PETROHAWK ENERGY CORP
Form 10-Q
May 05, 2010
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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 March 31, 2010

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 incorporation or organization)	**(I.R.S. Employer 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 April 28, 2010 the Registrant had 302,148,754 shares of Common Stock, $.001 par value, outstanding.

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Special note regarding forward-looking statements

This Quarterly 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, i achievable, anticipate, will, continue, potential, should, could and similar terms and phrases. Although we believe that the expectations in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. 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 Annual Report on Form 10-K for the year ended December 31, 2009, which describe factors that could cause our actual results to differ from those anticipated 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 Louisiana, Arkansas and Texas, including our resource-style plays such as the Haynesville, Bossier, Fayetteville and Eagle Ford Shales;
- volatility in commodity prices for oil and natural gas;
- 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 potential for production decline rates for our wells to be 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, necessary to execute 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 economic recession and credit crisis in the United States will be prolonged, which could adversely affect the demand for oil and natural gas and make it difficult to access financial markets;

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.

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Finally, our future results will depend upon various other risks and uncertainties, including, but not limited to, those detailed in the section entitled Risk Factors included in this report and in our Annual Report on Form 10-K for the year ended December 31, 2009. 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.

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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 March 31,	
	2010	**2009**
Operating revenues:		
Oil and natural gas	$ 300,591	$ 167,554
Marketing	130,119	89,693
Midstream	9,606	6,208
Total operating revenues	440,316	263,455
Operating expenses:		
Marketing	136,622	84,844
Production:		
Lease operating	17,395	16,411
Workover and other	2,378	723
Taxes other than income	12,843	12,180
Gathering, transportation and other	29,380	20,494
General and administrative	32,208	19,639
Depletion, depreciation and amortization	106,074	114,256
Full cost ceiling impairment		1,732,486
Total operating expenses	336,900	2,001,033
Income (loss) from operations	103,416	(1,737,578)
Other income (expenses):		
Net gain on derivative contracts	214,703	181,922
Interest expense and other	(62,846)	(56,068)
Total other income (expenses)	151,857	125,854
Income (loss) before income taxes	255,273	(1,611,724)
Income tax (provision) benefit	(99,138)	611,971
Net income (loss)	$ 156,135	$ (999,753)
Net income (loss) per share:		
Basic	$ 0.52	$ (3.87)
Diluted	$ 0.52	$ (3.87)
Weighted average shares outstanding:		
Basic	300,157	258,055

Diluted	302,668	258,055

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

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PETROHAWK ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)

(In thousands, except share and per share amounts)

	March 31, 2010	December 31, 2009
Current assets:		
Cash	$ 1,393	$ 1,511
Accounts receivable	259,632	239,264
Receivables from derivative contracts	248,511	112,441
Prepaids and other	40,886	32,434
Total current assets	550,422	385,650
Oil and natural gas properties (full cost method):		
Evaluated	6,464,093	5,984,765
Unevaluated	2,705,482	2,512,453
Gross oil and natural gas properties	9,169,575	8,497,218
Less accumulated depletion	(4,429,747)	(4,329,485)
Net oil and natural gas properties	4,739,828	4,167,733
Other operating property and equipment:		
Gas gathering systems and equipment	218,289	497,551
Other operating assets	30,913	26,002
Gross other operating property and equipment	249,202	523,553
Less accumulated depreciation	(22,021)	(26,287)
Net other operating property and equipment	227,181	497,266
Other noncurrent assets:		
Goodwill	932,802	932,802
Other intangible assets	97,632	100,395
Debt issuance costs, net of amortization	42,132	44,871
Deferred income taxes	197,540	245,413
Receivables from derivative contracts	114,961	50,421
Restricted cash	36,176	213,704
Assets held for sale	387,251	
Other	3,065	23,816
Total assets	$ 7,328,990	$ 6,662,071
Current liabilities:		
Accounts payable and accrued liabilities	$ 708,477	$ 633,171
Deferred income taxes	65,493	14,484
Liabilities from derivative contracts	2,346	1,807
Long-term debt	42,723	49,370
Total current liabilities	819,039	698,832

Long-term debt	2,977,425	2,592,544
Other noncurrent liabilities:		
Liabilities from derivative contracts	579	
Asset retirement obligations	45,894	44,000
Other	3,247	3,023
Commitments and contingencies (Note 7)		
Stockholders equity:		
Common stock: 500,000,000 shares of $.001 par value authorized;		
302,139,825 and 301,194,695 shares issued and outstanding at March 31, 2010 and December 31, 2009, respectively	302	301
Additional paid-in capital	4,602,662	4,599,664
Accumulated deficit	(1,120,158)	(1,276,293)
Total stockholders equity	3,482,806	3,323,672
Total liabilities and stockholders equity	$ 7,328,990	$ 6,662,071

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

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PETROHAWK ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)

(In thousands)

	Three Months Ended March 31, 2010	2009
Cash flows from operating activities:		
Net income (loss)	$ 156,135	$ (999,753)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation and amortization	106,074	114,256
Full cost ceiling impairment		1,732,486
Income tax provision (benefit)	99,138	(611,971)
Stock-based compensation	4,089	2,810
Net unrealized gain on derivative contracts	(190,095)	(100,765)
Other operating	8,349	4,921
Change in operating assets and operating liabilities:		
Accounts receivable	(20,368)	78,800
Prepaids and other	(8,452)	(17,712)
Accounts payable and accrued liabilities	(21,673)	(46,603)
Other	20,975	(111)
Net cash provided by operating activities	154,172	156,358
Cash flows from investing activities:		
Oil and natural gas capital expenditures	(638,999)	(390,674)
Proceeds received from sale of oil and natural gas properties	16,676	
Marketable securities purchased	(226,000)	(604,045)
Marketable securities redeemed	226,000	444,016
Decrease in restricted cash	177,528	
Other operating property and equipment expenditures	(72,591)	(69,709)
Net cash used in investing activities	(517,386)	(620,412)
Cash flows from financing activities:		
Proceeds from exercise of stock options and warrants	503	657
Proceeds from issuance of common stock		385,000
Offering costs		(8,988)
Proceeds from borrowings	571,000	619,674
Repayment of borrowings	(204,968)	(524,324)
Debt issuance costs		(13,154)
Other	(3,439)	
Net cash provided by financing activities	363,096	458,865
Net decrease in cash	(118)	(5,189)
Cash at beginning of period	1,511	6,883
Cash at end of period	$ 1,393	$ 1,694

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

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PETROHAWK ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1. FINANCIAL STATEMENT PRESENTATION

Petrohawk Energy Corporation (Petrohawk or the Company) is an independent oil and natural gas company engaged in the exploration, development and production of predominately natural gas properties located onshore in the United States. The Company operates in two segments, oil and natural gas production and midstream operations. The consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries. All intercompany accounts and transactions have been eliminated. 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 the results of operations for, the periods presented. During interim periods, Petrohawk follows the accounting policies disclosed in its 2009 Annual Report on Form 10-K, filed with the United States Securities and Exchange Commission (SEC). Please refer to the footnotes in the 2009 Annual Report on Form 10-K when reviewing interim financial results.

Use of Estimates

The preparation of the Company s condensed consolidated financial statements in conformity with accounting principles generally accepted in the United States requires the Company s management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the condensed consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. The Company bases its estimates and judgments on historical experience and on various other assumptions and information that are believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects cannot be perceived with certainty and, accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as the Company s operating environment changes. Actual results may differ from the estimates and assumptions used in the preparation of the Company s condensed consolidated financial statements.

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. The Company has evaluated events or transactions through the date of issuance of these condensed consolidated financial statements.

Marketing Revenue and Expense

A subsidiary of the Company purchases and sells 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.

Midstream Revenues

Revenues from the Company s midstream operations are derived from providing gathering and treating services for the Company and other owners in wells we operate. Revenues are recognized when services are provided at a fixed or determinable price, collectability is reasonably assured and evidenced by a contract. The midstream segment does not take title to the natural gas for which services are provided, with the exception of imbalances that are monthly cash settled. The imbalances are recorded using published natural gas market prices.

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Risk Management Activities

The Company follows Accounting Standards Codification (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 gain on derivative contracts* on the condensed consolidated statements of operations.

Gas Gathering Systems and Equipment and Other Operating Assets

Gas gathering systems and equipment are recorded at cost. Depreciation is calculated using the straight-line method over a 30-year estimated useful life. Upon disposition, the cost and accumulated depreciation are removed and any gains or losses are reflected in current operations. Maintenance and repair costs are charged to operating expense as incurred. Material expenditures, which increase the life of an asset, are capitalized and depreciated over the estimated remaining useful life of the asset. The Company capitalized $1.2 million of interest for the three months ended March 31, 2010 related to the construction of the Company s gas gathering system.

Gas gathering systems and equipment as of March 31, 2010 and December 31, 2009 consisted of the following:

	March 31, 2010(1)	December 31, 2009
	(In thousands)	
Gas gathering systems and equipment	$ 614,361	$ 497,551
Less accumulated depreciation	(18,989)	(14,618)
Net gas gathering systems and equipment	$ 595,372	$ 482,933

(1) Includes gas gathering systems and equipment of $397 million and related accumulated depreciation of $10 million associated with assets held for sale at March 31, 2010. See Assets Held for Sale below and Note 13, *Subsequent Events.*

Other operating property and equipment are recorded at cost. Depreciation is calculated using the straight-line method over the following estimated useful lives: automobiles, leasehold improvements, furniture and equipment, 5 years or the lesser of lease term; and computers, 3 years. Upon disposition, the cost and accumulated depreciation are removed and any gains or losses are reflected in current operations. Maintenance and repair costs are charged to operating expense as incurred. Material expenditures, which increase the life of an asset, are capitalized and depreciated over the estimated remaining useful life of the asset.

The Company reviews its property and equipment in accordance with ASC 360, *Property, Plant, and Equipment* (ASC 360). ASC 360 requires the Company to evaluate property and equipment as events occur or circumstances change that would more likely than not reduce the fair value of the property and equipment below the carrying amount. If the carrying amount of property and equipment is not recoverable from its undiscounted cash flows, then the Company would recognize an impairment loss for the difference between the carrying amount and the current fair value. Further, the Company evaluates the remaining useful lives of property and equipment at each reporting period to determine whether events and circumstances warrant a revision to the remaining depreciation periods.

Assets Held for Sale

As discussed in Note 13, *Subsequent Events,* the Company is in the process of divesting its Haynesville Shale gathering and treating business to form a new joint venture with KM Gathering LLC, of which the

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Company will own a 50% membership interest. The Company s assets related to the Haynesville Shale gathering and treating business are presented separately as assets held for sale in the condensed consolidated balance sheet as of March 31, 2010, in accordance with ASC 360. Assets held for sale were recorded at the carrying amount and were assessed for impairment, and based on this assessment, no impairment was necessary as of March 31, 2010. Additionally, the Company will not recognize depletion, depreciation and amortization on its long-lived assets while they are classified as held for sale.

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 events occur 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. The Company has determined that it has two reporting units: oil and natural gas production and midstream operations. All of the Company s goodwill has been allocated to its oil and natural gas production reporting unit as all of its historical goodwill relates to its acquisitions of oil and natural gas properties.

Other Intangible Assets

The Company treats the costs associated with transportation contracts acquired in the third quarter of 2009 as intangible assets. The initial amount recorded represents the fair value of the contract at the time of acquisition, which is amortized using the straight-line method over the life of the contract. Any unamortized balance of the Company s intangible assets is subject to impairment testing pursuant to the *Impairment or Disposal of Long-Lived Assets Subsections* of ASC Subtopic 360-10.

Amortization expense was $2.8 million for the three months ended March 31, 2010 and was allocated to operating expenses between *Marketing* and *Gathering, transportation and other* on the condensed consolidated statements of operations based on the usage of the contract. No amounts were amortized for the three months ended March 31, 2009. The estimated amortization expense will be approximately $11.1 million per year for the remainder of the contract through 2019.

Intangible assets subject to amortization at March 31, 2010 and December 31, 2009 are as follows:

	March 31, 2010	December 31, 2009
	(In thousands)	
Gross transportation contracts	$ 105,108	$ 105,108
Less accumulated amortization	(7,476)	(4,713)
Net transportation contracts	$ 97,632	$ 100,395

Recently Issued Accounting Pronouncements

In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2010-06, *Improving Disclosures about Fair Value Measurements* (ASU 2010-06). This update provides amendments to Subtopic 820-10 and requires new disclosures for 1) significant transfers in and out of Level 1 and Level 2 and the reasons for such transfers and 2) activity in Level 3 fair value measurements to show separate information about purchases, sales, issuances and settlements. In addition, this update amends Subtopic 820-10 to clarify existing disclosures around the disaggregation level of fair value measurements and disclosures for the valuation techniques and inputs utilized (for Level 2 and Level 3 fair value measurements). The provisions in ASU 2010-06 are applicable to interim and annual reporting periods beginning subsequent to December 15, 2009, with the exception of Level 3 disclosures of purchases, sales, issuances and settlements, which will be required in reporting periods beginning after December 15, 2010. The adoption of ASU 2010-06

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did not impact the Company s operating results, financial position or cash flows, but did impact the Company s disclosures on fair value measurements. See Note 5, *Fair Value Measurements.*

In February 2010, FASB issued ASU No. 2010-09, *Amendments to Certain Recognition and Disclosure Requirements* (ASU 2010-09). This update amends Subtopic 855-10 and gives a definition to SEC filer, and requires SEC filers to assess for subsequent events through the issuance date of the financial statements. This amendment states that an SEC filer is not required to disclose the date through which subsequent events have been evaluated for a reporting period. ASU 2010-09 becomes effective upon issuance of the final update. The Company adopted the provisions of ASU 2010-09 for the period ended March 31, 2010.

In April 2010, the FASB issued ASU No. 2010-12, *Accounting for Certain Tax Effects of the 2010 Health Care Reform Acts* (ASU 2010-12). This update clarifies questions surrounding the accounting implications of the different signing dates of the Health Care and Education Reconciliation Act (signed March 30, 2010) and the Patient Protection and Affordable Care Act (signed March 23, 2010). ASU 2010-12 states that the FASB and the Office of the Chief Accountant at the SEC would not be opposed to view the two Acts together for accounting purposes. The Company is currently assessing the impact, if any, the adoption of ASU 2010-12 will have on the Company s disclosures, operating results, financial position and cash flows.

2. ACQUISITIONS AND DIVESTITURES

Acquisitions

Kaiser Trading, LLC

On July 31, 2009, the Company purchased all outstanding membership interests in Kaiser Trading, LLC (Kaiser), now known as HK Transportation, LLC, 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.

Divestitures

Permian Basin Properties

On October 30, 2009, the Company sold its Permian Basin properties to a privately-owned company for $376 million in cash, before closing adjustments. The effective date of the sale was July 1, 2009. Proceeds from the sale were recorded as a reduction to the carrying value of the Company s full cost pool. In conjunction with the closing of this sale, the Company deposited the remaining net proceeds of $331 million with a qualified intermediary to facilitate like-kind exchange transactions ($37.6 million was previously received as a deposit). At March 31, 2010, the Company had $36.2 million remaining for use in future acquisitions.

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. Beginning December 31, 2009, full cost companies use the unweighted arithmetic average first day of the month price for oil and natural gas for the 12-month period preceding the calculation date to calculate the future net revenues of proved reserves. Prior to December 31,

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2009, companies used the price in effect at the calculation date and had the option, under certain circumstances, to elect to use subsequent commodity prices if they increased after the calculation date.

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 March 31, 2010 the ceiling test value of the Company s reserves was calculated based on the first day average of the 12-months ended March 31, 2010 of the West Texas Intermediate (WTI) posted price of $69.64 per barrel, adjusted by lease for quality, transportation fees, and regional price differentials, and the first day average of the 12-months ended March 31, 2010 of the Henry Hub price of $3.99 per million British thermal units (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 at March 31, 2010, did not exceed the ceiling amount. 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 December 31, 2009, the Company s net book value of oil and natural gas properties exceeded the ceiling amount based on the unweighted arithmetic average of the first day of each month for the 12-month period ended December 31, 2009 WTI posted price of $57.65 per barrel and the unweighted arithmetic average of the first day of each month for the 12-month period ended December 31, 2009 Henry Hub price of $3.87 per Mmbtu. As a result, the Company recorded a full cost ceiling impairment before income taxes of approximately $106 million and $65 million after income taxes.

At March 31, 2009, the ceiling test value of the Company s reserves was calculated based on the March 31, 2009 West Texas Intermediate 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 income taxes, $1.1 billion after income taxes. Accordingly, the Company recorded approximately $1.7 billion in full cost ceiling impairment at March 31, 2009 before income taxes.

4. LONG-TERM DEBT

Long-term debt as of March 31, 2010 and December 31, 2009 consisted of the following:

	March 31, 2010(1)	December 31, 2009(1)
	(In thousands)	
Senior revolving credit facility	$ 579,000	$ 203,000
10.5% $600 million senior notes (2)	556,102	554,154
7.875% $800 million senior notes	800,000	800,000
9.125% $775 million senior notes (3)	764,938	764,694
7.125% $275 million senior notes (4)	267,013	266,402
9.875% senior notes	224	224
Deferred premiums on derivatives	10,148	4,070
	$ 2,977,425	$ 2,592,544

(1) Amount excludes $42.7 million and $49.4 million of deferred premiums on derivatives which have been classified as current at March 31, 2010 and December 31, 2009, respectively.

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(2) Amount includes a $43.9 million and $45.8 million discount at March 31, 2010 and December 31, 2009, respectively, recorded by the Company in conjunction with the issuance of the $600 million notes. See 10.5% Senior Notes below for more details.

(3) This amount is comprised of the $650 million and $125 million private placements consummated in July 2006. These amounts include a $4.5 million and $4.8 million discount at March 31, 2010 and December 31, 2009, respectively, recorded by the Company in conjunction with the issuance of the $650 million notes. Additionally, these amounts include a $0.7 million and $0.8 million premium at March 31, 2010 and December 31, 2009, recorded by the Company in conjunction with the issuance of the $125 million notes. See 9.125% Senior Notes below for more details.

(4) Amount includes a $5.4 million and $6.0 million discount at March 31, 2010 and December 31, 2009, 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 s Fourth Amended and Restated Senior Revolving Credit Agreement, dated as of October 14, 2009 (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. and Wells Fargo Bank, N.A., as co-documentation agents for the Lenders, amends and restates its Third Amended and Restated Senior Revolving Credit Agreement dated September 10, 2008. The Senior Credit Agreement provides for 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 Company s $1.2 billion borrowing base attributable to its oil and natural gas properties was reduced $200 million to $1.0 billion upon the closing of the sale of the Company s Permian Basin properties on October 30, 2009. 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 (as defined in the Company s indentures), and is automatically determined quarterly. 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. Subsequent to March 31, 2010, the Company initiated a borrowing base redetermination under its Senior Credit Agreement. The Company s borrowing base was increased to $1.5 billion. This includes $1.2 billion related to Company s oil and gas properties and $0.3 billion related to the midstream assets. See Note 13, *Subsequent Events*.

Amounts outstanding under the Senior Credit Agreement bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 2.25% to 3.25% for Eurodollar loans or at specified margins over the Alternate Base Rate (ABR) of 0.75% to 1.75% for ABR loans. Such margins will fluctuate based on the utilization of the facility. Borrowings under the Senior Credit Agreement are 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.

The Senior Credit Agreement contains customary 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 (as defined in the Senior Credit Agreement) 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 March 31, 2010, the Company was in compliance with its financial debt covenants under the Senior Credit Agreement.

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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 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.

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 $43.9 million at March 31, 2010.

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.

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 Company issued the 2013 Notes in two tranches, $650 million on July 12, 2006 and $125 million on July 27, 2006. The $650 million tranche of 2013 Notes were issued at 98.735% of the face amount. The additional $125 million of 2013 Notes were issued pursuant to the same Indenture at 101.125% 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 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.

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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 $4.5 million at March 31, 2010. 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 $0.7 million at March 31, 2010.

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 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 2012 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

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 $5.4 million at March 31, 2010.

9.875% Senior Notes

On April 8, 2004, Mission Resources Corporation (Mission) issued $130 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 March 31, 2010. 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. At March 31, 2010 and December 31, 2009, the Company had approximately $42.1 million and $44.9 million, respectively, of debt issuance costs remaining that are being amortized over the lives of the respective debt.

5. FAIR VALUE MEASUREMENTS

Pursuant to ASC 820, *Fair Value Measurements and Disclosures* (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.

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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 March 31, 2010 and December 31, 2009. 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. There were no transfers between fair value hierarchy levels for the three months ended March 31, 2010.

	March 31, 2010			
	Level 1	**Level 2**	**Level 3**	**Total**
		(In thousands)		
Assets:				
Restricted Cash	$ 36,176	$	$	36,176
Receivables from derivative contracts		363,472		363,472
	$ 36,176	$ 363,472	$	$ 399,648
Liabilities:				
Liabilities from derivative contracts	$	$ 2,925	$	$ 2,925

	December 31, 2009			
	Level 1	**Level 2**	**Level 3**	**Total**
		(In thousands)		
Assets:				
Restricted Cash	$ 213,704	$	$	$ 213,704
Receivables from derivative contracts		162,862		162,862
	$ 213,704	$ 162,862	$	$ 376,566
Liabilities:				
Liabilities from derivative contracts	$	$ 1,807	$	$ 1,807

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

Derivatives listed above include collars, swaps, and put options that are carried at fair value. The Company records the net change in the fair value of these positions in *Net 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 March 31, 2010 and December 31, 2009, 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. 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 March 31, 2010 and December 31, 2009 (excluding premiums and discounts):

Debt	March 31, 2010 Carrying Amount	March 31, 2010 Estimated Fair Value	December 31, 2009 Carrying Amount	December 31, 2009 Estimated Fair Value
	(In thousands)			
10.5% $600 million senior notes	$ 600,000	$ 670,500	$ 600,000	$ 658,500
7.875% $800 million senior notes	800,000	815,000	800,000	804,000
9.125% $775 million senior notes	768,725	801,396	768,725	805,239
7.125% $275 million senior notes	272,375	273,056	272,375	273,056
9.875% senior notes	224	237	224	227
	$ 2,441,324	$ 2,560,189	$ 2,441,324	$ 2,541,022

6. ASSET RETIREMENT OBLIGATIONS

For wells drilled, 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* or *Gas gathering systems and equipment* during the period in which the obligation is incurred. 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 three months ended March 31, 2010 (in thousands):

Liability for asset retirement obligation as of December 31, 2009	$ 44,000
Liabilities settled and divested	(400)
Additions	2,015
Acquisitions	28
Accretion expense	538
Liability for asset retirement obligation as of March 31, 2010(1)	$ 46,181

(1) Includes liabilities for asset retirement obligations of $0.3 million as of March 31, 2010 associated with assets held for sale. See Assets Held for Sale in Note 1, *Financial Statement Presentation* and Note 13, *Subsequent Events.*

7. COMMITMENTS AND CONTINGENCIES

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. Provisions are established for contingent liabilities when it is probable that a liability has been incurred and the amount is reasonably estimable. While the outcome and impact of currently pending legal proceedings cannot be 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.

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Commitments

The Company leases corporate office space in Houston, Texas and Tulsa, Oklahoma as well as a number of other field office locations. In addition, the Company has lease commitments related to certain vehicles, machinery and equipment under long-term operating leases. Rent expense was $1.3 million and $1.1 million for the three months ended March 31, 2010 and 2009, respectively.

As of March 31, 2010, the Company had the following commitments:

	Total Obligation Amount (In thousands)	Years Remaining
Natural gas transportation commitments	$ 1,956,146	19
Drilling rig commitments	282,837	3
Non-cancelable operating leases	33,202	9
Various contractual commitments (including, among other things, pipeline and well equipment, and obtaining and processing seismic data)	78,702	3
Total commitments	$ 2,350,887	

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 the Company s 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 to 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. Historically, the Company has also entered 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 and may do so at some point in the future as situations present themselves.

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 March 31, 2010 the Company has entered into commodity collars, swaps, and put options. 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 gain on derivatives contracts* on the condensed consolidated statements of operations.

At March 31, 2010, the Company had 97 open commodity derivative contracts summarized in the tables below: 70 natural gas collar arrangements, 6 natural gas swap arrangements, 13 natural gas put options, one crude oil collar arrangement, and 7 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.

At December 31, 2009, the Company had 77 open commodity derivative contracts summarized in the tables below: 61 natural gas collar arrangements, one natural gas swap arrangement, 13 natural gas put options and two crude oil price swap arrangements.

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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 March 31, 2010 and December 31, 2009:

Derivatives not designated as hedging contracts under ASC 815	Asset derivative contracts: Balance sheet location	March 31, 2010	December 31, 2009	Liability derivative contracts: Balance sheet location	March 31, 2010	December 31, 2009
		(In thousands)			(In thousands)	
Commodity contracts	Current assets receivables from derivative contracts	$ 248,511	$ 112,441	Current liabilities liabilities from derivative contracts	$ (2,346)	$ (1,807)
Commodity contracts	Other noncurrent assets receivables from derivative contracts	114,961	50,421	Other noncurrent liabilities liabilities from derivative contracts	(579)	
Total derivatives not designated as hedging contracts under ASC 815		$ 363,472	$ 162,862		$ (2,925)	$ (1,807)

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	Amount of gain or (loss) recognized in income on derivative contracts three months ended March 31, 2010	2009
		(In thousands)	
Commodity contracts:			
Unrealized gain on commodity contracts	Other income (expenses) net gain on derivative contracts	$ 190,095	$ 100,765
Realized gain on commodity contracts	Other income (expenses) net gain on derivative contracts	24,608	81,147
Total net gain on commodity contracts		$ 214,703	$ 181,912
Interest rate swaps:			
Unrealized gain on interest rate swaps	Other income (expenses) net gain on derivative contracts	$	$
Realized gain on interest rate swaps	Other income (expenses) net gain on derivative contracts		10
Total net gain on interestrate swaps		$	$ 10
Total net gain on derivative contracts	Other income (expenses) net gain on derivative contracts	$ 214,703	$ 181,922

At March 31, 2010, the Company had the following open derivative contracts:

				March 31, 2010			
				Floors		Ceilings	
Period	Instrument	Commodity	Volume in Mmbtu s / Bbl s	Price /Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price

April 2010-December 2010	Collars	Natural gas	104,500,000	$ 5.00 -$7.00	$ 5.97	$ 9.00 -$10.00	$ 9.21
April 2010-December 2010	Swaps	Natural gas	1,375,000	8.22	8.22		
April 2010-December 2010	Put Options	Natural gas	22,040,000	4.49 - 5.00	4.92		
April 2010-December 2010	Swaps	Oil	206,250	75.15 -75.55	75.28		
January 2011-December 2011	Collars	Natural gas	189,800,000	5.50 - 6.00	5.55	9.00 - 10.30	9.66
January 2011-December 2011	Collars	Oil	365,000	75.00	75.00	101.00	101.00

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At March 31, 2010, the Company had the following open derivative contracts that were included in the sale of the Company s West Edmond Hunton Lime Unit (WEHLU) assets that closed on April 30, 2010. See Note 13, *Subsequent Events* for further discussion of the WEHLU sale.

			March 31, 2010		
Period	Instrument	Commodity	Volume in Mmbtu s / Bbl s	Price / Price Range	Weighted Average Price
April 2010-December 2010	Swaps	Natural gas	779,580	$ 5.06	$ 5.06
April 2010-December 2010	Swaps	Oil	99,025	80.63 - 82.82	81.77
January 2011-December 2011	Swaps	Natural gas	954,834	5.74	5.74
January 2011-December 2011	Swaps	Oil	107,950	82.84 - 84.09	83.46
January 2012-December 2012	Swaps	Natural gas	875,053	5.99	5.99
January 2012-December 2012	Swaps	Oil	88,825	83.95 - 84.95	84.43
January 2013-December 2013	Swaps	Natural gas	806,763	5.78 - 6.67	6.19
January 2013-December 2013	Swaps	Oil	74,120	84.63 - 85.51	85.03
January 2014-March 2014	Swaps	Natural gas	191,497	6.58 - 6.82	6.73
January 2014-March 2014	Swaps	Oil	16,575	85.37 - 85.56	85.46

At December 31, 2009, the Company had the following open derivative contracts:

			December 31, 2009				
				Floors		Ceilings	
Period	Instrument	Commodity	Volume in Mmbtu s / Bbl s	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
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	Put Options	Natural gas	25,640,000	4.49 - 5.00	4.87		
January 2010-December 2010	Swaps	Oil	273,750	75.15 -75.55	75.28		
January 2011-December 2011	Collars	Natural gas	142,350,000	5.50 - 6.00	5.56	9.00 - 10.30	9.88

9. STOCKHOLDERS EQUITY

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 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 expenses of $9 million.

Warrants, Options and Stock Appreciation Rights

During the three months ended March 31, 2010, the Company granted stock options covering 2.0 million shares of common stock to employees of the Company. The stock options have exercise prices ranging from $21.18 to $23.58 with a weighted average price of $21.19. 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 March 31, 2010, the unrecognized compensation expense related to non-vested stock appreciation rights and stock options totaled $23.7 million and will be recognized on a straight line basis over the weighted average remaining vesting period of 1.6 years.

During the three months ended March 31, 2009, the Company granted stock options covering 1.5 million shares of common stock to employees of the Company. The stock options have exercise prices ranging from $15.23 to $19.03 with a weighted average price of $15.25. 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 March 31, 2009 the unrecognized compensation expense related to non-vested stock appreciation rights and stock options totaled $12.6 million and will be recognized on a straight line basis over the weighted average remaining vesting period of 1.6 years.

During the three months ended March 31, 2009, there were 0.6 million warrants exercised at a price of $3.30 per share, leaving 14,906 remaining at March 31, 2009. Subsequent to the end of the quarter, the remaining warrants were exercised. These warrants, which were granted in conjunction with the recapitalization of the Company by PHAWK, LLC transaction in the second quarter of 2004, were set to expire on May 25, 2009.

Restricted Stock

During the three months ended March 31, 2010, the Company granted 1.1 million shares of restricted stock to employees of the Company and non-employee directors. These restricted shares were granted at prices ranging from $21.18 to $23.58 with a weighted average price of $21.20. 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 March 31, 2010, the unrecognized compensation expense related to non-vested restricted stock totaled $25.7 million and was to be recognized on a straight line basis over the weighted average remaining vesting period of 1.6 years.

During the three months ended March 31, 2009, the Company granted 0.6 million shares of restricted stock to employees of the Company. These restricted shares were granted at prices ranging from $15.23 to $19.03 with a weighted average price of $15.25. 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 March 31, 2009, the unrecognized compensation expense related to non-vested restricted stock totaled $13.5 million and was to be recognized on a straight line basis over the weighted average remaining vesting period of 1.5 years.

Assumptions

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

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Weighted average value per option granted during the period	$ 10.31	$ 7.13
Assumptions (1)(2)(3):		
Stock price volatility	62.0%	70.0%
Risk free rate of return	2.02%	1.49%
Expected term	4.0 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.

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10. EARNINGS PER SHARE

The following represents the calculation of earnings per share:

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
	(In thousands, except per share amounts)	
Basic		
Net income (loss)	$ 156,135	$ (999,753)
Weighted average basic number of shares outstanding	300,157	258,055
Basic net income (loss) per share	$ 0.52	$ (3.87)
Diluted		
Net income (loss)	$ 156,135	$ (999,753)
Weighted average basic number of shares outstanding	300,157	258,055
Common stock equivalent shares representing shares issuable upon exercise of stock options and stock appreciation rights	1,444	Anti-dilutive
Common stock equivalent shares representing shares issuable upon exercise of warrants		Anti-dilutive
Common stock equivalent shares representing shares included upon vesting of restricted shares	1,067	Anti-dilutive
Weighted average diluted number of shares outstanding	302,668	258,055
Diluted net income (loss) per share	$ 0.52	$ (3.87)

Common stock equivalents, including stock options, stock appreciation rights (SARS) and warrants, totaling 0.1 million shares were not included in the computations of diluted earnings per share because the effect would have been anti-dilutive for the three months ended March 31, 2010 because the grant prices were greater than the average market price of the common shares. Common stock equivalents, including stock options, SARS and warrants, totaling 7.0 million shares were not included in the computation of diluted earnings per share as the effect would have been anti-dilutive for the three months ended March 31, 2009 due to the net loss.

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11. ADDITIONAL FINANCIAL STATEMENT INFORMATION

Certain balance sheet amounts are comprised of the following:

	March 31, 2010	December 31, 2009
	(In thousands)	
Accounts receivable:		
Oil and natural gas revenues	$ 116,761	$ 100,294
Marketing revenues	41,596	38,180
Joint interest accounts	75,576	75,316
Income taxes receivable	10,573	22,743
Other	15,126	2,731
	$ 259,632	$ 239,264
Prepaids and other:		
Prepaid insurance	$ 1,933	$ 2,478
Prepaid drilling costs	32,670	27,617
Other	6,283	2,339
	$ 40,886	$ 32,434
Accounts payable and accrued liabilities:		
Trade payables	$ 48,156	$ 75,549
Revenues and royalties payable	190,597	155,568
Accrued oil and natural gas capital costs	222,030	175,369
Accrued midstream capital costs	79,632	29,570
Accrued interest expense	46,811	69,410
Prepayment liabilities	35,560	36,714
Accrued lease operating expenses	11,640	11,407
Accrued ad valorem taxes payable	7,682	5,151
Accrued employee compensation	6,000	11,820
Income taxes payable	668	533
Other	59,701	62,080
	$ 708,477	$ 633,171

12. SEGMENTS

In accordance with ASC 280, *Segment Reporting*, the Company has identified two reportable segments: oil and natural gas and midstream. In the beginning of the fourth quarter of 2009, the Company made a strategic decision to focus on and allocate resources to its midstream division. The decision to designate the midstream division as a separate business segment was due primarily to the recent growth and success within the division as a result of the significant investment of capital during 2009, as well as the Company s intention to increase third party throughput. The oil and natural gas segment is responsible for acquisition, exploration, development and production of oil and natural gas properties, while the midstream segment is responsible for gathering and treating natural gas for the Company and third parties. The Company s Chief Operating Decision Maker evaluates the performance of the reportable segments based on income (loss) before income taxes.

The Company s oil and natural gas segment and midstream segment revenues and expenses include intersegment transactions, which are generally based on transactions made at market-related rates. Consolidated revenues and expenses reflect the elimination of all intercompany transactions. The accounting policies of the reporting segments are the same as those described in the *Summary of Significant Events and Accounting Policies* in Note 1 of the 2009 Annual Report on Form 10-K.

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Summarized financial information concerning our reportable segments is shown in the following table (in thousands):

	Oil and Natural Gas	Midstream	Intersegment Eliminations	Consolidated Total
For the three months ended March 31, 2010:				
Revenues	$ 430,710	$ 9,606	$	$ 440,316
Intersegment revenues		24,352	(24,352)	
Total revenues	$ 430,710	$ 33,958	$ (24,352)	$ 440,316
Gathering, transportation and other	(46,641)	(7,091)	24,352	(29,380)
Depletion, depreciation and amortization	(101,932)	(4,142)		(106,074)
General and administrative	(30,535)	(1,673)		(32,208)
Interest expense and other	(54,403)	(8,443)		(62,846)
Income before income taxes	$ 243,458	$ 11,815	$	$ 255,273
Total assets (1)	$ 6,726,879	$ 684,649	$ (82,538)	$ 7,328,990
Capital expenditures	$ (644,372)	$ (67,218)	$	$ (711,590)
For the three months ended March 31, 2009:				
Revenues	$ 257,247	$ 6,208	$	$ 263,455
Intersegment revenues		7,510	(7,510)	
Total revenues	257,247	13,718	(7,510)	263,455
Gathering, transportation and other	(25,248)	(2,756)	7,510	(20,494)
Depletion, depreciation and amortization	(112,064)	(2,192)		(114,256)
Full cost ceiling impairment	(1,732,486)			(1,732,486)
General and administrative	(18,733)	(906)		(19,639)
Interest expense and other	(51,571)	(4,497)		(56,068)
(Loss) income before income taxes	$ (1,614,861)	$ 3,137	$	$ (1,611,724)
Total assets	$ 5,624,438	$ 297,712	$ (11,250)	$ 5,910,900
Capital expenditures	$ (391,539)	$ (68,844)	$	$ (460,383)

(1) Total assets for the midstream segment include $387 million associated with assets held for sale at March 31, 2010. See Note 1, *Financial Statement Presentation* and Note 13, *Subsequent Events* in the notes to the condensed consolidated financial statements.

13. SUBSEQUENT EVENTS

West Edmond Hunton Lime Unit Sale

On March 1, 2010, the Company announced that it had entered into definitive agreements to sell its interest in the WEHLU Field in Oklahoma County, Oklahoma for $155 million before customary closing adjustments. The transactions closed on April 30, 2010 and had an effective date of April 1, 2010. Proceeds from the sale will be recorded as a reduction to the carrying value of the Company s full cost pool. In conjunction with the closing, the Company assigned the following derivative contracts to one of the purchasers:

			March 31, 2010		
Period	**Instrument**	**Commodity**	**Volume in Mmbtu s / Bbl s**	**Price / Price Range**	**Weighted Average Price**
April 2010-December 2010	Swaps	Natural gas	779,580	$ 5.06	$ 5.06
April 2010-December 2010	Swaps	Oil	99,025	80.63 - 82.82	81.77
January 2011-December 2011	Swaps	Natural gas	954,834	5.74	5.74
January 2011-December 2011	Swaps	Oil	107,950	82.84 - 84.09	83.46
January 2012-December 2012	Swaps	Natural gas	875,053	5.99	5.99

January 2012-December 2012	Swaps	Oil	88,825	83.95 - 84.95	84.43
January 2013-December 2013	Swaps	Natural gas	806,763	5.78 - 6.67	6.19
January 2013-December 2013	Swaps	Oil	74,120	84.63 - 85.51	85.03
January 2014-March 2014	Swaps	Natural gas	191,497	6.58 - 6.82	6.73
January 2014-March 2014	Swaps	Oil	16,575	85.37 - 85.56	85.46

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Terryville Sale

On March 15, 2010, the Company announced that it had entered into a definitive agreement to sell its interest in Terryville Field, located in Lincoln and Claiborne Parishes, Louisiana, to a private company for $320 million before customary closing adjustments. The transaction is expected to close on or before May 31, 2010, with an effective date of January 1, 2010. The transaction is subject to customary closing conditions. Proceeds from the sale are expected to be recorded as a reduction to the carrying value of the Company s full cost pool.

Hawk Field Services, LLC Joint Venture

On April 12, 2010, Hawk Field Services, LLC (HFS), a wholly owned subsidiary of Petrohawk Energy Corporation (collectively with HFS, the Company), and KM Gathering LLC (Kinder Morgan), an affiliate of Kinder Morgan Energy Partners, L.P., a publicly traded master limited partnership, each entered into a Formation and Contribution Agreement (Contribution Agreement) relating to a new joint venture arrangement. The parties intend to form a new joint venture entity, KinderHawk Field Services LLC (KinderHawk), to engage in the natural gas midstream business in and around the Haynesville Shale formation of Northwest Louisiana. Pursuant to the Contribution Agreement, HFS will convey to KinderHawk its Haynesville Shale gathering and treating business in Northwest Louisiana, and Kinder Morgan will contribute $875 million in cash to KinderHawk, subject to certain adjustments. Each of the Company and Kinder Morgan will own a 50% membership interest in KinderHawk. KinderHawk will immediately distribute the $875 million, as adjusted, to the Company. The joint venture will have an economic effective date of January 1, 2010, and the Company will continue to operate the business during a transition period, after which KinderHawk will assume operations. The transaction is subject to customary closing conditions and adjustments and is anticipated to close at the end of May 2010. The Company classified the assets related to the Haynesville Shale gathering and treating business separately as assets held for sale in the condensed consolidated balance sheet as of March 31, 2010. See Note 1, *Financial Statement Presentation,* for further discussion.

The Company will be obligated to deliver minimum annual quantities of natural gas to KinderHawk equal to 50% of the Company s annual projected production from certain zones and formations in North Louisiana for the next five years, or in the alternative, pay an annual true-up fee to KinderHawk if such minimum annual quantities are not delivered. The Company will pay to KinderHawk negotiated gathering and treating fees, subject to an annual inflation adjustment factor and adjustments for KinderHawk s additional direct costs arising out of changes in law relating to certain environmental matters. The gathering fee will be equal to $0.34 per thousand cubic feet (Mcf) of the Company s natural gas delivered at KinderHawk s receipt points. The treating fee will be charged for gas delivered containing more than 2% by volume of carbon dioxide. For gas delivered containing between 2% and 5.5% carbon dioxide, the treating fee will be between $0.030 and $0.345 per Mcf, and for gas containing over 5.5% carbon dioxide, the treating fee will start at $0.365 per Mcf and increase on a scale of $0.09 per Mcf for each additional 1% of carbon dioxide content.

Borrowing Base Redetermination

During the first quarter of 2010, the Company initiated a borrowing base redetermination under its Senior Credit Agreement which was completed on April 30, 2010. The Company s borrowing base of $1.3 billion, which is comprised of $1.0 billion related to the Company s oil and natural gas properties and $0.3 billion related to the Company s Hawk Field Services, LLC midstream assets (midstream assets), was increased to $1.5 billion. This includes $1.2 billion related to the Company s oil and natural gas properties and $0.3 billion related to the midstream assets. Upon the consummation of the Hawk Field Services, LLC joint venture and the closings of the WEHLU and Terryville sales, the borrowing base shall be decreased by an appropriate amount as determined by the banks under the Senior Credit Agreement.

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

The following discussion is intended to assist in understanding our results of operations and our current financial position for the three months ended March 31, 2010 and 2009 and should be read in conjunction with our condensed consolidated financial statements and the notes thereto included in this Quarterly Report on 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 for the year ended December 31, 2009. Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, including those discussed below, which could cause actual results to differ from those expressed.

Overview

We are an independent oil and natural gas company engaged in the exploration, development and production of predominately natural gas properties located onshore in the United States. Our business is comprised of an oil and natural gas segment and a midstream segment. Our oil and natural gas properties are concentrated in four premier domestic shale plays that we believe have decades of future development potential. We organize our oil and natural gas operations into two principal regions: the Mid-Continent, which includes our Louisiana, Arkansas and East Texas properties; and the Western, which includes our South Texas and Oklahoma properties. Our midstream segment consists of our gathering subsidiary, Hawk Field Services, LLC (Hawk Field Services) which was formed to integrate our active drilling program with activities of third parties and to develop additional gathering and treating capacity serving the Haynesville Shale and Bossier Shale in North Louisiana, the Fayetteville Shale in Arkansas and the Eagle Ford Shale in South Texas.

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. 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 are expected to be an important factor determining our capital expenditures focus over the next two years.

Average daily production increased 52% in the first three months of 2010 which averaged 625 million cubic feet of natural gas equivalent (Mmcfe) per day (Mmcfe/d) compared to average daily production of 412 Mmcfe/d during the first three months of 2009. 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 169 gross wells (46.5 net wells) of which 168 gross (46.4 net) were successful resulting in a success rate of 99%.

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.

Our 2010 capital budget is focused on the development of non-proved reserve locations in our Haynesville, Bossier, Eagle Ford and Fayetteville Shale plays so that we can hold our acreage in these areas. We also believe these projects offer us the potential for high internal rates of return and reserve growth. Our original 2010 capital budget included spending of approximately $1.45 billion on drilling and completions during 2010, of which $900 million was allocated to our Haynesville and Bossier Shale properties, $350 million to our Eagle Ford Shale properties, $100 million to our Fayetteville Shale properties and $100 million to our remaining properties. On April 13, 2010, we announced a reallocation and $100 million reduction to our planned 2010 capital spending for drilling and completions. The revised 2010 capital budget for drilling and completions of approximately $1.35 billion includes $850 million allocated to our Haynesville and Bossier Shale properties, $390 million to our Eagle Ford Shale properties, $85 million to our Fayetteville Shale properties and $25 million to our remaining properties. Our future drilling plans are subject to change based upon various factors, some of which are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. To the extent these factors lead to reductions in our drilling 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 $1.8 billion during 2009 ($1.7 billion at March 31 and $106 million at December 31). At March 31, 2010, our net book value of oil and natural gas properties did not exceed the ceiling amount based on the 12-month average Henry Hub price of $3.99 per million British thermal unit (Mmbtu) and West Texas Intermediate (WTI) posted price of $69.64. Changes in prices, production rates, levels of reserves, future development costs, and other factors will determine our actual ceiling test calculation and impairment analyses in future periods.

During the third quarter of 2009, we announced our intent to improve our liquidity by identifying potential asset dispositions for 2010, including a transaction involving our midstream assets, divesting Terryville Field in Northwest Louisiana, divesting our interest in the West Edmond Hunton Lime Unit (WEHLU) in Central Oklahoma as well as other non-core assets. To date, we have entered into agreements to sell approximately $500 million in properties, including $155 million for the sale of our WEHLU Field in Oklahoma County, Oklahoma and $320 million for the sale of our Terryville Field in Lincoln and Claiborne Parishes, Louisiana, and an agreement to form a joint venture in which we will receive an additional $875 million for a 50% interest in our Haynesville Shale gathering and treating business in North Louisiana.

Hawk Field Services, LLC Joint Venture

On April 12, 2010, our wholly owned subsidiary, Hawk Field Services, LLC (HFS) and KM Gathering LLC (Kinder Morgan), an affiliate of Kinder Morgan Energy Partners, L.P., a publicly traded master limited partnership, entered into a Formation and Contribution Agreement (Contribution Agreement) relating to a new joint venture arrangement. The parties intended to form a new joint venture entity, KinderHawk Field Services LLC (KinderHawk), to engage in the natural gas midstream business in and around the Haynesville Shale formation of Northwest Louisiana. Pursuant to the Contribution Agreement, HFS will convey to KinderHawk our Haynesville Shale gathering and treating business in Northwest Louisiana, and Kinder Morgan will contribute $875 million in cash to KinderHawk, subject to certain adjustments. We, along with Kinder Morgan will own a 50% membership interest in KinderHawk. KinderHawk will immediately distribute the $875 million, as adjusted, to us. The joint venture will have an economic effective date of January 1, 2010, and we will continue to operate the business during a transition period, after which KinderHawk will assume operations. The transaction is subject to customary closing conditions and adjustments and is anticipated to close at the end of May 2010. We classified the assets related to the Haynesville Shale gathering and treating business separately as assets held for sale in the condensed consolidated balance sheet as of March 31, 2010. See Item 1. Condensed Consolidated Financial Statements Note 1, *Financial Statement Presentation.*

We will be obligated to deliver minimum annual quantities of natural gas to KinderHawk equal to 50% of our annual projected production from certain zones and formations in North Louisiana for the next five years, or

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in the alternative, pay an annual true-up fee to KinderHawk if such minimum annual quantities are not delivered. We will pay to KinderHawk negotiated gathering and treating fees, subject to an annual inflation adjustment factor and adjustments for KinderHawk s additional direct costs arising out of changes in law relating to certain environmental matters. The gathering fee will be equal to $0.34 per Mcf of our natural gas delivered at KinderHawk s receipt points. The treating fee will be charged for gas delivered containing more than 2% by volume of carbon dioxide. For gas delivered containing between 2% and 5.5% carbon dioxide, the treating fee will be between $0.030 and $0.345 per Mcf, and for gas containing over 5.5% carbon dioxide, the treating fee will start at $0.365 per Mcf and increase on a scale of $0.09 per Mcf for each additional 1% of carbon dioxide content.

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, asset dispositions, and access to capital markets, to the extent available. 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 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 future capital resources and liquidity depend, in part, on our success in developing our leasehold interests. Cash is required to fund capital expenditures necessary to offset inherent declines in our 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 2009, we 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, asset dispositions in 2010, 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 our lenders, and covenants under our Senior Credit Agreement and our senior unsecured debt indentures. Additionally, the indentures governing our senior unsecured debt contain covenants limiting our ability to incur additional indebtedness, including borrowings under our Senior Credit Agreement, unless we meet one of two alternative tests. The first test applies to all indebtedness and requires that after giving effect to the incurrence of additional debt the ratio of our adjusted consolidated EBITDA (as defined in our indentures) to our adjusted consolidated interest expense over the trailing four fiscal quarters will be at least 2.5 to 1.0. The second test applies only to borrowings under our Senior Credit Agreement that do not meet the first test and it limits these borrowings to the greater of a fixed sum (the most restrictive indenture limit being $100 million) and a percentage (the most restrictive indenture limit being 20%) of our adjusted consolidated net tangible assets (as defined in all of our indentures), which is determined using discounted future net revenues from proved natural gas and oil reserves as of the end of each year. 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 aggressive drilling plans 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 subject to market conditions.

During the first quarter of 2010, we initiated a borrowing base redetermination under our Senior Credit Agreement which was completed on April 30, 2010. Our borrowing base of $1.3 billion, which is comprised of $1.0 billion related to our oil and natural gas properties and $0.3 billion related to our Hawk Field Services, LLC midstream assets (midstream assets), was increased to $1.5 billion. This includes $1.2 billion related to our oil and natural gas properties and $0.3 billion related to the midstream assets. Upon the consummation of the Hawk Field Services, LLC joint venture and the closing of the WEHLU and Terryville sales, the borrowing base shall be decreased by an appropriate amount as determined by the banks under the Senior Credit Agreement.

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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 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 three months ended March 31, 2010 and 2009 were from operating and financing activities. Borrowings under our Senior Credit Agreement 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 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 in cash is summarized as follows:

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
	(In thousands)	
Cash flows provided by operating activities	$ 154,172	$ 156,358
Cash flows used in investing activities	(517,386)	(620,412)
Cash flows provided by financing activities	363,096	458,865
Net decrease in cash	$ (118)	$ (5,189)

Operating Activities. Net cash provided by operating activities for the three months ended March 31, 2010 and 2009 were $154.2 million and $156.4 million, respectively.

Net cash provided by operating activities decreased in 2010 due to the decrease in realized gains on our derivative contracts from $81.1 million for the three months ended March 31, 2009 to $24.6 million for the same period in 2010. This decrease was offset by a 19% increase in our average realized natural gas equivalent price compared to the same period in the prior year as well as a 52% 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 increased $0.85 per Mcfe to $5.34 per Mcfe from $4.49 per Mcfe in the prior year. Production for the first three months of 2010 averaged 625 Mmcfe/d compared to 412 Mmcfe/d during the same period of 2009. As a result of our 2010 capital budget program, we expect to continue to increase our production volumes throughout 2010 and 2011. 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 $517.4 million and $620.4 million for the three months ended March 31, 2010 and 2009, respectively.

During the first three months of 2010, we spent $639 million on oil and natural gas capital expenditures. To date in 2010, we participated in the drilling of 169 gross wells (46.5 net wells). We spent an additional $72.6 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.

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On February 10, 2010, we sold our Talihina properties in Latimer County, Oklahoma to Ward Energy, LLC for $17 million, subject to customary closing adjustments. The effective date of the sale was December 1, 2009.

On October 30, 2009, we sold our Permian Basin properties for $376 million in cash, before customary closing adjustments. 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 the remaining net proceeds of $331 million with a qualified intermediary to facilitate potential like-kind exchange transactions ($37.6 million was previously received as a deposit). As of March 31, 2010, $36.2 million remained with the intermediary.

During the first three months of 2009, we spent $390.7 million on acquisitions of oil and natural gas properties and capital expenditures. In 2009, we participated in the drilling of 165 gross wells (40.9 net wells). We spent an additional $69.7 million on other property and equipment expenditures, primarily to fund the completion of gathering systems in the Fayetteville Shale in Arkansas and the beginning stages of the development of our gathering systems in the Haynesville Shale in Louisiana.

During the first three months of 2009, we used a portion of the funds from our debt and equity offerings to purchase a net $160.0 million of marketable securities. These marketable securities were classified and accounted for as trading securities and were used primarily to fund a portion of our 2009 capital program.

Financing Activities. Net cash flows provided by financing activities were $363.1 million and $458.9 million for the three months ended March 31, 2010 and 2009, respectively.

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.

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 three months of 2010, we had net borrowings of $366 million. During the first three months of 2009, we had net borrowings of $95.4 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. Currently no sources of liquidity or financing are provided by off-balance sheet arrangements or transactions with unconsolidated, limited-purpose entities. The following table summarizes our contractual obligations and commitments as of March 31, 2010:

	Total Obligation Amount (In thousands)	Years Remaining
Natural gas transportation commitments	$ 1,956,146	19
Drilling rig commitments	282,837	3
Non-cancelable operating leases	33,202	9
Various contractual commitments (including, among other things, pipeline and well equipment, and obtaining and processing seismic data)	78,702	3
Total commitments	$ 2,350,887	

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Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations 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 material changes to our critical accounting policies from those described in our Annual Report on Form 10-K for the year ended December 31, 2009.

Results of Operations

Quarters Ended March 31, 2010 and 2009

We reported net income of $156.1 million for the three months ended March 31, 2010 compared to a net loss of $999.8 million for the comparable period in 2009, resulting in a net change of $1.2 billion. This change was primarily attributable to our full cost ceiling impairment of $1.7 billion in 2009 as well as our $215 million net gain on derivative contracts for the three months ended March 31, 2010 versus a net gain of $182 million for the 2009 period. Also contributing to the change were higher revenues in 2010.

In thousands (except per unit and per Mcfe amounts)	**Three Months Ended March 31, 2010**	**2009**	**Change**
Net income (loss)	$ 156,135	$ (999,753)	$ 1,155,888
Operating revenues:			
Oil and natural gas	300,591	167,554	133,037
Marketing	130,119	89,693	40,426
Midstream	9,606	6,208	3,398
Expenses:			
Marketing	136,622	84,844	51,778
Production:			
Lease operating	17,395	16,411	984
Workover and other	2,378	723	1,655
Taxes other than income	12,843	12,180	663
Gathering, transportation and other			
Oil and natural gas	22,289	17,738	4,551
Midstream	7,091	2,756	4,335
General and administrative:			
General and administrative	28,119	16,829	11,290
Stock-based compensation	4,089	2,810	1,279
Depletion, depreciation and amortization:			
Depletion Full cost	100,262	111,092	(10,830)
Depreciation Midstream	4,074	2,184	1,890
Depreciation Other	1,200	635	565
Accretion expense	538	345	193
Full cost ceiling impairment		1,732,486	(1,732,486)
Net gain on derivative contracts	214,703	181,922	32,781
Interest expense and other	(62,846)	(56,068)	(6,778)
Income tax (provision) benefit	(99,138)	611,971	(711,109)
Production(1):			
Natural gas Mmcf(2)	54,823	34,591	20,232
Crude oil MBbl	241	414	(173)
Natural gas equivalent Mmcfe	56,269	37,075	19,194
Daily production Mmcfe	625	412	213
Average price per unit *(1)(3)* **:**			
Natural gas price Mcf(2)	$ 5.15	$ 4.36	$ 0.79
Crude oil price Bbl	75.29	38.10	37.19
Equivalent Mcfe	5.34	4.49	0.85
Average cost per Mcfe:			
Production:			

Lease operating	0.31	0.44	(0.13)
Workover and other	0.04	0.02	0.02
Taxes other than income	0.23	0.33	(0.10)
Gathering, transportation and other			
Oil and natural gas	0.40	0.48	(0.08)
Midstream	0.12	0.07	0.05
General and administrative:			
General and administrative	0.50	0.45	0.05
Stock-based compensation	0.07	0.08	(0.01)
Depletion	1.78	3.00	(1.22)

(1) Oil and natural gas liquids are converted to equivalent gas production using a 6:1 equivalent ratio. This ratio does not assume price equivalency and given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

(2) Less than 1% and approximately 2% of natural gas production represents natural gas liquids (calculated with a 6:1 equivalent ratio) with an average price of $38.24 per barrel (Bbl) and $23.23 per Bbl for the three months ended March 31, 2010 and 2009, respectively.

(3) Amounts exclude the impact of cash paid/received on settled contracts as we did not elect to apply hedge accounting.

For the three months ended March 31, 2010, oil and natural gas revenues increased $133.0 million from the same period in 2009, to $300.6 million. The increase was primarily due to the increase in production of 19,194 Mmcfe, or 52% over the three months ended March 31, 2009, due to our recent drilling successes in resource-style plays in Louisiana, Arkansas and Texas. Increased production contributed to approximately $86 million in revenues for the three months ended March 31, 2010. Also contributing to this increase was an increase of $0.85 per Mcfe in our realized average price to $5.34 per Mcfe from $4.49 per Mcfe in the prior year. This increase per Mcfe led to a increase in oil and natural gas revenues of $47 million.

We had marketing revenues of $130.1 million and marketing expenses of $136.6 million for the three months ended March 31, 2010, resulting in a net decrease of $6.5 million as compared to a net increase of $4.8 million for the same period in 2009. A subsidiary of ours purchases and sells 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 decrease for the three months ended March 31, 2010 which is attributable to decreased margins and the amortization of our acquired transportation contracts.

We had gross revenues from our midstream segment of $34.0 million for the three months ended March 31, 2010 compared to the same period in 2009 of $13.7 million, an increase of $20.3 million of which $16.9 million represents inter-segment revenues that are eliminated in consolidation. The remaining $3.4 million increase represents gathering and treating revenues from third party owners in our operated wells and revenues associated with third party producers. On a net basis we had revenues of $9.6 million for the three months ended March 31, 2010, an increase of $3.4 million from the prior year. The increase in revenues was directly related to the increase in throughput on our gathering systems and treating facilities. Gathering throughput increased 35.2 Bcf to 56.7 Bcf for the three months ended March 31, 2010 compared to 21.5 Bcf for the three months ended March 31, 2009. The throughput increase resulted from the constructing of 178 miles of gathering pipeline in the Haynesville, Eagle Ford and Fayetteville Shales during the period from April 1, 2009 through March 31, 2010. As of March 31, 2010 we constructed 344 miles of gathering pipeline. Treating throughput increased 34.6 Bcf to 47.3 Bcf for the three months ended March 31, 2010 compared to 12.7 Bcf for the three months ended March 31, 2009, which was the result of additional wells coming on line and a greater treating capacity from the amine plants installed. As of March 31, 2010 we had 17 amine plants in service in the Haynesville and Eagle Ford Shales.

Lease operating expenses increased $1.0 million for the three months ended March 31, 2010 primarily due to our increased production in the current year. On a per unit basis, lease operating expenses decreased $0.13 per Mcfe to $0.31 per Mcfe in 2010 from $0.44 per Mcfe in 2009. The decrease on a per unit basis is primarily due to the increase in production during 2010 from our resource-style plays which typically have a lower per unit operating cost. Additionally, the sale of our Permian Basin properties in the fourth quarter of 2009 contributed to a decrease in costs for the three months ended March 31, 2010 over the same period in 2009.

Taxes other than income increased $0.7 million for the three months ended March 31, 2010 as compared to the same period in 2009. 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 $0.23 per Mcfe compared to $0.33 per Mcfe in 2009. This decrease on a per unit basis is primarily attributable to severance tax refunds related to drilling incentives for horizontal wells in the Haynesville Shale where we have continued to expand our capital and drilling program.

Gathering, transportation and other expense attributable to our oil and natural gas production segment increased $4.6 million, for the three months ended March 31, 2010 as compared to the same period in 2009. This increase was primarily due to the costs associated with our increases in production overall. On a per unit basis, gathering, transportation and other decreased $0.08 per Mcfe primarily due to increases in production in our Haynesville Shale play, which generally has lower per unit costs.

Gathering, transportation and other expenses attributable to our midstream segment increased $4.3 million for the three months ended March 31, 2010 compared to the same period in 2009. This increase was primarily due to the increase in throughput associated with the continued development of our gathering systems and treating facilities primarily in the Haynesville and Eagle Ford Shales. Gathering and treating throughput increased 69.8 Bcf to 104.0 Bcf for the three months ended March 31, 2010 compared to 34.2 Bcf for the three months ended March 31, 2009, which includes 12.7 Bcf of treating throughput. Gathering, transportation and other expense per Mcf for the three months ended March 31, 2010 was $0.07 per Mcf compared to $0.08 per Mcf for the three months ended March 31, 2009, a decrease of $0.01 per Mcf or 13% based on our total throughput.

General and administrative expense for the three months ended March 31, 2010 increased $11.3 million as compared to the same period 2009. This increase is primarily attributable to our recent growth. Payroll and employee related expenses increased $2.8 million for the three months ended March 31, 2010 compared to the same period in 2009. Our legal expense increased $5.0 million from the prior year to accrue for settlements and an additional $3.5 million in legal fees associated with our ongoing legal matters.

Depletion for oil and natural gas properties is calculated using the unit of production method, which 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 $10.8 million for the three months ended March 31, 2010 from the same period in 2009, to $100.3 million. On a per unit basis, depletion expense decreased $1.22 per Mcfe to $1.78 per Mcfe. This decrease on a per unit basis is primarily due to the ceiling test impairment write-downs of $1.7 billion and $106 million we recorded at March 31, 2009 and December 31, 2009, respectively.

Depreciation expense associated with our gas gathering systems increased $1.9 million to $4.1 million for the three months ended March 31, 2010. This increase was primarily due to the construction of our gas gathering systems and treating facilities in the Haynesville, Eagle Ford and Fayetteville Shales. We depreciate our gas gathering systems over a 30 year useful life and begin depreciating on the estimated placed in service date.

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. 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. For the first three quarters of 2009, we calculated the ceiling using prevailing oil and natural gas prices on the last day of the period, or a subsequent higher price under certain circumstances. At March 31, 2009, our ceiling was calculated using prices of $49.66 per barrel of oil and $3.63 per Mmbtu for natural gas. Accordingly, at March 31, 2009, our costs exceeded our ceiling limitation by approximately $1.7 billion, resulting in an approximate $1.7 billion writedown of our oil and natural gas properties before income taxes.

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 March 31, 2010, we had a $363.5 million derivative asset, $248.5 million of which was classified as current, and a $2.9 million derivative liability, $2.3 million of which was classified as current. We recorded a net derivative gain of $214.7 million ($190.1 million net unrealized gain and $24.6 million net gain for cash received on settled contracts) for the three months ended March 31, 2010 compared to a net derivative gain of $181.9 million ($100.8 million net unrealized gain and a $81.1 million gain for cash received on settled contracts) in the same period in 2009.

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Interest expense and other increased $6.8 million for the three months ended March 31, 2010 compared to the same period in 2009. Interest expense increased $5.1 million due to the inclusion of a full quarter of interest expense in 2010 and related discount amortization for issuance of the $600 million senior notes due 2014 (2014 Notes) in January 2010 compared to the same period in 2009 for which two months of interest and discount amortization was recognized. Interest expense associated with our Senior Credit Agreement increased $3.0 million in 2010 compared to the same period in 2009 as a result of additional borrowings to fund our 2010 capital program. For the three months ended March 31, 2010, interest expense included a $1.2 million reduction for the capitalization of interest associated with the ongoing construction of our gas gathering systems.

We had an income tax provision of $99.1 million for the three months ended March 31, 2010 due to our pre-tax income of $255.3 million compared to an income tax benefit of $612.0 million due to our pre-tax loss of $1.6 billion in the prior year. The effective tax rate for the three months ended March 31, 2010 was 39% compared to 38% for the three months ended March 31, 2009.

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, and put options. 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 March 31, 2010, 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 account for our derivative activities under the provisions of ASC 815, *Derivatives and Hedging* (ASC 815). 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.

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Interest Sensitivity

We are exposed to market risk related to adverse changes in interest rates. Our interest rate risk exposure results primarily from fluctuations in short-term rates, which are LIBOR and ABR based and may result in reductions of earnings or cash flows due to increases in the interest rates we pay on these obligations.

At March 31, 2010, total debt was $3.0 billion, of which approximately 80.8% bears interest at a weighted average fixed interest rate of 8.8% per year. The remaining 19.2% of our total debt balance at March 31, 2010 bears interest at floating or market interest rates that at our option are tied to prime rate or LIBOR. Fluctuations in market interest rates will cause our annual interest costs to fluctuate. At March 31, 2010, the interest rate on our variable rate debt was 2.8% per year. If the balance of our variable rate debt at March 31, 2010 were to remain constant, a 10% change in market interest rates would impact our cash flow by approximately $0.4 million per quarter.

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 March 31, 2010 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*).

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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.

We are also involved in natural gas exploration in the Haynesville Shale in Louisiana. 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, and Red River Parishes in Louisiana. On approximately December 14, 2009, the United States EPA informed us that it would be acting as lead enforcement agency regarding these alleged violations. We have identified additional well sites on which work may have been conducted without required authorizations under the Clean Water Act. Information related to these well sites has been disclosed to the Corps of Engineers and the EPA. We are investigating these allegations and are unable at this time to estimate our potential exposure related to this matter. As of this date our investigation has identified 36 additional well sites on which work was commenced while permits were still pending before the Corps of Engineers. All of this information has been disclosed to the Corps of Engineers and EPA. 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 material changes to the risk factors described in the Company s Annual Report on Form 10-K, for the year ended December 31, 2009, except as stated below.

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

Legislation has been proposed in Congress 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 oil and natural gas production. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with many of the wells for which we are the operator. Sponsors of bills currently pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process may be adversely impacting 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 are impairing groundwater or causing other damage. These bills, if adopted, could establish an additional level of regulation at the federal or state 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. Certain states have adopted or are considering similar disclosure legislation.

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In March 2010, the United States Environmental Protection Agency announced that it would conduct a wide-ranging study on the effects of hydraulic fracturing on human health and the environment. The agency also announced that one of its enforcement initiatives for 2011 to 2013 would be to focus on environmental compliance by the energy extraction sector. This study and enforcement initiative could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

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 March 31, 2010.

	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
January 2010	384	$ 25.60		
February 2010	43,485	21.41		
March 2010	113,713	21.87		

(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. (Removed and Reserved)

Item 5. Other Information

None.

Item 6. Exhibits

The following documents are included as exhibits to this Quarterly Report on 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	Formation and Contribution Agreement, dated April 12, 2010, by and among Petrohawk Energy Corporation, Hawk Field Services, LLC, and KM Gathering LLC (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed on April 16, 2010)
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).

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Exhibit No	Description
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 7/8% 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 1/8% 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).
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).
4.6	Second Supplemental Indenture dated July 12, 2006 among Petrohawk Energy Corporation, the successor by way of merger to KCS Energy, Inc., the parties named therein as guarantors, and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.4 to our Current Report on Form 8-K filed on July 17, 2006).
4.7	Third Supplemental Indenture dated as of July 12, 2006 among Petrohawk Energy Corporation, the successor by way of merger to KCS Energy, Inc., the parties named therein as existing guarantors, the parties named therein as new guarantors, and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.5 to our Current Report on Form 8-K filed on July 17, 2006).

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Exhibit No	Description
4.8	Fourth Supplemental Indenture dated as of August 3, 2007 among Petrohawk Energy Corporation, the successor by way of merger to KCS Energy, Inc., the parties named therein as existing guarantors, the parties named therein as new guarantors, and The Law Debenture Trust Company of New York, as the successor to U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.12 to our Quarterly Report on Form 10-Q filed on November 6, 2008).
4.9	Fifth Supplemental Indenture dated as of November 28, 2008 among Petrohawk Energy Corporation, HK Energy Marketing, LLC, the parties named therein as guarantors, and The Law Debenture Trust Company of New York, as the successor to U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.9 to our Annual Report on Form 10-K filed on February 25, 2009).
4.10	Sixth Supplemental Indenture dated as of January 26, 2009 among Winwell Resources, L.L.C., KCS Resources, LLC, Petrohawk Energy Corporation, the parties named therein as guarantors, and The Law Debenture Trust Company of New York, as the successor to U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.10 to our Annual Report on Form 10-K filed on February 25, 2009).
4.11	Seventh Supplemental Indenture dated as of August 4, 2009 among Kaiser Trading, LLC, Petrohawk Energy Corporation, the existing Guarantors, and Law Debenture Trust Company of New York, as the successor to U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.11 to our Quarterly Report on Form 10-Q filed on November 9, 2009)
4.12	Indenture dated July 12, 2006 among Petrohawk Energy Corporation, U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein, relating to Petrohawk Energy Corporation s 9 1/8% senior notes due 2013 (Incorporated by reference to Exhibit 4.6 to our Current Report on Form 8-K filed on July 17, 2006).
4.13	First Supplemental Indenture dated July 12, 2006 among Petrohawk Energy Corporation, U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein (Incorporated by reference to Exhibit 4.7 to our Current Report on Form 8-K filed on July 17, 2006).
4.14	Second Supplemental Indenture dated August 3, 2007 among Petrohawk Energy Corporation, One TEC, LLC, One TEC Operating, LLC, Bison Ranch, LLC, the parties named therein as existing guarantors and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.10 to our Quarterly Report on Form 10-Q filed on November 8, 2007).
4.15	Third Supplemental Indenture dated as of November 28, 2008 among Petrohawk Energy Corporation, HK Energy Marketing, LLC, the parties named therein as guarantors, and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.14 to our Annual Report on Form 10-K filed on February 25, 2009).
4.16	Fourth Supplemental Indenture dated as of January 26, 2009 among Winwell Resources, L.L.C., KCS Resources, LLC, Petrohawk Energy Corporation, the parties named therein as guarantors, and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.15 to our Annual Report on Form 10- K filed on February 25, 2009).
4.17	Fifth Supplemental Indenture dated as of August 4, 2009 among Kaiser Trading, LLC, Petrohawk Energy Corporation, the existing Guarantors, and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.17 to our Quarterly Report on Form 10-Q filed on November 5, 2009).
4.18	Indenture, dated May 13, 2008, among Petrohawk Energy Corporation, the subsidiary guarantors named therein, and U.S. Bank Trust National Association (Incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed on May 15, 2008).

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Exhibit No	Description
4.19	First Supplemental Indenture dated as of November 28, 2008 among Petrohawk Energy Corporation, HK Energy Marketing, LLC, and parties named therein as guarantors, and U.S. Bank Trust National Association, as trustee (Incorporated by reference to Exhibit 4.17 to our Annual Report on Form 10-K filed on February 25, 2009).
4.20	Second Supplemental Indenture dated as of January 26, 2009 among Winwell Resources, L.L.C., KCS Resources, LLC, Petrohawk Energy Corporation, the parties named therein as guarantors, and U.S. Bank Trust National Association, as trustee (Incorporated by reference to Exhibit 4.18 to our Annual Report on Form 10-K filed on February 25, 2009).
4.21	Third Supplemental Indenture dated as of August 4, 2009 among Kaiser Trading, LLC, Petrohawk Energy Corporation, the existing Guarantors, and U.S. Bank Trust National Association, as trustee (Incorporated by reference to Exhibit 4.21 to our Quarterly Report on Form 10-Q filed on November 5, 2009).
4.22	Registration Rights Agreement, dated May 13, 2008, among the Company, the subsidiary guarantors named therein, and Lehman Brothers Inc., on behalf of Lehman Brothers Inc., J.P. Morgan Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, BNP Paribas Securities Corp., Credit Suisse Securities (USA) LLC, Banc of America Securities LLC, Citigroup Global Markets Inc., BMO Capital Markets Corp., RBC Capital Markets Corporation, and Wells Fargo Securities, LLC. (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed on May 15, 2008).
4.23	Indenture, dated January 27, 2009, among the Petrohawk Energy Corporation, the subsidiary guarantors named therein, and U.S. Bank Trust National Association (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed on January 28, 2009).
4.24	First Supplemental Indenture, dated August 4, 2009, among the Kaiser Trading, LLC, Petrohawk Energy Corporation, the existing Guarantors, and U.S. Bank Trust National Association, as trustee (Incorporated by reference to Exhibit 4.26 to our Quarterly Report on Form 10-Q filed on November 5, 2009).
4.25	Registration Rights Agreement, dated January 27, 2009, among the Company, the subsidiary guarantors named therein, and J.P. Morgan Securities Inc., on behalf of J.P. Morgan Securities Inc., BNP Paribas Securities Corp., Wachovia Capital Markets, LLC, Banc of America Securities LLC, BMO Capital Markets Corp., Barclays Capital Inc., Fortis Securities LLC, Calyon Securities (USA) Inc., RBC Capital Markets Corporation, Capital One Southcoast, Inc., Wedbush Morgan Securities Inc., Natixis Bleichroeder Inc., Citigroup Global Markets Inc., BBVA Securities, Inc., and Piper Jaffray & Co. (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed on January 28, 2009).
10.1	Fourth Amended and Restated Senior Revolving Credit Agreement dated October 14, 2009, among Petrohawk Energy Corporation, each of the Lenders from time to time party thereto, BNP Paribas, as administrative agent for the Lenders, Bank of America, N.A and Bank of Montreal, as co-syndication agents for the Lenders, and JPMorgan Chase Bank, N.A. and Wells Fargo Bank, N.A., as co-documentation agents for the Lenders (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on October 20, 2009).
10.2	Fourth Amended and Restated Guarantee and Collateral Agreement dated October 14, 2009, made by Petrohawk Energy Corporation and each of its subsidiaries, as Grantors, in favor of BNP Paribas, as Administrative Agent (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed on October 20, 2009).
10.3	The Petrohawk Energy Corporation Second Amended and Restated 2004 Non-Employee Director Incentive Plan (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed on June 23, 2009).

Exhibit No	Description
10.4	Form of Restricted Stock Agreement for the Second Amended and Restated 2004 Non-Employee Director Incentive Plan (Incorporated by reference to Exhibit 10.4 of our Second Quarter 2005 Form 10-Q filed on August 11, 2005).
10.5	The Petrohawk Energy Corporation Third Amended and Restated 2004 Employee Incentive Plan (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed June 23, 2009).
10.6	Form of Stock Option Agreement for the Third Amended and Restated 2004 Employee Incentive Plan (Incorporated by reference to Exhibit 10.3 of our Annual Report on Form 10-K filed March 14, 2006).
10.7	Form of Restricted Stock Agreement for the Third Amended and Restated 2004 Employee Incentive Plan (Incorporated by reference to Exhibit 10.8 of our Second Quarter 2005 Form 10-Q filed on August 11, 2005).
12.1*	Computation of Ratio of Earnings to Combined Fixed Charges and Preference Dividends
31.1*	Certificate of Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certificate of Chief Financial Officer under Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certifications required by Rule 13a-14(b) or Rule 15d-14(b) under the Securities Exchange Act of 1934 and 18 U.S.C. Section 1350
101*	Interactive Data File

* Attached hereto.
Indicates management contract or compensatory plan or arrangement.

The registrant has not filed with this report copies of the instruments defining rights of all holders of long-term debt of the registrant and its consolidated subsidiaries based upon the exception set forth in Item 601 (b)(4)(iii)(A) of Regulation S-K. Copies of such instruments will be furnished to the Securities and Exchange Commission upon request.

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SIGNATURES

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

PETROHAWK ENERGY CORPORATION

Date: May 5, 2010	By:	/s/ Floyd C. Wilson Floyd C. Wilson Chairman of the Board and Chief Executive Officer
	By:	/s/ Mark J. Mize Mark J. Mize Executive Vice President, Chief Financial Officer and Treasurer
	By:	/s/ C. Byron Charboneau C. Byron Charboneau Vice President, Chief Accounting Officer and Controller