PETROHAWK ENERGY CORP
Form 10-Q
August 03, 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 June 30, 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	**(I.R.S. Employer**

incorporation or organization)	**Identification Number)**

1000 Louisiana, Suite 5600, Houston, Texas 77002

(Address of principal executive offices including ZIP code)

(832) 204-2700

(Registrant s telephone number)

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

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

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

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

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

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

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

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

As of July 30, 2010 the Registrant had 302,362,505 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, fracture stimulation services 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 June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Operating revenues:				
Oil and natural gas	$ 239,834	$ 157,977	$ 540,425	$ 325,531
Marketing	107,338	63,317	237,457	153,010
Midstream	6,331	6,006	15,937	12,214
Total operating revenues	353,503	227,300	793,819	490,755
Operating expenses:				
Marketing	117,309	60,292	253,931	145,136
Production:				
Lease operating	16,384	18,704	33,779	35,115
Workover and other	1,571	205	3,949	928
Taxes other than income	5,191	12,537	18,034	24,717
Gathering, transportation and other	34,870	22,633	64,250	43,127
General and administrative	43,341	23,992	75,549	43,631
Depletion, depreciation and amortization	101,175	84,435	207,249	198,691
Full cost ceiling impairment				1,732,486
Total operating expenses	319,841	222,798	656,741	2,223,831
Amortization of deferred gain	64,367		64,367	
Income (loss) from operations	98,029	4,502	201,445	(1,733,076)
Other income (expenses):				
Net (loss) gain on derivative contracts	(16,625)	16,006	198,078	197,928
Interest expense and other	(61,533)	(55,880)	(124,379)	(111,948)
Equity investment income	2,047		2,047	
Total other income (expenses)	(76,111)	(39,874)	75,746	85,980
Income (loss) before income taxes	21,918	(35,372)	277,191	(1,647,096)
Income tax (provision) benefit	(8,423)	13,368	(107,561)	625,339
Net income (loss)	$ 13,495	$ (22,004)	$ 169,630	$ (1,021,757)
Net income (loss) per share:				
Basic	$ 0.04	$ (0.08)	$ 0.56	$ (3.84)
Diluted	$ 0.04	$ (0.08)	$ 0.56	$ (3.84)

Weighted average shares outstanding:				
Basic	300,426	274,146	300,292	266,145
Diluted	302,446	274,146	302,715	266,145

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)

	June 30, 2010	December 31, 2009
Current assets:		
Cash	$ 2,142	$ 1,511
Marketable securities	281,006	
Accounts receivable	266,289	239,264
Receivables from derivative contracts	182,260	112,441
Receivable from equity affiliate	9,668	
Prepaids and other	50,846	32,434
Total current assets	792,211	385,650
Oil and natural gas properties (full cost method):		
Evaluated	6,643,163	5,984,765
Unevaluated	2,633,105	2,512,453
Gross oil and natural gas properties	9,276,268	8,497,218
Less accumulated depletion	(4,527,880)	(4,329,485)
Net oil and natural gas properties	4,748,388	4,167,733
Other operating property and equipment:		
Gas gathering systems and equipment	241,202	497,551
Other operating assets	36,711	26,002
Gross other operating property and equipment	277,913	523,553
Less accumulated depreciation	(24,596)	(26,287)
Net other operating property and equipment	253,317	497,266
Other noncurrent assets:		
Goodwill	932,802	932,802
Other intangible assets, net of amortization	94,868	100,395
Debt issuance costs, net of amortization	40,039	44,871
Deferred income taxes	211,531	245,413
Receivables from derivative contracts	98,426	50,421
Restricted cash	57,186	213,704
Equity investment	205,453	
Other	5,893	23,816
Total assets	$ 7,440,114	$ 6,662,071
Current liabilities:		
Accounts payable and accrued liabilities	$ 763,169	$ 633,171
Deferred income taxes	39,443	14,484
Liabilities from derivative contracts	224	1,807
Long-term debt	35,493	49,370

Total current liabilities	838,329	698,832
Long-term debt	2,404,989	2,592,544
Other noncurrent liabilities:		
Asset retirement obligations	37,867	44,000
Deferred gain on sale	649,399	
Other	2,254	3,023
Commitments and contingencies (Note 7)		
Stockholders equity:		
Common stock: 500,000,000 shares of $.001 par value authorized; 302,345,251 and 301,194,695 shares issued and outstanding at June 30, 2010 and December 31, 2009, respectively	302	301
Additional paid-in capital	4,613,637	4,599,664
Accumulated deficit	(1,106,663)	(1,276,293)
Total stockholders equity	3,507,276	3,323,672
Total liabilities and stockholders equity	$ 7,440,114	$ 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)

	Six Months Ended June 30, 2010	2009
Cash flows from operating activities:		
Net income (loss)	$ 169,630	$ (1,021,757)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation and amortization	207,249	198,691
Full cost ceiling impairment		1,732,486
Income tax provision (benefit)	107,561	(625,339)
Stock-based compensation	10,397	6,617
Net unrealized gain on derivative contracts	(102,671)	(18,419)
Amortization of deferred gain	(64,367)	
Equity investment income	(2,047)	
Other operating	20,993	9,460
Change in assets and liabilities:		
Accounts receivable	(27,025)	103,432
Prepaids and other	(18,538)	(11,898)
Accounts payable and accrued liabilities	14,075	(47,708)
Other	4,269	551
Net cash provided by operating activities	319,526	326,116
Cash flows from investing activities:		
Oil and natural gas capital expenditures	(1,206,288)	(748,102)
Proceeds received from sale of oil and natural gas properties	491,094	
Proceeds received from sale of Haynesville gas gathering systems	921,408	
Marketable securities purchased	(978,006)	(763,092)
Marketable securities redeemed	697,000	869,081
Increase in restricted cash	(75,005)	
Decrease in restricted cash	231,523	
Other operating property and equipment expenditures	(173,840)	(145,351)
Net cash used in investing activities	(92,114)	(787,464)
Cash flows from financing activities:		
Proceeds from exercise of stock options and warrants	1,276	1,956
Proceeds from issuance of common stock		385,000
Offering costs		(9,031)
Proceeds from borrowings	942,000	634,674
Repayment of borrowings	(1,165,780)	(542,159)
Debt issue costs	(704)	(13,237)
Other	(3,573)	
Net cash (used in) provided by financing activities	(226,781)	457,203
Net increase (decrease) in cash	631	(4,145)
Cash at beginning of period	1,511	6,883
Cash at end of period	$ 2,142	$ 2,738

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. The Company uses the equity method to account for investments in which the Company does not have a majority interest, but does have significant influence. 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 which the Company and third parties 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 (loss) 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 that increase the life of an asset are capitalized and depreciated over the estimated remaining useful life of the asset. The Company capitalized $1.3 million and $2.5 million of interest for the three and six months ended June 30, 2010, respectively, related to the construction of the Company s gas gathering systems.

Gas gathering systems and equipment as of June 30, 2010 and December 31, 2009 consisted of the following:

	June 30, 2010(1)	December 31, 2009
	(In thousands)	
Gas gathering systems and equipment	$ 241,202	$ 497,551
Less accumulated depreciation	(11,346)	(14,618)
Net gas gathering systems and equipment	$ 229,856	$ 482,933

(1) On May 21, 2010, the Company contributed its Haynesville Shale gas gathering and treating business for a 50% membership interest in a new joint venture entity, KinderHawk Field Services LLC, and approximately $921 million in cash. See Note 2, *Acquisitions and Divestitures* for more details.

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 that 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.

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Equity Method Investment

On May 21, 2010, the Company contributed its Haynesville Shale gas gathering and treating business for a 50% membership interest in a new joint venture entity, KinderHawk Field Services LLC (KinderHawk), and approximately $921 million in cash. The Company s investment in KinderHawk, in which the Company does not have a majority interest, but does have significant influence, is accounted for under the equity method. Under the equity method of accounting, the Company s share of net income (loss) from KinderHawk is reflected as an increase (decrease) in its investment account and is also recorded as equity investment income (loss). Distributions from KinderHawk are recorded as reductions of the Company s investment and contributions to KinderHawk are recorded as increases of the Company s investment. The Company reviews its equity method investment for potential impairment whenever events or changes in circumstances indicate that an other-than-temporary decline in the value of the investment has occurred. See Note 13, *Equity Method Investment*, for further discussion.

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 and $5.5 million for the three and six months ended June 30, 2010, respectively, 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 and six months ended June 30, 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 June 30, 2010 and December 31, 2009 are as follows:

	June 30, 2010	**December 31, 2009**
	(In thousands)	
Transportation contracts	$ 105,108	$ 105,108
Less accumulated amortization	(10,240)	(4,713)
Net transportation contracts	$ 94,868	$ 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 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 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 adoption of ASU 2010-12 did not impact the Company s operating results, financial position or 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 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 with no gain or loss recorded.

West Edmond Hunton Lime Unit

On April 30, 2010, the Company completed the sale of its interest in the West Edmond Hunton Lime Unit (WEHLU) Field in Oklahoma County, Oklahoma for $155 million before customary closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of the Company s full cost pool with no gain or loss recorded. The transaction had an effective date of April 1, 2010. In conjunction with the closing, the Company assigned five natural gas swaps and five crude oil swaps to one of the purchasers.

Terryville

On May 12, 2010, the Company completed the sale of its interest in Terryville Field, located in Lincoln and Claiborne Parishes, Louisiana for $320 million before customary closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of the Company s full cost pool with no gain or loss recorded. The transaction had an effective date of January 1, 2010. In conjunction with the closing, the Company deposited $75 million with a qualified intermediary to facilitate like-kind exchange transactions. At June 30, 2010, the Company had $57.2 million remaining for use in future acquisitions.

Hawk Field Services, LLC Joint Venture

On May 21, 2010, Hawk Field Services, LLC (HFS), a wholly owned subsidiary of Petrohawk and KM Gathering LLC (Kinder Morgan), an affiliate of Kinder Morgan Energy Partners, L.P., a publicly traded master limited partnership, formed a new joint venture pursuant to a Formation and Contribution Agreement (Contribution Agreement). The new joint venture entity, KinderHawk Field Services LLC (KinderHawk), engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville Shale formation. Pursuant to the Contribution Agreement, HFS contributed to KinderHawk its Haynesville Shale gathering and treating business in Northwest Louisiana, and Kinder Morgan contributed approximately $921 million in cash ($875 million for a 50% membership interest in KinderHawk and $46 million for certain closing adjustments including 2010 capital expenditures through the closing date) to KinderHawk. Each of the Company and Kinder Morgan own a 50% membership interest in KinderHawk. KinderHawk distributed the approximate $921 million to the Company. The joint venture has 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 Company accounts for its interest in KinderHawk under the equity method.

The Company is obligated to deliver minimum annual quantities of natural gas to KinderHawk equal to 50% of the Company s annual projected production from Petrohawk operated wells located on certain dedicated acreage from the Haynesville and Bossier Shales in Northwest 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 pays KinderHawk negotiated gathering and treating fees, subject to an annual inflation adjustment factor. The gathering fee is equal to $0.34 per thousand cubic feet (Mcf) of natural gas delivered at KinderHawk s receipt points. The treating fee is 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 is between $0.030 and $0.345 per Mcf, and for gas containing over 5.5% carbon dioxide, the treating fee starts at $0.365 per Mcf and increases on a scale of $0.09 per Mcf for each additional 1% of carbon dioxide content.

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, 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 June 30, 2010, the ceiling test value of the Company s reserves was calculated based on the first day average of the twelve months ended June 30, 2010 of the West Texas Intermediate (WTI) posted price of $75.61 per barrel, adjusted by lease for quality, transportation fees, and regional price differentials, and the first day average of the twelve months ended June 30, 2010 of the Henry Hub price of $4.10 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 June 30, 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 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 June 30, 2009, the ceiling test value of the Company s reserves was calculated based on the June 30, 2009 WTI posted price of $69.89 per barrel, adjusted by lease for quality, transportation fees, and regional price differentials, and the June 30, 2009 Henry Hub spot market price of $3.89 per Mmbtu, adjusted by lease for energy content, transportation fees, and regional price differentials. At June 30, 2009, the Company s net book value of oil and natural gas properties did not exceed the ceiling amount.

4. DEBT

Long-term debt as of June 30, 2010 and December 31, 2009 consisted of the following:

	June 30, 2010(1)	December 31, 2009(1)
	(In thousands)	
Senior revolving credit facility	$	$ 203,000
10.5% $600 million senior notes (2)	558,038	554,154
7.875% $800 million senior notes	800,000	800,000
9.125% $775 million senior notes (3)	765,187	764,694
7.125% $275 million senior notes (4)	267,636	266,402
9.875% senior notes		224
Deferred premiums on derivatives	14,128	4,070
	$ 2,404,989	$ 2,592,544

(1) Amount excludes $35.3 million and $49.4 million of deferred premiums on derivatives which have been classified as current at June 30, 2010 and December 31, 2009, respectively. Amount excludes $0.2 million of 9.875% Senior Notes due 2011 which have been classified as current at June 30, 2010.

(2) Amount includes a $42.0 million and $45.8 million discount at June 30, 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 $4.2 million and $4.8 million discount at June 30, 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 June 30, 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 $4.8 million and $6.0 million discount at June 30, 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 (as amended, 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

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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. After taking into account the sale of the Company s interests in the Terryville and WEHLU fields, the borrowing base was $1.3 billion, $1.0 billion of which related to the Company s oil and natural gas properties and up to $300 million (currently limited as described below) of which related to the Company s midstream assets. The portion of the borrowing base which relates to the Company s oil and natural gas properties will be redetermined on a semi-annual basis (with the Company and the Lenders each having the right to one annual interim unscheduled redetermination) and adjusted based on the Company s oil and natural gas properties, reserves, other indebtedness and other relevant factors. The component of the borrowing base related to the Company s midstream assets is limited to the lesser of $300 million or 3.5 times midstream EBITDA, and is automatically determined quarterly. As of June 30, 2010, the midstream component of the borrowing base was limited to approximately $29 million based on the EBITDA limitation. The Senior Credit Agreement was amended on May 17, 2010 to permit the transactions contemplated by the KinderHawk joint venture. 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.

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 June 30, 2010, the Company was in compliance with its financial debt covenants under the Senior Credit Agreement.

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 of its 10.5% senior notes due 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 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 $42.0 million at June 30, 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. 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.

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 $4.2 million at June 30, 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 June 30, 2010.

7.125% Senior Notes

On July 12, 2006, the date of the Company s merger with KCS Energy, Inc. (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. 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

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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 $4.8 million at June 30, 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 and classified as current as of June 30, 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 June 30, 2010 and December 31, 2009, the Company had approximately $40.0 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 June 30, 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 and six months ended June 30, 2010.

	June 30, 2010			
	Level 1	**Level 2**	**Level 3**	**Total**
	(In thousands)			
Assets:				
Marketable securities	$ 281,006	$	$	$ 281,006
Restricted cash	57,186			57,186
Receivables from derivative contracts		280,686		280,686
	$ 338,192	$ 280,686	$	$ 618,878
Liabilities:				
Liabilities from derivative contracts	$	$ 224	$	$ 224

	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

Marketable securities and restricted cash listed above are carried at fair value. The Company is able to value its marketable securities and restricted cash based on quoted fair values for identical instruments, which resulted in the Company reporting its marketable securities and 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 (loss) gain on derivative contracts* in the Company s condensed consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curve for commodity prices based on quoted markets prices and implied volatility factors related to changes in the forward curves.

As of June 30, 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, *Financial Instruments*. 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, long-term debt instruments as of June 30, 2010 and December 31, 2009 (excluding premiums and discounts and any amounts that have been classified as current):

	June 30, 2010		December 31, 2009	
Long-Term Debt	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
	(In thousands)			
10.5% $600 million senior notes	$ 600,000	$ 649,500	$ 600,000	$ 658,500
7.875% $800 million senior notes	800,000	824,000	800,000	804,000
9.125% $775 million senior notes	768,725	805,239	768,725	805,239
7.125% $275 million senior notes	272,375	273,328	272,375	273,056
9.875% senior notes			224	227
	$ 2,441,100	$ 2,552,067	$ 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 six months ended June 30, 2010 (in thousands):

Liability for asset retirement obligation as of December 31, 2009	$ 44,000
Liabilities settled and divested (1)	(11,142)
Additions	3,945
Acquisitions	28
Accretion expense	1,036
Liability for asset retirement obligation as of June 30, 2010	$ 37,867

(1) Refer to Note 2, *Acquisitions and Divestitures* for more details on the Company s divestiture activities.

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 $2.9 million and $2.4 million for the six months ended June 30, 2010 and 2009, respectively.

As of June 30, 2010, the Company had the following commitments:

	Total Obligation Amount(1) (in thousands)	Years Remaining
Natural gas transportation commitments	$ 1,972,597	19
Drilling rig commitments	238,286	3
Non-cancelable operating leases	31,411	9
Various contractual commitments (including, among other things, pipeline and well equipment, and obtaining and processing seismic data)	80,052	3
Total commitments	$ 2,322,346	

(1) On May 21, 2010, the Company created a new joint venture with Kinder Morgan, KinderHawk, which engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville Shale formation. As part of this transaction, the Company is committed to contribute up to an additional $143 million as of June 30, 2010, in capital during 2010 and 2011 if KinderHawk cannot finance its planned capital expenditures. In addition, the Company is obligated to deliver minimum annual quantities of natural gas to KinderHawk equal to 50% of the Company s annual projected production from Petrohawk operated wells located on certain dedicated acreage from the Haynesville and Bossier Shales 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 pays to KinderHawk negotiated gathering and treating fees, subject to an annual inflation adjustment factor. See Note 2, *Acquisitions and Divestitures* for more details.

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 June 30, 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

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records the net change in the mark-to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in *Net (loss) gain on derivatives contracts* on the condensed consolidated statements of operations.

At June 30, 2010, the Company had 107 open commodity derivative contracts summarized in the tables below: 84 natural gas collar arrangements, one natural gas swap arrangement, ten natural gas put options, ten crude oil collar arrangements, and two crude oil swap arrangements. Derivative commodity contracts settle based on NYMEX WTI 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 swap arrangements.

All derivative contracts are recorded at fair market value in accordance with ASC 815 and ASC 820 and included in the condensed consolidated balance sheets as assets or liabilities. The following table summarizes the location and fair value amounts of all derivative contracts in the condensed consolidated balance sheets as of June 30, 2010 and December 31, 2009:

Derivatives not designated as hedging contracts under ASC 815	**Asset derivative contracts** Balance sheet location	**June 30, 2010** (In thousands)	**December 31, 2009**	**Liability derivative contracts** Balance sheet location	**June 30, 2010** (In thousands)	**December 31, 2009**
Commodity contracts	Current assets receivables from derivative contracts	$ 182,260	$ 112,441	Current liabilities liabilities from derivative contracts	$ (224)	$ (1,807)
Commodity contracts	Other noncurrent assets receivables from derivative contracts	98,426	50,421	Other noncurrent liabilities liabilities from derivative contracts		
Total derivatives not designated as hedging contracts under ASC 815		$ 280,686	$ 162,862		$ (224)	$ (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 contracts**	**Amount of gain or (loss) recognized in income on derivative contracts three months ended June 30, 2010** (In thousands)	**2009**	**Amount of gain or (loss) recognized in income on derivative contracts six months ended June 30, 2010** (In thousands)	**2009**
Commodity contracts:					
Unrealized (loss) gain on commodity contracts	Other income (expenses) net (loss) gain on derivative contracts	$ (87,424)	$ (84,626)	$ 102,671	$ 16,139
Realized gain on commodity contracts	Other income (expenses) net (loss) gain on derivative contracts	70,799	98,074	95,407	179,221
Total net (loss) gain on commodity contracts		$ (16,625)	$ 13,448	$ 198,078	$ 195,360
Interest rate swaps:					

Unrealized gain on interest rate swaps	Other income (expenses) net (loss) gain on derivative contracts	$	$ 2,280	$	$ 2,280
Realized gain on interest rate swaps	Other income (expenses) net (loss) gain on derivative contracts		278		288
Total net gain on interest rate swaps		$	$ 2,558	$	$ 2,568
Total net (loss) gain on derivative contracts	Other income (expenses) net (loss) gain on derivative contracts	$ (16,625)	$ 16,006	$ 198,078	$ 197,928

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At June 30, 2010, the Company had the following open derivative contracts:

				June 30, 2010			
				Floors		Ceilings	
Period	Instrument	Commodity	Volume in Mmbtu s/ Bbl s	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
July 2010-December 2010	Collars	Natural gas	69,920,000	$ 5.00 - $7.00	$ 5.97	$ 9.00 - $10.00	$ 9.21
July 2010-December 2010	Swaps	Natural gas	920,000	8.22	8.22		
July 2010-December 2010	Put Options	Natural gas	18,400,000	5.00	5.00		
July 2010-December 2010	Collars	Oil	368,000	80.00	80.00	96.75 - 97.00	96.88
July 2010-December 2010	Swaps	Oil	138,000	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	1,460,000	75.00 - 80.00	78.75	100.05 -101.00	100.34
January 2012-December 2012	Collars	Natural gas	78,690,000	5.00	5.00	7.50 - 8.00	7.55
January 2012-December 2012	Collars	Oil	1,464,000	80.00	80.00	102.00 - 102.45	102.18

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 six months ended June 30, 2010, the Company granted stock options covering 2.1 million shares of common stock to employees of the Company. The stock options have exercise prices ranging from $17.90 to $23.58 with a weighted average price of $21.20. 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 June 30, 2010, the unrecognized compensation expense related to non-vested stock appreciation rights and stock options totaled $20.3 million and will be recognized on a straight-line basis over the weighted average remaining vesting period of 1.4 years.

During the six months ended June 30, 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 $26.12 with a weighted average price of $15.36. These awards vest over a three-year period at a rate of one-third on the annual anniversary date of the grant and expire ten years from the grant date.

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

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Restricted Stock

During the six months ended June 30, 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 $17.90 to $23.58 with a weighted average price of $21.21. 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 June 30, 2010, the unrecognized compensation expense related to non-vested restricted stock totaled $23.5 million and was to be recognized on a straight-line basis over the weighted average remaining vesting period of 1.4 years.

During the six months ended June 30, 2009, the Company granted 0.6 million shares of restricted stock to employees of the Company and non-employee directors. These restricted shares were granted at prices ranging from $15.23 to $26.12 with a weighted average price of $15.40. 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.

Assumptions

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

	Six Months Ended June 30,	
	2010	**2009**
Weighted average value per option granted during the period	$ 10.31	$ 7.18
Assumptions (1):		
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. Calculated using the Black-Scholes fair value based method. 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 June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(In thousands, except per share amounts)			
Basic				
Net income (loss)	$ 13,495	$ (22,004)	$ 169,630	$ (1,021,757)
Weighted average basic number of shares outstanding	300,426	274,146	300,292	266,145
Basic net income (loss) per share	$ 0.04	$ (0.08)	$ 0.56	$ (3.84)
Diluted				
Net income (loss)	$ 13,495	$ (22,004)	$ 169,630	$ (1,021,757)
Weighted average basic number of shares outstanding	300,426	274,146	300,292	266,145
Common stock equivalent shares representing shares issuable upon exercise of stock options and stock appreciation rights	883	Anti-dilutive	1,286	Anti-dilutive
Common stock equivalent shares representing shares issuable upon exercise of warrants		Anti-dilutive		Anti-dilutive
Common stock equivalent shares representing shares included upon vesting of restricted shares	1,137	Anti-dilutive	1,137	Anti-dilutive
Weighted average diluted number of shares	302,446	274,146	302,715	266,145
Diluted net income (loss) per share	$ 0.04	$ (0.08)	$ 0.56	$ (3.84)

Common stock equivalents, including stock options, stock appreciation rights (SARS) and warrants, totaling 0.2 million and 2.2 million shares were not included in the computations of diluted earnings per share for the three and six months ended June 30, 2010 as the effect would have been anti-dilutive 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 2.7 million and 2.6 million shares were not included in the computation of diluted earnings per share as the effect would have been anti-dilutive for the three and six months ended June 30, 2009 due to the net losses.

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11. ADDITIONAL FINANCIAL STATEMENT INFORMATION

Certain balance sheet amounts are comprised of the following:

	June 30, 2010	December 31, 2009
	(In thousands)	
Accounts receivable:		
Oil and natural gas revenues	$ 104,462	$ 100,294
Marketing revenues	35,908	38,180
Joint interest accounts	90,866	75,316
Income and other taxes receivable	28,485	22,743
Other	6,568	2,731
	$ 266,289	$ 239,264
Prepaids and other:		
Prepaid insurance	$ 2,240	$ 2,478
Prepaid drilling costs	45,491	27,617
Other	3,115	2,339
	$ 50,846	$ 32,434
Accounts payable and accrued liabilities:		
Trade payables	$ 102,935	$ 75,549
Revenues and royalties payable	148,317	155,568
Accrued oil and natural gas capital costs	241,863	175,369
Accrued midstream capital costs	31,631	29,570
Accrued interest expense	68,641	69,410
Prepayment liabilities	28,656	36,714
Accrued lease operating expenses	9,304	11,407
Accrued ad valorem taxes payable	10,655	5,151
Accrued employee compensation	13,167	11,820
Income taxes payable	47,501	533
Other	60,499	62,080
	$ 763,169	$ 633,171

12. SEGMENTS

In accordance with ASC 280, *Segment Reporting*, the Company has identified two reportable segments: oil and natural gas and midstream. 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* .

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 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. As discussed in Note 2, *Acquisitions and Divestitures* and Note 13 *Equity Method Investment* , on May 21, 2010, the Company contributed its Haynesville Shale gathering and treating business to form a new joint venture entity with Kinder Morgan. The Company accounts for its 50% investment in the new entity, KinderHawk Field Services LLC, under the equity method and the revenues and expenses associated with the Haynesville Shale gathering and treating business are no longer presented within the Company s consolidated revenues and expenses in the condensed consolidated income statements. Although the Haynesville Shale gathering and treating business represents a significant portion of the Company s midstream segment revenues and expenses, the Company s midstream segment continues to operate in the Fayetteville and Eagle

Ford Shales. The Company pays to KinderHawk negotiated gathering and treating fees, which are included in *Gathering, transportation and other* on the condensed consolidated income statements, and are discussed further in Note 2, *Acquisitions and Divestitures.*

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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.

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 June 30, 2010:				
Revenues	$ 347,172	$ 6,331	$	$ 353,503
Intersegment revenues		14,786	(14,786)	
Total revenues	$ 347,172	$ 21,117	$ (14,786)	$ 353,503
Gathering, transportation and other	(45,075)	(4,581)	14,786	(34,870)
Depletion, depreciation and amortization	(99,375)	(1,800)		(101,175)
General and administrative	(32,374)	(10,967)		(43,341)
Amortization of deferred gain		64,367		64,367
Interest expense and other	(60,767)	(766)		(61,533)
Equity investment income		2,047		2,047
(Loss) income before income taxes	$ (47,000)	$ 68,918	$	$ 21,918
Total assets	$ 6,651,621	$ 816,136	$ (27,643)	$ 7,440,114
Capital expenditures	$ (572,951)	$ (95,587)	$	$ (668,538)
For the three months ended June 30, 2009:				
Revenues	$ 221,294	$ 6,006	$	$ 227,300
Intersegment revenues		9,946	(9,946)	$
Total revenues	$ 221,294	$ 15,952	$ (9,946)	$ 227,300
Gathering, transportation and other	(26,937)	(5,642)	9,946	(22,633)
Depletion, depreciation and amortization	(81,685)	(2,750)		(84,435)
General and administrative	(22,369)	(1,623)		(23,992)
Interest expense and other	(52,314)	(3,566)		(55,880)
(Loss) income before income taxes	$ (37,552)	$ 2,180	$	$ (35,372)
Total assets	$ 5,490,217	$ 362,596	$ (21,196)	$ 5,831,617
Capital expenditures	$ (358,855)	$ (74,215)	$	$ (433,070)
For the six months ended June 30, 2010:				
Revenues	$ 777,882	$ 15,937	$	$ 793,819
Intersegment revenues		39,138	(39,138)	
Total revenues	$ 777,882	$ 55,075	$ (39,138)	$ 793,819
Gathering, transportation and other	(91,716)	(11,672)	39,138	(64,250)
Depletion, depreciation and amortization	(201,307)	(5,942)		(207,249)
General and administrative	(62,909)	(12,640)		(75,549)
Amortization of deferred gain		64,367		64,367
Interest expense and other	(115,170)	(9,209)		(124,379)
Equity investment income		2,047		2,047
Income before income taxes	$ 196,458	$ 80,733	$	$ 277,191
Total assets	$ 6,651,621	$ 816,136	$ (27,643)	$ 7,440,114
Capital expenditures	$ (1,217,323)	$ (162,805)	$	$ (1,380,128)

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	Oil and Natural Gas	Midstream	Intersegment Eliminations	Consolidated Total
For the six months ended June 30, 2009:				
Revenues	$ 478,541	$ 12,214	$	$ 490,755
Intersegment revenues		17,456	(17,456)	
Total revenues	$ 478,541	$ 29,670	$ (17,456)	$ 490,755
Gathering, transportation and other	(52,185)	(8,398)	17,456	(43,127)
Depletion, depreciation and amortization	(193,749)	(4,942)		(198,691)
Full cost ceiling impairment	(1,732,486)			(1,732,486)
General and administrative	(41,102)	(2,529)		(43,631)
Interest expense and other	(103,885)	(8,063)		(111,948)
(Loss) income before income taxes	$ (1,652,413)	$ 5,317	$	$ (1,647,096)
Total assets	$ 5,490,217	$ 362,596	$ (21,196)	$ 5,831,617
Capital expenditures	$ (750,394)	$ (143,059)	$	$ (893,453)

13. EQUITY METHOD INVESTMENT

The Company s investment in an unconsolidated entity in which the Company does not have a majority interest, but does have significant influence, is accounted for under the equity method. Under the equity method of accounting, the Company s share of net income (loss) from the equity affiliate is reflected as an increase (decrease) in its investment account and is also recorded as equity investment income (loss). Distributions from the equity affiliate are recorded as reductions of the Company s investment and contributions to the equity affiliate are recorded as increases of the Company s investment. The Company s equity method investment is included in *Other noncurrent assets* in the condensed consolidated balance sheets and the Company s net share of earnings or losses is reported as *Equity investment income (loss)* in the condensed consolidated statements of operations.

The Company reviews its equity method investment for potential impairment whenever events or changes in circumstances indicate that an other-than-temporary decline in the value of the investment has occurred.

Investment in KinderHawk Field Services LLC

As discussed in Note 2, *Acquisitions and Divestitures,* on May 21, 2010, the Company and Kinder Morgan formed a new joint venture entity, KinderHawk Field Services LLC, which engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville Shale formation. As part of the transaction, the Company contributed its Haynesville Shale gathering and treating business in Northwest Louisiana to KinderHawk and Kinder Morgan contributed approximately $921 million in cash, to the new entity. Each of the Company and Kinder Morgan owns a 50% membership interest in KinderHawk. The Company accounts for its 50% membership interest in KinderHawk as an equity method investment. As of June 30, 2010, the Company s investment in KinderHawk totaled $205.5 million.

As a result of the transaction, the Company recorded a deferred gain of approximately $713.8 million for the difference between 50% of the net carrying value of the assets the Company contributed to the joint venture and the net cash proceeds from KinderHawk, representing the cash contributed by Kinder Morgan at closing for its 50% membership interest in KinderHawk. The Company will amortize the portion of the deferred gain equal to its capital commitment over the remainder of 2010 and 2011 as contributions to KinderHawk are made or upon expiration. In addition to the capital commitment, the Company guaranteed to deliver certain minimum volumes of natural gas through the Haynesville gathering system for the next five years, as discussed in Note 2, *Acquisitions and Divestitures* . The Company will amortize the remaining deferred gain as volumes are delivered through the Haynesville gathering system over the next five years.

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The summarized unaudited income statement information for KinderHawk from May 21, 2010 (date of formation) through June 30, 2010 is as follows (in thousands):

Operating revenues	$ 10,858
Operating expenses	(6,704)
Operating income	4,154
Interest expense and other	(60)
Income tax expense	
Net income available to KinderHawk	$ 4,094

14. SUBSEQUENT EVENT

The Company and its senior secured lenders are working on an amendment to the Company s revolving credit agreement. The Company expects to finalize the amendment during the third quarter of 2010. The amended credit agreement is expected to, among other things, adjust the borrowing base to take into account the KinderHawk joint venture, adjust the specified interest rate margins paid by the Company on outstanding borrowings and extend the maturity of the facility from July 1, 2013 to July 1, 2014. Under the amended credit facility the borrowing base is expected to be approximately $1.1 billion, approximately $1.0 billion of which relates to the Company s oil and natural gas properties and up to $100 million of which relates to the Company s midstream assets, limited to the lesser of $100 million or 3.5 times midstream EBITDA. Amounts outstanding under the amended credit facility are expected to bear interest at specified margins over LIBOR of 2.00% to 3.00% for Eurodollar loans or at specified margins over ABR of 1.00% to 2.00% for ABR loans, revised from 2.25% to 3.25% for Eurodollar loans and .75% to 1.75% for ABR loans. These margins will fluctuate based on the utilization of the facility. As with the Company s current revolving credit agreement, borrowings under the amended credit agreement are expected to be secured by first priority liens on substantially all of the Company s assets, including all of the assets of, and equity interests in, the Company s subsidiaries.

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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 and six months ended June 30, 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 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. On May 21, 2010, Hawk Field Services contributed our Haynesville Shale gathering and treating business to a new joint venture entity, KinderHawk Field Services LLC in exchange for a 50% membership interest and approximately $921 million in cash. See further discussion of the new joint venture below.

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.

The table below reflects our net undeveloped and mineral acreage as of December 31, 2009 that will expire by year if we do not establish production in paying quantities on the units in which such acreage is included or do not pay (or do not have the contractual right to pay) delay rentals or other extensions to maintain the lease.

Year	Percentage Expiration
2010	12%
2011	35%
2012	15%
2013	10%
2014	
2015 & beyond	28%
	100%

Our average daily oil and natural gas production increased 40% in the first six months of 2010, during which we averaged 625 million cubic feet of natural gas equivalent (Mmcfe) per day (Mmcfe/d) compared to average daily production of 448 Mmcfe/d during the first six months of 2009. The increase in production

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compared to the prior year period is driven by our drilling successes in the Haynesville, Fayetteville and Eagle Ford Shales as our production gains have made up for our sold production associated with our 2010 asset sales, as discussed below. Overall, we drilled or participated in the drilling of 403 gross wells (103.8 net wells) of which 401 gross (103.2 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, 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. Our current 2010 capital budget includes spending for drilling and completions of approximately $1.35 billion and 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. Recently, our costs for certain well completion services have begun to increase significantly, primarily in response to strong demand among oil and natural gas companies operating in the Eagle Ford and Haynesville Shale plays. We are actively engaged in efforts to control or offset these costs. However, if we are unable to control or offset these costs, we estimate that actual 2010 capital expenditures may exceed our current budget. We continually monitor our capital expenditures program and may alter our capital expenditures budget and future drilling plans in response to these and various other 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 or increases in our 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 June 30, 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 $4.10 per million British thermal unit (Mmbtu) and West Texas Intermediate (WTI) posted price of $75.61 per Bbl. Changes in prices, production rates, levels of reserves, future development costs, and other factors will determine our ceiling test calculation and impairment analyses in future periods.

During the third quarter of 2009, we announced our intent to strengthen our balance sheet 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 sold 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. We also formed a joint venture, discussed in greater detail below, in which we received approximately $921 million (including approximately

$46 million in closing adjustments) for a 50% interest in our Haynesville Shale gathering and treating business in North Louisiana. During the second half of 2010 we intend to market our upstream and midstream assets in the Fayetteville Shale in Arkansas. A divestment will only occur if we receive bids that we determine are favorable. Any such closing would likely be in the fourth quarter of 2010 or the first quarter of 2011.

Hawk Field Services, LLC Joint Venture

On May 21, 2010, our wholly owned subsidiary, Hawk Field Services, and KM Gathering LLC (Kinder Morgan), an affiliate of Kinder Morgan Energy Partners, L.P., a publicly traded master limited partnership, formed a new joint venture pursuant to a Formation and Contribution Agreement (Contribution Agreement). The new joint venture entity, KinderHawk Field Services LLC (KinderHawk), engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville Shale formation. Pursuant to the Contribution Agreement, Hawk Field Services contributed to KinderHawk our Haynesville Shale gathering and treating business in Northwest Louisiana, and Kinder Morgan contributed approximately $921 million in cash ($875 million for a 50% membership interest in KinderHawk and $46 million for certain closing adjustments including 2010 capital expenditures through the closing date) to KinderHawk. We, along with Kinder Morgan, own a 50% membership interest in KinderHawk. KinderHawk distributed the approximate $921 million to us. The joint venture has 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. We account for our interest in KinderHawk under the equity method.

We are obligated to deliver minimum annual quantities of natural gas to KinderHawk equal to 50% of our annual projected production from Petrohawk operated wells located on certain dedicated acreage from the Haynesville and Bossier Shales 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. We pay KinderHawk negotiated gathering and treating fees, subject to an annual inflation adjustment factor. The gathering fee is equal to $0.34 per Mcf of natural gas delivered at KinderHawk s receipt points. The treating fee is 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 is between $0.030 and $0.345 per Mcf, and for gas containing over 5.5% carbon dioxide, the treating fee starts at $0.365 per Mcf and increases 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, 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. Our 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. We are subject to additional covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. 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.

The Senior Credit Agreement provides for a $2.0 billion facility. After taking into account the sale of our interests in the Terryville and WEHLU fields, the borrowing base is $1.3 billion, $1.0 billion of which relates to our oil and natural gas properties and $300 million of which relates to our midstream assets. The Senior Credit Agreement was amended on May 17, 2010 to permit the transactions contemplated by the KinderHawk joint venture. The portion of the borrowing base which relates to our 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 our oil and natural gas properties, reserves, other indebtedness and other relevant factors. The component of the borrowing base related to our midstream assets is limited to the lesser of $300 million or 3.5 times midstream EBITDA, is automatically determined quarterly and is currently limited to approximately $29 million based on the EBITDA limitation.

We and our senior secured lenders are working on an amendment to our revolving credit agreement. We expect to finalize the amendment during the third quarter of 2010. The amended credit agreement is expected to, among other things, adjust the borrowing base to take into account the KinderHawk joint venture, adjust the specified interest rate margins paid by us on outstanding borrowings and extend the maturity of the facility from July 1, 2013 to July 1, 2014. Under the amended credit facility the borrowing base is expected to be approximately $1.1 billion, approximately $1.0 billion of which relates to our oil and natural gas properties and up to $100 million of which relates to our midstream assets, limited to the lesser of $100 million or 3.5 times midstream EBITDA. Amounts outstanding under the amended credit facility are expected to bear interest at specified margins over LIBOR of 2.00% to 3.00% for Eurodollar loans or at specified margins over ABR of 1.00% to 2.00% for ABR loans, revised from 2.25% to 3.25% for Eurodollar loans and 0.75% to 1.75% for ABR loans. These margins will fluctuate based on the utilization of the facility. As with our current revolving credit agreement, borrowings under the amended credit agreement are expected to be secured by first priority liens on substantially all of our assets, including all of the assets of, and equity interests in, our subsidiaries.

In conjunction with the KinderHawk joint venture discussed previously, we are obligated to commit up to an additional $143 million, as of June 30, 2010, in capital contributions to KinderHawk during 2010 and 2011, if KinderHawk is not able to fund its capital expenditures. Additional contributions above this amount can be made at our discretion. The obligation of capital contributions to KinderHawk could impact our development plans by reducing the amount of capital available to fund our drilling program. Capital contributions required to be made to KinderHawk will be factored into our overall analysis of capital resources and liquidity on an ongoing basis.

Our long-term cash flows are subject to a number of variables including our level of oil and natural gas 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 oil and 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 six months ended June 30, 2010 were funds from asset sales and operating activities, which were partially offset by net repayments of our Senior Credit Agreement and cash used in investing activities to fund our drilling program and acquisition activities. Our primary sources of cash for the six months ended June 30, 2009 were from operating and financing activities. Proceeds from the sale of common stock, the issuance of new senior debt and cash received from operations were offset by repayments of our Senior Credit Agreement and cash used in investing activities to fund our drilling program and acquisition activities. Cash received from asset sales 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 increase (decrease) in cash is summarized as follows:

	Six Months Ended June 30,	
	2010	2009
	(In thousands)	
Cash flows provided by operating activities	$ 319,526	$ 326,116
Cash flows used in investing activities	(92,114)	(787,464)
Cash flows (used in) provided by financing activities	(226,781)	457,203
Net increase (decrease) in cash	$ 631	$ (4,145)

Operating Activities. Net cash provided by operating activities for the six months ended June 30, 2010 and 2009 were $319.5 million and $326.1 million, respectively.

Net cash provided by operating activities decreased in 2010 due to the decrease in realized gains on our derivative contracts from $179.2 million for the six months ended June 30, 2009 to $95.4 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 40% increase in our average daily production volumes due to our drilling successes in the Haynesville, Fayetteville and Eagle Ford Shales. Our natural gas equivalent price increased $0.76 per Mcfe to $4.77 per Mcfe from $4.01 per Mcfe in the prior year. Production for the first six months of 2010 averaged 625 Mmcfe/d compared to 448 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 $92.1 million and $787.5 million for the six months ended June 30, 2010 and 2009, respectively.

During the first six months of 2010, we spent $1.2 billion on oil and natural gas capital expenditures. To date in 2010, we participated in the drilling of 403 gross wells (103.8 net wells). We spent an additional $173.8 million on other operating property and equipment expenditures, primarily to fund the development of our gathering systems in the Haynesville Shale in Northwest Louisiana and the Eagle Ford Shale in South Texas.

On May 21, 2010, our wholly owned subsidiary, Hawk Field Services, and Kinder Morgan entered into a joint venture arrangement to create a new entity, KinderHawk, which engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville Shale formation. Hawk Field Services contributed to KinderHawk our Haynesville Shale gathering and treating business in Northwest Louisiana, and Kinder Morgan contributed approximately $921 million in cash ($875 million for a 50% membership interest in KinderHawk and $46 million for certain closing adjustments including 2010 capital expenditures through the closing date) to KinderHawk. We, along with Kinder Morgan, own a 50% membership interest in KinderHawk. KinderHawk distributed the approximate $921 million to us.

On May 12, 2010, we completed the sale of our interest in Terryville Field, located in Lincoln and Claiborne Parishes, Louisiana for $320 million before customary closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of our full cost pool with no gain or loss recorded. The transaction had an effective date of January 1, 2010. In conjunction with the closing, we deposited $75 million with a qualified intermediary to facilitate like-kind exchange transactions. At June 30, 2010, we had $57.2 million remaining for use in future acquisitions.

On April 30, 2010, we completed the sale of our interest in the WEHLU Field in Oklahoma County, Oklahoma for $155 million before customary closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of our full cost pool with no gain or loss recorded. The transaction had an effective date of April 1, 2010. In conjunction with the closing, we assigned 5 natural gas swaps and 5 crude oil swaps to one of the purchasers.

During the first six months of 2010, we sold our interests in various non-core properties for aggregate proceeds of approximately $38 million. Proceeds from the sales were recorded as a reduction to the carrying value of our full cost pool with no gain or loss recorded.

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 with no gain or loss recorded.

During the first six months of 2010, we purchased a net $281.0 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 2010 capital program.

During the first six months of 2010, we had a net decrease in restricted cash of $156.5 million. Restricted cash was used to fund a portion of our 2010 oil and natural gas acquisitions.

During the first six months of 2009, we spent $748.1 million on oil and natural gas capital expenditures. We participated in the drilling of 297 gross wells (75.2 net wells). We spent an additional $145.4 million on other 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 Northwest Louisiana and the Eagle Ford Shale in Texas.

During the first six months of 2009, we sold a net $106.0 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 used in financing activities for the six months ended June 30, 2010 were $226.8 million and net cash flows provided by financing activities for the six months ended June 30, 2009 were $457.2 million.

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 2014 (the 2014 Notes). 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 six months of 2010, we had net repayments of borrowings of $223.8 million. During the first six months of 2009, we had net borrowings of $92.5 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 June 30, 2010:

	Total Obligation Amount[1] (in thousands)	Years Remaining
Natural gas transportation commitments	$ 1,972,597	19
Drilling rig commitments	238,286	3
Non-cancelable operating leases	31,411	9
Various contractual commitments (including, among other things, pipeline and well equipment, and obtaining and processing seismic data)	80,052	3
Total commitments	$ 2,322,346	

(1) On May 21, 2010, we created a new joint venture with Kinder Morgan, KinderHawk, which engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville Shale formation. As part of this transaction, we are committed to contribute up to an additional $143 million as of June 30, 2010 in capital during 2010 and 2011 if KinderHawk cannot finance its planned capital expenditures. In addition, we are obligated to deliver minimum annual quantities of natural gas to KinderHawk equal to 50% of our annual projected production from Petrohawk operated wells located on certain dedicated acreage from the Haynesville and Bossier Shales 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. We pay to KinderHawk negotiated gathering and treating fees, subject to an annual inflation adjustment factor.

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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, other than as discussed below.

On May 21, 2010, we created a new joint venture with Kinder Morgan, KinderHawk, which engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville Shale formation. As part of the transaction, we contributed our Haynesville Shale gathering and treating business in Northwest Louisiana to KinderHawk and Kinder Morgan contributed approximately $921 million in cash to the new entity. We and Kinder Morgan each own a 50% membership interest in KinderHawk. We account for our 50% membership interest in KinderHawk as an equity method investment. As a result of the transaction, we recorded a deferred gain of approximately $713.8 million for the difference between 50% of the net carrying value of the assets we contributed to the joint venture and the net cash proceeds from KinderHawk, representing the cash contributed by Kinder Morgan at closing for its 50% membership interest in KinderHawk. We will amortize the portion of the deferred gain equal to our capital commitment over the remainder of 2010 and 2011 as contributions to KinderHawk are made or upon expiration. In addition to the capital commitment, we guaranteed to deliver certain minimum volumes of natural gas through the Haynesville gathering system for the next five years. We will amortize the remaining deferred gain as volumes are delivered through the Haynesville gathering system over the next five years. This amortization is included in *Income (loss) from operations* in our condensed consolidated statements of income.

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Results of Operations

Quarters Ended June 30, 2010 and 2009

We reported net income of $13.5 million for the three months ended June 30, 2010 compared to a net loss of $22.0 million for the comparable period in 2009, resulting in a net change of $35.5 million. This change was primarily attributable to the amortization of our deferred gain on the sale of our Haynesville gas gathering system of $64.4 million offset by our loss on derivative contracts of $16.6 million in 2010 compared to a gain of $16.0 million in the prior year.

	Three Months Ended June 30,		
In thousands (except per unit and per Mcfe amounts)	**2010**	**2009**	**Change**
Net income (loss)	$ 13,495	$ (22,004)	$ 35,499
Operating revenues:			
Oil and natural gas	239,834	157,977	81,857
Marketing	107,338	63,317	44,021
Midstream	6,331	6,006	325
Expenses:			
Marketing	117,309	60,292	57,017
Production:			
Lease operating	16,384	18,704	(2,320)
Workover and other	1,571	205	1,366
Taxes other than income	5,191	12,537	(7,346)
Gathering, transportation and other:			
Oil and natural gas	30,289	16,991	13,298
Midstream	4,581	5,642	(1,061)
General and administrative:			
General and administrative	37,033	20,185	16,848
Stock-based compensation	6,308	3,807	2,501
Depletion, depreciation and amortization:			
Depletion Full cost	98,133	80,656	17,477
Depreciation Midstream	1,774	2,735	(961)
Depreciation Other	770	689	81
Accretion expense	498	355	143
Amortization of deferred gain	64,367		64,367
Net (loss) gain on derivative contracts	(16,625)	16,006	(32,631)
Interest expense and other	(61,533)	(55,880)	(5,653)
Equity investment income	2,047		2,047
Income tax (provision) benefit	(8,423)	13,368	(21,791)
Production:			
Natural gas Mmcf	54,494	40,927	13,567
Crude oil MBbl	225	407	(182)
Natural gas liquids MBbl	179	93	86
Natural gas equivalent Mmcfe (1)	56,918	43,927	12,991
Daily production Mmcfe (1)	625	483	142
Average price per unit (2):			
Natural gas price Mcf	$ 3.97	$ 3.26	$ 0.71
Crude oil price Bbl	74.55	53.72	20.83
Natural gas liquids price Bbl	36.30	27.25	9.05
Equivalent Mcfe (1)	4.21	3.60	0.61
Average cost per Mcfe:			
Production:			
Lease operating	0.29	0.43	(0.14)
Workover and other	0.03		0.03
Taxes other than income	0.09	0.29	(0.20)
Gathering, transportation and other:			
Oil and natural gas	0.53	0.39	0.14
Midstream	0.08	0.13	(0.05)
General and administrative:			

General and administrative	0.65	0.46	0.19
Stock-based compensation	0.11	0.09	0.02
Depletion	1.72	1.84	(0.12)

(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) 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 June 30, 2010, oil and natural gas revenues increased $81.9 million from the same period in 2009, to $239.8 million. The increase was primarily due to the increase in our production of 12,991 Mmcfe, or 29.6% over the three months ended June 30, 2009, primarily due to our drilling successes in resource-style plays in Louisiana, Arkansas and Texas. Increased production contributed to approximately $47 million in revenues for the three months ended June 30, 2010. Also contributing to this increase was an increase of $0.61 per Mcfe in our realized average price to $4.21 per Mcfe from $3.60 per Mcfe in the prior year period. This increase per Mcfe led to an increase in oil and natural gas revenues of $35 million.

We had marketing revenues of $107.3 million and marketing expenses of $117.3 million for the three months ended June 30, 2010, resulting in a net loss of $10.0 million as compared to a net gain of $3.0 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. Our net loss for the three months ended June 30, 2010 is primarily attributable to decreased margins, the amortization of our acquired transportation contracts and payments for unused pipeline capacity.

We had gross revenues from our midstream segment of $21.1 million for the three months ended June 30, 2010 compared to the same period in 2009 of $16.0 million, an increase of $5.1 million of which $4.8 million represents inter-segment revenues that are eliminated in consolidation. The remaining $0.3 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 $6.3 million for the three months ended June 30, 2010, an increase of $0.3 million from the prior year. The increase in revenues was directly related to an increase in throughput on our gathering systems and treating facilities and connecting additional wells to our gathering systems. Gathering throughput increased 8.7 Bcf to 36.6 Bcf for the three months ended June 30, 2010 compared to 27.9 Bcf for the three months ended June 30, 2009. The throughput increase resulted from the constructing of 57 miles of gathering pipeline and connecting 38 additional wells in the Eagle Ford and Fayetteville Shales during the period from July 1, 2009 through June 30, 2010, as well as, the constructing of approximately 100 miles and connecting 75 additional wells in the Haynesville Shale during the period from July 1, 2009 through May 20, 2010. As of June 30, 2010, we constructed 206 miles of gathering pipeline in the Eagle Ford and Fayetteville Shales. As of May 20, 2010, we constructed approximately 204 miles of gathering pipeline in the Haynesville Shale, which on May 21, 2010 we contributed to KinderHawk. Treating throughput increased 7.8 Bcf to 28.5 Bcf for the three months ended June 30, 2010 compared to 20.7 Bcf for the three months ended June 30, 2009, which was the result of additional wells coming on line and a greater treating capacity from the associated amine plants installed. As of June 30, 2010, we had two amine plants in service in the Eagle Ford Shale. As of May 20, 2010, we had 17 amine plants in service in the Haynesville Shale.

Lease operating expenses decreased $2.3 million for the three months ended June 30, 2010 primarily due to our continued cost control efforts as well as the sale of our higher cost properties in 2009 and 2010. On a per unit basis, lease operating expenses decreased $0.14 per Mcfe to $0.29 per Mcfe in 2010 from $0.43 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, as well as the sale of our Terryville and WEHLU properties in the second quarter of 2010, contributed to a decrease in costs for the three months ended June 30, 2010 over the same period in 2009 as these properties historically operated with higher operating costs per unit.

Taxes other than income decreased $7.3 million for the three months ended June 30, 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 $0.20 per Mcfe to $0.09 per Mcfe compared to $0.29 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, and for horizontal wells in Texas and Oklahoma. For the three months ended June 30, 2010, we recorded $11.1 million associated with severance tax refunds on horizontal wells that we drilled.

Gathering, transportation and other expense attributable to our oil and natural gas production segment increased $13.3 million, for the three months ended June 30, 2010 as compared to the same period in 2009. This increase was primarily due to the closing of our KinderHawk joint venture with Kinder Morgan on May 21, 2010, as gathering and treating fees now paid to KinderHawk historically had been paid to Hawk Field Services and eliminated in consolidation. We now pay $0.34 per Mcf of gas that is delivered at KinderHawk s receipt points for gathering and a treating fee that ranges between $0.030 per Mcf and $0.365 per Mcf or more depending on carbon dioxide content. On a per unit basis, gathering, transportation and other expenses increased $0.14 per Mcfe to $0.53 per Mcfe in 2010 compared to $0.39 per Mcfe in 2009, which increase on a per unit basis is also primarily attributable to the gathering and treating fees we are paying to KinderHawk which historically had been paid to Hawk Field Services and eliminated in consolidation.

Gathering, transportation and other expenses attributable to our midstream segment decreased $1.1 million for the three months ended June 30, 2010 compared to the same period in 2009. This decrease was primarily due to a decrease in costs associated with the Fayetteville Shale which was still in the development stages of operations through the first half of 2009. Gathering and treating throughput increased 16.5 Bcf to 65.1 Bcf for the three months ended June 30, 2010 compared to 48.6 Bcf for the three months ended June 30, 2009, which includes 20.7 Bcf of treating throughput. Gathering, transportation and other expense per Mcf for the three months ended June 30, 2010 was $0.07 per Mcf compared to $0.12 per Mcf for the three months ended June 30, 2009, a decrease of $0.05 per Mcf or 42% based on our total throughput.

General and administrative expense for the three months ended June 30, 2010 increased $16.8 million as compared to the same period in 2009. This increase is primarily attributable to the closing of our joint venture with Kinder Morgan. In conjunction with the formation of KinderHawk, we paid $7.5 million for services to our advisors on the transaction. This increase was also attributable to a $4.3 million increase in payroll and employee costs, including salaries, medical and incentives associated with the building of our work force as a result of the continued growth in our Company. In addition, professional fees increased $4.3 million.

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 increased $17.5 million for the three months ended June 30, 2010 from the same period in 2009, to $98.1 million. On a per unit basis, depletion expense decreased $0.12 per Mcfe to $1.72 per Mcfe. This decrease on a per unit basis is primarily due to the ceiling test impairment write-down of $106 million we recorded at December 31, 2009 as well as our property sales in 2009 and 2010.

Depreciation expense associated with our gas gathering systems decreased $1.0 million to $1.8 million for the three months ended June 30, 2010. This decrease was primarily due to the contribution of the gas gathering systems and treating facilities in the Haynesville Shale to KinderHawk and resulted in a $420 million decrease in gas gathering system and equipment assets. We depreciate our gas gathering systems over a 30 year useful life and begin depreciating on the estimated placed in service date.

On May 21, 2010, we contributed our Haynesville Shale gathering and treating business in exchange for a 50% membership interest in a new joint venture entity, KinderHawk, and approximately $921 million in cash. As a result of this transaction, we recorded a deferred gain of approximately $713.8 million for the difference between 50% of the net carrying value of the assets we contributed to the joint venture and the net cash proceeds from KinderHawk, representing the cash contributed by Kinder Morgan at closing for its 50% membership interest in KinderHawk. We will amortize the portion of the deferred gain equal to our capital commitment over the remainder of 2010 and 2011 as contributions to KinderHawk are made or upon expiration. In addition to the capital commitment, we guaranteed to deliver certain minimum volumes of natural gas through the Haynesville Shale gathering system for the next five years. We will amortize the remaining deferred gain as volumes are delivered through the Haynesville Shale gathering system over the next five years. Amortization of the deferred gain for the three months ended June 30, 2010 was $64.4 million.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Historically, we have also entered into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates (such as those on our Senior Credit Agreement) to fixed interest rates. 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 June 30, 2010, we had a $280.7 million derivative asset, $182.3 million of which was classified as current, and a $0.2 million derivative liability, all of which was classified as current. We recorded a net derivative loss of $16.6 million ($87.4 million net unrealized loss and $70.8 million net gain for cash received on settled contracts) for the three months ended June 30, 2010 compared to a net derivative gain of $16.0 million ($82.4 million net unrealized loss and a $98.4 million net gain for cash received on settled contracts) in the same period in 2009.

Interest expense and other increased $5.7 million for the three months ended June 30, 2010 compared to the same period in 2009. The increase is primarily related to the increased utilization of our Senior Credit Agreement, an increase in debt issue costs, and a decrease in capitalized interest. Interest expense increased $3.0 million due to utilization of the Senior Credit Agreement in the three months ended June 30, 2010 compared to the same period in 2009 to fund our 2010 capital program. Amortization of debt issue costs increased $0.8 million in the second quarter of 2010 as compared to the same period in 2009 due to the Senior Credit Agreement. Capitalized interest decreased $1.2 million which is primarily associated with the disposition of our Haynesville midstream assets into the KinderHawk joint venture.

Our investment in KinderHawk in which we do not have a majority interest, but do have significant influence, is accounted for under the equity method. Under the equity method of accounting, our share of net income (loss) from KinderHawk is reflected as an increase (decrease) in our investment account and is also recorded as equity investment income (loss). Distributions from KinderHaw