or market interest rates. If we incur future indebtedness which bears interest at variable rates, fluctuations in market interest rates could cause our annual interest costs to fluctuate.

Table of Contents

Item 4. Controls and Procedures

In accordance with Exchange Act Rule 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2009 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There were no changes in the Company s internal control over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

From time to time, we may be a plaintiff or defendant in a pending or threatened legal proceeding arising in the normal course of our business. While the outcome and impact of currently pending legal proceedings cannot be predicted with certainty, our management and legal counsel believe that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on our condensed consolidated operating results, financial position or cash flows.

Under rules promulgated by the SEC, administrative or judicial proceedings arising under any Federal, State or local provisions that have been enacted or adopted regulating the discharge of materials into the environment or primarily for the purpose of protecting the environment are disclosed if the governmental authority is a party to such proceeding and the proceeding involves potential monetary sanctions of $100,000 or more. We are not party to any such proceedings, except as described below.

We are involved in natural gas exploration in the Fayetteville Shale play in North Central Arkansas. Our subsidiary, Hawk Field Services, LLC, has been constructing a pipeline to transport natural gas from wellheads. Hawk Field Services activities are being performed pursuant to required environmental permits issued by the Arkansas Department of Environmental Quality (ADEQ) and the United States Army Corps of Engineers (Corps). The terrain in and around the Fayetteville Shale play is very hilly and requires that the pipeline cross numerous small creeks and streams. Some of these streams ultimately drain into larger waters that are home to an endangered freshwater mussel known as the Speckled Pocketbook (*Lampsilis streckeri*).

In 2008, the United States Fish and Wildlife Service (USFWS) opened an investigation into the activities of Hawk Field Services and the Company in the Fayetteville Shale play. The investigation focused on the pipeline stream crossings and potential impacts on the Speckled Pocketbook. On April 22, 2009, we received a letter from the United States Attorney s Office for the Eastern District of Arkansas and the Environmental Crimes Section of the United States Department of Justice notifying us that we are under criminal investigation for alleged violations of the Federal Clean Water Act and the Federal Endangered Species Act with respect to the endangered Speckled Pocketbook. The full details of the investigation are not yet known. In addition, the ADEQ has issued inspection letters that note alleged violations for failure to properly install or maintain sediment control structures in connection with construction of the pipeline. At this time, we are not able to estimate our potential exposure related to these matters. We potentially could, however, be indicted for felony violations of the Endangered Species Act and Clean Water Act, plead guilty to the violations, or enter into an alternative agreement to resolve the allegations. We could be subject to criminal and/or civil sanctions, including requirements to pay a monetary penalty and undertake certain injunctive measures, such as implementing additional construction management practices to control the discharge of sediment from our construction activities or other restrictions on our operations. The implementation of these management practices or other injunctive measures could delay or increase the cost of construction.

On July 27, 2009, we received a Cease and Desist Order from the Corps alleging violations of the Federal Clean Water Act for unauthorized land clearing and discharges of dredged or fill material into wetlands associated with the development of three gas wells in Bossier, Caddo, Red River Parishes in Louisiana. We are investigating these allegations and are unable at this time to estimate our potential exposure related to this matter. We could be required to pay a monetary penalty, undertake certain restoration or mitigation activities, and cease development of the subject wells until the matter is resolved. If we are required to cease development of these wells, it would delay and impact our ability to produce and sell gas from these wells.

Item 1A. Risk Factors

There have been no changes to the risk factors described in the Company s annual report on Form 10-K, as amended, for the year ended December 31, 2008, other than those described below.

Estimates of proved oil and natural gas reserves are imprecise and any material inaccuracies in these reserve estimates will materially affect the quantities and the value of our reserves.

Our report on Form 10-K for the year ended December 31, 2008, as amended, contains estimates of our proved oil and natural gas reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from those estimated. Any significant variance could materially affect the estimated quantities and the value of our reserves. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

At December 31, 2008, approximately 44% of our estimated reserves were classified as proved undeveloped. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of these oil and natural gas reserves and the costs associated with development of these reserves in accordance with SEC regulations, actual capital expenditures will likely vary from estimated capital expenditures, development may not occur as scheduled and actual results may not be as estimated.

We may incur substantial costs to comply with, and demand for our products may be reduced by, climate change legislation and regulatory initiatives.

Recent studies have indicated that emissions of certain gases may be contributing to warming of the Earth s atmosphere. In response to these studies, many nations have agreed to limit emissions of greenhouse gases , or GHGs , pursuant to the United Nations Framework Convention on Climate Change and the Kyoto Protocol. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas, and refined petroleum products, are considered greenhouse gases regulated by the Kyoto Protocol. Although

Table of Contents

the United States is not participating in the Kyoto Protocol, several states have adopted legislation and regulations to reduce emissions of greenhouse gases. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect our operations and demand for our products. Additionally, the United States Supreme Court has ruled, in Massachusetts, et al. v. EPA, that the United States Environmental Protection Agency (EPA) abused its discretion under the Clean Air Act by refusing to regulate carbon dioxide emissions from mobile sources. As a result of the Supreme Court decision and the change in presidential administrations, the EPA recently issued a proposed finding and announced a rule to be proposed that would result in federal greenhouse gas regulations and emissions limits under the Clean Air Act, even without Congressional action. The EPA s proposed finding and announced greenhouse gas regulation would result in federal regulation of carbon dioxide emissions and other GHGs, and may affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry. On September 22, 2009, the EPA also issued GHG monitoring and reporting rule that requires certain parties, including the oil and gas industry, to monitor and report their GHG emissions, including methane and carbon dioxide to EPA. The emissions will be published on a register to be made available on the Internet. These regulations may apply to the company s operations.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

President Obama s Proposed Fiscal Year 2010 Budget includes proposed legislation that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key United States federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in United States federal income tax laws could negatively affect our financial condition and results of operations.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas we produce.

On June 26, 2009, the United States House of Representatives approved adoption of the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey cap-and-trade legislation or ACESA. On September 30, 2009, Senators Barbara Boxer and John Kerry filed a bill entitled the Clean Energy Jobs and American Power Act of 2009 that is similar in many ways to ACESA. One purpose of these bills is to control and reduce emissions of greenhouse gases, or GHGs, in the United States. These bills would establish an economy-wide cap on emissions of GHGs in the United States and would require an overall reduction in GHG emissions of 17% to 20% (from 2005 levels) by 2020, and by over 80% by 2050. Under these bills, most sources of GHG emissions would be required to obtain GHG emission allowances corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The net effect of these bills will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas.

President Obama has indicated that he supports the adoption of legislation such as the two bills discussed above. In addition, recent federal appeals court rulings have permitted plaintiffs to continue lawsuits seeking, in one case, to impose GHG reductions on several utility defendants, and, in another case, permitting plaintiffs to seek damages from certain GHG emitters on the basis that their emissions contributed to the intensity of Hurricane Katrina, thereby increasing their damages. These cases and subsequent similar actions may increase exposure to litigation and costs for companies that emit GHG s, including methane, as well as increase pressure on Congress to enact climate change legislation.

Table of Contents

In a recent Texas District Court case, a citizens group has sued the Texas Commission on Environmental Quality (TCEQ) asserting that the agency was required to regulate carbon dioxide emissions from parties applying for permits under the Texas Clean Air Act. This lawsuit could result in additional regulations, if the Texas courts require the TCEQ to regulate carbon dioxide and other GHGs, such as methane.

The potential regulation, legislation and litigation discussed above could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business or demand for the oil and natural gas we produce.

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.

Congress is currently considering legislation to impose restrictions on certain transactions involving derivatives, which could affect the use of derivatives in hedging transactions. ACESA contains provisions that would prohibit private energy commodity derivative and hedging transactions. ACESA would expand the power of the Commodity Futures Trading Commission, or CFTC, to regulate derivative transactions related to energy commodities, including oil and natural gas, and to mandate clearance of such derivative contracts through registered derivative clearing organizations. Under ACESA, the CFTC s expanded authority over energy derivatives would terminate upon the adoption of general legislation covering derivative regulatory reform. The Chairman of the CFTC has announced that the CFTC intends to conduct hearings to determine whether to set limits on trading and positions in commodities with finite supply, particularly energy commodities, such as crude oil, natural gas and other energy products. The CFTC also is evaluating whether position limits should be applied consistently across all markets and participants. In addition, the Treasury Department recently has indicated that it intends to propose legislation to subject all OTC derivative dealers and all other major OTC derivative market participants to substantial supervision and regulation, including by imposing conservative capital and margin requirements and strong business conduct standards. Derivative contracts that are not cleared through central clearinghouses and exchanges may be subject to substantially higher capital and margin requirements. Although it is not possible at this time to predict whether or when Congress may act on derivatives legislation or how any climate change bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Congress is currently considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of bills currently pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, these bills, if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Table of Contents

Delay or increased difficulties in the construction of gathering lines and well sites in our areas of operations or in the receipt of environmental regulatory approvals could adversely affect our business.

Natural gas exploration and production and related construction activities in some of the areas in which we operate, including construction of well sites, access roads, and gathering lines, have come under increased environmental regulatory scrutiny. Obtaining regulatory approvals or complying with conditions of approvals, such as construction best management practices, could become more difficult and costly. Delays or difficulties in obtaining regulatory approvals or complying with conditions of approvals could delay or otherwise affect our ability to produce gas from these areas.

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

The following table sets forth certain information with respect to the surrender of our common stock by employees in exchange for the payment of certain tax obligations during the three months ended September 30, 2009.

	Total Number of Shares Purchased[(1)]	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
July 2009	5,684	$ 19.64		
August 2009	34,476	$ 23.04		
September 2009	1,158	$ 21.77		

(1) All of the shares were surrendered by employees in exchange for the payment of tax withholding upon the vesting of restricted stock awards. The acquisition of the surrendered shares was not part of a publicly announced program to repurchase shares of our common stock, nor were they considered as or accounted for as Treasury shares.

Item 3. Defaults Upon Senior Securities

None.

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

None.

Item 5. Other Information

None.

Table of Contents

Item 6. Exhibits

The following documents are included as exhibits to this Form 10-Q. Those exhibits incorporated by reference are so indicated by the information supplied with respect thereto. Those exhibits which are not incorporated by reference are attached hereto.

Exhibit No	Description
2.1	Agreement of Sale and Purchase, dated September 18, 2009, between Petrohawk Properties, LP and KCS Resources, LLC, together as seller, and Merit Management Partners I, L.P., as purchaser (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed on September 23, 2009).
3.1	Certificate of Incorporation for Petrohawk Energy Corporation (Incorporated by reference to Exhibit 3.1 to our Form S-8 (File No. 333-117733) filed on July 29, 2004).
3.2	Certificate of Amendment to Certificate of Incorporation for Petrohawk Energy Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on November 24, 2004).
3.3	Certificate of Amendment of Certificate of Incorporation of Petrohawk Energy Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on August 3, 2005).
3.4	Amended and Restated Bylaws of Petrohawk Energy Corporation effective as of July 12, 2006 (Incorporated by reference to Exhibit 3.2 of our Current Report on Form 8-K filed on July 17, 2006).
3.5	Certificate of Amendment to Certificate of Incorporation of Petrohawk Energy Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on July 17, 2006).
3.6	Certificate of Designations of Series A Junior Preferred Stock of Petrohawk Energy Corporation effective as of October 15, 2008 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on October 16, 2008).
3.7	Certificate of Amendment to Certificate of Incorporation of Petrohawk Energy Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on June 23, 2009).
4.1	Indenture dated as of April 8, 2004, among Mission Resources Corporation, the Guarantors named therein and The Bank of New York, as Trustee, relating to Petrohawk Energy Corporation s 9/8% Senior Notes due 2011 (Incorporated by reference to Exhibit 4.1 to Mission Resources Corporation s Current Report on Form 8-K/A filed on April 15, 2004).
4.2	First Supplemental Indenture dated as of July 28, 2005, among Petrohawk Energy Corporation, the successor by way of merger to Mission Resources Corporation, the parties named therein as Existing Subsidiary Guarantors, the parties named therein as Additional Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as successor trustee to The Bank of New York (Incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed on August 3, 2005).
4.3	Second Supplemental Indenture dated as of July 12, 2006, among Petrohawk Energy Corporation, as successor by merger to Mission Resources Corporation, the parties named therein as subsidiary guarantors, and The Bank of New York Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed on July 17, 2006).
4.4	Indenture dated April 1, 2004 among KCS Energy, Inc., U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein, relating to KCS Energy, Inc. s 7/8% senior notes due 2012 (Incorporated by reference to Exhibit 4.1 to KCS Energy, Inc. s Quarterly Report on Form 10-Q filed on May 10, 2004).

Exhibit No	**Description**
4.5	First Supplemental Indenture, dated as of April 8, 2005, to Indenture dated as of April 1, 2004, among KCS Energy, Inc., certain of its subsidiaries and U.S. Bank National Association (Incorporated by reference to Exhibit 4.1 of KCS Energy, Inc. s Form 8-K filed on April 11, 2005).