PETROHAWK ENERGY CORP
Form 10-K/A
December 05, 2011

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

FORM 10-K/A
(Amendment No. 1)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2010

Commission file number 001-33334

PETROHAWK ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**86-0876964**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**

1000 Louisiana, Suite 5600, Houston, Texas 77002
(Address of principal executive offices including ZIP code)

(832) 204-2700
(Registrant's telephone number)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ý

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 and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

(Check one):

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

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

The aggregate market value of common stock, par value $.001 per share, held by non-affiliates (based upon the closing sales price on the New York Stock Exchange on June 30, 2010), the last business day of registrant's most recently completed second fiscal quarter was approximately $5.1 billion.

As of December 2, 2011, there were 100 shares of common stock outstanding, all of which were held by BHP Billiton Petroleum (North America) Inc., a wholly owned subsidiary of BHP Billiton Limited.

DOCUMENTS INCORPORATED BY REFERENCE

Information required by Part III, Items 10, 11, 12, 13 and 14, is incorporated by reference to portions of the registrant's definitive proxy statement for its 2011 annual meeting of stockholders which was filed on April 15, 2011.

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Explanatory Note

Petrohawk Energy Corporation (Petrohawk or the Company) is filing this Amendment No. 1 to its Annual Report on Form 10-K (the Amendment) to restate and amend the Company's previously issued consolidated financial statements and related financial information as of and for the year ended December 31, 2010. In addition, the Company is restating and amending its Quarterly Reports on Form 10-Q for the quarters ended March 31, 2011 and June 30, 2011. The restatement relates to the accounting treatment associated with a joint venture transaction entered into on May 21, 2010 between the Company and KM Gathering LLC (Kinder Morgan), an affiliate of Kinder Morgan Energy Partners, L.P., a publicly traded master limited partnership. In this transaction, the Company contributed its Haynesville Shale gathering and treating system in Northwest Louisiana to KinderHawk Field Services LLC (KinderHawk), Kinder Morgan contributed approximately $917 million in cash, which was distributed to the Company as consideration for 50% of the Haynesville Shale gathering and treating system. In connection with the transaction the Company entered into a gathering agreement with KinderHawk which requires the Company to deliver natural gas to the operator of the gathering and treating system, KinderHawk, from dedicated oil and natural gas lease acreage for the life of the dedicated lease acreage, or approximately 30 years, and includes a minimum delivery commitment over a five year period. Upon the completion of the transaction both the Company and Kinder Morgan held a 50% membership interest in KinderHawk. The Company originally accounted for the transaction as a partial sale for which the Company deferred a gain of approximately $719.4 million and recorded its 50% membership interest KinderHawk as an equity method investment. The deferred gain was to be recognized as commitments associated with KinderHawk, consisting of a capital commitment of approximately $200 million callable during a two-year period and a five-year delivery commitment were settled. Income and distributions related to the venture were recorded as adjustments to the Company's equity method investment.

The Company subsequently determined that the KinderHawk joint venture transaction should have been accounted for and disclosed in accordance with the Financial Accounting Standards Board's (FASB) Accounting Standards Codification (ASC) Subtopic 360-20, *Property, Plant and Equipment Real Estate Sales*, (ASC 360-20). ASC 360-20 establishes standards for recognition of profit on all real estate sales transactions other than retail land sales, without regard to the nature of the seller's business. In making the determination of whether a transaction qualifies, in substance, as a sale of real estate, the nature of the entire real estate being sold is considered, including the land plus the property improvements and the integral equipment. The Haynesville Shale gathering and treating system, consists of right of ways, pipelines and processing facilities. Due to the gathering agreement which constitutes extended continuing involvement under ASC 360-20, it has been determined that the contribution of the Company's Haynesville Shale gathering and treating system to form KinderHawk should be accounted for as a failed sale of in substance real estate. As a result of the failed sale the Company would account for the continued operations of the gas gathering system and reflect a financing obligation, representing the proceeds received, under the financing method of real estate accounting. Under the financing method, the historical cost of the Haynesville Shale gas gathering system contributed to KinderHawk should have continued to be carried at the full historical basis of the assets on the consolidated balance sheets in *"Gas gathering systems and equipment"* and depreciated over the remaining useful life of the assets. The financing obligation is recorded on the consolidated balance sheets in *"Payable on financing arrangement,"* in the amount of approximately $917 million. Reductions to the obligation and the non cash interest on the obligation are tied to the gathering and treating services, as the Company delivers natural gas through the Haynesville Shale gathering and treating system. Interest and principal are determined based upon the allocable income to Kinder Morgan, and interest is limited up to an amount that is calculated based upon the Company's weighted average cost of debt as of the date of the transaction. Allocable income in excess of the calculated value will be reflected as reductions of principal. Interest is recorded in *"Interest expense and other"* on the consolidated statements of operations. Any obligation remaining once the gathering agreement

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expires will be reversed, resulting in the recognition of a gain. Additionally the Company records KinderHawk's revenues, net of eliminations for intercompany amounts associated with gathering and treating services provided to the Company, and expenses on the consolidated statements of operations in *"Midstream revenues," "Taxes other than income," "Gathering, transportation and other," "General and administrative," "Interest expense and other"* and *"Depletion, depreciation and amortization."*

The following sections of the originally filed Form 10-K have been revised and restated and are set forth in their entirety in this Amendment: Part I Item 1*Business*; Part II Item 6*Selected Financial Data*; Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*; Item 8. *Financial Statements and Supplementary Data*; Item 9A. *Controls and Procedures*; and Part IV Item 15*Exhibits and Financial Statement Schedules*. Additionally, in this Amendment, the Company is including (i) a revised Management's Report on Internal Control over Financial Reporting; (ii) currently dated certifications from the Company's Principal Executive Officer and Principal Financial Officer as required by Section 302 of the Sarbanes-Oxley Act of 2002 in Exhibits 31.1 and 31.2; (iii) a currently dated certification from the Company's Principal Executive Officer and Principal Financial Officer as required by Section 906 of the Sarbanes-Oxley Act of 2002 in Exhibit 32; and (iv) updated signature pages. The effect of the restatement on the Company's net income for the year ended December 31, 2010 was a reduction of approximately $98.7 million. This resulted in a reduction of net income of $0.33 per basic and diluted share for the year ended December 31, 2010.

Except to the extent described above and set forth herein, the financial statements and other disclosures in the Form 10-K initially filed on February 22, 2011 (the initial Form 10-K) are unchanged and this amendment does not reflect any events that have occurred after the initial Form 10-K was filed. Accordingly, this amendment should be read in conjunction with the Company's initial Form 10-K and the Company's subsequent filings with the United States Securities and Exchange Commission.

In light of the restatement, readers should not rely on the Company's previously filed financial statements as of and for the fiscal year ended December 31, 2010, and unaudited interim financial statements as of and for the periods ended June 30, 2010, September 30, 2010, March 31, 2011 and June 30, 2011.

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Special note regarding forward-looking statements

This Amendment No. 1 to the Annual Report on Form 10-K 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 and location of wells to be drilled in the future, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "believe," "intend," "achievable," "anticipate," "will," "continue," "potential," "should," "could" and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. 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 the previously filed Annual Report on Form 10-K, as well as sections of this report 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 in our resource plays such as the Haynesville, Lower Bossier 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 play holdings;
- management's ability to execute our plans to meet our goals;

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

the cost and availability of goods and services, such as drilling rigs, fracture stimulation services and tubulars;

access to and availability of water and other treatment materials to carry out planned fracture stimulations in our resource plays;

access to adequate gathering systems and transportation take-away capacity, necessary to fully execute our capital program;

our ability to secure firm transportation and other marketing outlets for the natural gas, natural gas liquids and crude oil and condensate we produce and to sell these products 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 economic conditions in the United States will worsen and that capital markets are disrupted, which could adversely affect demand for oil and natural gas and make it difficult to access financial markets;
- social unrest, political instability or armed conflict in oil and natural gas producing regions, such as the Middle East, and armed conflict 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.

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 the previously filed Annual Report on Form 10-K. 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

ITEM 1. BUSINESS

Overview

We are an independent oil and natural gas company engaged in the exploration, development and production of predominately natural gas properties located in the United States. Our business is comprised of an oil and natural gas production segment and a midstream operations segment. Our oil and natural gas properties are concentrated in three 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 and East Texas properties; and the Western, which includes our South Texas properties. Our midstream segment consists of our wholly owned gathering and treating subsidiary, Hawk Field Services, LLC (Hawk Field Services). We formed Hawk Field Services to enhance shareholder value by integrating our active drilling program with activities of third parties to develop additional gathering and treating capacity. Hawk Field Services currently serves the Haynesville Shale and Lower Bossier Shale in North Louisiana through our investment in KinderHawk Field Services LLC (KinderHawk) and the Eagle Ford Shale in South Texas.

At December 31, 2010, our estimated total proved oil and natural gas reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc. (Netherland, Sewell), were approximately 3,392 billion cubic feet of natural gas equivalent (Bcfe), consisting of 3,110 billion cubic feet (Bcf) of natural gas, 20 million barrels (MMBbls) of oil, and 27 MMBbls of natural gas liquids. Approximately 35% of our proved reserves were classified as proved developed. We maintain operational control of approximately 82% of our proved reserves. Production for the fourth quarter of 2010 averaged 761 million cubic feet of natural gas equivalent (Mmcfe) per day (Mmcfe/d). Full year 2010 production averaged 675 Mmcfe/d compared to 502 Mmcfe/d in 2009. Our total operating revenues for 2010 were approximately $1.6 billion.

We focus on properties within our core operating areas that 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 unit lease operating costs. We continue to selectively expand our leasehold position in our existing resource plays in the Haynesville and Lower Bossier Shales in North Louisiana and the Eagle Ford Shale in South Texas. We expect to continue to grow our production and reserves from these existing areas, with a near-term focus on holding our acreage positions and growing our crude oil and natural gas liquids production. We also expect to continue to evaluate new entry in areas that may be prospective for the resource plays we seek in order to capitalize on our expertise and extensive experience.

Recent Developments

2012 Note Refinancing

On January 31, 2011, we completed the issuance of an additional $400 million aggregate principal amount of our 7.25% senior notes due 2018 (the 2018 Notes). We will utilize a portion of the proceeds from this issuance to redeem our $275 million 7.125% senior notes, which have been called for redemption.

Senior Revolving Credit Facility

Effective August 2, 2010, we amended and restated our existing credit facility dated October 14, 2009 by entering into the Fifth Amended and Restated Senior Revolving Credit Agreement (the Senior Credit Agreement), among us, 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 Bank of Montreal as co-syndication agents for the Lenders, and JPMorgan Chase Bank, N.A. and Wells Fargo Bank, N.A., as co-documentation agents for the Lenders. The Senior Credit Agreement provides for a $2.0 billion facility. As of December 31, 2010, the borrowing base was approximately $1.65 billion, $1.55 billion of which related to our oil and natural gas properties and up to $100 million (currently limited as described below) related to our midstream assets. The portion of the borrowing base relating to our oil and natural gas properties is redetermined on a semi-annual basis (with us and the Lenders each having the right to one annual interim unscheduled redetermination) and adjusted based on our oil and natural gas properties, reserves, other indebtedness and other relevant factors. The component of the borrowing base relating to our midstream assets is limited to the lesser of $100 million or 3.5 times midstream earnings before interest, taxes, depreciation and amortization (EBITDA), and is calculated quarterly. As of December 31, 2010, the midstream component of the borrowing base was limited to approximately $38 million based on midstream EBITDA. Our 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 unsecured senior or senior subordinated notes that we may issue. In January 2011, we issued an additional $400 million aggregate principal amount of our 7.25% senior notes, a portion of the proceeds of which will be used to redeem all of our 7.125% $275 million senior notes, which have been called for redemption. Accordingly, our borrowing base was reduced to approximately $1.6 billion.

Amounts outstanding under the Senior Credit Agreement bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 2.00% to 3.00% for Eurodollar loans or at specified margins over the Alternate Base Rate (ABR) of 1.00% to 2.00% 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 our assets, including pursuant to the terms of the Fifth Amended and Restated Guarantee and Collateral Agreement, all of the assets of, and equity interests in, our subsidiaries. Amounts drawn on the facility will mature on July 1, 2014.

Fayetteville Shale Divestiture

On December 22, 2010, we completed the sale of our interest in natural gas properties and other operating assets in the Fayetteville Shale for $575 million in cash, before customary closing adjustments. As part of the transaction, the buyer also assumed certain firm pipeline transportation obligations of approximately $100 million. As of December 31, 2009, we had approximately 299 Bcf of proved reserves associated with the Fayetteville Shale. Production from the Fayetteville Shale as of the sale date was approximately 98 Mmcfe/d. Proceeds from the sale of the natural gas properties were recorded as a reduction to the carrying value of our full cost pool with no gain or loss recorded. In conjunction with the sale of the other operating assets, we recorded a loss of approximately $0.5 million in the year ended December 31, 2010. On January 7, 2011, we completed the sale of our midstream assets in the Fayetteville Shale for $75 million in cash, before customary closing adjustments. As of December 31, 2010, the Fayetteville Shale midstream assets were classified as held for sale on our consolidated balance sheet. Assets held for sale were recorded at the lesser of the carrying amount or the fair value less costs to sell, which resulted in a write down of the carrying amount of approximately $69.7 million before income taxes in the year ended December 31, 2010, which is included in *"Loss from discontinued operations net of income taxes"* on the consolidated statements of operations. Both transactions had an effective date of October 1, 2010.

2013 Note Refinancing

During the third quarter of 2010, we issued $825 million aggregate principal amount of our 7.25% senior notes due 2018 (the 2018 Notes). The proceeds from the 2018 Notes were utilized to redeem our $775 million 9.125% senior notes due 2013 (the 2013 Notes), which allowed us to reduce our future interest expense as a result of the lower interest rate and to extend the maturity of these bonds. Due to the early redemption of the 2013 Notes, we incurred charges of approximately $47 million in

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the third quarter of 2010. These charges are recorded in *"Interest expense and other"* on the consolidated statements of operations and include the cash premium paid to noteholders for the early redemption of the 2013 Notes, as well as non-cash charges related to the write-off of debt issuance costs, discounts and premiums associated with the 2013 Notes.

Mid-Continent Properties Divestiture

On September 29, 2010, we completed the sale of our interest in certain Mid-Continent properties in Texas, Oklahoma and Arkansas for $123 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. The transaction had an effective date of July 1, 2010.

Hawk Field Services, LLC Joint Venture

On May 21, 2010, 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 joint venture pursuant to a Formation and Contribution Agreement (Contribution Agreement). The joint venture entity, KinderHawk, engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville and Lower Bossier Shales. Pursuant to the Contribution Agreement, Hawk Field Services contributed to KinderHawk its Haynesville Shale gathering and treating business in Northwest Louisiana, and Kinder Morgan contributed approximately $917 million in cash ($875 million for a 50% membership interest in KinderHawk and $42 million for certain closing adjustments including 2010 capital expenditures through the closing date) to KinderHawk. Each of Hawk Field Services and Kinder Morgan own a 50% membership interest in KinderHawk. KinderHawk distributed approximately $917 million to Hawk Field Services. The joint venture had an economic effective date of January 1, 2010, and Hawk Field Services continued to operate the business until September 30, 2010, at which date Hawk Field Services and Kinder Morgan terminated the transition services agreement and KinderHawk assumed operations of the joint venture. In connection with the joint venture transaction we entered into a gathering agreement with KinderHawk which requires us to deliver natural gas to KinderHawk from dedicated lease acreage for the life of the dedicated lease acreage, or approximately 30 years, and includes a minimum delivery commitment over a five-year period.

We are obligated to deliver to KinderHawk agreed upon minimum annual quantities of natural gas from our operated wells producing from the Haynesville and Lower Bossier Shales, within specified acreage in Northwest Louisiana through May 2015, 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 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.

The KinderHawk joint venture is accounted for as a failed sale of in substance real estate under the provisions of the Financial Accounting Standards Board's (FASB) Accounting Standards Codification (ASC) Subtopic 360-20, *Property, Plant and Equipment Real Estate Sales* (ASC 360-20). ASC 360-20 establishes standards for recognition of profit on all real estate sales transactions other than retail land sales, without regard to the nature of the seller's business. In making the determination of whether a transaction qualifies, in substance, as a sale of real estate, the nature of the entire real estate being sold is considered, including the land plus the property improvements and the integral equipment. The Haynesville Shale gathering and treating system, consists of right of ways, pipelines and processing facilities. Due to the gathering agreement which constitutes extended continuing involvement

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under ASC 360-20, it has been determined that the contribution of our Haynesville Shale gathering and treating system to form KinderHawk should be accounted for as a failed sale of in substance real estate.

As a result of the failed sale we account for the continued operations of the gas gathering system and reflect a financing obligation, representing the proceeds received, under the financing method of real estate accounting. Under the financing method, the historical cost of the Haynesville Shale gas gathering system contributed to KinderHawk is carried at the full historical basis of the assets on the consolidated balance sheets in *"Gas gathering systems and equipment"* and depreciated over the remaining useful life of the assets. The financing obligation is recorded on the consolidated balance sheets in *"Payable on financing arrangement,"* in the amount of approximately $917 million. Reductions to the obligation and the non cash interest on the obligation are tied to the gathering and treating services, as we deliver natural gas through the Haynesville Shale gathering and treating system. Interest and principal are determined based upon the allocable income to Kinder Morgan, and interest is limited up to an amount that is calculated based upon our weighted average cost of debt as of the date of the transaction. Allocable income in excess of the calculated value is reflected as reductions of principal. Interest is recorded in *"Interest expense and other"* on the consolidated statements of operations. Any obligation remaining once the gathering agreement expires will be reversed, resulting in the recognition of a gain. Additionally we record KinderHawk's revenues, net of eliminations for intercompany amounts associated with gathering and treating services provided to us, and expenses on the consolidated statements of operations in *"Midstream revenues," "Taxes other than income," "Gathering, transportation and other," "General and administrative," "Interest expense and other"* and *"Depletion, depreciation and amortization."*

Terryville Divestiture

On May 12, 2010, we completed the sale of our interest in the Terryville Field, located in Lincoln and Claiborne Parishes, Louisiana for $320 million in cash, before customary closing adjustments. As of December 31, 2009, we had approximately 100 Bcfe of proved reserves associated with the Terryville Field. Production from the Terryville Field as of the sale date was approximately 20 Mmcfe/d. 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.

West Edmond Hunton Lime Unit Divestiture

On April 30, 2010, we completed the sale of our interest in the West Edmond Hunton Lime Unit (WEHLU) Field in Oklahoma County, Oklahoma for $155 million in cash, before customary closing adjustments. As of December 31, 2009, we had approximately 23 Bcfe of proved reserves associated with the WEHLU Field. Production from the WEHLU Field as of the sale date was approximately 12 Mmcfe/d. 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.

Acreage Acquisitions

During 2010, we completed acquisitions of acreage for a total of approximately $635 million. Leasehold acquisitions for 2010 included approximately $420 million in the Eagle Ford Shale, primarily in the Black Hawk area, approximately $141 million in the Haynesville Shale and approximately $74 million in other areas.

2011 Capital budget

We expect to spend approximately $2.3 billion during 2011, of which $1.9 billion is expected to be allocated for drilling and completions, $200 million is expected to be allocated for midstream operations and $200 million will be allocated for potential leasehold acreage acquisitions. Of the $1.9 billion budget for drilling and completions, $900 million is planned for the Haynesville and Lower Bossier Shales, which will enable us to fulfill our lease capture goals, $900 million is budgeted for the Eagle Ford Shale, and approximately $100 million is budgeted for various other projects. Our 2011 drilling and completion budget contemplates an increase in drilling activity in the Eagle Ford Shale throughout the year and a significant decrease in the Haynesville Shale operated rig count in the second half of the year as our lease-holding activities are fulfilled. Our 2011 program will emphasize the development of our extensive condensate-rich properties, largely in the Eagle Ford Shale, and a shift away from dry gas development. The $1.9 billion drilling and completion budget for 2011 is based on our current view of market conditions, our ability to accelerate certain areas of our Eagle Ford Shale position, and the desire to reduce capital allocated to pure natural gas drilling once the Haynesville Shale lease capture period is effectively completed.

We expect to fund our 2011 capital budget with cash flows from operations, proceeds from potential asset dispositions, a portion of the proceeds from our recent senior note offering and borrowings under our Senior Credit Agreement. We strive to maintain financial flexibility and may access capital markets as necessary to 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. In the event our cash flows or proceeds from potential asset dispositions are materially less than anticipated and other sources of capital we historically have utilized are not available on acceptable terms, we may curtail our capital spending.

Business Strategy

Our primary objective is to increase stockholder value by exploiting resource plays within our established core areas and exploring for new unconventional plays. We leverage our technical expertise in tight-gas and shale reservoirs to establish and develop large-scale operations in some of the fastest growing shale plays in the country. Once we establish an area as core, we focus on aggressively developing the asset through cost-effective drilling, active reservoir management, infrastructure optimization, and selected leasehold expansion and highgrading. Our operations offer the potential for predictable, long-term production with low costs achieved through effective drilling and completions techniques, efficient field management and scalable operations. Our strategy emphasizes:

Concentrated portfolio of properties We currently hold a high-quality portfolio of properties within a limited number of core plays, notably the Haynesville, Lower Bossier and Eagle Ford Shales. We believe we have significant exploitation and development opportunities in these plays where we can apply our technical experience and economies of scale to achieve profitable future growth. Currently our portfolio is more heavily weighted toward natural gas; however, in the future we expect our product mix to shift toward a greater percentage of liquids, especially as our Eagle Ford Shale programs increase.

Attractive undeveloped reserves We seek to maintain a portfolio of long-lived properties focused on resource plays within our core operating areas. Resource plays are typically characterized by lower geological risk and a large inventory of identified drilling opportunities. Our current plays include the Haynesville and Lower Bossier Shales in North Louisiana and East Texas and the Eagle Ford Shale in South Texas. We believe these properties have the potential to contribute significant growth in production and reserves over the long term.

Reduce operating costs We focus on reducing the per unit operating costs associated with our properties and have been successful in lowering our unit lease operating expenses from $0.47 Mcfe in 2008 to $0.43 per Mcfe in 2009 and $0.26 per Mcfe in 2010, including $0.22 per Mcfe during the fourth quarter.

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Divestment of non-core properties We continually evaluate our property portfolio to identify opportunities to divest non-core, higher cost or less productive properties with limited development potential. This highgrading strategy allows us to achieve a more concentrated portfolio of core properties with significant potential to increase our proved reserves and production and reduce our per unit operating costs. To allow us to concentrate on our core properties and further enhance our liquidity position, in 2010 we contributed our Haynesville Shale midstream business to a joint venture, and sold our interest in the Terryville Field in Northwest Louisiana, the WEHLU Field in central Oklahoma, and the Fayetteville Shale in Arkansas, as well as divested other non-core assets in the Mid-Continent region. Total proceeds from these transactions was approximately $2.1 billion.

Maintenance of financial flexibility We strive to maintain financial flexibility by balancing our financial resources with our plans to develop our key properties and pursue opportunities for growth and expansion. We intend to maintain substantial borrowing capacity under our Senior Credit Agreement to facilitate drilling on our large undeveloped acreage position in resource plays, selectively expand our position in these and other emerging resource plays and expand our infrastructure projects. We may access capital markets as necessary to maintain substantial borrowing capacity under our Senior Credit Agreement. We hedge a substantial portion of our production to provide downside price protection.

Oil and Natural Gas Reserves

Estimates of proved reserves at December 31, 2010, 2009, and 2008 were prepared by Netherland, Sewell & Associates, Inc., our independent consulting petroleum engineers. The technical persons responsible for preparing the reserve estimates are independent petroleum engineers and geoscientists that meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Our board of directors has established an independent reserves committee composed of three outside directors, all of whom have experience in energy company reserve evaluations. Our independent engineering firm reports jointly to the reserves committee and to our Senior Vice President Corporate Reserves. The reserves committee is charged with ensuring the integrity of the process of selection and engagement of the independent engineering firm and in making a recommendation to our board of directors as to whether to accept the report prepared by our independent consulting petroleum engineers. For information regarding the experience and qualifications of the members of the reserves committee of our board of directors and our Senior Vice President Corporate Reserves, see Item 10*Directors, Executive Officers and Corporate Governance.*

The reserves information in this report represents only estimates. There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control, such as commodity pricing. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent we acquire additional properties containing proved reserves or conduct successful exploration and development activities or both, our proved reserves will decline as reserves are produced. For additional information regarding estimates of proved reserves, the preparation of such estimates by Netherland, Sewell and other information about our oil and natural gas reserves, see Item 8. *Consolidated Financial Statements and Supplementary Data* "*Supplemental Oil and Gas Information (Unaudited).*"

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Proved reserve estimates are based on the unweighted arithmetic average prices on the first day of each month for the 12-month period ended December 31, 2010. Average prices for the 12-month period were as follows: West Texas Intermediate (WTI) spot price of $79.43 per barrel (Bbl) for oil and natural gas liquids, adjusted by lease or field for quality, transportation fees, and regional price differentials and a Henry Hub spot market price of $4.38 per million British thermal unit (Mmbtu) for natural gas, as adjusted by lease or field for energy content, transportation fees, and regional price differentials. All prices and costs associated with operating wells were held constant in accordance with the amended United States Securities and Exchange Commission (SEC) guidelines which were effective for financial statements for periods ending on or after December 31, 2009. The following table presents certain information as of December 31, 2010.

	Mid-Continent Region	Western Region	Total
Proved Reserves at Year End (Bcfe)[1]			
Developed	1,018.2	166.0	1,184.2
Undeveloped	1,637.4	570.0	2,207.4
Total	2,655.6	736.0	3,391.6

(1) *Oil and natural gas liquids are converted to equivalent gas reserves with 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.*

The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2010 and 2009. Shut-in wells currently not capable of production are excluded from producing well information.

	Years Ended December 31,			
	2010		2009	
	Gross	Net[1]	Gross	Net[1]
Oil	2.0	1.8	343.0	72.8
Natural Gas	2,814.0	1,281.7	4,687.0	1,703.2
Total	2,816.0	1,283.5	5,030.0	1,776.0

(1) *Net wells represent our working interest share of each well. The term "net" as used in "net acres" or "net production" throughout this document refers to amounts that include only acreage or production that we own and produce to our interest, less royalties and production due to others.*

Operating Segments

During the fourth quarter of 2009, we made a strategic shift in focus on and allocation of resources to our midstream division. As a result, we identified two reportable segments: oil and natural gas production and midstream operations. A further description of our operating segments is included in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 13, "*Segments*".

Oil and Natural Gas Production

Core Operating Regions

Mid-Continent Region

In the Mid-Continent Region, we concentrate our drilling program primarily in North Louisiana and East Texas. We believe our Mid-Continent Region operations provide us with a solid base for

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future production and reserve growth. During 2010, we drilled 805 wells in this region (of which 107 were operated and 698 were non-operated), and all were successful. In 2011, we plan to drill approximately 122 operated wells in this region and an additional 243 non-operated wells which are dependent upon other operators for execution. In 2010, we produced 216 Bcfe in this region, or 593 Mmcfe/d. As of December 31, 2010, approximately 78% of our proved reserves, or 2,656 Bcfe, were located in our Mid-Continent Region, which included 1,018 Bcfe of proved developed reserves. We sold our interest in natural gas properties and other operating assets in the Fayetteville Shale, which was part of our Mid-Continent Region and is located primarily in Cleburne and Van Buren Counties, Arkansas, in late December 2010 for approximately $575 million in cash, before customary closing adjustments. For further discussion of the Fayetteville Shale divestiture, see Item 1. *Business "Recent Developments."*

Haynesville Shale The Haynesville Shale has become one of the most active natural gas plays in the United States. This area is defined by a shale formation located approximately 1,500 feet below the base of the Cotton Valley formation at depths ranging from approximately 10,500 feet to 13,000 feet. The formation is as much as 300 feet thick and is composed of an organic rich black shale. It is located across numerous parishes in Northwest Louisiana, primarily in Caddo, Bossier, Red River, DeSoto, Webster and Bienville parishes and also in East Texas, primarily in Harrison, Panola, Shelby and Nacogdoches counties. Our Elm Grove/Caspiana acreage position is located near what we believe is the center of the play. We currently own leasehold interests in approximately 363,000 net acres in the area that we currently believe to be prospective for the Haynesville Shale. We own varying working and net revenue interests in this area.

Our current drilling and completion methodology focuses on completing wells with longer laterals and maximizing the number of fracture stages, averaging approximately 325 feet in length. The objective of this technique is to minimize the total number of wells required to effectively drain the reservoir, resulting in lower overall development costs. We are currently targeting lateral lengths between 4,300 feet and 4,800 feet with up to 15 fracture stages. At year-end 2010, we had 14 operated horizontal rigs running in the Haynesville Shale. Spud-to-first sales averaged approximately 90 days during 2010.

As of December 31, 2010, we had approximately 175 operated wells on production in North Louisiana producing approximately 694 Mmcfe/d gross. We have changed our production practice in the Haynesville Shale from one that typically produced at initial rates ranging from 18 Mmcfe/d to 24 Mmcfe/d to a typical range from 7 Mmcfe/d to 10 Mmcfe/d in an effort to maintain higher surface flowing pressures and lessen the rate of pressure decline, which we believe better maintains the permeability in the reservoir and ultimately allows for higher ultimate recovery of gas from each well. We had 10 operated wells that were pending completion and 14 operated wells that were drilling in this area at December 31, 2010.

In 2010, we produced 154 Bcfe, or 421 Mmcfe/d. As of December 31, 2010, proved reserves for this field were approximately 2,349 Bcfe, of which approximately 33% were classified as proved developed and approximately 67% as proved undeveloped. The proved reserves include 518 proved developed wells and 704 proved undeveloped locations. During 2010, we drilled 351 wells (101 operated and 250 non-operated), all of which were successful. We plan to drill 100 operated wells in this area in 2011, with eight to nine wells expected to be completed per month. We have preliminarily budgeted for an additional 230 non-operated wells in 2011 which will be dependent upon other operators for execution. We expect to operate an average of 12 rigs in the play in 2011, with an emphasis on growing production and reserves while at the same time holding our acreage position.

Lower Bossier Shale During 2010, the combination of wells we have drilled in the Haynesville Shale and wells drilled by other operators provided sufficient petrophysical and geochemical data

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to support the premise that there are potentially significant reserves in the Lower Bossier Shale. The Lower Bossier Shale is located approximately 200 feet to 400 feet above the Haynesville Shale. The net thickness of the shale is approximately the same as the Haynesville Shale and it also has many of the same reservoir parameters as the Haynesville Shale, particularly in the southern area of the Haynesville Shale trend. We currently own leasehold interests in approximately 150,000 net acres in the area that we currently believe to be prospective for the Lower Bossier Shale. The Whitney Corporation 19 #1H, our first Lower Bossier well, was completed in August 2010 at an initial production rate of 7.7 Mmcfe/d on a $^{14}/_{64}$" choke. We also participated in 15 Lower Bossier Shale wells as a non-operator with very positive results. We expect that it will be late 2012, and after our Haynesville Shale acreage is held by production, before we begin a significant operated Lower Bossier Shale development program. We own varying working and net revenue interests in this area. As of December 31, 2010, proved reserves for this reservoir were approximately 13 Bcfe, of which approximately 72% were classified as proved developed and approximately 28% as proved undeveloped.

Elm Grove and Caspiana Fields Located primarily in Bossier and Caddo Parishes of North Louisiana, our Elm Grove and Caspiana fields produce from the Hosston and Cotton Valley formations. These zones are composed of low permeability sandstones that require fracture stimulation treatments to produce. We currently own leasehold interests in approximately 26,000 net acres in the area that we currently believe to be prospective for Cotton Valley and/or Hosston formations. We own varying working and net revenue interests in these fields. We produced 24 Bcfe in 2010 in these fields, or 65 Mmcfe/d. As of December 31, 2010, proved reserves for the Elm Grove/Caspiana fields were approximately 290 Bcfe, of which approximately 83% were classified as proved developed, and 17% were classified as proved undeveloped. The proved reserves include 1,070 proved developed wells and 138 proved undeveloped locations. We owned an interest in 644 operated, producing wells in the Elm Grove and Caspiana fields as of December 31, 2010.

As this area is substantially held by production, the majority of our capital during 2010 was allocated to the Haynesville Shale as part of our plan to hold our Haynesville Shale acreage. For 2011, we will continue an allocation of capital to the Cotton Valley and Hosston program with one operated Cotton Valley formation horizontal well scheduled and a limited workover program in the Hosston formation.

Western Region

Our Western Region assets are focused primarily in the Hawkville and Black Hawk area in the Eagle Ford Shale play in South Texas. We believe our Eagle Ford Shale properties provide us with opportunities for future growth in oil, natural gas, and natural gas liquids production and reserves. During 2010 we divested other assets that the Western Region managed, including properties located in the Anadarko Basin in Oklahoma, the Arkoma Basin in Oklahoma and Arkansas and the East Texas Basin. Net production from the region was 30 Bcfe (82 Mmcfe/d) in 2010. During 2010, we drilled 69 operated wells and 32 non-operated wells with a 98% success rate. As of December 31, 2010, the proved reserves for the region were approximately 736 Bcfe of which 166 Bcfe were classified as proved developed and 570 Bcfe as proved undeveloped. There are 141 operated wells plus an additional 23 non-operated wells that are budgeted for 2011.

Hawkville Field We have approximately 236,000 net acres under lease that are located in LaSalle and McMullen Counties, Texas. Our average working interest and net revenue interest in 57 operated wells are approximately 85% and 64%, respectively. Our average working interest and net revenue interest in 12 non-operated wells are approximately 32% and 24%, respectively.

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The Hawkville Eagle Ford Shale pay thickness is over 300 feet. The wells have an average true vertical depth that ranges from 10,500 feet to 12,500 feet and they are drilled with horizontal laterals currently ranging from 5,000 feet to 7,000 feet. The wells are cased hole completed and are currently being fracture stimulated with an average of 18 stages. There are currently 27 wells which produce condensate with yields ranging from six barrels per million cubic feet (Bbls/Mmcf) to 199 Bbls/Mmcf and had an average initial producing rate of 311 barrels of oil per day (Bo/d). There are currently 23 wells which produce dry gas and had an average initial producing rate of 8.6 million cubic feet of natural gas per day (Mmcf/d). We had 16 operated wells and four non-operated wells that were pending completion and three wells that were drilling in this field at year-end.

The gross operated production from this field is currently 90 Mmcf/d plus 3,500 Bo/d. As of December 31, 2010, the proved reserves were approximately 627 Bcfe of which approximately 21% were classified as proved developed and 498 Bcfe as proved undeveloped. The proved reserves include 65 proved developed wells and 203 proved undeveloped locations. During 2010, we drilled 36 operated wells and five non-operated wells with no dry holes and there are 51 operated plus 23 non-operated wells budgeted for 2011.

Black Hawk We have approximately 69,000 net acres under lease that are located in Karnes and DeWitt Counties, Texas. Petrohawk is the operator during the drilling and completion phase of the wells and a private company is the operator after the wells are placed on production. Our average working interest and net revenue interest in 27 wells are approximately 66% and 50%, respectively.

The Black Hawk Eagle Ford Shale pay thickness is over 170 feet. The wells have an average true vertical depth that ranges from 12,000 feet to 13,500 feet and they are drilled with horizontal laterals currently averaging over 5,500 feet. The wells are cased hole completed and are currently being fracture stimulated with an average of 18 stages. There are currently 12 wells which produce condensate with yields ranging from 213 Bbls/Mmcf to 517 Bbls/Mmcf and had an average initial producing rate of 1,170 Bo/d. We had 15 wells that were pending completion and five wells that were drilling in this field at December 31, 2010. The gross production from this field is currently 22 Mmcf/d plus 8,200 Bo/d. As of December 31, 2010, proved reserves were approximately 109 Bcfe of which approximately 34% were classified as proved developed and 72 Bcfe as proved undeveloped. The proved reserves include 27 proved developed wells and 41 proved undeveloped locations. During 2010, we drilled 29 wells with no dry holes and there are 85 wells budgeted for 2011.

Black Hawk Extension We acquired approximately 10,500 net acres from a private company in December 2010. This new acreage is a west/southwest extension of our existing Black Hawk acreage. We will be the operator and will have approximately 96% working interest and 79% net revenue interest in the acreage. There is currently no production on this acreage and we are expecting to spud the first well in 2012.

Red Hawk We own leases or have options on approximately 77,000 net acres that are located in Zavala County, Texas. Our working interest in this acreage ranges from 81% to 90% and our net revenue interest ranges from 61% to 68%. The Red Hawk Eagle Ford Shale pay thickness ranges from 100 feet to 140 feet. Three wells were drilled in 2010, two of which were completed and on production as of December 31, 2010. These have an average true vertical depth of 5,500 feet and they were drilled with horizontal laterals that averaged 5,500 feet. The wells are cased hole completed and were fracture stimulated with an average of 17 stages. The wells were drilled in an oil window of the Eagle Ford Shale and their initial producing rate averaged 375 Bo/d with an insignificant volume of gas. There are five wells budgeted for 2011.

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Midstream Operations

During the fourth quarter of 2009, we made a strategic decision to focus on and allocate resources to our midstream division. As a result, we identified two reportable segments: oil and natural gas production and midstream operations. A further description of our operating segments is included in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 13, "*Segments*". Our midstream business provides greater control over the transportation of our production for delivery into major intrastate and interstate pipelines through the access of multiple interconnects. We operate our midstream division through our subsidiary, Hawk Field Services, which constructed our own gathering systems and treating facilities to service our operated wells and third party production from the Eagle Ford, Fayetteville and Haynesville Shales.

During 2010 we expanded our gathering and treating systems in both the Haynesville Shale and Eagle Ford Shale. Approximately 214 miles of gathering pipeline and 750 gallons per minute (GPM) of treating capacity were added in the Haynesville Shale during 2010. On January 7, 2011, we completed the sale of our midstream assets in the Fayetteville Shale for $75 million in cash, before customary closing adjustments.

Haynesville Shale Hawk Field Services currently serves the Haynesville Shale and Lower Bossier Shale in North Louisiana through our membership interest in KinderHawk. To date, the Haynesville Shale system comprises approximately 365 miles of pipeline and 2,360 GPM of treating capacity. As of December 31, 2010, daily system throughput averaged 753 Mmcf/d. In May 2010, Hawk Field Services contributed its Haynesville Shale gathering and treating business to form a new joint venture entity with Kinder Morgan, called KinderHawk, in exchange for a 50% membership interest and approximately $917 million in cash.

Eagle Ford Shale During June 2009, we initiated construction of a high pressure gathering systems in the Eagle Ford Shale to transport our production to various intrastate and interstate pipelines through the access of multiple interconnects. Our Eagle Ford Shale midstream activities have evolved into two separate midstream systems serving the Hawkville and Black Hawk areas.

In the Hawkville area, our gathering and treating system currently consists of approximately 114 miles of 6-inch to 16-inch diameter pipeline and two treating plants. Our Hawkville area system had a throughput capacity of 550 Mmcf/d and treating capacity of 250 GPM as of December 31, 2010.

In the Black Hawk area, our system consists of approximately 42 miles of 6-inch to 16-inch diameter gas pipeline and approximately 17 miles of 4-inch to 12-inch diameter liquid pipeline. Our Black Hawk area system had a throughput capacity of 250 Mmcf/d of natural gas and 100,000 barrels per day (Bbls/d) of condensate as of December 31, 2010. We plan to continue construction of the system throughout 2011 and expect construction of our stabilization and liquid handling facility to be operational during 2011, which will treat the Black Hawk area's natural gas and stabilize condensate in preparation for delivery to end-user markets.

Risk Management

We have designed a risk management policy for the use of derivative instruments to provide partial protection against certain risks relating to our ongoing business operations, such as commodity price risk and interest rate risk. Derivative contracts are utilized to economically hedge our exposure to price fluctuations and reduce the variability in our cash flows associated with anticipated sales on future oil, natural gas and natural gas liquids production. We hedge a substantial, but varying, portion of anticipated oil, natural gas, and natural gas liquids production for the next 12 to 36 months. Periodically, we enter into interest rate swaps to mitigate exposure to market rate fluctuations by

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converting variable interest rates (such as those on our Senior Credit Agreement) to fixed interest rates.

Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While there are many different types of derivatives available, we typically use collar agreements, swap agreements and put options to attempt to manage price risk more effectively. The collar agreements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. Periodically, we may pay a fixed premium to increase the floor price above the existing market value at the time we enter into the arrangement. All collar agreements provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price is below the floor. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of oil, natural gas, and natural gas liquids for the period is greater or less than the fixed price established for that period when the swap is put in place. Under put options, we pay a fixed premium to lock in a specified floor price. If the index price falls below the floor price, the counterparty pays us net of the fixed premium. If the index price rises above floor price, we pay the fixed premium.

It is our 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 our derivative contracts is a lender in our Senior Credit Agreement. We will continue to evaluate the benefit of employing derivatives in the future. See Item 7A. *Quantitative and Qualitative Disclosures about Market Risk* in our Annual Report on Form 10-K filed on February 22, 2011 for additional information.

Oil and Natural Gas Operations

Our principal properties consist of developed and undeveloped oil and natural gas leases and the reserves associated with these leases. Generally, developed oil and natural gas leases remain in force as long as production is maintained. Undeveloped oil and natural gas leaseholds are typically for a primary term of three to five years within which we are generally required to develop the property or the lease will expire. In some cases, the primary term of our undeveloped leases can be extended by option payments; the payments and time extended vary by lease.

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The table below sets forth the results of our drilling activities for the periods indicated:

	Years Ended December 31,					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive[(1)]	2	1.9			2	1.8
Dry						
Total Exploratory	2	1.9			2	1.8
Extension Wells[(2)]:						
Productive[(1)]	827	192.0	601	156.8	553	181.2
Dry	2	0.6	1	0.2	12	2.0
Total Extension	829	192.6	602	157.0	565	183.2
Development Wells:						
Productive[(1)]	75	23.8	24	5.1	172	82.4
Dry						
Total Development	75	23.8	24	5.1	172	82.4
Total Wells:						
Productive[(1)]	904	217.7	625	161.9	727	265.4
Dry	2	0.6	1	0.2	12	2.0
Total	906	218.3	626	162.1	739	267.4

(1) *Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly extension or exploratory wells where there is no production history.*

(2) *An extension well is a well drilled to extend the limits of a known reservoir.*

We own interests in developed and undeveloped oil and natural gas acreage in the locations set forth in the table below. These ownership interests generally take the form of working interests in oil and natural gas leases that have varying terms. The following table presents a summary of our acreage interests as of December 31, 2010:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
State						
Alabama			27,298	22,747	27,298	22,747
Arkansas			1,109	560	1,109	560
Indiana			3,543	3,260	3,543	3,260
Louisiana	131,903	110,540	219,093	192,594	350,996	303,134
Oklahoma	40	20	97,064	52,679	97,104	52,699
Texas	84,261	57,662	542,414	331,801	626,675	389,463
Total Acreage	216,204	168,222	890,521	603,641	1,106,725	771,863

The table below reflects our net undeveloped and mineral acreage as of December 31, 2010 that will expire each year if we do not establish production in paying quantities on the units in which such

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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
2011	44%
2012	33%
2013	16%
2014	3%
2015	3%
2016 & beyond	1%
	100%

At December 31, 2010, we had estimated proved reserves of approximately 3.4 trillion cubic feet of natural gas equivalent (Tcfe) comprised of 3,110 Bcf of natural gas, 27 MMBbls of natural gas liquids, and 20 MMBbls of oil. The following table sets forth, at December 31, 2010, these reserves:

	Proved Developed	Proved Undeveloped	Total Proved
Natural Gas (Bcf)	1,118.7	1,991.4	3,110.1
Oil (MMBbls)	5.7	14.1	19.8
Natural Gas Liquids (MMBbls)	5.2	21.9	27.1
Equivalent (Bcfe)	1,184.2	2,207.4	3,391.6

(1)

Oil and natural gas liquids are converted to equivalent gas reserves using a 6:1 equivalent ratio.

At December 31, 2010, our estimated proved undeveloped (PUD) reserves were approximately 2,207 Bcfe, a 362 Bcfe net increase over the previous year's estimate of 1,845 Bcfe. The net increase is comprised of additions of 1,185 Bcfe, primarily attributable to drilling in the Haynesville and Eagle Ford Shales. The increase was partially offset by a reduction of approximately 823 Bcfe, which primarily relates to PUD reserves estimated as of December 31, 2009 that are currently scheduled for development at least five years from December 31, 2010 due to changes in the development timing of new and existing PUD reserves, and to the sale of certain non-core properties. During 2010, the majority of our total drilling and completion capital was allocated to drilling undeveloped leases in the Haynesville Shale to hold acreage. As of December 31, 2010, all of our PUD reserves included in the reserve report are less than five years in age and over 97% are less than three years in age. The following table summarizes the amount of PUD reserves that have been developed in each of the last three years using the amount of PUD reserves that we reported in the prior year:

	2010	2009	2008
PUD reserves at beginning of year (Bcfe)	1,845.0	625.8	454.8
PUD reserves developed (Bcfe)	109.2	22.0	71.3
% PUD reserves developed	6%	4%	16%

The estimates of quantities of proved reserves above were made in accordance with the definitions contained in SEC Release No. 33-8995, *Modernization of Oil and Gas Reporting*. For additional information on our oil and natural gas reserves, see Item 8. *Consolidated Financial Statements and Supplementary Data "Supplementary Oil and Gas Information (Unaudited)."*

We account for our oil and natural gas producing activities using the full cost method of accounting in accordance with SEC regulations. Accordingly, all costs incurred in the acquisition, exploration, and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of evaluated oil and natural gas properties are subject to a quarterly full cost ceiling test. At December 31, 2010 the ceiling test value of our reserves was calculated based on the first day average of the 12-months ended December 31, 2010 of the WTI spot price of $79.43 per barrel, adjusted by lease or field for quality, transportation fees, and regional price differentials, and the first day average of the 12-months ended December 31, 2010 of the Henry Hub price of $4.38 per Mmbtu, adjusted by lease or field for energy content, transportation fees, and regional price differentials. Using these prices, our net book value of oil and natural gas properties at December 31, 2010, did not exceed the ceiling amount. We recorded a full cost ceiling test impairment before income taxes of approximately $1.7 billion and $1.0 billion at March 31, 2009 and December 31, 2008, respectively, at which time the WTI posted price was $49.66 and $41.00 per barrel for oil, respectively, and the Henry Hub spot market price was $3.63 and $5.71 per Mmbtu for natural gas, respectively. At December 31, 2009, our 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 in accordance with SEC Release No. 33-8995, *Modernization of Oil and Gas Reporting*. As a result, we recorded a full cost ceiling test impairment before income taxes of approximately $106 million and $65 million after taxes.

Capitalized costs of our evaluated and unevaluated properties at December 31, 2010, 2009 and 2008 are summarized as follows:

	December 31,		
	2010	**2009**	**2008**
		(In thousands)	
Oil and natural gas properties (full cost method):			
Evaluated	$ 7,520,446	$ 5,984,765	$ 4,894,357
Unevaluated	2,387,037	2,512,453	2,287,968
Gross oil and natural gas properties	9,907,483	8,497,218	7,182,325
Less accumulated depletion	(4,774,579)	(4,329,485)	(2,111,038)
Net oil and natural gas properties	$ 5,132,904	$ 4,167,733	$ 5,071,287

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The following table summarizes our oil, natural gas and natural gas liquids production volumes, average sales price per unit and average costs per unit. In addition, this table summarizes our production for each field that contains 15% or more of our total proved reserves:

	Years Ended December 31,		
	2010	2009	2008
Production:			
Natural gas Mmcf			
Haynesville Shale	153,813	77,117	6,243
Eagle Ford Shale	15,047	6,688	123
Elm Grove / Caspiana	23,324	34,254	42,599
Other	42,354	54,237	51,178
Total	234,538	172,296	100,143
Oil MBbl			
Haynesville Shale			
Eagle Ford Shale	893	124	4
Elm Grove / Caspiana	83	133	151
Other	292	1,263	1,399
Total	1,268	1,520	1,554
Natural gas liquids MBbl			
Haynesville Shale			
Eagle Ford Shale	660		
Elm Grove / Caspiana			
Other	21	290	355
Total	681	290	355
Production:			
Natural gas equivalent Mmcfe(1)	246,232	183,156	111,597
Average daily production Mmcfe(1)	675	502	305
Average price per unit:(2)			
Natural gas price Mcf	$ 4.18	$ 3.69	$ 8.54
Crude oil price Bbl	76.98	56.15	95.16
Natural gas liquids price Bbl	38.03	28.20	56.63
Natural gas equivalent price Mcfe(1)	4.49	3.99	9.17
Average cost per Mcfe:			
Production:			
Lease operating	$ 0.26	$ 0.43	$ 0.47
Workover and other	0.07	0.02	0.05
Taxes other than income	0.04	0.31	0.42
Gathering, transportation and other:			
Oil and natural gas	0.34	0.38	0.39
Midstream	0.06	0.06	

(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 or received on settled commodities derivative contracts as we did not elect to apply hedge accounting.*

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The 2010, 2009, and 2008 average oil, natural gas, and natural gas liquids sales prices above do not reflect the impact of cash paid on, or cash received from, settled derivative contracts as these amounts are reflected as "*Net gain on derivative contracts*" in the consolidated statements of operations, consistent with our decision not to elect hedge accounting. Including this impact 2010, 2009, and 2008 average crude oil sales prices were $76.90, $58.86, and $74.82 per Bbl and average natural gas sales prices were $5.22, $5.83, and $8.13 per Mcf. During 2010 we began hedging a portion of our natural gas liquids production for the first time. Including the impact of these hedges, our average natural gas liquids sales price was $37.10 per Bbl.

Competitive Conditions in the Business

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater financial and other resources. Many of these companies explore for, produce and market oil and natural gas, as well as carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, obtaining sufficient availability of drilling and completion equipment and services, obtaining purchasers and transporters of the oil and natural gas we produce and hiring and retaining key employees. There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States and the states in which our properties are located. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation.

Other Business Matters

Markets and Major Customers

In 2010, none of the individual purchasers of our production each accounted for in excess of 10% of our total sales. Three individual purchasers of our production each accounted for approximately 9% of our total sales, collectively representing approximately 27% of our total sales. In 2009, two individual purchasers of our production each accounted for in excess of 10% of our total sales, collectively representing 25% of our total sales. In 2008, two individual purchasers of our production each accounted for in excess of 10% of our total sales, collectively representing 30% of our total sales. We do not believe the loss of any one of our purchasers would materially affect our ability to sell the oil and natural gas we produce. We believe other purchasers are available in our areas of operations.

Seasonality of Business

Weather conditions affect the demand for, and prices of, natural gas and can also delay drilling activities, disrupting our overall business plans. Demand for natural gas is typically higher during the winter, resulting in higher natural gas prices for our natural gas production during our first and fourth fiscal quarters. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of the results that we may realize on an annual basis.

Operational Risks

Oil and natural gas exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that we will discover or acquire additional oil and natural gas in commercial quantities. Oil and natural gas operations also involve the risk that well fires, blowouts, equipment failure, human error and other events may cause accidental leakage of toxic or hazardous materials, such as petroleum liquids or drilling fluids into the environment, or cause significant injury to persons or property. In such event, substantial liabilities to third parties or governmental entities may be incurred, the satisfaction of which could substantially reduce available cash and possibly result in loss of oil and natural gas properties. Such hazards may also cause damage to or destruction of wells, producing formations, production facilities and pipeline or other processing facilities.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our operating results, financial position or cash flows. For further discussion on risks see Item 1A. *Risk Factors* in our Annual Report on Form 10-K filed on February 22, 2011.

Regulations

All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the plugging and abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas properties, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the establishment of maximum allowable rates of production from fields and individual wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Environmental Regulations

Our operations are subject to stringent federal, state and local laws regulating the discharge of materials into the environment or otherwise relating to health and safety or the protection of the environment. Numerous governmental agencies, such as the United States Environmental Protection Agency, commonly referred to as the EPA, issue regulations to implement and enforce these laws, which often require difficult and costly compliance measures. Failure to comply with these laws and regulations may result in the assessment of substantial administrative, civil and criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities. In addition, some laws and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, which could result in liability for environmental damages and cleanup costs without regard to negligence or fault on our part.

Environmental regulatory programs typically regulate the permitting, construction and operations of a facility. Many factors, including public perception, can materially impact the ability to secure an environmental construction or operation permit. Once operational, enforcement measures can include significant civil penalties for regulatory violations regardless of intent. Under appropriate circumstances, an administrative agency can issue a cease and desist order to terminate operations. New programs and changes in existing programs are anticipated, some of which include natural occurring radioactive materials, oil and natural gas exploration and production, waste management, and underground injection of waste material. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have a material adverse effect on our financial condition and results of operations.

Comprehensive Environmental Response, Compensation and Liability Act and Hazardous Substances

The federal Comprehensive Environmental Response, Compensation and Liability Act, referred to as CERCLA or the Superfund law, and comparable state laws impose liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances that have been released at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the costs of some health studies. In addition, companies that incur liability frequently confront additional claims because it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

The Solid Waste Disposal Act and Waste Management

The federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, referred to as RCRA, generally does not regulate most wastes generated by the exploration and production of oil and natural gas because that act specifically excludes drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil and natural gas from regulation as hazardous wastes. However, these wastes may be regulated by the EPA or state agencies as non-hazardous wastes as long as these wastes are not commingled with regulated hazardous wastes. Moreover, in the ordinary course of our operations, wastes generated in connection with our exploration and production activities may be regulated as hazardous waste under RCRA or hazardous substances under CERCLA. From time to time, releases of materials or wastes have occurred at locations we own or at which we have operations. These properties and the materials or wastes released thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we have been and may be required to remove or remediate these materials or wastes. At this time, with respect to any properties where materials or wastes may have been released, but of which we have not been made aware, it is not possible to estimate the potential costs that may arise from unknown, latent liability risks.

The Clean Water Act, wastewater and storm water discharges

Our operations are also subject to the federal Clean Water Act and analogous state laws. Under the Clean Water Act, the EPA has adopted regulations concerning discharges of storm water runoff. This program requires covered facilities to obtain individual permits, or seek coverage under a general permit. Some of our properties may require permits for discharges of storm water runoff and, as part of our overall evaluation of our current operations, we will apply for storm water discharge permit coverage and updating storm water discharge management practices at some of our facilities. We believe that we will be able to obtain, or be included under, these permits, where necessary, and make minor modifications to existing facilities and operations that would not have a material effect on us. The Clean Water Act and similar state acts regulate other discharges of wastewater, oil, and other pollutants to surface water bodies, such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges could result in civil and criminal penalties, orders to cease such discharges, and costs to remediate and pay natural resources damages. These laws also require the preparation and implementation of Spill Prevention, Control, and Countermeasure Plans in connection with on-site storage of significant quantities of oil.

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The Safe Drinking Water Act, groundwater protection, and the Underground Injection Control Program

The federal Safe Drinking Water Act (SWDA) and the Underground Injection Control (UIC) program promulgated under the SWDA and state programs regulate the drilling and operation of salt water disposal wells. EPA directly administers the UIC program in some states and in others it is delegated to the state for administering. Permits must be obtained before drilling salt water disposal permits, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking saltwater to groundwater. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SWDA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with many of the wells for which we are the operator. Certain states have adopted and are considering laws that require the disclosure of the chemical constituents in hydraulic fracturing fluids. In addition, in 2010, the EPA announced that it would be conducting a study on the environmental effects of hydraulic fracturing. The study is expected to be completed in 2012. Additional disclosure requirements could result in increased regulation, operational delays, and increased operating costs that could make it more difficult to perform hydraulic fracturing.

The Clean Air Act

The federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed and continues to develop stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Our operations, or the operations of service companies engaged by us, may in certain circumstances and locations be subject to permits and restrictions under these statutes for emissions of air pollutants. In addition, the EPA has indicated that in 2011 it may revise its national emissions standards for hazardous air pollutants for crude oil and natural gas production and gas transmission and storage, as well as its new source performance standards for oil and gas production.

Climate change legislation and greenhouse gas regulation

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, many nations have agreed to limit emissions of "greenhouse gases" or "GHGs" pursuant to the United Nations Framework Convention on Climate Change, and the "Kyoto Protocol." Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas, and refined petroleum products, are considered "greenhouse gases" regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol, several states have adopted legislation and regulations to reduce emissions of greenhouse gases. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect our operations and demand for our products. Additionally, the United States Supreme Court has ruled, in *Massachusetts, et al. v. EPA*, that the EPA abused its discretion under the Clean Air Act by refusing to regulate carbon dioxide emissions from mobile sources. As a result of the Supreme Court decision and the change in presidential administrations, on December 7, 2009, the EPA issued a finding that serves as the foundation under the Clean Air Act to issue other rules that would result in federal greenhouse gas regulations and emissions limits under the Clean Air Act, even without Congressional action. As part of this array of new regulations, on September 22, 2009, the EPA also issued a GHG monitoring and reporting rule that requires certain parties, including participants in the oil and natural gas industry, to monitor and report their GHG emissions, including methane and carbon dioxide, to the EPA. The emissions will be

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published on a register to be made available on the Internet. These regulations may apply to our operations. The EPA has issued two other rules that would regulate GHGs, one of which regulates GHGs from stationary sources, and one which requires sources in the oil and natural gas exploration and production industry and the pipeline industry to report GHG emissions. The EPA's finding, the greenhouse gas reporting rules, and the rules to regulate the emissions of greenhouse gases may affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry.

Two recent court decisions, one before the United States Second Circuit Court of Appeals and one before the United States Fifth Circuit Court of Appeals (The Fifth Circuit) have allowed cases to proceed. In the first case, *Connecticut v. American Electric Power*, the Second Circuit ruled that several states and other plaintiffs could continue a suit to impose GHG reductions on several utility defendants, concluding that a political question and standing objections of the defendants did not prohibit the suit from going forward. In December 2010, the United States Supreme Court granted American Electric Power's petition for certiorari, and the case will be heard in 2011.The Fifth Circuit, in *Comer v. Murphy Oil*, ruled that plaintiffs could similarly pursue a damage suit and the political question did not prohibit the suit. This case involves claims by plaintiffs who suffered damages from Hurricane Katrina that are seeking to recover damages from certain GHG emitters asserting their emissions contributed to their increased damages. Even if no new federal greenhouse gas regulations are enacted, more than one-third of the states have begun taking action on their own to control and/or reduce emissions of greenhouse gases. Several multi-state programs have been developed or are in the process of being developed: the Regional Greenhouse Gas Initiative involving 10 Northeastern states, the Western Climate Initiative involving seven western states, and the Midwestern Greenhouse Gas Reduction Accord involving seven states. The latter two programs have several other states acting as observers and they may join one of the programs at a later date. Any of the climate change regulatory and legislative initiatives described above could have a material adverse effect on our business, financial condition, and results of operations.

The National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

Threatened and endangered species, migratory birds, and natural resources

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Water Act and CERCLA. The United States Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat, or natural resources occur or may occur, government entities or at times private parties may act to prevent oil and gas exploration activities or seek damages for harm to species, habitat, or natural resources resulting from drilling or construction or releases of

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oil, wastes, hazardous substances or other regulated materials, and may seek natural resources damages and in some cases, criminal penalties.

Hazard communications and community right to know

We are subject to federal and state hazard communications and community right to know statutes and regulations. These regulations govern record keeping and reporting of the use and release of hazardous substances, including, but not limited to, the federal Emergency Planning and Community Right-to- Know Act.

Occupational Safety and Health Act

We are subject to the requirements of the federal Occupational Safety and Health Act, commonly referred to as OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and the public.

Employees

As of December 31, 2010, we had 598 full-time employees. We hire independent contractors on an as needed basis. We have no collective bargaining agreements with our employees. We believe that our employee relationships are satisfactory.

Access to Company Reports

We file periodic reports, proxy statements and other information with the SEC in accordance with the requirements of the Securities Exchange Act of 1934, as amended. We make our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and Forms 3, 4 and 5 filed on behalf of directors and officers, and any amendments to such reports available free of charge through our corporate website at *www.petrohawk.com* as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. In addition, our corporate governance guidelines, code of conduct, code of ethics for our chief executive officer (CEO) and senior financial officers, audit committee charter, compensation committee charter and nominating and corporate governance committee charter are available on our website under the heading "Company Profile Corporate Governance". Within the time period required by the SEC and the New York Stock Exchange (NYSE), as applicable, we will post on our website any modifications to the code of conduct and the code of ethics for our Chief Executive Officer and senior financial officers and any waivers applicable to senior officers as defined in the applicable code, as required by the Sarbanes-Oxley Act of 2002. You may also read and copy any document we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, our reports, proxy and information statements, and our other filings are also available to the public over the internet at the SEC's website at *www.sec.gov*. Unless specifically incorporated by reference in this Amendment No. 1 to the Annual Report on Form 10-K, information that you may find on our website is not part of this report.

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Executive Officers

The following table sets forth the names and ages of all of our corporate officers, the positions and offices with us held by such persons, the terms of their office and the length of their continuous service as a corporate officer as of February 22, 2011:

Name	Corporate Officer Since	Age	Position
Floyd C. Wilson	May 2004	63	Chairman of the Board and Chief Executive Officer
Richard K. Stoneburner	May 2004	57	President and Chief Operating Officer
Mark J. Mize	July 2005	39	Executive Vice President Chief Financial Officer and Treasurer
Larry L. Helm	July 2004	63	Executive Vice President Finance and Administration
Stephen W. Herod	May 2004	51	Executive Vice President Corporate Development and Assistant Secretary
David S. Elkouri	August 2007	57	Executive Vice President General Counsel and Secretary
H. Weldon Holcombe	March 2007	58	Executive Vice President Mid-Continent Region
Charles W. Latch	November 2007	66	Senior Vice President Western Region
Tina S. Obut	March 2007	45	Senior Vice President Corporate Reserves
Ellen R. DeSanctis	September 2010	54	Senior Vice President Corporate Communications
C. Byron Charboneau	March 2008	34	Vice President Chief Accounting Officer and Controller
Joan W. Dunlap	July 2007	36	Vice President Investor Relations
Charles E. Cusack III	May 2008	52	Vice President Exploration

Our executive officers are appointed to serve until the meeting of the board of directors following the next annual meeting of stockholders and until their successors have been elected and qualified.

Floyd C. Wilson has served as our Chairman of the Board and Chief Executive Officer since May 25, 2004. Mr. Wilson also served as our President from May 25, 2004 until September 8, 2009. Prior to May 25, 2004, he was President and Chief Executive Officer of PHAWK, LLC which he founded in June 2003. Mr. Wilson was the Chairman and Chief Executive Officer of 3TEC Energy Corporation from August 1999 until its merger with Plains Exploration & Production Company in June 2003. Mr. Wilson founded W/E Energy Company L.L.C., formerly known as 3TEC Energy Company L.L.C. in 1998 and served as its President until August 1999. Mr. Wilson began his career in the energy business in Houston, Texas in 1970 as a completion engineer. He moved to Wichita, Kansas in 1976 to start an oil and gas operating company, one of several private energy ventures which preceded the formation of Hugoton Energy Corporation in 1987, where he served as Chairman, President and Chief Executive Officer. In 1994, Hugoton completed an initial public offering and was merged into Chesapeake Energy Corporation in 1998.

Richard K. Stoneburner has served as our President and Chief Operating Officer since September 8, 2009. Mr. Stoneburner served as Executive Vice President Chief Operating Officer from September 13, 2007 until September 8, 2009 and had previously has served as Executive Vice President Exploration from August 1, 2005, until September 13, 2007. Mr. Stoneburner served as Vice President Exploration from May 25, 2004 until August 1, 2005. Prior to joining us, he was employed by PHAWK, LLC from its formation in June 2003 until May 2004. He joined 3TEC in August 1999 and was its Vice President Exploration from December 1999 until its merger with Plains Exploration & Production Company in June 2003. Mr. Stoneburner was employed by W/ E Energy

Company as District Geologist from 1998 to 1999. Prior to joining 3TEC, Mr. Stoneburner worked as a geologist for Texas Oil & Gas, The Reach Group, Weber Energy Corporation, Hugoton and, independently through his own company, Stoneburner Exploration, Inc. Mr. Stoneburner has over 31 years of experience in the energy business.

Mark J. Mize has served as Executive Vice President Chief Financial Officer and Treasurer since August 10, 2007. Mr. Mize was also appointed and has served as our Chief Ethics Officer and Insider Trading Compliance Officer through June 17, 2009. He served as Vice President, Chief Accounting Officer and Controller from July 2005 until August 10, 2007. Mr. Mize joined us on November 29, 2004 as Controller. Prior to joining us, he was the Manager of Financial Reporting of Cabot Oil & Gas Corporation, a public oil and gas exploration company, from January 2003 to November 2004. Prior to his employment at Cabot Oil & Gas Corporation, he was an Audit Manager with PricewaterhouseCoopers LLP from 1996 to 2002. Mr. Mize is a Certified Public Accountant.

Larry L. Helm has served as Executive Vice President Finance and Administration since August 10, 2007. Mr. Helm served as Vice President Chief Administrative Officer from July 15, 2004 until August 1, 2005, and as Executive Vice President Chief Administrative Officer from August 1, 2005 until August 9, 2007. Prior to serving as an executive officer, Mr. Helm served on our board of directors for approximately two months. Mr. Helm was employed with Bank One Corporation from December 1989 through December 2003. Most recently Mr. Helm served as Executive Vice President of Middle Market Banking from October 2001 to December 2003. From April 1998 to August 1999, he served as Executive Vice President of the Energy and Utilities Banking Group. Prior to joining Bank One, he worked for 16 years in the banking industry primarily serving the oil and gas sector. He served as director of 3TEC Energy Corporation from 2000 to June 2003.

Stephen W. Herod has served as Executive Vice President Corporate Development and Assistant Secretary since August 1, 2005. Mr. Herod served as Vice President Corporate Development from May 25, 2004 until August 1, 2005. Prior to joining us, he was employed by PHAWK, LLC from its formation in June 2003 until May 2004. He served as Executive Vice President Corporate Development for 3TEC Energy Corporation from December 1999 until its merger with Plains Exploration & Production Company in June 2003 and as Assistant Secretary from May 2001 until June 2003. Mr. Herod served as a director of 3TEC from July 1997 until January 2002. Mr. Herod served as the Treasurer of 3TEC from 1999 until 2001. From July 1997 to December 1999, Mr. Herod was Vice President Corporate Development of 3TEC. Mr. Herod served as President and a director of Shore Oil Company from April 1992 until the merger of Shore with 3TEC's predecessor in June 1997. He joined Shore's predecessor as Controller in February 1991. Mr. Herod was employed by Conquest Exploration Company from 1984 until 1991 in various financial management positions, including Operations Accounting Manager. From 1981 to 1984, Superior Oil Company employed Mr. Herod as a financial analyst.

David S. Elkouri has served as Executive Vice President General Counsel and Secretary of the Company since August 1, 2007. Mr. Elkouri has also served as Chief Ethics Officer and Insider Trading Compliance Officer since June 18, 2009. Mr. Elkouri has served as lead outside counsel for Petrohawk since 2004 and has been actively involved with the Company's growth since that time. Prior to that time he served as lead outside counsel for 3TEC Energy Corporation from its inception in 1999 until it was acquired in 2003 and for Hugoton Energy Corporation from its inception in 1994 until it was acquired in 1998. Mr. Elkouri's practice has focused on tax, corporate and securities law with an emphasis on the oil and gas industry. Mr. Elkouri is a graduate of the University of Kansas School of Law where he served as a Research Editor of the Kansas Law Review.

H. Weldon Holcombe joined the Company on July 12, 2006, effective upon the merger of KCS Energy, Inc. (KCS) with and into the Company and served as Senior Vice President Mid-Continent Region from March 1, 2007 until October 1, 2007 when he became Executive Vice President Mid-Continent Region. After the merger of KCS and Petrohawk, Mr. Holcombe became responsible for all of the merged company's operations in the Mid-Continent Region including our interests in the Elm Grove and Terryville fields among others throughout the Mid-Continent Region. With the Company's acquisition of Fayetteville Shale acreage in Arkansas and Haynesville Shale acreage in North Louisiana and East Texas, Mr. Holcombe became responsible for the growth and development of these key assets. Prior to the merger of KCS and Petrohawk, Mr. Holcombe served as Senior Vice President of KCS responsible for operations and engineering. Prior to joining KCS in 1996, he spent many years with Exxon in project and management positions associated with sour gas treatment, drilling, completions and reservoir management. Mr. Holcombe holds a degree in engineering from Auburn University.

Charles W. Latch has served as the Company's Senior Vice President Western Region since November 2007. From July 2006 through October 2007, Mr. Latch served as the Company's Vice President of Operations. From 2004 until joining the Company in July 2006, Mr. Latch was employed by KCS Resources, serving as Vice President of Operations since November 2004. Mr. Latch was Senior Vice President of Technical Services with El Paso Production Company from November 2002 until joining KCS Resources.

Tina S. Obut has served as Senior Vice President Corporate Reserves since May 15, 2008. Ms. Obut served as Vice President Corporate Reserves from March 2007 to May 15, 2008. Ms. Obut initially joined the Company in April 2006 as Manager of Corporate Reserves. Prior to joining us, Ms. Obut was employed by El Paso Production Company as Manager of Reservoir Engineering Evaluations from July 2004 until April 2006. From 2001 to 2004, Ms. Obut was Planning and Asset Manager at Mission Resources. From 1992 to 2001, Ms. Obut was a Vice President with Ryder Scott Company, and from 1989 to 1992, she worked as a reservoir engineer with Chevron. Ms. Obut is a Registered Petroleum Engineer.

Ellen R. DeSanctis has served as the Company's Senior Vice President Corporate Communications since September 2010. Prior to joining Petrohawk, Ellen was employed as Executive Vice President, Strategy and Development for Rosetta Resources since 2008. From 2006 to 2008, Ms. DeSanctis ran E. R. DeSanctis Consulting Services, which specialized in strategy development, and investor relations for exploration and production companies. From 2000 to 2006, she served as Vice President-Corporate Communications and Strategic Planning for Burlington Resources. She spent several years with Vastar Resources in various capacities and spent eight years in the Atlantic Richfield organization. She began her career at Shell Oil Company. She holds a bachelor's degree in geological & geophysical sciences from Princeton University and an M.B.A. from the University of California, Los Angeles.

C. Byron Charboneau has served as the Company's Vice President Chief Accounting Officer and Controller since March 2008. From August 2007 through February 2008, Mr. Charboneau served as the Financial Controller and from January 2005 through July 2007, Mr. Charboneau served as the Company's Director of Compliance and Accounting Research. From 1999 until joining the Company in January 2005, Mr. Charboneau was employed in the audit practice of PricewaterhouseCoopers, most recently as an audit manager with the Energy, Utilities and Mining Industry group. Mr. Charboneau is a Certified Public Accountant in New York.

Joan W. Dunlap has served as Vice President Investor Relations since July 2007. From August 2004 until 2006, Ms. Dunlap served as the Company's Assistant Treasurer. Prior to joining Petrohawk, she was employed as an investment banking associate with JPMorgan Chase, accredited with Series 7 and Series 63, and as a financial analyst and research assistant for the Federal Reserve Bank. Ms. Dunlap holds a bachelor's degree in economics from Tulane University and an M.B.A. from Rice University.

Charles E. Cusack III has served as Vice President Exploration since May 2008. Mr. Cusack is responsible for the exploration and land leasing efforts of the company. He was most recently Exploration Manager for the Gulf Coast Division prior to its sale in 2007. Mr. Cusack has 29 years of industry experience having held various positions with 3TEC Energy, Cockrell Oil, Amerada Hess, Chevron, Tenneco Oil, and Gulf Oil. He holds an engineering geology degree from Texas A&M University.

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PART II.

ITEM 6. SELECTED FINANCIAL DATA

The following table presents selected historical financial data derived from our consolidated financial statements. The following data is only a summary and should be read with our historical consolidated financial statements and related notes contained in this document.

	Years Ended December 31,				
	2010 Revised(6)	2009	2008	2007	2006
	(In thousands, except per share data)				
Income Statement Data:					
Total operating revenues	$ 1,600,647	$ 1,070,676	$ 1,090,864	$ 883,405	$ 587,762
Income (loss) from operations(1)(2)	266,025	(1,806,164)	(536,087)	250,663	154,540
Income (loss) from continuing operations, net of income taxes	135,905	(1,022,329)	(386,867)	52,906	116,563
Net income (loss)	89,921	(1,025,451)	(388,052)	52,897	116,563
Net income (loss) available to common stockholders	89,921	(1,025,451)	(388,052)	52,897	116,346
Net income (loss) from continuing operations per share of common stock:(3)					
Basic	$ 0.45	$ (3.65)	$ (1.77)	$ 0.31	$ 0.95
Diluted	$ 0.45	$ (3.65)	$ (1.77)	$ 0.31	$ 0.92

	As of December 31,				
	2010 Revised(6)	2009	2008	2007	2006
	(In thousands)				
Balance sheet data:					
Working capital deficit	$ (223,654)	$ (313,182)	$ (77,880)	$ (171,304)	$ (85,307)
Total assets	7,899,753	6,662,071	6,907,329	4,672,439	4,279,656
Total long-term debt(4)(5)	2,612,852	2,592,544	2,283,874	1,595,127	1,326,239
Stockholders' equity	3,445,539	3,323,672	3,404,910	2,008,897	1,928,344

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(1) *2009 includes an approximate $1.8 billion before taxes full cost ceiling test impairment charge.*

(2) *2008 includes an approximate $1.0 billion before taxes full cost ceiling test impairment charge.*

(3) *No cash dividends were declared or paid for any periods presented.*

(4) *Amount excludes the current portion of deferred premiums on derivatives for all periods presented.*

(5) *For 2010, amount excludes $0.2 million of 9.875% senior notes due 2011 which have been classified as current at December 31, 2010.*

(6) *Previously issued consolidated financial statements as of and for the year ended December 31, 2010 have been restated, see Item 8. Consolidated Financial Statements and Supplementary Data* Note 16 *"Restatement of Consolidated Financial Statements."*

ITEM 7. 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 condition. Our consolidated financial statements and the accompanying notes included elsewhere in this Amendment No. 1 to the Annual Report on Form 10-K contain additional information that should be referred to when reviewing this material.

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. Management's discussion and analysis has been revised for the effects of the restatement. For further discussion of the restatement, see Item 8. *Consolidated Financial Statements and Supplementary Data* Note 16 *"Restatement of Consolidated Financial Statements."*

Overview

We are an independent oil and natural gas company engaged in the exploration, development and production of predominately natural gas properties located in the United States. Our business is comprised of an oil and natural gas production segment and a midstream operations segment. Our oil and natural gas properties are concentrated in three premier domestic shale plays that we believe have decades of future development potential. We organize our oil and natural gas production operations into two principal regions: the Mid-Continent, which includes our Louisiana and East Texas properties; and the Western, which includes our South Texas properties. Our midstream operations 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 to develop additional gathering and treating capacity. Hawk Field Services currently serves the Haynesville Shale and Lower Bossier Shale in North Louisiana through our investment in KinderHawk Field Services (KinderHawk) and the Eagle Ford Shale in South Texas.

Historically, we have grown through acquisitions of proved oil and natural gas reserves and undeveloped acreage, with a focus on properties within our core operating areas that we believe have significant development and exploration opportunities. In the past few years, we significantly expanded our leasehold position in resource plays, particularly in the Haynesville Shale play in Northern Louisiana and East Texas and the Eagle Ford Shale play in South Texas, where we believe we can apply our technical experience and economies of scale to increase production and proved reserves while lowering unit lease operating costs. 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 primary lease term (generally three to five years) or the lease will expire. Lease expirations are expected to be an important factor in determining our capital expenditures focus over the next nine to twelve months.

At December 31, 2010, our estimated total proved oil and natural gas reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell, were approximately 3,392 Bcfe, consisting of 3,110 Bcf of natural gas, 20 MMBbls of oil and 27 MMBbls of natural gas liquids. Approximately 35% of our proved reserves were classified as proved developed. We maintain operational control of approximately 82% of our proved reserves. Production for the fourth quarter of 2010 averaged 761 million Mmcfe/d. Full year 2010 production averaged 675 Mmcfe/d compared to 502 Mmcfe/d in 2009. Our total operating revenues for 2010 were approximately $1.6 billion.

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 budget was focused on the development of non-proved reserve locations in our Haynesville, Lower Bossier, Eagle Ford and Fayetteville Shale plays so that we could hold our acreage in these areas. In addition, we believed these projects offered us the potential for high internal rates of return and reserve growth which is evidenced by our actual 2010 operating results. In 2010, we were also determined to maintain our liquidity position despite the large amount of capital that was required to execute our aggressive 2010 operational plan. We were able to accomplish this task by completing a number of asset dispositions that also enabled us to highgrade our asset portfolio and continue to lower our per unit operating costs. In 2010, we sold approximately $1.2 billion in producing properties, including $155 million for the sale of our WEHLU Field in Oklahoma County, Oklahoma, $320 million for the sale of our Terryville Field in Lincoln and Claiborne Parishes, Louisiana, approximately $123 million for certain Mid-Continent properties in Texas, Oklahoma and Arkansas, approximately $575 million for the sale of our Fayetteville Shale area in Arkansas, and approximately $38 million for other various non-core properties. We also formed a joint venture, on May 21, 2010, discussed in greater detail below, in which we received approximately $917 million (including approximately $42 million in closing adjustments) for a 50% interest in our Haynesville Shale gathering and treating business in North Louisiana.

We expect to spend approximately $2.3 billion of capital during 2011, of which $1.9 billion is expected to be allocated for drilling and completions, $200 million is expected to be allocated for midstream operations and $200 million will be allocated for potential leasehold acquisitions. Of the $1.9 billion budget for drilling and completions, $900 million is planned for the Haynesville and Lower Bossier Shales, which will enable us to fulfill our held-by-production goals, $900 million is budgeted for the Eagle Ford Shale, and approximately $100 million is budgeted for various other projects. Our 2011 drilling and completion budget contemplates an increase in drilling activity in the Eagle Ford Shale throughout the year and a significant decrease in the Haynesville Shale operated rig count in the second half of the year as our lease-holding activities are fulfilled. Our 2011 program will emphasize the development of our extensive condensate-rich properties, largely in the Eagle Ford Shale, and a shift away from dry gas development in our core areas. The $1.9 billion drilling and completion budget for 2011 is based on our current view of market conditions, our ability to accelerate certain areas of our Eagle Ford Shale position, and the desire to reduce capital allocated to pure natural gas drilling once the Haynesville Shale lease capture period is effectively completed.

We expect to fund our 2011 capital budget with cash flows from operations, proceeds from potential asset dispositions, a portion of the proceeds from our recent senior note offering and borrowings under our Senior Credit Agreement. We strive to maintain financial flexibility and may access capital markets as necessary to maintain substantial borrowing capacity under our Senior Credit Agreement, facilitate drilling on our large undeveloped acreage position and selectively expand our acreage position and infrastructure projects. In the event our cash flows or proceeds from potential asset dispositions are materially less than anticipated and other sources of capital we historically have utilized are not available on acceptable terms, we may curtail our capital spending.

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 joint venture pursuant to a Formation and Contribution Agreement (Contribution Agreement). The joint venture entity, KinderHawk Field Services LLC (KinderHawk), engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville and

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Lower Bossier Shales. Pursuant to the Contribution Agreement, Hawk Field Services contributed to KinderHawk its Haynesville Shale gathering and treating business in Northwest Louisiana, and Kinder Morgan contributed approximately $917 million in cash ($875 million for a 50% membership interest in KinderHawk and $42 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 $917 million to us. The joint venture had an economic effective date of January 1, 2010, and Hawk Field Services continued to operate the business until September 30, 2010, at which date Hawk Field Services and Kinder Morgan terminated the transition services agreement and KinderHawk assumed operations of the joint venture. In connection with the joint venture transaction we entered into a gathering agreement with KinderHawk which requires us to deliver natural gas to KinderHawk from dedicated lease acreage for the life of the dedicated lease acreage, or approximately 30 years, and includes a minimum delivery commitment over a five-year period.

We are obligated to deliver to KinderHawk agreed upon minimum annual quantities of natural gas from our operated wells producing from the Haynesville and Lower Bossier Shales, within specified acreage in Northwest Louisiana through May 2015, 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.

The KinderHawk joint venture is accounted for as a failed sale of in substance real estate under the provisions of the Financial Accounting Standards Board's (FASB) Accounting Standards Codification (ASC) Subtopic 360-20, *Property, Plant and Equipment Real Estate Sales* (ASC 360-20). ASC 360-20 establishes standards for recognition of profit on all real estate sales transactions other than retail land sales, without regard to the nature of the seller's business. In making the determination of whether a transaction qualifies, in substance, as a sale of real estate, the nature of the entire real estate being sold is considered, including the land plus the property improvements and the integral equipment. The Haynesville Shale gathering and treating system, consists of right of ways, pipelines and processing facilities. Due to the gathering agreement which constitutes extended continuing involvement under ASC 360-20, it has been determined that the contribution of our Haynesville Shale gathering and treating system to form KinderHawk should be accounted for as a failed sale of in substance real estate.

As a result of the failed sale we account for the continued operations of the gas gathering system and reflect a financing obligation, representing the proceeds received, under the financing method of real estate accounting. Under the financing method, the historical cost of the Haynesville Shale gas gathering system contributed to KinderHawk is carried at the full historical basis of the assets on the consolidated balance sheets in *"Gas gathering systems and equipment"* and depreciated over the remaining useful life of the assets. The financing obligation is recorded on the consolidated balance sheets in *"Payable on financing arrangement,"* in the amount of approximately $917 million. Reductions to the obligation and the non cash interest on the obligation are tied to the gathering and treating services, as we deliver natural gas through the Haynesville Shale gathering and treating system. Interest and principal are determined based upon the allocable income to Kinder Morgan, and interest is limited up to an amount that is calculated based upon our weighted average cost of debt as of the date of the transaction. Allocable income in excess of the calculated value is reflected as reductions of principal. Interest is recorded in *"Interest expense and other"* on the consolidated statements of operations. Any obligation remaining once the gathering agreement expires will be reversed, resulting in the recognition of a gain. Additionally we record KinderHawk's revenues, net of eliminations for intercompany amounts associated with gathering and treating services provided to us, and expenses on the consolidated statements of operations in *"Midstream revenues," "Taxes other than income," "Gathering, transportation and other," "General and administrative," "Interest expense and other"* and *"Depletion, depreciation and amortization."*

Capital Resources and Liquidity

Our primary sources of capital 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 continuously monitor our liquidity and the capital markets and 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 (net of discounts and expenses). In 2010, we redeemed our $775 million 2013 Notes in August with the issuance of $825 million of Senior Notes due in 2018 (2018 Notes). In early 2011, we will redeem our $275 million 2012 Notes, which have been called for redemption, with a portion of the proceeds from the issuance of $400 million of additional 2018 Notes, which is discussed further below.

Our Senior Credit Agreement provides for a $2.0 billion credit facility. As of December 31, 2010, the borrowing base was approximately $1.65 billion, $1.55 billion of which relates to our oil and natural gas properties and $100 million of which relates to our midstream assets (currently limited as described below). The portion of the borrowing base which relates to our oil and natural gas properties is redetermined on a semi-annual basis (with us and the lenders each having the right to one annual interim unscheduled redetermination) and adjusted based on our oil and natural gas properties, reserves, other indebtedness and other relevant factors. The component of the borrowing base related to our midstream assets is limited to the lesser of $100 million or 3.5 times midstream EBITDA and is calculated quarterly. As of December 31, 2010, the midstream component of the borrowing base was limited to approximately $38 million based on the midstream EBITDA limitation. Our ability to utilize the full amount of our borrowing capacity is influenced by a variety of factors, including redeterminations of our borrowing base, 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, increasing to $1 billion upon redemption of the 2012 Notes) and a percentage (the most restrictive indenture limit currently being 20%, but increasing to 30% upon redemption of the 2012 Notes) of our adjusted consolidated net tangible assets (as defined in all of our indentures), which is determined using discounted future net revenues from proved oil and natural gas reserves as of the end of each year. As of December 31, 2010, we had $146 million of debt outstanding under the Senior Credit Agreement and $1.4 billion of additional borrowing capacity available.

Our borrowing base, EBITDA and consolidated net tangible assets are significantly influenced by, among other things, oil and natural gas prices. We strive to maintain financial flexibility while continuing our aggressive drilling plans and may access the capital markets to, among other things, maintain substantial borrowing capacity under our Senior Credit Agreement, facilitate drilling on our large undeveloped acreage position and permit us to selectively expand our acreage position and infrastructure projects. Our ability to complete future debt and equity offerings is subject to market conditions.

During the third quarter of 2010, we issued $825 million aggregate principal amount of our 7.25% senior notes due 2018 (the 2018 Notes). The proceeds from the 2018 Notes were utilized to redeem our $775 million outstanding 9.125% senior notes due 2013 (the 2013 Notes), which allowed us to reduce our future interest expense as a result of the lower interest rate and to extend the maturity of these bonds. Due to the early repurchase of the 2013 Notes, we incurred charges of approximately $47 million in the third quarter of 2010. These charges are recorded in *"Interest expense and other"* on the consolidated statements of operations and include the cash premium paid to noteholders for the early repurchase of the 2013 Notes, as well as non-cash charges related to the write-off of debt issuance costs, discounts and premiums associated with the 2013 Notes.

On January 31, 2011, we completed the issuance of an additional $400 million aggregate principal amount of our 2018 Notes. A portion of the proceeds from this issuance will be utilized to redeem our $275 million 7.125% senior notes due 2012, which have been called for redemption. For further discussion of this transaction, see Item 8. *Consolidated Financial Statements and Supplementary Data* Note 15 *"Subsequent Event."*

In conjunction with the KinderHawk joint venture, we are obligated to commit up to an additional $78.2 million, as of December 31, 2010, in capital contributions to KinderHawk during 2011, if KinderHawk requires capital to fund its capital expenditures. Additional contributions above this amount can be made at our discretion. Capital contributions to KinderHawk could impact our development plans by reducing the amount of capital available to fund our drilling program. Capital contributions 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 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 in 2010, 2009 and 2008 were from operating and financing activities. In 2009 and 2008, proceeds from the sale of common stock, the issuance of new senior debt and cash received from operations were offset by repayments of borrowings under our Senior Credit Agreement and cash used in investing activities to fund our drilling program and acquisition activities, net of any divestiture activities. Operating cash flow fluctuations were substantially driven by changes in

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commodity prices and changes in our production volumes. Working capital was substantially influenced by these variables. Fluctuation in commodity prices and our overall 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 fluctuations 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 sales.

	Years Ended December 31, 2010	2009	2008
	(In thousands)		
Cash flows provided by operating activities	$ 505,627	$ 679,127	$ 608,955
Cash flows used in investing activities	(1,314,003)	(1,866,638)	(3,030,450)
Cash flows provided by financing activities	808,456	1,182,139	2,426,566
Net increase (decrease) in cash	$ 80	$ (5,372)	$ 5,071

Operating Activities. Net cash flows provided by operating activities were $505.6 million, $679.1 million and $609.0 million for the years ended December 31, 2010, 2009, and 2008, respectively. Key drivers of net operating cash flows are commodity prices, production volumes and operating costs.

Net cash provided by operating activities decreased $173.5 million in 2010 primarily due to the decrease in cash received on settled derivative contracts from $375.1 million in 2009 to $243.0 million in 2010. This decrease was partially offset by a 34% increase in our average daily production volumes due to our continued drilling success primarily in the Haynesville, Fayetteville and Eagle Ford Shales. Production for 2010 averaged 675 Mmcfe/d compared to 502 Mmcfe/d during 2009. Also contributing to the increase was the increase in our natural gas equivalent price of $0.50 per Mcfe to $4.49 per Mcfe from $3.99 per Mcfe in the prior year. As a result of our drilling program, we expect to continue to increase our production volumes throughout 2011. However, we are unable to predict future production levels or future commodity prices with certainty, and, therefore, we cannot provide assurance about future levels of net cash provided by operating activities.

Net cash flows provided by operating activities increased in 2009 primarily due to our 65% increase in our average daily production volumes due to our drilling success in the Haynesville, Fayetteville and Eagle Ford Shales, which was partially offset by a 56% decrease in our average realized natural gas equivalent price compared to the same period in 2008.

Net cash flows provided by operating activities increased in 2008 primarily due to our 21% increase in average realized natural gas equivalent price, partially offset by a 4% decrease in production volumes due to the sale of our Gulf Coast properties during the fourth quarter of 2007.

Investing Activities. The primary driver of cash used in investing activities is capital spending, inclusive of acquisitions and net of divestitures. Net cash used in investing activities was $1.3 billion, $1.9 billion and $3.0 billion for the years ended December 31, 2010, 2009 and 2008, respectively.

In 2010, we spent $2.4 billion on oil and natural gas capital expenditures. We participated in the drilling of 906 gross wells (218.3 net wells). We spent an additional $282.4 million on other operating property and equipment capital 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.

In 2010, we purchased and redeemed $1.1 billion of marketable securities. These marketable securities were classified and accounted for as trading securities.

In 2010, we had a net decrease in restricted cash of $213.7 million. Restricted cash was used to fund a portion of our 2010 oil and natural gas acquisitions.

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On December 22, 2010, we completed the sale of our interest in natural gas properties and other operating assets in the Fayetteville Shale for approximately $575 million in cash, before customary closing adjustments. Proceeds from the sale of the interest in natural gas properties 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 October 1, 2010.

On September 29, 2010, we completed the sale of our interest in certain Mid-Continent properties in Texas, Oklahoma and Arkansas for approximately $123 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 July 1, 2010.

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 all of which has been spent as of December 31, 2010.

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 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.

In 2009, we spent $1.7 billion on acquisitions of oil and natural gas properties and capital expenditures. We participated in the drilling of 626 gross wells (162.1 net wells). We spent an additional $309.5 million on other operating property and equipment expenditures, primarily to fund the completion of gathering systems in the Fayetteville Shale in Arkansas and the development of our gathering systems in the Haynesville Shale in Louisiana and the Eagle Ford Shale in Texas.

In 2009, we redeemed a net $123.0 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. No amounts remained outstanding as of December 31, 2009.

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

On October 30, 2009, we sold our Permian Basin properties for $376 million in cash, before customary closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of our full cost pool. In conjunction with the closing of this sale, we deposited the remaining net proceeds of $331 million with a qualified intermediary to facilitate potential like-kind exchange transactions ($37.6 million was previously received as a deposit). As of December 31, 2009, $213.7 million remained with the intermediary.

In 2008, we spent $3.1 billion on acquisitions of oil and natural gas properties and capital expenditures. Our acquisitions were partially funded by the remaining restricted cash that we had deposited with a qualified intermediary to facilitate like-kind exchange transactions following the sale of

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our Gulf Coast properties in November 2007. We participated in the drilling of 739 gross wells (267.4 net wells) in 2008. We spent an additional $164.8 million on other operating property and equipment during 2008 as well, primarily to fund the development of gathering systems primarily in the Fayetteville Shale in Arkansas and the beginning stages of the development of our gathering system in the Haynesville Shale in Louisiana.

In 2008, we used a portion of the funds from our debt and equity offerings to purchase a net $123.0 million of marketable securities. These marketable securities were classified and accounted for as trading securities and were used primarily to fund our leasing and acquisition activities in the Haynesville Shale.

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

Financing Activities. Net cash flows provided by financing activities were $808.5 million, $1.2 billion and $2.4 billion for the years ended December 31, 2010, 2009 and 2008, respectively. The primary driver of cash provided by financing activities in 2010 is from our contribution of our Haynesville Shale gathering and treating business in Northwest Louisiana to KinderHawk in exchange for approximately $917 million in cash. This cash inflow was offset by net repayments on our Senior Credit Agreement and the net impact of our debt issuance and refinancing activities in 2010 of approximately $87.4 million.

On August 17, 2010, we completed a private placement offering to eligible purchasers of an aggregate principal amount of $825 million 7.25% senior notes due August 15, 2018. The net proceeds from the sale of the 2018 Notes were approximately $809.5 million, after deducting offering expenses. We capitalized $16.7 million of debt issuance costs in conjunction with the issuance of the 2018 Notes.

On August 16, 2010, tenders and consents had been received from holders of $652.7 million in aggregate principal amount of the 2013 Notes, representing approximately 85% of the outstanding 2013 Notes. On August 17, 2010, we accepted the 2013 Notes that had been so tendered and utilized approximately $689.5 million in net proceeds from the sale of the 2018 Notes to repurchase such 2013 Notes. The remaining approximately $116.0 million in aggregate principal amount of 2013 Notes were redeemed on September 20, 2010.

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 and Lower Bossier Shales. Hawk Field Services contributed to KinderHawk our Haynesville Shale gathering and treating business in Northwest Louisiana, and Kinder Morgan contributed approximately $917 million in cash ($875 million for a 50% membership interest in KinderHawk and $42 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 $917 million to us.

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

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

On January 27, 2009, we completed a private placement to eligible purchasers of an aggregate principal amount of $600 million 10.5% senior notes due August 1, 2014 (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.

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

On June 19, 2008, we issued $300 million aggregate principal amount of 7.875% senior notes due 2015 (2015 Notes) in a private placement to eligible purchasers. The net proceeds from the sale of the 2015 Notes were approximately $294 million, after deducting the initial purchaser's discount and offering expenses.

On May 13, 2008, we issued $500 million aggregate principal amount of the 2015 Notes in a private placement to eligible purchasers. The net proceeds from the sale of the 2015 Notes were approximately $490 million, after deducting the initial purchaser's discounts and offering expenses, including commissions.

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

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

Capital financing and excess cash flow are used to repay debt to the extent available. In 2010, we had net repayments of borrowings under our Senior Credit Agreement of $87.4 million primarily due to the proceeds received from asset sales offset by the cash requirements of our drilling activities. As of December 31, 2010, our Senior Credit Agreement had a $1.65 billion borrowing base and we had $146 million outstanding.

Cash flows provided by financing activities include net borrowings of $282.0 million and $677.7 million for the years ended December 31, 2009 and 2008, respectively, primarily due to our acquisition activities and our ongoing drilling activities.

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Contractual Obligations

We believe we have a significant degree of flexibility to adjust the level of our future capital expenditures as circumstances warrant. Our level of capital expenditures will vary in future periods depending on the success we experience in our acquisition, developmental 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 by payment periods as of December 31, 2010.

	Payments Due by Period				
Contractual Obligations	**Total**	**2011**	**2012-2013**	**2014-2015**	**2016 and Beyond**
			(In thousands)		
Senior revolving credit facility	$ 146,000	$	$	$ 146,000	$
7.25% $825 million senior notes(1)	825,000				825,000
10.5% $600 million senior notes(2)	600,000			600,000	
7.875% $800 million senior notes	800,000			800,000	
7.125% $275 million senior notes(3)	272,375		272,375		
9.875% senior notes	224	224			
Interest expense on long-term debt(4)	1,023,151	216,316	398,657	251,170	157,008
Deferred premiums on derivatives(5)	25,381	14,566	10,815		
Rig commitments	297,031	183,990	110,751	2,290	
Gathering and transportation contracts	1,946,576	127,844	371,551	360,726	1,086,455
Pipeline and well equipment	127,279	127,279			
Other commitments(6)	59,902	45,269	14,633		
Operating leases	29,205	6,901	14,000	7,276	1,028
Total contractual obligations	$ 6,152,124	$ 722,389	$ 1,192,782	$ 2,167,462	$ 2,069,491

(1) *The 7.25% $825 million senior notes due 2018 were issued in the third quarter of 2010 to fund the repurchase of the 9.125% $775 million senior notes, which were due in 2013. On January 31, 2011, we issued an additional $400 million of these notes which are not reflected in the table. See "7.25% Senior Notes", below for further details.*

(2) *Excludes $37.9 million unamortized discount recorded in conjunction with the issuance of the notes. See "10.5% Senior Notes" below for more details.*

(3) *Excludes a net $3.5 million unamortized discount recorded in conjunction with our merger with KCS. See "7.125% Senior Notes" below for more details.*

(4) *Future interest expense was calculated based on interest rates and amounts outstanding at December 31, 2010 less required annual repayments.*

(5) *Approximately $14.6 million of this amount has been classified as current at December 31, 2010.*

(6) *Other commitments pertains to exploration, development and production activities including, among other things, commitments for obtaining and processing seismic data and fracture stimulation services.*

The contractual obligations table does not include obligations to taxing authorities due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations. In addition, amounts related to our asset retirement obligations are not included in the table above given the uncertainty regarding the actual timing of such expenditures. The total amount of asset retirement obligations at December 31, 2010 is $31.7 million.

On May 21, 2010, we created a joint venture with Kinder Morgan, KinderHawk, which engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville and Lower

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Bossier Shales. As part of this transaction, we are committed to contribute up to an additional $78.2 million, as of December 31, 2010, in capital during 2011 in the event KinderHawk requires capital to finance its planned capital expenditures. In addition, we are obligated to deliver to KinderHawk agreed upon minimum annual quantities of natural gas from our operated wells producing from the Haynesville and Lower Bossier Shales in North Louisiana through May 2015, or in the alternative, pay an annual true-up fee to KinderHawk if such minimum annual quantities are not delivered. These obligations are not reflected in the amounts shown in the table above. We pay to KinderHawk negotiated gathering and treating fees, subject to an annual inflation adjustment factor.

We account for the KinderHawk joint venture as a failed sale of in substance real estate under the provisions of ASC 360-20. Due to the gathering agreement entered into with the formation of KinderHawk, which constitutes extended continuing involvement under ASC 360-20, it has been determined that the contribution of our Haynesville Shale gathering and treating system to form KinderHawk is accounted for as a failed sale of in substance real estate. As a result of the failed sale, we recorded a financing obligation, representing the proceeds received, under the financing method of real estate accounting. The financing obligation is recorded on the consolidated balance sheets in *"Payable on financing arrangement,"* in the amount of approximately $917 million. Reductions to the obligation and the non cash interest on the obligation are tied to the gathering and treating services, as we deliver natural gas through the Haynesville Shale gathering and treating system. Interest and principal are determined based upon the allocable income to Kinder Morgan, and interest is limited up to an amount that is calculated based upon our weighted average cost of debt as of the date of the transaction. Allocable income in excess of the calculated value is reflected as reductions of principal. Interest is recorded in *"Interest expense and other"* on the consolidated statements of operations. The balance of our financing obligation as of December 31, 2010, was approximately $940.9 million, of which approximately $7.1 million was classified as current. This obligation is not reflected in the amounts shown in the table above.

Senior Revolving Credit Facility

Effective August 2, 2010, we amended and restated our existing credit facility dated October 14, 2009 by entering into the Fifth Amended and Restated Senior Revolving Credit Agreement (the Senior Credit Agreement), among us, 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 Bank of Montreal as co-syndication agents for the Lenders, and JPMorgan Chase Bank, N.A. and Wells Fargo Bank, N.A., as co-documentation agents for the Lenders. The Senior Credit Agreement provides for a $2.0 billion facility. As of December 31, 2010, the borrowing base was approximately $1.65 billion, $1.55 billion of which related to our oil and natural gas properties and up to $100 million (currently limited as described below) related to our midstream assets. The portion of the borrowing base relating to our oil and natural gas properties is redetermined on a semi-annual basis (with us and the Lenders each having the right to one annual interim unscheduled redetermination) and adjusted based on our oil and natural gas properties, reserves, other indebtedness and other relevant factors. The component of the borrowing base relating to our midstream assets is limited to the lesser of $100 million or 3.5 times midstream EBITDA, and is calculated quarterly. As of December 31, 2010, the midstream component of the borrowing base was limited to approximately $38 million based on midstream EBITDA. Our 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 unsecured senior or senior subordinated notes that we may issue. In January 2011, we issued an additional $400 million aggregate principal amount of our 7.25% senior notes due 2018, as discussed below, and accordingly, our borrowing base was reduced to approximately $1.6 billion.

Amounts outstanding under the Senior Credit Agreement 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. Such margins will fluctuate based on the percentage utilization of the facility.

Borrowings under the Senior Credit Agreement are secured by first priority liens on substantially all of our assets, including pursuant to the terms of the Fifth Amended and Restated Guarantee and Collateral Agreement, all of the assets of, and equity interests in, our subsidiaries. Amounts drawn down on the facility will mature on July 1, 2014.

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, we are 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 December 31, 2010, we were in compliance with our financial debt covenants under the Senior Credit Agreement.

7.25% Senior Notes

On August 17, 2010, we completed a private placement offering to eligible purchasers of an aggregate principal amount of $825 million 7.25% senior notes due 2018 (the 2018 Notes) at a purchase price of 100% of the principal amount of the 2018 Notes.

In connection with the sale of the 2018 Notes, we entered into a Registration Rights Agreement, dated August 17, 2010, among us and the initial purchasers (the Registration Rights Agreement). Pursuant to the Registration Rights Agreement, we agreed to conduct a registered exchange offer for the 2018 Notes or cause to become effective a shelf registration statement providing for the resale of the 2018 Notes. The registration statement for the exchange offer became effective on September 29, 2010.

The 2018 Notes bear interest at a rate of 7.25% per annum, payable semi-annually on February 15 and August 15 of each year, commencing on February 15, 2011. The 2018 Notes will mature on August 15, 2018. The 2018 Notes are senior unsecured obligations of ours and rank equally with all of our current and future senior indebtedness. The 2018 Notes are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by our subsidiaries. Petrohawk Energy Corporation, the issuer of the 2018 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

On January 31, 2011, we completed the issuance of an additional $400 million aggregate principal amount of our 2018 Notes. We will utilize a portion of the proceeds from this issuance to redeem our 7.125% $275 million senior notes due 2012, which have been called for redemption. For further discussion of this transaction, see *Item 8 Consolidated Financial Statements and Supplementary Data* Note 15, *"Subsequent Event."*

10.5% Senior Notes

On January 27, 2009, we issued $600 million principal amount of our 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 us, U.S. Bank National Association, as trustee, and our subsidiaries named therein as guarantors. The 2014 Notes bear interest at 10.5% per annum, payable semi-annually on February 1 and August 1 of each year, commencing on August 1, 2009. The 2014 Notes will mature on August 1, 2014. The 2014 Notes were priced at 91.279% of the face value to yield 12.7% to maturity. The 2014 Notes are senior unsecured obligations and rank equally with all of our current and future senior indebtedness.

In conjunction with the issuance of the $600 million 2014 Notes, we 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 $37.9 million at December 31, 2010.

7.875% Senior Notes

On May 13, 2008 and June 19, 2008, we issued $500 million principal amount and $300 million principal amount, respectively, of our 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 us, U.S. Bank Trust National Association, as trustee, and our 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 and rank equally with all of our current and future senior indebtedness. The 2015 Notes were issued at par value, with no discount or premium recorded.

9.125% Senior Notes

On July 12 and 27, 2006, we issued a total of $775 million principal amount 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 us, our subsidiaries named therein as guarantors, and U.S. Bank National Association, as trustee. We issued the 2013 Notes in two tranches, $650 million on July 12, 2006 and $125 million on July 27, 2006. The additional $125 million in 2013 Notes were issued pursuant to the same Indenture at 101.125% of the face amount. We applied the net proceeds from the sale of the additional 2013 Notes to repay indebtedness outstanding under our revolving credit facility. The $650 million tranche of 2013 Notes were issued at 98.735% of the face amount for gross proceeds of approximately $642.0 million, before estimated offering expenses and the initial purchasers' discount. We applied a portion of the net proceeds from the sale of the 2013 Notes to fund the cash paid by us to the KCS stockholders in connection with our merger with KCS and our repurchase of the 9.875% notes due 2011 (2011 Notes) pursuant to a tender offer we concluded in July 2006.

In conjunction with the issuance of the $650 million 2013 Notes, we 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 zero at December 31, 2010. In conjunction with the issuance of the $125 million 2013 Notes, we 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 zero at December 31, 2010.

Upon issuance of the 2018 Notes, as discussed above, on August 3, 2010, we commenced a cash tender offer for any and all of the outstanding of the 2013 Notes and a solicitation of consents to amend the indenture governing the 2013 Notes (the 2013 Notes Indenture). On August 17, 2010, we announced that it had received the requisite consents to amend the 2013 Notes Indenture, and we entered into the Sixth Supplemental Indenture, dated August 17, 2010, with U.S. Bank National Association, as Trustee for the 2013 Notes. The Sixth Supplemental Indenture eliminated or made less restrictive the most restrictive covenants contained in the 2013 Notes Indenture, including those with respect to Securities Exchange Commission (SEC) reporting, incurrence of indebtedness, distributions to stockholders, creation of liens, assets sales, transactions with affiliates, business activities, change of control, payment of taxes and business combinations. The amendments contained in the Sixth Supplemental Indenture became effective when we accepted and repurchased the tendered 2013 Notes.

On August 16, 2010, tenders and consents had been received from holders of $652.7 million in aggregate principal amount of the 2013 Notes, representing approximately 85% of the outstanding 2013 Notes. On August 17, 2010, we accepted the 2013 Notes that had been tendered and utilized approximately $689.5 million in net proceeds from the sale of the 2018 Notes to repurchase the tendered 2013 Notes. Approximately $116.0 million in aggregate principal amount of 2013 Notes were not tendered.

On August 19, 2010, we elected to exercise our right under the 2013 Indenture to redeem effective on September 20, 2010 (the Redemption Date) the remaining $116.0 million aggregate principal amount of the outstanding 2013 Notes at a redemption price of 104.563% of the principal amount thereof (the Redemption Price), plus accrued and unpaid interest on the 2013 Notes redeemed to the Redemption Date. Holders of the 2013 Notes were paid the Redemption Price upon presentation and surrender of their 2013 Notes for redemption to the Trustee.

7.125% Senior Notes

In our merger with KCS, we assumed (pursuant to the Second Supplemental Indenture relating to the 7.125% senior notes, also referred to as the 2012 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 7.125% senior notes due 2012. The 2012 Notes are guaranteed on an unsubordinated, unsecured basis by all of our current subsidiaries. Interest on the 2012 Notes is payable semi-annually, on each April 1 and October 1.

In conjunction with the assumption of the 7.125% Notes from KCS, we 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 was $3.5 million at December 31, 2010.

See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 15, "*Subsequent Event",* for discussion of the anticipated redemption of the 2012 Notes.

9.875% Senior Notes

On April 8, 2004, Mission Resources Corporation (Mission) issued $130.0 million of its 9.875% senior notes due 2011 (the 2011 Notes). We assumed these notes upon the closing of our merger with Mission. In conjunction with our merger with KCS, we extinguished substantially all of the 2011 Notes.

Off-Balance Sheet Arrangements

At December 31, 2010, we did not have any material off-balance sheet arrangements.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and natural gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Actual results may differ from the estimates and assumptions used in the preparation of our consolidated financial statements. Described below are the most significant policies we apply in preparing our consolidated financial statements, some of which are subject to alternative treatments under accounting principles generally accepted in the United States. We also describe the most significant estimates and assumptions we make in applying these policies. We discussed the development, selection and disclosure of each of these with our audit committee. See Results of Operations above and Item 8. *Consolidated Financial Statements and Supplementary Data* Note 1, "*Summary of Significant Events and Accounting Policies,"* for a discussion of additional accounting policies and estimates made by management.

Oil and Natural Gas Activities

Accounting for oil and natural gas activities is subject to unique rules. Two generally accepted methods of accounting for oil and natural gas activities are available successful efforts and full cost. The most significant differences between these two methods are the treatment of unsuccessful exploration costs and the manner in which the carrying value of oil and natural gas properties are amortized and evaluated for impairment. The successful efforts method requires unsuccessful exploration costs to be expensed as they are incurred upon a determination that the well is uneconomical while the full cost method provides for the capitalization of these costs. Both methods generally provide for the periodic amortization of capitalized costs based on proved reserve quantities. Impairment of oil and natural gas properties under the successful efforts method is based on an evaluation of the carrying value of individual oil and natural gas properties against their estimated fair value, while impairment under the full cost method requires an evaluation of the carrying value of oil and natural gas properties included in a cost center against the net present value of future cash flows from the related proved reserves, using the unweighted arithmetic average of the first day of the month for each of the 12-month prices for oil and natural gas within the period, holding prices and costs constant and applying a 10% discount rate.

Full Cost Method

We use the full cost method of accounting for our oil and natural gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized into a cost center (the amortization base). Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. All general and administrative costs unrelated to drilling activities are expensed as incurred. The capitalized costs of our oil and natural gas properties, plus an estimate of our future development and abandonment costs are amortized on a unit-of-production method based on our estimate of total proved reserves. Our financial position and results of operations could have been significantly different had we used the successful efforts method of accounting for our oil and natural gas activities.

Proved Oil and Natural Gas Reserves

Estimates of our proved reserves included in this report are prepared in accordance with accounting principles generally accepted in the United States and SEC guidelines. Our engineering estimates of proved oil and natural gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization expense and the full cost ceiling test limitation. Proved oil and natural gas reserves are the estimated quantities of oil and natural gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under defined economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The accuracy of a reserve estimate is a function of: (i) the quality and quantity of available data; (ii) the interpretation of that data; (iii) the accuracy of various mandated economic assumptions and (iv) the judgment of the persons preparing the estimate. The data for a given reservoir may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil and natural gas prices, operating costs and expected performance from a given reservoir also will result in revisions to the amount of our estimated proved reserves.

Our estimated proved reserves for the years ended December 31, 2010, 2009 and 2008 were prepared by Netherland, Sewell, an independent oil and natural gas reservoir engineering consulting firm. For more information regarding reserve estimation, including historical reserve revisions, refer to Item 8. *Consolidated Financial Statements and Supplementary Data* "*Supplemental Oil and Gas Information (Unaudited).*"

Depreciation, Depletion and Amortization

Our rate of recording depreciation, depletion and amortization expense (DD&A) is primarily dependent upon our estimate of proved reserves, which is utilized in our unit-of-production method calculation. If the estimates of proved reserves were to be reduced, the rate at which we record DD&A expense would increase, reducing net income. Such a reduction in reserves may result from calculated lower market prices, which may make it non-economic to drill for and produce higher cost reserves. A five percent positive or negative revision to proved reserves would decrease or increase the DD&A rate by approximately $0.10 per Mcfe.

Full Cost Ceiling Test Limitation

Under the full cost method, we are subject to quarterly calculations of a ceiling or limitation on the amount of our oil and natural gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and natural gas properties exceed the cost center ceiling, we are subject to a ceiling test write down to the extent of such excess. If required, it would reduce earnings and impact stockholders' equity in the period of occurrence and result in lower amortization expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated prices of oil and natural gas reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that we use the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ending at the balance sheet date. If average oil and natural gas prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that write downs of our oil and natural gas properties could occur in the future.

If the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ended December 31, 2010 had been 10% lower while all other factors remained constant, our ceiling amount related to our net book value of oil and natural gas properties would have been reduced approximately $802 million. This reduction would not have resulted in a full costing ceiling impairment.

Future Development Costs

Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production facilities, gathering systems and related structures and restoration costs. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, well depth, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis. A five percent decrease or increase in future development and abandonment costs would decrease or increase the DD&A rate by approximately $0.06 per Mcfe.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and facilities associated with our oil and natural gas wells and our gathering systems, and to restore land at the end of oil and natural gas production operations. Our removal and restoration obligations are associated with plugging and abandoning wells and our gathering systems. Estimating the future restoration and removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Inherent in the present value calculations are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlements and changes in the legal, regulatory, environmental and political environments.

Accounting for Derivative Instruments and Hedging Activities

We account for our derivative activities under the provisions of ASC 815, *Derivatives and Hedging*, (ASC 815). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. From time to time, we may hedge a portion of our forecasted oil, natural gas, and natural gas liquids production. Derivative contracts entered into by us have consisted of transactions in which we hedge the variability of cash flow related to a forecasted transaction. We elected to not designate any of our positions for hedge accounting. Accordingly, we record the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in *"Net gain on derivative contracts"* on the consolidated statements of operations.

Goodwill

We account for goodwill in accordance with ASC 350, *Intangibles Goodwill and Other* (ASC 350). 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 requires that intangible assets with indefinite lives, including goodwill, be evaluated on an annual basis for impairment or more frequently if an event occurs or circumstances change that could potentially result in impairment. The goodwill impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. We have determined that we have two reporting units: oil and natural gas production and midstream operations. All of our goodwill has been allocated to our oil and natural gas production segment as all of our historical goodwill relates to our acquisitions of oil and natural gas companies.

We perform our goodwill test annually during the third quarter or more often if circumstances require. Our goodwill impairment reviews consists of a two-step process. The first step is to determine the fair value of our reporting units and compare it to the carrying value of the related net assets. Fair value is determined based on our estimates of market values. If this fair value exceeds the carrying value no further analysis or goodwill write-down is required. The second step is required if the fair value of the reporting units is less than the carrying value of the net assets. In this step the implied fair value of the reporting units is allocated to all the underlying assets and liabilities, including both recognized and unrecognized tangible and intangible assets, based on their fair values. If necessary, goodwill is then written-down to its implied fair value. If the fair value of the reporting units is less than the book value (including goodwill), then goodwill is reduced to its implied fair value and the amount of the write down is charged against earnings. The assumptions we used in calculating our reporting unit fair values at the time of the test include our market capitalization and discounted future cash flows based on estimated reserves and production, future costs and future oil and natural gas prices. Material adverse changes to any of these factors could lead to an impairment of all or a portion of our goodwill in future periods.

Income Taxes

Our provision for taxes includes both state and federal taxes. We account for income taxes using the asset and liability method wherein deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

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We follow ASC 740, *Income Taxes*, (ASC 740). ASC 740 creates a single model to address accounting for the uncertainty in income tax positions and prescribes a minimum recognition threshold a tax position must meet before recognition in the financial statements. We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact our financial position, results of operations and cash flows. The evaluation of a tax position in accordance with ASC 740 is a two-step process. The first step is a recognition process to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more likely than not recognition threshold, it is presumed that the position will be examined by the appropriate taxing authority with full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more likely than not recognition threshold is calculated to determine the amount of benefit/expense to recognize in the financial statements. The tax position is measured at the largest amount of benefit/expense that is more likely than not of being realized upon ultimate settlement.

Accounting for KinderHawk Joint Venture

The KinderHawk joint venture is accounted for as a failed sale of in substance real estate under the provisions of ASC 360-20. ASC 360-20 establishes standards for recognition of profit on all real estate sales transactions other than retail land sales, without regard to the nature of the seller's business. In making the determination of whether a transaction qualifies, in substance, as a sale of real estate, the nature of the entire real estate being sold is considered, including the land plus the property improvements and the integral equipment. The Haynesville Shale gathering and treating system, consists of right of ways, pipelines and processing facilities. Due to the gathering agreement, entered into with the formation of KinderHawk, which constitutes extended continuing involvement under ASC 360-20, it has been determined that the contribution of our Haynesville Shale gathering and treating system to KinderHawk should be accounted for as a failed sale of in substance real estate. As a result of the failed sale we account for the continued operations of the gas gathering system and reflect a financing obligation, representing the proceeds received, under the financing method of real estate accounting. Under the financing method, the historical cost of the Haynesville Shale gas gathering system contributed to KinderHawk is carried at the full historical basis of the assets on the consolidated balance sheets in *"Gas gathering systems and equipment"* and depreciated over the remaining useful life of the assets. The financing obligation is recorded on the consolidated balance sheets in *"Payable on financing arrangement,"* in the amount of approximately $917 million. Reductions to the obligation and the non cash interest on the obligation are tied to the gathering and treating services, as we deliver natural gas through the Haynesville Shale gathering and treating system. Interest and principal are determined based upon the allocable income to Kinder Morgan, and interest is limited up to an amount that is calculated based upon our weighted average cost of debt as of the date of the transaction. Allocable income in excess of the calculated value will be reflected as reductions of principal. Interest is recorded in *"Interest expense and other"* on the consolidated statements of operations. Any obligation remaining once the gathering agreement expires will be reversed, resulting in the recognition of a gain. Additionally we record KinderHawk's revenues, net of eliminations for intercompany amounts associated with gathering and treating services provided to us, and expenses on the consolidated statements of operations in *"Midstream revenues," "Taxes other than income," "Gathering, transportation and other," "General and administrative," "Interest expense and other"* and *"Depletion, depreciation and amortization."*

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Comparison of Results of Operations

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

We reported income from continuing operations, net of income taxes, of $135.9 million for the year ended December 31, 2010 compared to a loss from continuing operations, net of income taxes, of $1.0 billion for the comparable period in 2009. The following table summarizes key items of comparison and their related change for the periods indicated.

	Years Ended December 31,		
In thousands (except per unit and per Mcfe amounts)	**2010**	**2009**	**Change**
Income (loss) from continuing operations, net of income taxes	$ 135,905	$ (1,022,329)	$ 1,158,234
Operating revenues:			
Oil and natural gas	1,107,401	732,137	375,264
Marketing	475,030	320,121	154,909
Midstream	18,216	18,418	(202)
Operating expenses:			
Marketing	521,378	316,987	204,391
Production:			
Lease operating	64,744	78,700	(13,956)
Workover and other	18,119	2,749	15,370
Taxes other than income	9,543	57,360	(47,817)
Gathering, transportation and other:			
Oil and natural gas	84,082	69,287	14,795
Midstream	15,293	10,695	4,598
General and administrative:			
General and administrative	132,264	96,551	35,713
Stock-based compensation	23,229	14,458	8,771
Depletion, depreciation and amortization:			
Depletion Full cost	445,094	380,003	65,091
Depreciation Midstream	13,843	7,398	6,445
Depreciation Other	5,054	2,761	2,293
Accretion expense	1,979	1,447	532
Full cost ceiling impairment		1,838,444	(1,838,444)
Other income (expenses):			
Net gain on derivative contracts	301,121	260,248	40,873
Interest expense and other	(336,307)	(229,419)	(106,888)
Income (loss) from continuing operations before income taxes			
Oil and natural gas	234,799	(1,793,070)	2,027,869
Midstream	(3,960)	17,735	(21,695)
Income tax (provision) benefit	(94,934)	753,006	(847,940)
Production:			
Natural gas Mmcf	234,538	172,296	62,242
Crude oil MBbl	1,268	1,520	(252)
Natural gas liquids MBbl	681	290	391
Natural gas equivalent Mmcfe[1]	246,232	183,156	63,076
Average daily production Mmcfe[1]	675	502	173
Average price per unit[2]:			
Natural gas price Mcf	$ 4.18	$ 3.69	$ 0.49
Crude oil price Bbl	76.98	56.15	20.83
Natural gas liquids price Bbl	38.03	28.20	9.83
Natural gas equivalent price Mcfe[1]	4.49	3.99	0.50
Average cost per Mcfe:			
Production:			
Lease operating	0.26	0.43	(0.17)
Workover and other	0.07	0.02	0.05
Taxes other than income	0.04	0.31	(0.27)
Gathering, transportation and other:			
Oil and natural gas	0.34	0.38	(0.04)
Midstream	0.06	0.06	
General and administrative:			
General and administrative	0.54	0.53	0.01
Stock-based compensation	0.09	0.08	0.01
Depletion	1.81	2.07	(0.26)

(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.*

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For the year ended December 31, 2010, oil and natural gas revenues increased $375.3 million from the same period in 2009, to $1.1 billion. The increase was primarily due to the increase in our production of 63,076 Mmcfe, or 34% over 2009, primarily due to our drilling successes in resource plays in Louisiana, Arkansas and Texas. Increased production contributed to approximately $252 million in revenues for the year ended December 31, 2010. Also contributing to this increase was an increase of $0.50 per Mcfe in our realized average price to $4.49 per Mcfe from $3.99 per Mcfe in the prior year period. The increase per Mcfe led to an increase in oil and natural gas revenues of $123 million.

We had marketing revenues of $475.0 million and marketing expenses of $521.4 million in 2010, resulting in a loss before taxes of $46.4 million as compared to income before taxes of $3.1 million for the same period in 2009. Our marketing subsidiary purchases and sells our own and third party natural gas produced from wells which we and third parties 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 loss before taxes for the year ended December 31, 2010 is primarily attributable to decreased margins and the inclusion of a full year of amortization of our acquired transportation contracts during the third quarter of 2009.

We had gross revenues from our midstream segment of $82.2 million for year ended December 31, 2010 compared to the same period in 2009 of $63.3 million, an increase of $18.9 million. The increase was primarily attributed to the expansion of our gas gathering and treating systems in the Haynesville and Eagle Ford Shales. In addition, on May 21, 2010, we contributed our Haynesville Shale gas gathering and treating systems to a new joint venture entity, KinderHawk, in exchange for a 50% membership interest. We record KinderHawk's revenues, net of eliminations for intercompany amounts, in accordance with the financing method for a failed sale of in substance real estate. For the year ended December 31, 2010, approximately $2.8 million of KinderHawk's revenues, after intercompany eliminations, were reported in midstream revenues on the consolidated statements of operations. Gross revenues of $82.2 million also included $64.0 million of inter-segment revenues that were eliminated in consolidation. On a net basis, we had revenues of $18.2 million for the year ended December 31, 2010, or a decrease of $0.2 million from the prior year.

Lease operating expenses decreased $14.0 million for the year ended December 31, 2010 as compared to the same period in 2009. The decrease was 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 $0.17 per Mcfe to $0.26 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 plays which historically 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 year ended December 31, 2010 over the same period in 2009 as these properties historically operated with higher operating costs per unit.

Workover expenses increased $15.4 million for the year ended December 31, 2010 compared to the same period in 2009. The increase was primarily due to an increase in activity in the Haynesville Shale related to the replacement of corroded conventional tubing with chrome tubing in a number of our wells.

Taxes other than income decreased $47.8 million for the year ended December 31, 2010 as compared to the same period in 2009. The largest components of taxes other than income are production and severance taxes which are generally assessed as either a fixed rate based on production or as a percentage of gross oil and natural gas sales. The decrease is primarily due to severance tax refunds related to drilling incentives for horizontal wells in the Haynesville Shale in Louisiana and, to a lesser extent, in Texas and Oklahoma. For the year ended December 31, 2010, we recorded severance tax refunds totaling $47.7 million compared to $3.6 million in refunds for the year ended December 31, 2009. On a per unit basis, excluding the severance tax refunds, taxes other than income decreased $0.10 per Mcfe to $0.23 per Mcfe compared to $0.33 per Mcfe in 2009. This adjusted decrease from prior year is due to severance tax exemptions related to the drilling incentives as well as a reduction in the Louisiana statutory severance tax rate.

Gathering, transportation and other expense attributable to our oil and natural gas production segment increased $14.8 million for the year ended December 31, 2010 as compared to the same period in 2009. The increase is primarily the result of our increased production from our drilling successes in resource plays in Louisiana, Arkansas and Texas. This increase was partially offset by the closing of our KinderHawk joint venture with Kinder Morgan on May 21, 2010, as gathering and treating fees paid to KinderHawk are recorded as a reduction in the financing obligation and interest expense on the financing obligation. The financing obligation was recorded in accordance with the financing method for a failed sale of in substance real estate. On a per unit basis, gathering, transportation and other expenses decreased $0.04 per Mcfe to $0.34 per Mcfe in 2010 compared to $0.38 per Mcfe in 2009.

Gathering, transportation and other expenses attributable to our midstream segment increased $4.6 million for the year ended December 31, 2010 compared to the same period in 2009. Our midstream segment currently serves the Eagle Ford Shale and the Haynesville Shale through our investment KinderHawk. The increase was primarily due to the expansion of our gas gathering and treating systems in the Haynesville and Eagle Ford Shales. We record KinderHawk's expenses in accordance with the financing method for a failed sale of in substance real estate. For the year ended December 31, 2010, approximately $4.0 million of KinderHawk's expenses were reported in "*Gathering, transportation and other"* on the consolidated statements of operations.

General and administrative expense for the year ended December 31, 2010 increased $35.7 million as compared to the same period in 2009. In 2010, we had a $7.9 million increase in professional fees, including $4.3 million for the implementation of new software systems, as well as increases in legal fees and settlements. The closing of our joint venture with Kinder Morgan also contributed to the increase. In conjunction with the formation of KinderHawk, we paid $7.5 million for services to our advisors on the transaction. The remaining increase of $20.3 million was primarily due to an increase in payroll and employee costs, including salaries, benefits and incentives associated with the building of our work force as a result of the continued growth in our Company.

Stock-based compensation increased $8.8 million for the year ended December 31, 2010 as compared to the same period in the prior year. This increase was primarily due to the increase in our overall employee headcount as we have gone from 469 full time employees as of December 31, 2009 to 598 employees as of December 31, 2010. In addition, the weighted average value per option granted in 2009 was $7.30, which increased to $10.20 in 2010.

Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs associated with evaluated properties plus future development costs based on the ratio of production volumes for the current period to total remaining reserve volumes for the evaluated properties. Depletion expense increased $65.1 million for the year ended December 31, 2010 from the same period in 2009, to $445.1 million. On a per unit basis, depletion expense decreased $0.26 per Mcfe to $1.81 per Mcfe. This decrease on a per unit basis is primarily due to the ceiling test impairment write down of $1.8 billion before taxes for the year ended December 31, 2009.

Depreciation expense associated with our gas gathering systems increased $6.4 million to $13.8 million for the year ended December 31, 2010. The increase was primarily due to the growth in our midstream operations segment from capital spending over the course of the year inclusive of capital

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spending associated with our KinderHawk joint venture. The KinderHawk joint venture is accounted for in accordance with the financing method for a failed sale of in substance real estate. Under the financing method, the historical basis of the Haynesville Shale gas gathering assets contributed to KinderHawk is carried on the consolidated balance sheets and depreciated over the remaining useful life of the assets. We depreciate our gas gathering systems over a 30 year useful life commencing on the estimated placed in service date.

We utilize the full cost method of accounting to account for our oil and natural gas exploration and development activities. Under this method of accounting, we are required on a quarterly basis to determine whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the "ceiling", based upon the expected after tax present value (discounted at 10%) of the future net cash flows from our proved reserves. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non-cash impairment expense. We recorded a full cost ceiling test impairment of approximately $1.8 billion for the year ended December 31, 2009. For the first three quarters of 2009, we calculated the ceiling using prevailing oil and natural gas prices on the last day of the period, or a subsequent higher price under certain circumstances. At March 31, 2009, our ceiling was calculated using prices of $49.66 per barrel of oil and $3.63 per Mmbtu. Accordingly, at March 31, 2009, our costs exceeded our ceiling limitation by approximately $1.7 billion, resulting in an approximate $1.7 billion write down of our oil and natural gas properties. At December 31, 2009, our net book value of oil and gas properties exceeded the ceiling amount based on the unweighted arithmetic average of the first day of each month for the 12-month period end December 31, 2009 WTI posted price of $57.65 per barrel and Henry Hub price of $3.87 per Mmbtu. As a result, we recorded a full cost ceiling test impairment before income taxes of approximately $106 million and $65 million after taxes.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil, natural gas, and natural gas liquids 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 consolidated statements of operations. At December 31, 2010, we had a $258.7 million derivative asset, $217.0 million of which was classified as current, and a $19.4 million derivative liability, $5.8 million of which was classified as current. We recorded a net derivative gain of $301.1 million ($58.1 million net unrealized gain and $243.0 million net gain for cash received on settled contracts) for the year ended December 31, 2010 compared to a net derivative gain of $260.2 million ($120.4 million net unrealized loss and a $380.6 million gain for cash received on settled contracts) in the same period in 2009.

Interest expense and other increased $106.9 million for year ended December 31, 2010. Approximately $40.5 million of the increase is the result of our accounting for the KinderHawk joint venture under the financing method for a failed sale of in substance real estate. This increase includes interest expense on the financing obligation recorded as a result of the transaction, as well as the recording of KinderHawk's interest expense. In addition, $47 million of the increase was due to the early repurchase of the 2013 Notes, which occurred in the third quarter of 2010. Also contributing to the increase was interest expense associated with the utilization of our Senior Credit Agreement.

We had an income tax provision of $94.9 million for the year ended December 31, 2010 due to our income from continuing operations before income taxes of $230.8 million compared to an income tax benefit of $753.0 million due to our loss from continuing operations before income taxes of $1.8 billion in the prior year. The effective tax rate for the year ended December 31, 2010 was 41.1% compared to 42.4% for the year ended December 31, 2009. The change in the effective tax rate is primarily due to changes in estimates of tax benefits associated with amended tax filings in 2009 and a reduction in the state tax rate.

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Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

We reported a loss from continuing operations, net of income taxes, of $1.0 billion for the year ended December 31, 2009 compared to a loss from continuing operations, net of income taxes, of $386.9 million for the comparable period in 2008. The following table summarizes key items of comparison and their related change for the periods indicated.

In thousands (except per unit and per Mcfe amounts)	Years Ended December 31, 2009	2008	Change
Loss from continuing operations, net of income taxes	$ (1,022,329)	$ (386,867)	$ (635,462)
Operating revenues:			
Oil and natural gas	732,137	1,025,995	(293,858)
Marketing	320,121	63,553	256,568
Midstream	18,418	1,316	17,102
Operating expenses:			
Marketing	316,987	58,581	258,406
Production:			
Lease operating	78,700	52,462	26,238
Workover and other	2,749	5,624	(2,875)
Taxes other than income	57,360	47,104	10,256
Gathering, transportation and other:			
Oil and natural gas	69,287	43,012	26,275
Midstream	10,695	140	10,555
General and administrative:			
General and administrative	96,551	61,703	34,848
Stock-based compensation	14,458	12,310	2,148
Depletion, depreciation and amortization:			
Depletion Full cost	380,003	391,042	(11,039)
Depreciation Midstream	7,398	586	6,812
Depreciation Other	2,761	2,342	419
Accretion expense	1,447	1,246	201
Full cost ceiling impairment	1,838,444	950,799	887,645
Other income (expenses):			
Net gain on derivative contracts	260,248	156,870	103,378
Interest expense and other	(229,419)	(151,825)	(77,594)
(Loss) income from continuing operations before income taxes:			
Oil and natural gas	(1,793,070)	(527,856)	(1,265,214)
Midstream	17,735	(3,186)	20,921
Income tax benefit	753,006	144,175	608,831
Production:			
Natural gas Mmcf	172,296	100,143	72,153
Crude oil MBbl	1,520	1,554	(34)
Natural gas liquids MBbl	290	355	(65)
Natural gas equivalent Mmcfe[(1)]	183,156	111,597	71,559
Daily production Mmcfe[(1)]	502	305	197
Average price per unit[(2)]:			
Natural gas price Mcf	$ 3.69	$ 8.54	$ (4.85)
Crude oil price Bbl	56.15	95.16	(39.01)
Natural gas liquids price Bbl	28.20	56.63	(28.43)
Equivalent Mcfe[(1)]	3.99	9.17	(5.18)
Average cost per Mcfe:			
Production:			
Lease operating	0.43	0.47	(0.04)
Workover and other	0.02	0.05	(0.03)
Taxes other than income	0.31	0.42	(0.11)
Gathering, transportation and other:			
Oil and natural gas	0.38	0.39	(0.01)
Midstream	0.06		0.06
General and administrative:			
General and administrative	0.53	0.55	(0.02)
Stock-based compensation	0.08	0.11	(0.03)
Depletion	2.07	3.50	(1.43)

(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.*

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For the year ended December 31, 2009, oil and natural gas revenues decreased $293.9 million from the same period in 2008, to $732.1 million. The decrease was primarily due to the decrease of $5.18 per Mcfe in our realized average price to $3.99 per Mcfe from $9.17 per Mcfe in the prior year. This decrease per Mcfe led to a decrease in oil and natural gas revenues of $949 million. The effect of lower prices was partially offset by an increase in production of 71,559 Mmcfe or 64% over 2008 due to our continued drilling successes in resource plays in Louisiana, Arkansas and Texas. Increased production contributed approximately $655 million in revenues for the year ended December 31, 2009.

We had marketing revenues of $320.1 million and marketing expenses of $317.0 million in 2009, resulting in income before taxes of $3.1 million. During the fourth quarter of 2008, a subsidiary of ours began purchasing and selling our own and third party natural gas produced from wells we and third parties operate. We report the revenues and expenses related to these marketing activities on a gross basis as part of our operating revenues and operating expenses. Marketing revenues are recorded at the time natural gas is physically delivered to third parties at a fixed or index price. Marketing expenses attributable to gas purchases are recorded as we take physical title to the natural gas and transport the purchased volumes to the point of sale.

We had gross revenues from our midstream segment of $63.3 million for the year ended December 31, 2009 compared to the same period in 2008 of $1.9 million, an increase of $61.4 million of which $44.3 million represents inter-segment revenues that are eliminated in consolidation. The remaining $17.1 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 $18.4 million for the year ended December 31, 2009, an increase of $17.1 million from the prior year. The increase in revenues was primarily related to the increase in throughput on our Haynesville gathering system and treating facilities. Gathering throughput increased 105.3 Bcf to 108.6 Bcf for the year ended December 31, 2009 compared to 3.3 Bcf for the year ended December 31, 2008. The throughput increase resulted from the constructing of 149 miles of gathering pipeline in the Haynesville Shale.

Lease operating expenses increased $26.2 million for the year ended December 31, 2009 as compared to the same period in 2008. This increase was primarily due to our increased production in the current year. On a per unit basis, lease operating expenses decreased $0.04 per Mcfe to $0.43 per Mcfe in 2009 from $0.47 per Mcfe in 2008. This decrease on a per unit basis is primarily due to the increase in production during 2009 from our resource plays which historically have a lower per unit operating cost.

Taxes other than income increased $10.3 million for the year ended December 31, 2009 as compared to the same period in 2008. The increase was primarily due to increased severance taxes resulting from increased production in the current year. Severance taxes 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 $0.11 per Mcfe to $0.31 per Mcfe compared to $0.42 per Mcfe in 2008. This decrease on a per unit basis is primarily attributable to the decrease in our realized oil and natural gas prices.

Gathering, transportation and other expense attributable to our oil and natural gas production segment increased $26.3 million for the year ended December 31, 2009 as compared to the same period in 2008. This increase was primarily due to the increase in production discussed above. On a per unit basis, gathering, transportation and other expense decreased $0.01 per Mcfe primarily due to increases in production in our Haynesville Shale play, which generally has lower costs.

Gathering, transportation and other expenses attributable to our midstream segment increased $10.6 million for the year ended December 31, 2009 compared to the same period in 2008. This increase was primarily due to the increase in throughput associated with the continued development of our gathering system and treating facilities in the Haynesville Shale.

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General and administrative expense for the year ended December 31, 2009 increased $34.9 million to $96.6 million compared to $61.7 million in the same period 2008. This increase is primarily attributable to our recent growth. Payroll and benefits increased $10.4 million. Office expense, other professional services, and other increased $1.3 million, $1.9 million, and $3.0 million respectively. Our legal expense increased $17.8 million to accrue for settlements and an additional $2.2 million in legal fees associated with the settlements.

Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs associated with evaluated properties plus future development costs based on the ratio of production volumes for the current period to total remaining reserve volumes for the evaluated properties. Depletion expense decreased $11.0 million for the year ended December 31, 2009 from the same period in 2008, to $380.0 million. On a per unit basis, depletion expense decreased $1.43 per Mcfe to $2.07 per Mcfe. This decrease on a per unit basis is primarily due to the ceiling test impairment write down of $1.7 billion at March 31, 2009 and $950.8 million at December 31, 2008.

Depreciation expense associated with our gas gathering systems increased $6.8 million to $7.4 million for the year ended December 31, 2009. This increase was primarily due to the construction of our gas gathering systems and treating facilities of which we spent $247 million in the Haynesville and Eagle Ford Shales. We depreciate our gas gathering systems over a 30 year useful life and begin depreciating on the estimated placed in service date.

We recorded a full cost ceiling test impairment of approximately $1.8 billion for the year ended December 31, 2009. We utilize the full cost method of accounting to account for our oil and natural gas exploration and development activities. Under this method of accounting, we are required on a quarterly basis to determine whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the "ceiling", based upon the expected after tax present value (discounted at 10%) of the future net cash flows from our proved reserves. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non-cash impairment expense. For the first three quarters of 2009, we calculated the ceiling using prevailing oil and natural gas prices on the last day of the period, or a subsequent higher price under certain circumstances. At March 31, 2009, our ceiling was calculated using prices of $49.66 per barrel of oil and $3.63 per Mmbtu. Accordingly, at March 31, 2009, our costs exceeded our ceiling limitation by approximately $1.7 billion, resulting in an approximate $1.7 billion write down of our oil and natural gas properties. At December 31, 2009, our net book value of oil and gas properties exceeded the ceiling amount based on the unweighted arithmetic average of the first day of each month for the 12-month period end December 31, 2009 WTI posted price of $57.65 per barrel and Henry Hub price of $3.87 per Mmbtu. As a result, we recorded a full cost ceiling test impairment before income taxes of approximately $106 million and $65 million after taxes.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Consistent with the prior year, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the consolidated statement of operations. At December 31, 2009, we had a $162.9 million derivative asset, $112.4 million of which was classified as current and we had a $1.8 million derivative liability, all of which was classified as current. We recorded a net derivative gain of $260.2 million ($120.4 million net unrealized loss and $380.6 million net gain for cash received on settled contracts) for the year ended December 31, 2009 compared to a net derivative gain of $156.9 million ($230.6 million net unrealized gain and $73.7 million net loss for cash paid on settled contracts) in the prior year.

Interest expense and other was $229.4 million and $151.8 million for the years ended December 31, 2009 and 2008, respectively, increasing $77.6 million from the same period in 2008. Interest expense increased $84.0 million due to the issuance of new long-term debt ($25.5 million for the $800 million 7.875% senior notes due 2015 and $58.5 million for the $600 million 10.5% senior notes due 2014). In conjunction with the new notes, amortization of debt issuance costs and amortization of the discount recorded on the 2014 Notes accounted for $10.8 million. This was partially offset by a $14.4 million reduction in interest expense associated with the decrease in our outstanding balance on our Senior Credit Agreement compared to the prior year. For the year ended 2009, interest expense included a $5.9 million reduction for the capitalization of the interest associated with the ongoing construction of our gas gathering systems. In addition, we withdrew the proposed public offering of master limited partnership units during 2008 and expensed the related costs of $3.4 million. Due to our utilization of marketable securities and miscellaneous items, interest income decreased $6.7 million.

Income tax benefit for the year ended December 31, 2009 increased $608.8 million from the prior year. The increase in our income tax benefit from the prior year was primarily due to our loss from continuing operations before income taxes of $1.8 billion for the year ended December 31, 2009 compared to our loss from continuing operations before income taxes of $531.0 million in 2008. The effective tax rates for the years ended December 31, 2009 and 2008 were 42.4% and 27.1%, respectively. The change in the effective tax rate from the prior year is primarily due to the benefit generated by the pre-tax loss and changes in estimates of tax benefits associated with amended tax filings.

Related Party Transactions

None.

Recently Issued Accounting Pronouncements

We discuss recently adopted and issued accounting standards in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 1, "*Summary of Significant Events and Accounting Policies*."

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ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
(As Revised)

Management of Petrohawk Energy Corporation (the Company), including the Company's Principal Executive Officer and Principal Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting for the Company, as defined by Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control over financial reporting is a process designed by, or under the supervision of, our Principal Executive Officer and Principal Financial Officer, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Internal control over financial reporting includes those policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In connection with the filing of our Annual Report on Form 10-K on February 22, 2011, our management, with the participation of our then Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of internal control over financial reporting as of December 31, 2010 and concluded that our internal control over financial reporting was effective as of December 31, 2010.

In connection with the filing of this Amendment No. 1 to the Annual Report on Form 10-K, management, including our Principal Executive Officer and Principal Financial Officer, reassessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2010 based on the criteria established in the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its reassessment, including consideration of the material weakness described below, management concluded that internal control over financial reporting was ineffective as of December 31, 2010.

The Company identified an error in its previous accounting for the KinderHawk joint venture, as further described in Note 16 to the consolidated financial statements included elsewhere in this filing. In response to the identification of the error, management reassessed the design and operating effectiveness of controls relating to new transactions entered into by the Company. As a result of its reassessment, management identified a deficiency in the operating effectiveness of a control that had been designed to identify and evaluate all applicable generally accepted accounting principles and related authoritative guidance. While several generally accepted accounting principles and related authoritative guidance had been identified and thoroughly assessed by the Company in consideration of the appropriate accounting treatment for the joint venture transaction, ASC Subtopic 360-20, *Property, Plant, and Equipment Real Estate Sales*, had inadvertently not been considered. Management concluded that this deficiency constitutes a material weakness in internal control over financial reporting.

Deloitte & Touche LLP, the Company's independent registered public accounting firm, has issued an attestation report on management's revised assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2010 which is included in Item 8. *Consolidated Financial Statements and Supplementary Data.*

/s/ RICHARD K. STONEBURNER	/s/ JOHN A. SIMMONS
Richard K. Stoneburner **Principal Executive Officer**	**John A. Simmons** **Principal Financial Officer**

Houston, Texas
December 5, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Petrohawk Energy Corporation
Houston, Texas

We have audited the internal control over financial reporting of Petrohawk Energy Corporation and subsidiaries (the "Company") as of December 31, 2010, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting (As Revised). Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our report dated February 21, 2011, we expressed an unqualified opinion on internal control over financial reporting. As described in the following paragraph, a material weakness was subsequently identified as a result of the restatement of the previously issued financial statements. Accordingly, management has revised its assessment about the effectiveness of the Company's internal control over financial reporting and our present opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2010, as expressed herein, is different from that expressed in our previous report.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. The following material weakness has been identified and included in management's assessment: as it relates to new transactions entered into by the Company, management identified a deficiency in the operating effectiveness of a control that had been designed to identify and evaluate all applicable generally accepted accounting principles and related authoritative guidance. This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the consolidated financial statements as of and for the year ended December 31, 2010, of the Company and this report does not affect our report on such consolidated financial statements.

In our opinion, because of the effect of the material weakness identified above on the achievement of the objectives of the control criteria, the Company did not maintain effective internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2010 of the Company and our report dated February 21, 2011 (December 5, 2011 as to the effects of the restatement discussed in Note 16) expressed an unqualified opinion on those consolidated financial statements and included explanatory paragraphs regarding the adoption of Accounting Standards Update No. 2010-3, *"Oil and Gas Reserve Estimation and Disclosures"*, and the restatement discussed in Note 16.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
February 21, 2011 (December 5, 2011 as to the effects of the material weakness described in Management's Report on Internal Control over Financial Reporting (As Revised))

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Petrohawk Energy Corporation
Houston, Texas

We have audited the accompanying consolidated balance sheets of Petrohawk Energy Corporation and subsidiaries (the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Petrohawk Energy Corporation and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, on December 31, 2009, the Company adopted Accounting Standards Update No. 2010-3, *"Oil and Gas Reserve Estimation and Disclosures."*

As discussed in Note 16 to the consolidated financial statements, the accompanying consolidated financial statements have been restated.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2011 (December 5, 2011 as to the effects of the material weakness described in Management's Report on Internal Control over Financial Reporting (As Revised)) expressed an adverse opinion on the Company's internal control over financial reporting because of a material weakness.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
February 21, 2011 (December 5, 2011 as to the effects of the restatement discussed in Note 16)

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PETROHAWK ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	Years Ended December 31,		
	2010 Restated[(1)]	**2009**	**2008**
Operating revenues:			
Oil and natural gas	$ 1,107,401	$ 732,137	$ 1,025,995
Marketing	475,030	320,121	63,553
Midstream	18,216	18,418	1,316
Total operating revenues	1,600,647	1,070,676	1,090,864
Operating expenses:			
Marketing	521,378	316,987	58,581
Production:			
Lease operating	64,744	78,700	52,462
Workover and other	18,119	2,749	5,624
Taxes other than income	9,543	57,360	47,104
Gathering, transportation and other	99,375	79,982	43,152
General and administrative	155,493	111,009	74,013
Depletion, depreciation and amortization	465,970	391,609	395,216
Full cost ceiling impairment		1,838,444	950,799
Total operating expenses	1,334,622	2,876,840	1,626,951
Income (loss) from operations	266,025	(1,806,164)	(536,087)
Other income (expenses):			
Net gain on derivative contracts	301,121	260,248	156,870
Interest expense and other	(336,307)	(229,419)	(151,825)
Total other income (expenses)	(35,186)	30,829	5,045
Income (loss) from continuing operations before income taxes	230,839	(1,775,335)	(531,042)
Income tax (provision) benefit	(94,934)	753,006	144,175
Income (loss) from continuing operations, net of income taxes	135,905	(1,022,329)	(386,867)
Loss from discontinued operations, net of income taxes	(45,984)	(3,122)	(1,185)
Net income (loss)	$ 89,921	$ (1,025,451)	$ (388,052)
Net income (loss) per share:			
Basic:			
Continuing operations	$ 0.45	$ (3.65)	$ (1.77)
Discontinued operations	(0.15)	(0.01)	
Total	$ 0.30	$ (3.66)	$ (1.77)
Diluted:			
Continuing operations	$ 0.45	$ (3.65)	$ (1.77)
Discontinued operations	(0.16)	(0.01)	

Total	$ 0.29	$ (3.66)	$ (1.77)
Weighted average shares outstanding:			
Basic	300,452	280,039	218,993
Diluted	302,367	280,039	218,993

(1) *See further discussion at Note 16, "Restatement of Consolidated Financial Statements*."

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

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PETROHAWK ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share amounts)

	December 31, 2010 Restated(1)	2009
Current assets:		
Cash	$ 1,591	$ 1,511
Accounts receivable	356,597	239,264
Receivables from derivative contracts	217,018	112,441
Prepaids and other	62,831	32,434
Total current assets	638,037	385,650
Oil and natural gas properties (full cost method):		
Evaluated	7,520,446	5,984,765
Unevaluated	2,387,037	2,512,453
Gross oil and natural gas properties	9,907,483	8,497,218
Less accumulated depletion	(4,774,579)	(4,329,485)
Net oil and natural gas properties	5,132,904	4,167,733
Other operating property and equipment:		
Gas gathering systems and equipment	593,388	497,551
Other operating assets	55,315	26,002
Gross other operating property and equipment	648,703	523,553
Less accumulated depreciation	(27,635)	(26,287)
Net other operating property and equipment	621,068	497,266
Other noncurrent assets:		
Goodwill	932,802	932,802
Other intangible assets, net of amortization	89,342	100,395
Debt issuance costs, net of amortization	45,941	44,871
Deferred income taxes	316,546	245,413
Receivables from derivative contracts	41,721	50,421
Restricted cash		213,704
Assets held for sale	74,448	
Other	6,944	23,816
Total assets	$ 7,899,753	$ 6,662,071
Current liabilities:		
Accounts payable and accrued liabilities	$ 787,238	$ 633,171
Deferred income taxes	45,815	14,484
Liabilities from derivative contracts	5,820	1,807
Payable to KinderHawk Field Services LLC	976	
Payable on financing arrangement	7,052	
Long-term debt	14,790	49,370
Total current liabilities	861,691	698,832

Long-term debt	2,612,852	2,592,544
Other noncurrent liabilities		
Liabilities from derivative contracts	13,575	
Asset retirement obligations	31,741	44,000
Payable on financing arrangement	933,811	
Other	544	3,023
Commitments and contingencies (Note 7)		
Stockholders' equity:		
Common stock: 500,000,000 shares of $.001 par value authorized; 302,489,501 and 301,194,695 shares issued and outstanding at December 31, 2010 and 2009, respectively	302	301
Additional paid-in capital	4,631,609	4,599,664
Accumulated deficit	(1,186,372)	(1,276,293)
Total stockholders' equity	3,445,539	3,323,672
Total liabilities and stockholders' equity	$ 7,899,753	$ 6,662,071

(1) *See further discussion at Note 16, "Restatement of Consolidated Financial Statements."*

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

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PETROHAWK ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands)

	Common		Additional	(Accumulated Deficit)	Total
	Shares	Amount	Paid-in Capital	Retained Earnings Restated[(1)]	Stockholders' Equity Restated[(1)]
Balances at January 1, 2008	171,221	$ 171	$ 1,871,516	$ 137,210	$ 2,008,897
Sale of common stock	78,200	78	1,831,872		1,831,950
Equity compensation vesting			16,279		16,279
Warrants exercised	1,222	1	883		884
Common stock issuances	1,874	2	13,661		13,663
Purchase of shares to cover individuals' tax withholding	(153)		(3,798)		(3,798)
Reduction in shares to cover individuals' tax withholding			(1,150)		(1,150)
Offering costs			(73,763)		(73,763)
Net loss				(388,052)	(388,052)
Balances at December 31, 2008	252,364	252	3,655,500	(250,842)	3,404,910
Sale of common stock	47,000	47	956,453		956,500
Equity compensation vesting			19,846		19,846
Warrants exercised	503	1	392		393
Common stock issuances	1,623	1	3,694		3,695
Purchase of shares to cover individuals' tax withholding	(277)		(5,388)		(5,388)
Offering costs			(30,748)		(30,748)
Reduction in shares to cover individuals' tax withholding	(18)		(85)		(85)
Net loss				(1,025,451)	(1,025,451)
Balances at December 31, 2009	301,195	301	4,599,664	(1,276,293)	3,323,672
Equity compensation vesting			32,637		32,637
Common stock issuances	1,495	1	3,076		3,077
Purchase of shares to cover individuals' tax withholding	(171)		(3,672)		(3,672)
Reduction in shares to cover individuals' tax withholding	(29)		(96)		(96)
Net income				89,921	89,921
Balances at December 31, 2010	302,490	$ 302	$ 4,631,609	$ (1,186,372)	$ 3,445,539

(1) *See further discussion at Note 16, "Restatement of Consolidated Financial Statements."*

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

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PETROHAWK ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31,		
	2010 Restated[(1)]	2009	2008
Cash flows from operating activities:			
Net income (loss)	$ 89,921	$ (1,025,451)	$ (388,052)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	470,172	396,644	396,556
Full cost ceiling impairment		1,838,444	950,799
Income tax provision (benefit)	66,686	(754,968)	(144,953)
Write down of midstream assets and loss on sale	70,195		
Stock-based compensation	23,229	14,458	12,310
Net unrealized (gain) loss on derivative contracts	(58,075)	120,401	(230,640)
Loss on early extinguishment of debt	38,404		
Other operating	45,381	24,230	4,552
Change in assets and liabilities:			
Accounts receivable	(183,708)	48,089	(110,479)
Payable to KinderHawk Field Services LLC	976		
Prepaid and other	(30,523)	7,629	(19,044)
Accounts payable and accrued liabilities	(41,424)	31,663	135,382
Other	14,393	(22,012)	2,524
Net cash provided by operating activities	505,627	679,127	608,955
Cash flows from investing activities:			
Oil and natural gas capital expenditures	(2,424,292)	(1,718,741)	(3,121,736)
Proceeds received from sale of oil and natural gas properties	1,178,937	357,360	109,268
Marketable securities purchased	(1,122,016)	(1,457,608)	(3,777,427)
Marketable securities redeemed	1,122,016	1,580,617	3,654,418
Increase in restricted cash	(198,210)	(331,561)	
Decrease in restricted cash	411,914	117,857	269,837
Other operating property and equipment capital expenditures	(282,352)	(309,454)	(164,810)
Other intangible assets acquired		(105,108)	
Net cash used in investing activities	(1,314,003)	(1,866,638)	(3,030,450)
Cash flows from financing activities:			
Proceeds from exercise of stock options and warrants	2,927	3,945	14,438
Proceeds from issuance of common stock		956,500	1,831,950
Offering costs		(30,748)	(73,763)
Proceeds from borrowings	3,362,000	1,448,674	2,764,000
Repayment of borrowings	(3,449,402)	(1,166,711)	(2,086,266)
Increase in payable on financing arrangement	917,437		
Debt issuance costs	(20,738)	(24,048)	(23,793)
Other	(3,768)	(5,473)	
Net cash provided by financing activities	808,456	1,182,139	2,426,566
Net increase (decrease) in cash	80	(5,372)	5,071
Cash at beginning of period	1,511	6,883	1,812
Cash at end of period	$ 1,591	$ 1,511	$ 6,883

(1) *See further discussion at Note 16, "Restatement of Consolidated Financial Statements*."

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

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PETROHAWK ENERGY CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

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 in the United States. The Company operates in two segments, oil and natural gas production and midstream operations. The consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries. All intercompany accounts and transactions have been eliminated. Certain prior year amounts have been reclassified to conform to the current year presentation. The Company has evaluated events or transactions through the date of issuance of this report in conjunction with the preparation of these consolidated financial statements.

Use of Estimates

The preparation of the Company's 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 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 consolidated financial statements.

Marketable Securities

From time to time, the Company invests a portion of its cash in money market mutual funds which are highly liquid marketable securities. The Company accounts for marketable securities in accordance with Financial Accounting Standards Board's (FASB) Accounting Standards Codification (ASC) 320, *Investments Debt and Equity Securities*, (ASC 320) and classifies marketable securities as trading, available-for-sale, or held-to-maturity. The appropriate classification of its marketable securities is determined at the time of purchase and reevaluated at each balance sheet date. The Company had no amounts outstanding at December 31, 2010 and 2009.

Allowance for Doubtful Accounts

The Company establishes provisions for losses on accounts receivable if it determines that it will not collect all or part of the outstanding balance. The Company regularly reviews collectability and establishes or adjusts the allowance as necessary using the specific identification method. There are no significant allowances for doubtful accounts at December 31, 2010 or 2009.

Oil and Natural Gas Properties

The Company accounts for its oil and natural gas producing activities using the full cost method of accounting as prescribed by the United States Securities and Exchange Commission (SEC). Accordingly, all costs incurred in the acquisition, exploration, and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of proved oil and natural gas properties are subject to a full cost ceiling test limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%, net of tax considerations.

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

Gas Gathering Systems and Equipment and Other Operating Assets

Gas gathering systems and equipment are recorded at cost. Depreciation is calculated using the straight-line method over a 30-year estimated useful life. Upon disposition, the cost and accumulated depreciation are removed and any gains or losses are reflected in current operations. Maintenance and repair costs are charged to operating expense as incurred. Material expenditures, which increase the life of an asset, are capitalized and depreciated over the estimated remaining useful life of the asset. The Company capitalized $3.5 million and $5.9 million of interest for the years ended December 31, 2010 and 2009, respectively, related to the construction of the Company's gas gathering systems.

The contribution of the Company's Haynesville Shale gas gathering and treating business to KinderHawk Field Services LLC (KinderHawk) on May 21, 2010 for a 50% membership interest and approximately $917 million in cash is accounted for in accordance with the Financial Accounting Standards Board's (FASB) Accounting Standards Codification (ASC) Subtopic 360-20, *Property, Plant and Equipment Real Estate Sales* (ASC 360-20). See Note 2,*"Acquisitions and Divestitures"* for more details regarding the KinderHawk joint venture arrangement and for discussion of the accounting treatment related to the arrangement. Under the financing method, the historical cost of the Haynesville Shale gas gathering system contributed to KinderHawk is carried at the full historical basis of the assets on the consolidated balance sheets in *"Gas gathering systems and equipment"* and depreciated over the remaining useful life of the assets. Contributions to KinderHawk from the Company and the joint venture partner are recorded as increases in *"Gas gathering systems and equipment"* on the consolidated balance sheets.

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

	December 31,	
	2010[(1)(2)]	2009
	(In thousands)	
Gas gathering systems and equipment	$ 748,112	$ 497,551
Less accumulated depreciation	(22,170)	(14,618)
Net gas gathering systems and equipment	$ 725,942	$ 482,933

(1) *Under the financing method, the historical cost of the Haynesville Shale gas gathering system contributed to KinderHawk is carried at the full historical basis of the assets on the consolidated balance sheets in "Gas gathering systems and equipment" and depreciated over the remaining*

useful life of the assets. As of December 31, 2010, the table above includes approximately $434.6 million attributed to the net carrying value of the assets contributed to KinderHawk.

(2) *Includes gas gathering systems and equipment of approximately $155 million and related accumulated depreciation of approximately $11 million associated with the Fayetteville Shale midstream assets, which were classified as "Assets held for sale" in the consolidated balance sheet at December 31, 2010. "Assets held for sale" were recorded at the lesser of the carrying amount or the fair value less costs to sell, which resulted in a write down of approximately $69.7 million that was recorded in the year ended December 31, 2010. "Assets held for sale" were approximately $74 million as of December 31, 2010. See "Assets Held for Sale" below for further discussion.*

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, five years or lesser of lease term; rental equipment, seven years; and computers, three years. Upon disposition, the cost and accumulated depreciation are removed and any gains or losses are reflected in current operations. Maintenance and repair costs are charged to operating expense as incurred. Material expenditures, which increase the life of an asset, are capitalized and depreciated over the estimated remaining useful life of the asset.

The Company reviews its gas gathering systems and equipment and other operating assets in accordance with ASC 360, *Property, Plant, and Equipment* (ASC 360). ASC 360 requires the Company to evaluate gas gathering systems and equipment and other operating assets as events occur or circumstances change that would more likely than not reduce the fair value below the carrying amount. If the carrying amount 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 its gas gathering systems and equipment and other operating assets at each reporting period to determine whether events and circumstances warrant a revision to the remaining depreciation periods.

Assets Held for Sale

As discussed in Note 2, *"Acquisitions and Divestitures,"* the Company divested its Fayetteville Shale midstream operations on January 7, 2011 for approximately $75 million in cash, before customary closing adjustments. The Company's assets related to the Fayetteville Shale midstream operations are presented separately as "*Assets held for sale*" in the consolidated balance sheet at December 31, 2010, in accordance with ASC 360. Assets held for sale were recorded at the lesser of the carrying amount or the fair value less costs to sell, which resulted in a write down of the carrying amount of approximately $69.7 million that was recorded in the year ended December 31, 2010.

Discontinued Operations

Certain amounts related to the Company's Fayetteville Shale midstream operations and other operating assets have been reclassified to discontinued operations for all periods presented. Unless otherwise noted, information contained in the notes to the consolidated financial statements relates to the Company's continuing operations. See Note 14, *"Discontinued Operations,"* for further discussion of the presentation of the Company's Fayetteville Shale midstream and other operating assets as discontinued operations.

Payable on Financing Arrangement

The contribution of the Company's Haynesville Shale gas gathering and treating business to KinderHawk on May 21, 2010 for a 50% membership interest and approximately $917 million in cash is accounted for in accordance with ASC 360-20. Due to the gathering agreement entered into with the formation of KinderHawk, which constitutes extended continuing involvement under ASC 360-20, it has been determined that the contribution of the Company's Haynesville Shale gathering and treating system to form KinderHawk is accounted for as a failed sale of in substance real estate. See Note 2, *"Acquisitions and Divestitures"* for more details regarding the KinderHawk joint venture arrangement and for discussion of the accounting treatment related to the arrangement. Under the financing method for a failed sale of in substance real estate, on May 21, 2010, the Company recorded a financing obligation on the consolidated balance sheets in *"Payable on financing arrangement,"* in the amount of approximately $917 million. Reductions to the obligation and the non cash interest on the financing obligation are tied to the gathering and treating services, as the Company delivers natural gas through the Haynesville Shale gathering and treating system. Interest and principal are determined based upon the allocable income to the joint venture partner, and interest is limited up to an amount that is calculated based upon the Company's weighted average cost of debt as of the date of the transaction. Allocable income in excess of the calculated value is reflected as reductions of principal. Interest is recorded in *"Interest expense and other"* on the consolidated statements of operations. The balance of the Company's financing obligation as of December 31, 2010, was approximately $940.9 million, of which approximately $7.1 million was classified as current.

Revenue Recognition

Revenues from the sale of crude oil, natural gas, and natural gas liquids are recognized when the product is delivered at a fixed or determinable price, title has transferred, collectability is reasonably assured and evidenced by a contract. The Company follows the "sales method" of accounting for its oil and natural gas revenue, so it recognizes revenue on all crude oil, natural gas, and natural gas liquids sold to purchasers, regardless of whether the sales are proportionate to its ownership in the property. A receivable or liability is recognized only to the extent that the Company has an imbalance on a specific property greater than the expected remaining proved reserves.

Marketing Revenue and Expense

A subsidiary of the Company purchases and sells the Company's own and third party natural gas produced from wells which the Company and third parties operate. 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 operations 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.

The contribution of the Company's Haynesville Shale gas gathering and treating business to KinderHawk on May 21, 2010 for a 50% membership interest and approximately $917 million in cash is accounted for in accordance with ASC 360-20. Under the financing method for a failed sale of in substance real estate, the Company records KinderHawk's revenues, net of eliminations for intercompany amounts associated with gathering and treating services provided to the Company, and expenses on the consolidated statements of operations in *"Midstream revenues."*

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Concentrations of Credit Risk

The Company operates a substantial portion of its oil and natural gas properties. As the operator of a property, the Company makes full payments for costs associated with the property and seeks reimbursement from the other working interest owners in the property for their share of those costs. The Company's joint interest partners consist primarily of independent oil and natural gas producers. If the oil and natural gas exploration and production industry in general were adversely affected, the ability of the Company's joint interest partners to reimburse the Company could be adversely affected.

The purchasers of the Company's oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. The Company has not experienced any significant losses from uncollectible accounts. In 2010, none of the Company's individual purchasers of its production accounted for in excess of 10% of the Company's total sales. Three individual purchasers of the Company's production each accounted for approximately 9% of its total sales, collectively representing 27% of the Company's total sales. In 2009, two individual purchasers of the Company's production each accounted for in excess of 10% of its total sales, collectively representing 25% of the Company's total sales. In 2008, two individual purchasers of the Company's production each accounted for in excess of 10% of its total sales, collectively representing 30% of the Company's total sales.

Risk Management Activities

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

Income Taxes

The Company accounts for income taxes using the asset and liability method wherein deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

The Company follows ASC 740, *Income Taxes*, (ASC 740). ASC 740 creates a single model to address accounting for the uncertainty in income tax positions and prescribes a minimum recognition threshold a tax position must meet before recognition in the consolidated financial statements.

The evaluation of a tax position in accordance with ASC 740 is a two-step process. The first step is a recognition process to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more likely than not recognition threshold, it is presumed that the position will be examined by the appropriate taxing authority with full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more likely than not recognition threshold is calculated to determine the amount of benefit/expense to recognize in the consolidated financial statements. The tax position is measured at the largest amount of benefit/expense that is more likely than not of being realized upon ultimate settlement.

The Company includes interest and penalties relating to uncertain tax positions within "*Interest expense and other*" on the Company's consolidated statements of operations. Refer to Note 10, "*Income Taxes"*, for more details.

Generally, the Company's tax years 2007 through 2010 are either currently under audit or remain open and subject to examination by federal tax authorities or the tax authorities in Arkansas, Louisiana, New Mexico, Oklahoma and Texas, which are the jurisdictions in which the Company has had its principal operations. In certain of these jurisdictions, the Company operates through more than one legal entity, each of which may have different open years subject to examination. Additionally, it is important to note that years are technically open for examination until the statute of limitations in each respective jurisdiction expires.

Tax audits may be ongoing at any point in time. Tax liabilities are recorded based on estimates of additional taxes which may be due upon the conclusion of these audits. Estimates of these tax liabilities are made based upon prior experience and are updated for changes in facts and circumstances. However, due to the uncertain and complex application of tax regulations, it is possible that the ultimate resolution of audits may result in liabilities which could be materially different from these estimates.

Asset Retirement Obligation

ASC 410, *Asset Retirement and Environmental Obligations* (ASC 410) requires that the fair value of an asset retirement cost, and corresponding liability, should be recorded as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The Company records asset retirement obligations to reflect the Company's legal obligations related to future plugging and abandonment of its oil and natural gas wells and gas gathering systems and equipment. The Company estimates the expected cash flow associated with the obligation and discounts the amounts using a credit-adjusted, risk-free interest rate. At least annually, the Company reassesses the obligation to determine whether a change in the estimated obligation is necessary. The Company evaluates whether there are indicators that suggest the estimated cash flows underlying the obligation have materially changed. Should those indicators suggest the estimated obligation may have materially changed on an interim basis (quarterly), the Company will accordingly update its assessment. Additional retirement obligations increase the liability associated with new oil and natural gas wells and gas gathering systems and equipment as these obligations are incurred.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in an acquisition. ASC 350, *Intangibles Goodwill and Other* (ASC 350) requires that intangible assets with indefinite lives, including goodwill, be evaluated on an annual basis for impairment or more frequently if an event occurs or circumstances change that could potentially result in impairment. The goodwill impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. 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 companies.

The Company performs its goodwill test annually during the third quarter or more often if circumstances require. The Company's goodwill impairment review consists of a two-step process. The first step is to determine the fair value of its reporting units and compare it to the carrying value of the related net assets. Fair value is determined based on the Company's estimates of market values. If this fair value exceeds the carrying value no further analysis or goodwill write down is required. The second step is required if the fair value of the Company's reporting units are less than the carrying value of the net assets. In this step the implied fair value of the Company's reporting units are allocated to all the underlying assets and liabilities, including both recognized and unrecognized tangible and intangible assets, based on their fair values. If necessary, goodwill is then written down to its implied fair value. If the fair value of the Company's reporting units is less than the book value (including goodwill), then goodwill is reduced to its implied fair value and the amount of the write down is charged against earnings. The assumptions used by the Company in calculating its reporting unit fair values at the time of the test include the Company's market capitalization and discounted future cash flows based on estimated reserves and production, future development and operating costs and future oil and natural gas prices. Material adverse changes to any of these factors could lead to an impairment of all or a portion of the Company's goodwill in future periods.

As a result of full cost ceiling test impairments recorded by the Company for the years ended December 31, 2009 and 2008 and the quarter ended March 31, 2009, the Company reviewed its goodwill for impairment as of December 31, 2009, March 31, 2009 and December 31, 2008. The Company completed its annual goodwill impairment test during the third quarters of 2010, 2009 and 2008. Based on these reviews, no goodwill impairments were deemed necessary.

Other Intangible Assets

The Company treats the costs associated with acquired transportation contracts as intangible assets which will be amortized over the life of the extended agreement. The initial amount recorded represents the fair value of the contract at the time of acquisition, which is amortized under the straight-line method over the life of the contract. Any unamortized balance of the Company's intangible assets will be subject to impairment testing pursuant to the *Impairment or Disposal of Long-Lived Assets Subsections* of ASC Subtopic 360-10 (ASC 360-10). The Company reviews its intangible assets for potential impairment whenever events or changes in circumstances indicate that an other-than-temporary decline in the value of the investment has occurred.

Amortization expense was $11.1 million and $4.7 million for the year ended December 31, 2010 and for the period from acquisition through December 31, 2009, respectively, and was allocated to operating expenses between *"Marketing"* and *"Gathering, transportation and other"* on the consolidated statements of operations based on the usage of the contract. 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 December 31, 2010 and 2009 are as follows:

	December 31,	
	2010	**2009**
	(In thousands)	
Transportation contracts	$ 105,108	$ 105,108
Less accumulated amortization	(15,766)	(4,713)
Net transportation contracts	$ 89,342	$ 100,395

401(k) Plan

The Company sponsors a 401(k) tax deferred savings plan, whereby the Company matches a portion of employees' contributions in cash. Participation in the plan is voluntary and all employees of the Company who are 21 years of age are eligible to participate. The Company charged to expense plan contributions of $4.3 million, $3.3 million, and $2.6 million in 2010, 2009, and 2008, respectively. The Company matches employee contributions dollar-for-dollar on the first 10% of an employee's pretax earnings.

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Recently Issued Accounting Pronouncements

In December 2008, the SEC issued Release No. 33-8995, *Modernization of Oil and Gas Reporting* (ASC 2010-3), which amended the oil and gas disclosures for oil and gas producers contained in Regulations S-K and S-X, and added a section to Regulation S-K (Subpart 1200) to codify the revised disclosure requirements in Securities Act Industry Guide 2, which was eliminated. The goal of Release No. 33-8995 is to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. Energy companies affected by Release No. 33-8995 are now required to price proved oil and gas reserves using the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. SEC Release No. 33-8995 is effective beginning for financial statements for fiscal years ending on or after December 31, 2009. The Company adopted SEC Release No. 33-8995 effective December 31, 2009. The impact on the Company's operating results, financial position and cash flows has been recorded in the financial statements and additional disclosures were added to the accompanying notes to the consolidated financial statements for the Company's supplemental oil and gas disclosure. See *Supplemental Oil and Gas Information* for more details.

In January 2010, the FASB issued Accounting Standards Update (ASU) No. 2010-02, *Accounting and Reporting for Decreases in Ownership of a Subsidiary a Scope Clarification* (ASU 2010-02). ASU 2010-02 provides amendments to ASC Subtopic 810-10 to clarify that the scope of the decrease in ownership provisions of Subtopic 810-10 includes: 1) a subsidiary or group of assets that is a business or nonprofit activity, 2) a subsidiary that is a business or nonprofit activity that is transferred to an equity method investee or joint venture and 3) an exchange of a group of assets that constitutes a business or nonprofit activity for a noncontrolling interest in an entity. ASU 2010-02 also clarifies that the decrease in ownership guidance in Subtopic 810-10 does not apply to: 1) sales of in substance real estate and 2) conveyances of oil and gas mineral rights. This update is effective beginning in the period in which a company adopts FASB Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statements* (which is now included in Subtopic 810-10) and the amendments in this update should be applied retrospectively to the first period that a company adopted FASB Statement No. 160. The Company adopted the provisions in the year ended December 31, 2010 and applied the provisions to its KinderHawk joint venture, which qualifies for the in substance real estate scope exception. See further discussion in Note 2, "*Acquisitions and Divestitures."*

In January 2010, the FASB issued ASU No. 2010-03 *Oil and Gas Estimation and Disclosures* (ASU 2010-03). This update aligns the current oil and natural gas reserve estimation and disclosure requirements of the Extractive Industries Oil and Gas topic of the FASB ASC Topic 932 with the changes required by the SEC final rule ASC 2010-3. As discussed above, ASU 2010-03 expands the disclosures required for equity method investments, revises the definition of oil- and natural gas-producing activities to include nontraditional resources in reserves unless not intended to be upgraded into synthetic oil or natural gas, amends the definition of proved oil and natural gas reserves to require 12-month average pricing in estimating reserves, amends and adds definitions in the Master Glossary that is used in estimating proved oil and natural gas quantities and provides guidance on geographic area with respect to disclosure of information about significant reserves. ASU 2010-03 must be applied prospectively as a change in accounting principle that is inseparable from a change in accounting estimate and is effective for entities with annual reporting periods ending on or after a change in accounting estimate and is effective for entities with annual reporting periods ending on or after December 31, 2009. The Company adopted ASU 2010-03 effective December 31, 2009. See *Supplemental Oil and Gas Information* for more details.

In January 2010, the FASB issued 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

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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, cash flows or disclosures.

In December 2010, the FASB issued ASU No. 2010-28, *When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts* (ASU 2010-28). This codification update modifies Step 1 of the goodwill impairment test for reporting units with zero or negative carrying amounts and requires reporting units with such carrying amounts to perform Step 2 of the goodwill impairment test if it is more likely than not that a goodwill impairment exists. ASU 2010-28 is effective for fiscal years and interim periods beginning after December 15, 2010 and early adoption is not permitted. The Company will adopt the provisions of this update in its Quarterly Report on Form 10-Q for the three months ended March 31, 2011. The Company is currently evaluating the impact that this adoption will have on its operating results, financial position, cash flows or disclosures but does not expect a material impact if any, as a result of the adoption.

In December 2010, the FASB issued ASU No. 2010-29, *Disclosure of Supplementary Pro Forma Information for Business Combinations* (ASU 2010-29). ASU 2010-29 requires a public entity who discloses comparative pro forma information for business combinations that occurred in the current reporting period to disclose revenue and earnings of the combined entity as though the business combination(s) occurred as of the beginning of the comparable prior annual period only. This update also expands the supplemental pro forma disclosures required to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. ASU 2010-29 is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010 and early adoption is permitted. The Company will adopt the provisions of this update for any business combinations that occur after January 1, 2011.

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2. ACQUISITIONS AND DIVESTITURES

Acquisitions

Kaiser Trading, LLC

On July 31, 2009, the Company purchased all outstanding membership interests in Kaiser Trading, LLC (Kaiser) for approximately $105 million. Kaiser's only assets were transportation-related contracts including a firm transportation contract, interruptible gas transportation service agreement, parking and lending services agreement, and a pooling services agreement. The initial firm transportation contract runs through 2013 and at no additional cost, the Company has the contractual right to extend firm supply through 2019.

Fayetteville Shale

On February 8, 2008, the Company purchased additional properties located in the Fayetteville Shale for approximately $231 million after customary closing adjustments. The acquired properties included interests primarily in Van Buren and Cleburne Counties, Arkansas that were substantially undeveloped.

Elm Grove Field

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

Divestitures

Fayetteville Shale

On December 22, 2010, the Company completed the sale of its interest in natural gas properties and other operating assets in the Fayetteville Shale for $575 million in cash, before customary closing adjustments. Proceeds from the sale of the interest in natural gas properties were recorded as a reduction to the carrying value of the Company's full cost pool with no gain or loss recorded. In conjunction with the sale of the other operating assets, the Company recorded a loss of approximately $0.5 million in the year ended December 31, 2010. As a result of the Fayetteville Shale sale of natural gas properties, the Company's borrowing base under its Senior Credit Agreement was reduced by approximately $200 million to $1.65 billion as of December 31, 2010. On January 7, 2011, the Company completed the sale of its midstream assets in the Fayetteville Shale for approximately $75 million in cash, before customary closing adjustments. Upon the completion of the Fayetteville Shale midstream sale, the midstream component of the Company's borrowing base, that was limited to $38 million based on midstream EBITDA as of December 31, 2010, was further reduced to approximately $15 million. As of December 31, 2010, the Fayetteville Shale midstream assets were classified as *"Assets held for sale"* on the Company's consolidated balance sheet. "*Assets held for sale*" were recorded at the lesser of the carrying amount or the fair value less costs to sell, which resulted in a write down of the carrying amount of approximately $69.7 million in the year ended December 31, 2010. Both transactions had an effective date of October 1, 2010.

Mid-Continent Properties

On September 29, 2010, the Company completed the sale of its interest in certain Mid-Continent properties in Texas, Oklahoma and Arkansas for $123 million in cash, 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 July 1, 2010.

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Hawk Field Services, LLC Joint Venture

On May 21, 2010, Hawk Field Services, LLC (Hawk Field Services), 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, engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville and Lower Bossier Shales. Pursuant to the Contribution Agreement, Hawk Field Services contributed to KinderHawk its Haynesville Shale gathering and treating business in Northwest Louisiana, and Kinder Morgan contributed approximately $917 million in cash ($875 million for a 50% membership interest in KinderHawk and $42 million for certain closing adjustments including 2010 capital expenditures through the closing date) to KinderHawk. Each of Hawk Field Services and Kinder Morgan own a 50% membership interest in KinderHawk. KinderHawk distributed approximately $917 million to Hawk Field Services. The joint venture had an economic effective date of January 1, 2010, and Hawk Field Services continued to operate the business until September 30, 2010, at which date Hawk Field Services and Kinder Morgan terminated the transition services agreement and KinderHawk assumed operations of the joint venture. In connection with the joint venture transaction the Company entered into a gathering agreement with KinderHawk which requires the Company to deliver natural gas to KinderHawk from dedicated lease acreage for the life of the dedicated lease acreage, or approximately 30 years, and includes a minimum delivery commitment over a five-year period.

The Company is obligated to deliver to KinderHawk agreed upon minimum annual quantities of natural gas from Petrohawk operated wells producing from the Haynesville and Lower Bossier Shales with specified acreage in Northwest Louisiana through May 2015, 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.

The KinderHawk joint venture is accounted for as a failed sale of in substance real estate under the provisions of ASC 360-20. ASC 360-20 establishes standards for recognition of profit on all real estate sales transactions other than retail land sales, without regard to the nature of the seller's business. In making the determination of whether a transaction qualifies, in substance, as a sale of real estate, the nature of the entire real estate being sold is considered, including the land plus the property improvements and the integral equipment. The Haynesville Shale gathering and treating system, consists of right of ways, pipelines and processing facilities. Due to the gathering agreement which constitutes extended continuing involvement under ASC 360-20, it has been determined that the contribution of the Company's Haynesville Shale gathering and treating system to form KinderHawk should be accounted for as a failed sale of in substance real estate.

As a result of the failed sale the Company accounts for the continued operations of the gas gathering system and reflects a financing obligation, representing the proceeds received, under the financing method of real estate accounting. Under the financing method, the historical cost of the Haynesville Shale gas gathering system contributed to KinderHawk is carried at the full historical basis of the assets on the consolidated balance sheets in *"Gas gathering systems and equipment"* and depreciated over the remaining useful life of the assets. The financing obligation is recorded on the consolidated balance sheets in *"Payable on financing arrangement,"* in the amount of approximately $917 million. Reductions to the obligation and non cash interest on the financing obligation are tied to the gathering and treating services, as the Company delivers natural gas through the Haynesville Shale gathering and treating system. Interest and principal are determined based upon the allocable income to Kinder Morgan, and interest is limited up to an amount that is calculated based upon the Company's weighted average cost of debt as of the date of the transaction. Allocable income in excess of the calculated value is reflected as reductions of principal. Interest is recorded in *"Interest expense and other"* on the consolidated statements of operations. Additionally the Company records KinderHawk's revenues, net of eliminations for intercompany amounts associated with gathering and treating services provided to the Company, and expenses on the consolidated statements of operations in *"Midstream revenues," "Taxes other than income," "Gathering, transportation and other," "General and administrative," "Interest expense and other"* and *"Depletion, depreciation and amortization."*

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 in cash, 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 all of which had been spent as of December 31, 2010.

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) in Oklahoma County, Oklahoma for $155 million in cash, 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.

Permian Basin Properties

On October 30, 2009, the Company sold its Permian Basin properties to a privately-owned company for $376 million in cash, before closing adjustments. The effective date of the sale was July 1, 2009. Proceeds from the sale were recorded as a reduction to the carrying value of the Company's full cost pool with no gain or loss recorded. In conjunction with the closing of this sale, the Company deposited and subsequently spent the remaining net proceeds of $331 million with a qualified intermediary to facilitate like-kind exchange transactions ($37.6 million was previously received as a deposit).

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3. OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties as of December 31, 2010 and 2009 consisted of the following:

	December 31, 2010	December 31, 2009
	(In thousands)	
Subject to depletion	$ 7,520,446	$ 5,984,765
Not subject to depletion:		
Exploration and extension wells in progress	82,776	91,227
Other capital costs:		
Incurred in 2010	594,996	
Incurred in 2009	414,360	496,309
Incurred in 2008	1,281,930	1,657,489
Incurred in 2007 and prior	12,975	267,428
Total not subject to depletion	2,387,037	2,512,453
Gross oil and natural gas properties	9,907,483	8,497,218
Less accumulated depletion	(4,774,579)	(4,329,485)
Net oil and natural gas properties	$ 5,132,904	$ 4,167,733

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. Prior to December 31, 2009, companies used the price in effect at the end of each accounting quarter and had the option, under certain circumstances, to elect to use subsequent commodity prices if they increased after the end of the accounting quarter.

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 and the full cost ceiling test limitation.

At December 31, 2010 the ceiling test value of the Company's reserves was calculated based on the first day average of the 12-months ended December 31, 2010 of the West Texas Intermediate (WTI) spot price of $79.43 per barrel, adjusted by lease or field for quality, transportation fees, and regional price differentials, and the first day average of the 12-months ended December 31, 2010 of the Henry Hub price of $4.38 per million British thermal units (Mmbtu), adjusted by lease or field 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 December 31, 2010 did not exceed the ceiling amount. Changes in production rates, levels of reserves, future development costs, and other factors will determine the Company's actual ceiling test calculation and impairment analyses in future periods.

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At December 31, 2009, the ceiling test value of the Company's reserves was calculated based on the first day average of the 12-months ended December 31, 2009 of the WTI posted price of $57.65 per barrel, adjusted by lease or field for quality, transportation fees, and regional price differentials, and the first day average of the 12-months ended December 31, 2009 of the Henry Hub price of $3.87 per Mmbtu, adjusted by lease or field 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 December 31, 2009 exceeded the ceiling amount. As a result, the Company recorded a full cost ceiling test impairment before income taxes of $106 million and $65 million after taxes. For the period ended March 31, 2009, the Company recorded a full cost ceiling test impairment before income taxes of $1.7 billion and $1.1 billion after taxes.

At December 31, 2008, the ceiling test value of the Company's reserves was calculated based on the December 31, 2008 WTI posted price of $41.00 per barrel adjusted by lease for quality, transportation fees, and regional price differentials, and the December 31, 2008 Henry Hub spot market price of $5.71 per Mmbtu adjusted by lease or field for energy content, transportation fees, and regional price differentials. Using these prices, the Company's net book value of oil and natural gas properties would have exceeded the ceiling amount by approximately $1.0 billion before tax and $574 million after tax, at December 31, 2008. Subsequent to year-end, the market price for Henry Hub gas and WTI oil did not increase. Accordingly, the Company recorded an approximate $1.0 billion full cost ceiling impairment at December 31, 2008.

4. LONG-TERM DEBT

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

	December 31,	
	2010[(1)]	**2009**[(1)]
	(In thousands)	
Senior revolving credit facility	$ 146,000	$ 203,000
7.25% $825 million senior notes[(2)]	825,000	
10.5% $600 million senior notes[(3)]	562,115	554,154
7.875% $800 million senior notes	800,000	800,000
9.125% $775 million senior notes[(4)]		764,694
7.125% $275 million senior notes[(5)]	268,922	266,402
9.875% senior notes		224
Deferred premiums on derivative contracts	10,815	4,070
	$ 2,612,852	$ 2,592,544

(1) *Table excludes $14.6 million and $49.4 million of deferred premiums on derivative contracts which have been classified as current at December 31, 2010 and 2009, respectively. Table also excludes $0.2 million of 9.875% senior notes due 2011 which have been classified as current at December 31, 2010.*

(2) *The 7.25% $825 million senior notes due 2018 were issued in the third quarter of 2010 to fund the repurchase of the 9.125% $775 million senior notes, which were due in 2013. See "7.25% Senior Notes" below for further details.*

(3) *Amount includes a $37.9 million and $45.8 million unamortized discount at December 31, 2010 and 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*

(4) *The 9.125% $775 million senior notes were repurchased during the third quarter of 2010. See "9.125% Senior Notes" below for more details.*

(5) *Amount includes a $3.5 million and $6.0 million unamortized discount at December 31, 2010 and 2009, respectively, recorded by the Company in conjunction with the assumption of the notes. See "7.125% Senior Notes" below for more details. See Note 15, "Subsequent Event" for the discussion of the anticipated repurchase of the 7.125% $275 million senior notes.*

Senior Revolving Credit Facility

Effective August 2, 2010, the Company amended and restated its existing credit facility dated October 14, 2009 by entering into the Fifth Amended and Restated Senior Revolving Credit Agreement (the Senior Credit Agreement), among 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 Bank of Montreal as co-syndication agents for the Lenders, and JPMorgan Chase Bank, N.A. and Wells Fargo Bank, N.A., as co-documentation agents for the Lenders. The Senior Credit Agreement provides for a $2.0 billion facility. As of December 31, 2010, the borrowing base was approximately $1.65 billion, $1.55 billion of which related to the Company's oil and natural gas properties and up to $100 million (currently limited as described below) related to the Company's midstream assets. The portion of the borrowing base relating to the Company's oil and natural gas properties is 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 relating to the Company's midstream assets is limited to the lesser of $100 million or 3.5 times midstream EBITDA, and is calculated quarterly. As of December 31, 2010, the midstream component of the borrowing base was limited to approximately $38 million based on midstream EBITDA. At December 31, 2010, the Company had approximately $24 million outstanding letters of credit with various customers, vendors and others. 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 unsecured senior or senior subordinated notes that the Company may issue. In January 2011, the Company issued an additional $400 million aggregate principal amount of its 7.25% senior notes, a portion of the proceeds of which will be used to redeem all of the Company's 7.125% $275 million senior notes, which have been called for redemption. Accordingly, the Company's borrowing base was reduced to approximately $1.6 billion.

Amounts outstanding under the Senior Credit Agreement bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 2.00% to 3.00% for Eurodollar loans or at specified margins over the Alternate Base Rate (ABR) of 1.00% to 2.00% 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 Fifth 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, 2014.

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 December 31, 2010, the Company was in compliance with its financial debt covenants under the Senior Credit Agreement.

7.25% Senior Notes

On August 17, 2010, the Company completed a private placement offering to eligible purchasers of an aggregate principal amount of $825 million of its 7.25% senior notes due 2018 (the 2018 Notes) at a

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purchase price of 100% of the principal amount of the 2018 Notes. The 2018 Notes were issued under and are governed by an indenture dated August 17, 2010, between the Company, U.S. Bank Trust National Association, as trustee, and the Company's subsidiaries named therein as guarantors (the 2018 Indenture). The Company applied the net proceeds from the sale of the 2018 Notes to redeem its $775 million 9.125% senior notes due 2013.

In connection with the sale of the 2018 Notes, the Company entered into a Registration Rights Agreement, dated August 17, 2010, among the Company and the Initial Purchasers (the Registration Rights Agreement). Pursuant to the Registration Rights Agreement, the Company agreed to conduct a registered exchange offer for the 2018 Notes or cause to become effective a shelf registration statement providing for the resale of the 2018 Notes. The registration statement for the exchange offer became effective on September 29, 2010.

The 2018 Notes bear interest at a rate of 7.25% per annum, payable semi-annually on February 15 and August 15 of each year, commencing on February 15, 2011. The 2018 Notes will mature on August 15, 2018. The 2018 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness. The 2018 Notes are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by the Company's subsidiaries. Petrohawk Energy Corporation, the issuer of the 2018 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

On or prior to August 15, 2013, the Company may redeem up to 35% of the aggregate principal amount of the 2018 Notes with the net cash proceeds of certain equity offerings at a redemption price of 107.25% of the principal amount, plus accrued and unpaid interest to the redemption date; provided that at least 65% in aggregate principal amount of the 2018 Notes originally issued under the 2018 Indenture remain outstanding immediately after the redemption. In addition, at any time prior to August 15, 2014, the Company may redeem some or all of the 2018 Notes for the principal amount, plus accrued and unpaid interest, plus a make whole premium equal to the excess, if any of (a) the present value at such time of (i) the redemption price of such note at August 15, 2014, (ii) any required interest payments due on the notes (except for currently accrued and unpaid interest), computed using a discount rate equal to the Treasury Rate plus 50 basis points, discounted to the redemption date on a semi-annual basis, over (b) the principal amount of such note.

On or after August 15, 2014, the Company may redeem all or part of the 2018 Notes at any time or from time to time at the redemption prices (expressed as a percentage of principal amount) set forth in the following table plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the 12-month period beginning August 15 of the years indicated below:

Year	**Percentage**
2014	103.625
2015	101.813
2016 and thereafter	100.000

The Company may be required to offer to repurchase the 2018 Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined in the 2018 Indenture. The 2018 Indenture contains covenants that, among other things, restrict or limit the ability of the Company and its subsidiaries to: borrow money; pay dividends on stock; purchase or redeem stock or subordinated indebtedness; make investments; create liens; enter into transactions with affiliates; sell assets; and merge with or into other companies or transfer all or substantially all of the Company's assets.

On January 31, 2011, the Company completed the issuance of an additional $400 million aggregate principal amount of its 2018 Notes. The Company will to utilize a portion of the proceeds from this issuance to redeem the Company's 7.125% $275 million senior notes due 2012, which have been called for redemption. For further discussion of this transaction, see Note 15, *"Subsequent Event."*

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10.5% Senior Notes

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

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

On or before February 1, 2012, the Company may redeem up to 35% of the aggregate principal amount of the 2014 Notes with the net cash proceeds of certain equity offerings at a redemption price of 110.5% of the principal amount plus accrued interest and unpaid interest to the redemption date provided that at least 65% in aggregate principal amount of the 2014 Notes originally issued under the 2014 Indenture remain outstanding immediately after the redemption. In addition, at any time prior to February 1, 2012, the Company may redeem some or all of the 2014 Notes for the principal amount thereof, plus accrued and unpaid interest plus a make whole premium equal to the excess, if any of (a) the present value at such time of (i) the redemption price of such note at February 1, 2012, (ii) plus required interest payments due on the notes, computed using a discount rate based upon the yield of United States Treasury securities with a constant maturity most nearly equal to the period from the redemption date to February 1, 2012 plus 50 basis points, over (b) the principal amount of such note.

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

Year	Percentage
2012	110.500
2013	105.250
2014	100.000

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

In conjunction with the issuance of the $600 million 2014 Notes, the Company recorded a discount of $52.3 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized discount was $37.9 million and $45.8 million at December 31, 2010 and 2009, respectively.

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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) pursuant to an indenture (the 2015 Indenture). 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, fully and unconditionally guaranteed on a senior unsecured basis by the Company's subsidiaries. Petrohawk Energy Corporation, the issuer of the Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

On or before June 1, 2011, the Company may redeem up to 35% of the aggregate principal amount of the 2015 Notes with the net cash proceeds of certain equity offerings at a redemption price of 107.875% of the principal amount plus accrued interest and unpaid interest to the redemption date provided that: at least 65% in aggregate principal amount of the 2015 Notes originally issued under the 2015 Indenture remain outstanding immediately after the redemption. In addition, at any time prior to June 1, 2012, the Company may redeem some or all of the 2015 Notes for the principal amount thereof, plus accrued and unpaid interest plus a make whole premium equal to the excess, if any of (a) the present value at such time of (i) the redemption price of such note at June 1, 2012, (ii) plus required interest payments due on the notes, computed using a discount rate based upon the yield of United States Treasury securities with a constant maturity most nearly equal to the period from the redemption date to June 1, 2012 plus 50 basis points, over (b) the principal amount of such note.

On or after June 1, 2012, the Company may redeem some or all of the 2015 Notes at any time or from time to time at the redemption prices (expressed as a percentage of principal amount) set forth in the following table plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the 12-month period beginning June 1 of the years indicated below:

Year	Percentage
2012	103.938
2013	101.969
2014	100.000

The Company may be required to offer to repurchase the 2015 Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined in the 2015 Indenture. The 2015 Indenture contains covenants that, among other things, restrict or limit the ability of the Company and its subsidiaries to: borrow money; pay dividends on stock; purchase or redeem stock or subordinated indebtedness; make investments; create liens; enter into transactions with affiliates; sell assets; and merge with or into other companies or transfer all or substantially all of the Company's assets.

9.125% Senior Notes

On July 12 and 27, 2006, the Company issued a total of $775 million principal amount of its 9.125% senior notes due 2013 (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 additional $125 million in 2013 Notes were issued pursuant to the same Indenture at 101.125% of the face amount. The Company applied the net proceeds from the sale of the additional 2013 Notes to repay indebtedness outstanding under its Senior Credit Agreement. The $650 million tranche of 2013 Notes were issued at 98.735% of the face amount for gross proceeds of approximately $642.0 million, before estimated offering expenses and the initial purchasers' discount. The Company applied a portion of the net proceeds from the initial sale of the 2013 Notes to fund the cash consideration paid by the Company in connection with the Company's merger with KCS Energy, Inc, (KCS) and the Company's repurchase of the 2011 Notes pursuant to a tender offer the Company concluded in July 2006.

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, fully and unconditionally guaranteed on a senior unsecured basis by the Company's subsidiaries, including, pursuant to the 2013 First Supplemental Indenture, the KCS subsidiaries acquired in the Company's merger with KCS. Petrohawk Energy Corporation, the issuer of the 2013 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

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 Company had no remaining unamortized discount at December 31, 2010 and $4.8 million at December 31, 2009. In conjunction with the issuance of the $125 million 2013 Notes, the Company recorded a premium of $1.4 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The Company had no remaining unamortized premium at December 31, 2010 and $0.8 million at December 31, 2009.

Upon issuance of the 2018 Notes, as discussed above, on August 3, 2010, the Company commenced a cash tender offer for any and all of the outstanding of the 2013 Notes and a solicitation of consents to amend the indenture governing the 2013 Notes (the 2013 Notes Indenture). On August 17, 2010, the Company announced that it had received the requisite consents to amend the 2013 Notes Indenture, and the Company entered into the Sixth Supplemental Indenture, dated August 17, 2010, with U.S. Bank National Association, as Trustee for the 2013 Notes. The Sixth Supplemental Indenture eliminated or made less restrictive the most restrictive covenants contained in the 2013 Notes Indenture, including those with respect to SEC reporting, incurrence of indebtedness, distributions to stockholders, creation of liens, assets sales, transactions with affiliates, business activities, change of control, payment of taxes and business combinations. The amendments contained in the Sixth Supplemental Indenture became effective when the Company accepted and redeemed the tendered 2013 Notes.

On August 16, 2010, tenders and consents had been received from holders of $652.7 million in aggregate principal amount of the 2013 Notes, representing approximately 85% of the outstanding 2013 Notes. On August 17, 2010, the Company accepted the 2013 Notes that had been tendered and utilized approximately $689.5 million in net proceeds from the sale of the 2018 Notes to repurchase the tendered 2013 Notes. Approximately $116.0 million in aggregate principal amount of 2013 Notes were not tendered.

On August 19, 2010, the Company elected to exercise its right under the 2013 Notes Indenture to redeem effective on September 20, 2010 (the Redemption Date) the remaining $116.0 million aggregate principal amount of the outstanding 2013 Notes at a redemption price of 104.563% of the principal amount thereof (the Redemption Price), plus accrued and unpaid interest on the 2013 Notes redeemed to, but not including, the Redemption Date. Holders of the 2013 Notes were paid the Redemption Price upon presentation and surrender of their 2013 Notes for redemption to the Trustee.

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As a result of the early redemption of the 2013 Notes, the Company incurred charges of approximately $47 million in the third quarter of 2010. These charges are recorded within "*Interest expense and other*" on the consolidated statements of operations.

7.125% Senior Notes

Upon effectiveness of the Company's merger with KCS, the Company assumed (pursuant to the Second Supplemental Indenture relating to the 7.125% senior notes, also referred to as the 2012 Notes), and subsidiaries of the Company guaranteed (pursuant to the Third Supplemental Indenture relating to such notes), all the obligations (approximately $275 million) of KCS under the 2012 Notes and the Indenture dated April 1, 2004 (the 2012 Indenture) among KCS, U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein, which governs the terms of the 2012 Notes. The 2012 Notes are guaranteed on an unsubordinated, unsecured basis by all of the Company's current subsidiaries, including the subsidiaries of KCS that the Company acquired in the merger. Interest on the 2012 Notes is payable semi-annually, on each April 1 and October 1. On or after April 1, 2008, the Company may redeem all or a portion of the 2012 Notes. If the notes are redeemed during any 12-month period beginning on April 1, 2010, the Company must pay 100% of the principal price plus accrued and unpaid interest thereon, if any.

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 was $3.5 million and $6.0 million at December 31, 2010 and 2009, respectively.

The 2012 Notes are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by the Company's subsidiaries. Petrohawk Energy Corporation, the issuer of the Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

See Note 15, "*Subsequent Event"* for discussion of the anticipated redemption of the 2012 Notes.

9.875% Senior Notes

On April 8, 2004, Mission Resources Corporation (Mission) issued $130.0 million of its 9.875% senior notes due 2011 (the 2011 Notes). The Company assumed these notes upon the closing of the Company's merger with Mission. In conjunction with the Company's merger with KCS, the Company extinguished substantially all of its 2011 Notes. There were approximately $0.2 million of the notes which were not redeemed and are still outstanding as of December 31, 2010 and 2009. The $0.2 million of the notes outstanding were classified as current as of December 31, 2010. In connection with the extinguishment of substantially all of the 2011 Notes, the Company requested and received from the noteholders consent to eliminate most significant debt covenants associated with the 2011 Notes.

Debt Maturities

Aggregate maturities required on long-term debt at December 31, 2010 are due in future years as follows (in thousands):

2011(1)	$ 14,790
2012(2)	283,190
2013	
2014	746,000
2015	800,000
Thereafter(2)	825,000
Total	$ 2,668,980

(1) *Amount represents $14.6 million of deferred premiums on derivatives which have been classified as current at December 31, 2010. Amount also includes $0.2 million of 9.875% senior notes due 2011 which have been classified as current at December 31, 2010.*

(2) *See Note 15, "Subsequent Event" for a discussion of the Company's issuance of an additional $400 million of the 2018 Notes and its anticipated redemption of the 2012 Notes.*

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Debt Issuance Costs

The Company capitalizes certain direct costs associated with the issuance of long-term debt. During 2010, the Company capitalized approximately $20.7 million in costs associated with its issuance of the 2018 Notes and with amendments to the Senior Credit Agreement. The Company expensed approximately $19.7 million in debt issuance costs during 2010, which includes both amortization and write downs in capitalized costs due to reductions in the Senior Credit Agreement for asset sales and the issuance of new bonds. During 2009, the Company capitalized approximately $24.0 million in costs associated with its issuance of the 2014 Notes and with amendments to the Senior Credit Agreement. The Company expensed approximately $9.7 million in debt issuance costs during 2009, which includes both amortization and write downs in capitalized costs due to reductions in the Senior Credit Agreement for the issuance of new bonds. At December 31, 2010 and 2009, the Company had approximately $45.9 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 consolidated balance sheets, but also the impact of the Company's nonperformance risk on its own 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.

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 December 31, 2010 and 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 years ended December 31, 2010 and 2009.

	December 31, 2010			
	Level 1	**Level 2**	**Level 3**	**Total**
	(In thousands)			
Assets				
Receivables from derivative contracts	$	$ 258,739	$	$ 258,739
	$	$ 258,739	$	$ 258,739
Liabilities				
Liabilities from derivative contracts	$	$ 19,395	$	$ 19,395

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

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

As discussed in Note 2, *"Acquisitions and Divestitures,"* the Company divested its Fayetteville Shale midstream operations on January 7, 2011 for approximately $75 million in cash, before customary closing adjustments. The Company's assets related to the Fayetteville Shale midstream operations are presented separately as "*Assets held for sale*" in the consolidated balance sheet at December 31, 2010, in accordance with ASC 360. Assets held for sale were recorded at the lesser of the carrying amount or the fair value less costs to sell, which resulted in a write down of the carrying amount of approximately $69.7 million that was recorded in the year ended December 31, 2010.

Derivatives listed above include collars, swaps, and put options that are carried at fair value. The Company records the net change in the fair value of these positions in *"Net gain on derivative contracts"* in the Company's 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 December 31, 2010 and 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 December 31, 2010 and 2009 (excluding premiums and discounts, deferred premiums on derivative contracts, and any amounts that have been classified as current):

Debt	December 31, 2010 Carrying Amount	December 31, 2010 Estimated Fair Value	December 31, 2009 Carrying Amount	December 31, 2009 Estimated Fair Value
	(In thousands)			
7.25% $825 million senior notes	$ 825,000	$ 832,425	$	$
10.5% $600 million senior notes	600,000	684,000	600,000	658,500
7.875% $800 million senior notes	800,000	834,000	800,000	804,000
9.125% $775 million senior notes			768,725	805,239
7.125% $275 million senior notes	272,375	273,465	272,375	273,056
9.875% senior notes			224	227
	$ 2,497,375	$ 2,623,890	$ 2,441,324	$ 2,541,022

The fair values of the Company's fixed interest debt instruments were calculated using quoted market prices based on trades of such debt as of December 31, 2010 and 2009, respectively.

6. ASSET RETIREMENT OBLIGATION

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 and equipment, 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 consolidated balance sheets and capitalizes a portion of 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 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 the ARO liability for the years ended December 31, 2010 and 2009 (in thousands):

Liability for asset retirement obligation as of December 31, 2008	$ 28,644
Liabilities settled and divested(1)	(10,218)
Additions	3,744
Acquisitions	14
Accretion expense	1,461
Revisions in estimated cash flows(2)	20,355
Liability for asset retirement obligation as of December 31, 2009	44,000
Liabilities settled and divested(1)	(24,206)
Additions	9,933
Acquisitions	28
Accretion expense	1,986
Liability for asset retirement obligation as of December 31, 2010	$ 31,741

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

(2) *During 2009, the Company recognized a revision of $20.4 million to its asset retirement obligation which resulted primarily from an overall increase in the Company's abandonment cost estimates.*

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7. COMMITMENTS AND CONTINGENCIES

Lease 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 also has lease commitments related to certain vehicles, machinery and equipment under long-term operating leases. Rent expense was $6.4 million, $5.1 million, and $4.1 million for the years ended December 31, 2010, 2009, and 2008, respectively.

As of December 31, 2010, future minimum lease payments for all non-cancelable operating leases are as follows (in thousands):

2011	$ 6,901
2012	6,996
2013	7,004
2014	4,828
2015	2,448
Thereafter	1,028
Total	$ 29,205

As of December 31, 2010, the Company has drilling rig commitments totaling $297.0 million as follows (in thousands):

2011	$ 183,990
2012	83,266
2013	27,485
2014	2,290
2015	
Thereafter	
Total	$ 297,031

As of December 31, 2010, the Company has gathering and transportation commitments totaling $1.9 billion as follows (in thousands):

2011	$ 127,844
2012	187,805
2013	183,746
2014	181,562
2015	179,164
Thereafter	1,086,455
Total	$ 1,946,576

As of December 31, 2010, the Company has pipeline and well equipment commitments totaling $127.3 million as follows (in thousands):

2011	$ 127,279
2012	
2013	
2014	
2015	
Thereafter	
Total	$ 127,279

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The Company has various other contractual commitments pertaining to exploration, development and production activities. The Company has work related commitments for, among other things, obtaining and processing seismic data and fracture stimulation services. As of December 31, 2010, the Company is obligated pay $59.9 million as follows (in thousands):

2011	$ 45,269
2012	12,452
2013	2,181
2014	
2015	
Thereafter	
Total	$ 59,902

On May 21, 2010, the Company created a joint venture with Kinder Morgan, KinderHawk, which engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville and Lower Bossier Shales. As part of this transaction, the Company is committed to contribute up to an additional $78.2 million, as of December 31, 2010, in capital during 2011 in the event KinderHawk requires capital to finance its planned capital expenditures. In addition, the Company is obligated to deliver to KinderHawk agreed upon minimum annual quantities of natural gas from Petrohawk operated wells producing from the Haynesville and Lower Bossier Shales in North Louisiana through May 2015, or in the alternative, pay an annual true-up fee to KinderHawk if such minimum annual quantities are not delivered. These obligations are not reflected in the amounts shown in the above tables. 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.

The contribution of the Company's Haynesville Shale gas gathering and treating business to KinderHawk is accounted for in accordance with ASC 360-20. Due to the gathering agreement entered into with the formation of KinderHawk, which constitutes extended continuing involvement under ASC 360-20, it has been determined that the contribution of the Company's Haynesville Shale gathering and treating system to form KinderHawk is accounted for as a failed sale of in substance real estate. See Note 2, *"Acquisitions and Divestitures"* for more details regarding the KinderHawk joint venture arrangement and for discussion of the accounting treatment related to the arrangement. As a result of the failed sale, the Company recorded a financing obligation, representing the proceeds received, under the financing method of real estate accounting. The financing obligation is recorded on the consolidated balance sheets in "*Payable on financing arrangement,"* in the amount of approximately $917 million. Reductions to the obligation and the non cash interest on the obligation are tied to the gathering and treating services, as the Company delivers natural gas through the Haynesville Shale gathering and treating system. Interest and principal are determined based upon the allocable income to Kinder Morgan, and interest is limited up to an amount that is calculated based upon the Company's weighted average cost of debt as of the date of the transaction. Allocable income in excess of the calculated value is reflected as reductions of principal. Interest is recorded in *"Interest expense and other"* on the consolidated statements of operations. The balance of the Company's financing obligation as of December 30, 2010, was approximately $940.9 million, of which approximately $7.1 million was classified as current. This obligation is not reflected in the amounts shown in the above tables.

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Contingencies

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

8. DERIVATIVE AND HEDGING ACTIVITIES

The Company is exposed to certain risks relating to its ongoing business operations, such as commodity price risk and interest rate risk. Derivative contracts are utilized to economically hedge its exposure to price fluctuations and reduce the variability in the Company's cash flows associated with anticipated sales on future oil, natural gas and natural gas liquids production. The Company generally hedges a substantial, but varying, portion of anticipated oil, natural gas and natural gas liquids production for the next 12 to 36 months. Derivatives are carried at fair value on the consolidated balance sheets, with the changes in the fair value included in the 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 December 31, 2010 and 2009, the Company had entered into commodity collars, swaps and put options. The Company has elected to not designate any of its derivative contracts for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in *"Net gain on derivative contracts"* on the consolidated statements of operations.

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

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

At December 31, 2010, the Company had 79 open commodity derivative contracts summarized in the tables below: 60 natural gas collar arrangements, two natural gas swap arrangements, 16 crude oil collar arrangements, and one natural gas liquids swap (which was an ethane swap). Derivative commodity contracts in 2010 settled based on NYMEX West Texas Intermediate and Henry Hub prices, or the applicable information service for the Company's natural gas liquids contracts, which may

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have differed from the actual price received by the Company for the sale of its oil, natural gas and natural gas liquids production.

At December 31, 2009, the Company had 77 open commodity derivative contracts summarized in the tables below: 61 natural gas collar arrangements, one natural gas swap arrangement, 13 natural gas put options and two crude oil price swap arrangements. Derivative commodity contracts in 2009 settled based on NYMEX West Texas Intermediate and Henry Hub prices which may have differed from the actual price received by the Company for the sale of its oil and natural gas production.

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

	Asset derivative contracts			Liability derivative contracts		
		December 31,			December 31,	
Derivatives not designated as hedging contracts under ASC 815	**Balance sheet location**	**2010**	**2009**	**Balance sheet location**	**2010**	**2009**
		(In thousands)			*(In thousands)*	
Commodity contracts	Current assets receivables from derivative contracts	$217,018	$112,441	Current liabilities liabilities from derivative contracts	$ (5,820)	$(1,807)
Commodity contracts	Other noncurrent assets receivables from derivative contracts	41,721	50,421	Other noncurrent liabilities liabilities from derivative contracts	(13,575)	
Total derivatives not designated as hedging contracts under ASC 815		$258,739	$162,862		$(19,395)	$(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 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 derivatives contracts year ended December 31, 2010**	**2009**	**2008**
		(In thousands)		
Commodity contracts:				
Unrealized gain (loss) on commodity contracts	Other income (expenses) net gain on derivative contracts	$ 58,075	$ (120,401)	$ 230,640
Realized gain (loss) on commodity contracts	Other income (expenses) net gain on derivative contracts	243,046	375,116	(75,270)
Total net gain on commodity contracts		$ 301,121	$ 254,715	$ 155,370
Interest rate swaps:				
Unrealized gain (loss) on interest rate swaps	Other (expenses) income net gain on derivative contracts	$	$	$
Realized gain on interest rate swaps	Other (expenses) income net gain on derivative contracts		5,533	1,500
Total net gain on interest rate swaps		$	$ 5,533	$ 1,500
Total net gain on derivative contracts	Other income (expenses) net gain on derivative contracts	$ 301,121	$ 260,248	$ 156,870

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At December 31, 2010 and 2009, the Company had the following open derivative contracts:

				December 31, 2010			
				Floors		Ceilings	
Period	Instrument	Commodity	Volume in Mmbtu's/ Bbl's/Gal's	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
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	Crude oil	2,007,500	75.00 - 80.00	78.00	95.00 - 101.00	98.88
January 2011 December 2011	Swaps	Natural gas liquids	4,800,000	0.46	0.46		
January 2012 December 2012	Collars	Natural gas	118,950,000	4.75 - 5.00	4.92	5.72 - 8.00	6.96
January 2012 December 2012	Swaps	Natural gas	7,320,000	5.20	5.20		
January 2012 December 2012	Collars	Crude oil	3,660,000	75.00 - 80.00	77.00	98.00 - 102.45	100.00

				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	Crude 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 estimated expenses of $22 million.

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

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

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

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

For the years ended December 31, 2010, 2009 and 2008, respectively, the Company has recognized $23.2 million, $14.5 million, and $12.3 million, respectively, of non-cash stock-based compensation expense.

Incentive Plans

The Company's Incentive Plans include the Third Amended and Restated 2004 Employee Incentive Plan (2004 Employee Plan), Second Amended and Restated 2004 Non-Employee Director Incentive Plan (2004 Non-Employee Director Plan), 1999 Incentive and Non-Statutory Stock Option Plan, Mission Resources Corporation 1994 Stock Incentive Plan (Mission 1994 Plan), Mission Resources Corporation 1996 Stock Incentive Plan (Mission 1996 Plan) and Mission Resources Corporation 2004 Incentive Plan (Mission 2004 Plan), KCS Energy, Inc. 2001 Employee and Directors Stock Plan (KCS 2001 Plan) and the KCS Energy, Inc. 2005 Employee and Directors Stock Plan (KCS 2005 Plan) as of December 31, 2010.

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Warrants, Options and Stock Appreciation Rights

Certain of the Company's incentive plans permit awards of stock appreciation rights (SARS) and stock options. A stock appreciation right is similar to a stock option, in that it represents the right to realize the increase in market price, if any, of a fixed number of shares over the grant value of the right, which is equal to the market price of the Company's common stock on the date of grant. Stock options, when exercised, are settled through the payment of the exercise price in exchange for shares of stock underlying the option. SARS, when exercised, are settled without cash in exchange for a net of tax number of shares of common stock valued on the date of settlement. Both SARS and stock options vest one-third annually after the original grant date and have a term of ten years from the date of grant.

The weighted average grant date fair value of options granted in 2010, 2009, and 2008 was $22.5 million, $11.6 million, and $6.1 million, respectively. At December 31, 2010, 2009, and 2008, the unrecognized compensation expense related to non-vested stock options totaled $13.4 million, $6.7 million, and $3.9 million respectively. The weighted average remaining vesting period as of December 31, 2010, 2009 and 2008 was 0.9 years. There were 19,131 options, 19,268 options, and 11,559 options which expired in 2010, 2009, and 2008, respectively.

The following table sets forth the warrants, options and stock appreciation rights transactions for the years ended December 31, 2010, 2009, and 2008:

	Number of Shares	Weighted Average Exercise Price Per Share	Aggregate Intrinsic Value[1] (In thousands)	Weighted Average Remaining Contractual Life (Years)
Outstanding at December 31, 2007	8,145,648	$ 7.64	$ 78,779	4.9
Granted	1,102,800	19.02		
Exercised	(3,036,031)	7.03		
Forfeited	(71,795)	13.19		
Outstanding at December 31, 2008	6,140,622	$ 9.92	$ 45,390	6.3
Granted	1,588,950	15.61		
Exercised	(1,281,304)	4.46		
Forfeited	(78,175)	16.01		
Outstanding at December 31, 2009	6,370,093	$ 12.40	$ 74,454	6.9
Granted	2,202,750	20.97		
Exercised	(294,594)	12.09		
Forfeited	(192,060)	19.46		
Outstanding at December 31, 2010	8,086,189	$ 14.58	$ 36,856	6.8

(1) *The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option. The aggregate intrinsic value of stock options exercised during the years ended December 31, 2010, 2009, and 2008 was approximately $2.1 million, $11.9 million and $47.5 million, respectively.*

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Warrants, options and stock appreciation rights outstanding at December 31, 2010 consisted of the following:

Range of Grant Prices Per Share		Outstanding Number	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Life (Years)	Exercisable Number	Weighted Average Exercise Price per Share
$0.73	$11.00	2,300,269	$ 7.38	4.0	2,300,269	$ 7.38
11.43	14.89	1,219,847	12.28	5.9	1,214,963	12.27
15.23	21.00	2,435,373	16.39	7.9	1,071,765	16.88
21.18	47.16	2,130,700	21.60	9.1	70,115	28.28

During the second quarter of 2004, and in connection with the recapitalization of the Company by PHAWK, LLC transaction, the Company issued PHAWK, LLC 5.0 million five-year common stock purchase warrants at a price of $3.30 per share. The warrants were exercisable at any time and expired on May 25, 2009. On July 8, 2005, shares and warrants held by PHAWK, LLC were distributed to its members, including certain members of the Company's management. The Company had 0.6 million, and 1.4 million warrants exercised and a net 0.5 million, and 1.2 million shares of company stock issued during the years ended 2009 and 2008, respectively. These exercises were included within the options and warrants transactions table above. In 2010, no warrants were issued nor outstanding.

Restricted Stock

From time to time, the Company grants shares of restricted stock to employees and non-employee directors of the Company. 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. The weighted average grant date fair value of the shares granted in 2010, 2009, and 2008 was $26.5 million, $15.5 million and $11.4 million, respectively. At December 31, 2010, 2009 and 2008, the unrecognized compensation expense related to non-vested restricted stock totaled $14.5 million, $7.2 million and $6.8 million, respectively. The weighted average remaining vesting period as of December 31, 2010, 2009, and 2008 was 1.0 years, 0.9 years and 1.4 years, respectively.

The following table sets forth the restricted stock transactions for the years ended December 31, 2010, 2009 and 2008:

	Number of Shares	Weighted Average Grant Date Fair Value Per Share	Aggregate Intrinsic Value(1) (In thousands)
Unvested outstanding shares at December 31, 2007	1,406,843	$ 12.75	$ 24,352
Granted	570,549	19.90	
Vested	(730,964)	22.14	
Forfeited	(38,286)	15.05	
Unvested outstanding shares at December 31, 2008	1,208,142	$ 15.31	$ 18,883
Granted	950,214	16.36	
Vested	(947,584)	15.21	
Forfeited	(44,948)	15.27	
Unvested outstanding shares at December 31, 2009	1,165,824	$ 16.24	$ 27,968
Granted	1,280,750	20.71	
Vested	(668,160)	16.04	
Forfeited	(88,774)	19.39	
Unvested outstanding shares at December 31, 2010	1,689,640	$ 19.54	$ 30,836

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(1) *The intrinsic value of restricted stock was calculated as the closing market price on December 31, 2010, 2009 and 2008 of the underlying stock multiplied by the number of restricted shares. The total fair value of shares vested were $10.7 million, $14.4 million and $16.2 million for the years 2010, 2009, and 2008, respectively.*

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Performance Shares

In conjunction with the Company's merger with KCS, the Company assumed the KCS 2005 Plan under which performance share awards had been granted. The performance awards provide for a contingent right to receive shares of common stock. The Company recognized $0.7 million in compensation cost for the year ended December 31, 2008 associated with these awards. In conjunction with the completion of the performance period on December 31, 2008, a total of 200,864 shares were issued on February 16, 2009.

2004 Employee Incentive Plan

Upon stockholder approval and effective July 28, 2005, the Company's Amended and Restated 2004 Employee Incentive Plan was amended and restated to be the Second Amended and Restated 2004 Employee Incentive Plan to increase the aggregate number of shares that can be issued under the 2004 Employee Plan from 2.75 million to 4.25 million. The 2004 Employee Plan permits the Company to grant to management and other employees shares of common stock with no restrictions, shares of common stock with restrictions, stock appreciation rights and options to purchase shares of common stock.

On July 12, 2006, the Company and its stockholders approved an amendment to the 2004 Employee Plan to increase the number of shares available for issuance thereunder from 4.25 million shares to 7.05 million shares. On July 18, 2007, the Company and its stockholders approved an amendment to the 2004 Employee Plan to increase the number of shares available for issuance thereunder from 7.05 million shares to 12.55 million shares. On June 18, 2009, the Company and its stockholders approved an amendment to the 2004 Employee Plan to increase the number of shares available for issuance thereunder from 12.55 million shares to 17.85 million shares. At December 31, 2010, 5.63 million shares were available under the 2004 Employee Plan for future issuance.

2004 Non-Employee Director Incentive Plan

In July 2004 the Company adopted the 2004 Non-Employee Director Plan covering 0.20 million shares. The plan provides for the grant of both incentive stock options and restricted shares of the Company's stock. This plan was designed to attract and retain the services of directors. At the adoption of the plan, each non-employee director received 7,500 restricted shares of the Company's common stock and each new non-employee director would receive 7,500 shares of the Company's common stock. Additional grants of 5,000 restricted shares of the Company's common stock were issued to each non-employee director on each anniversary of his or her service. Effective August, 2006, the annual equity grant to both new and existing non-employee directors increased to 10,000 shares of restricted stock, with the vice chairman of the board of directors to receive 15,000 shares of restricted stock annually. Effective June 2008, the annual compensation awarded to new and existing non-employee directors changed to $150,000, as well as an additional $75,000 for the Vice Chairman. The annual compensation awards were granted in the form of restricted stock, which totaled 8,200 shares for non-employee directors and 12,300 shares for the Vice Chairman for the year-end December 31, 2009. The annual compensation awards granted in the form of restricted stock for the year ended December 31, 2010 was 10,700 or 12,400 shares for non-employee directors and 16,000 shares for the Vice Chairman. These shares vest over a six-month period from the date of grant. Shares issued under this plan for the years ended December 31, 2010, 2009 and 2008, were 105,600, 71,000, and 50,200 shares, respectively and there had been no forfeited or cancelled shares.

On July 12, 2006, the Company and its stockholders approved an amendment to the Company's 2004 Non-Employee Director Plan to increase the number of shares available for issuance thereunder from 0.4 million to 0.6 million shares. On June 18, 2009, the Company and its stockholders approved an amendment to the Company's 2004 Non-Employee Director Plan to increase the number of shares available for issuance thereunder from 0.6 million to 1.1 million shares. At December 31, 2010, 0.6 million shares were available under the Plan for future issuance. At December 31, 2010, all non-employee director grants were fully vested.

KCS and Mission Incentive Plans

Upon consummation of the Company's merger with KCS, the Company assumed the KCS 2001 Plan, as amended, the KCS 2005 Plan, as amended, and associated obligations relating to grants of restricted stock, stock options and performance shares under those plans which were granted prior to the closing of the Company's merger with KCS. At December 31, 2010 no options were available under the Plan for future issuance.

No options were issued in 2010, 2009 or 2008 under the KCS 2005 Plan. In 2007, the Company granted stock appreciation rights covering 0.4 million shares of common stock to employees of the Company under the KCS 2005 Plan. The stock appreciation rights have an exercise price of $11.64 with a weighted average price of $11.64. These stock appreciation rights vested 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.

In conjunction with the merger with Mission on July 28, 2005, the Company assumed three incentive plans. The three plans were the Mission 1994 Plan, Mission 1996 Plan and Mission 2004 Plan. At December 31, 2010, there were no options available under these plans for future issuance. No options were issued in 2010, 2009 or 2008 under the three Mission plans.

Assumptions

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

	Years Ended December 31,		
	2010	**2009**	**2008**
Weighted average value per option granted during the period	$ 10.20	$ 7.30	$ 5.52
Assumptions(1):			
Stock price volatility(2)	62.0%	70.0%	39.6%
Risk free rate of return	2.02%	1.49%	2.00%
Expected term	4.0 years	3.0 years	3.0 years

(1) *The Company's estimated future forfeiture is 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.*

(2) *In 2010, the Company used a combination of implied and historic volatility. In 2009 and 2008, the Company used historical volatility.*

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10. INCOME TAXES

Income tax (provision) benefit for the indicated periods is comprised of the following:

	Years Ended December 31, 2010	2009	2008
		(In thousands)	
Current:			
Federal	$ (106,831)	$ (388)	$ 10,124
State	530	(13,807)	5,053
	(106,301)	(14,195)	15,177
Deferred:			
Federal	26,759	670,907	175,873
State	(15,392)	96,294	(46,875)
	11,367	767,201	128,998
Total income tax (provision) benefit	$ (94,934)	$ 753,006	$ 144,175

The actual income tax (provision) benefit differs from the expected income tax (provision) benefit as computed by applying the United States Federal corporate income tax rate of 35% for each period as follows:

	Years Ended December 31, 2010[(1)]	2009[(2)(3)]	2008[(4)]
		(In thousands)	
Expected tax (provision) benefit	$ (80,795)	$ 621,367	$ 185,863
State income taxes, net	(13,696)	63,546	24,561
Change in state income tax rate	2,631	21,120	(64,796)
Change in estimate of income tax basis		49,587	
Other	(3,074)	(2,614)	(1,453)
Total income tax (provision) benefit	$ (94,934)	$ 753,006	$ 144,175

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(1) *"State income taxes, net" in 2010 include a $6.6 million valuation allowance attributed to the sale of Fayetteville Shale assets.*

(2) *"Change in state income tax rate" for 2009 includes changes in estimates of income tax benefits associated with amended tax filings. The Company expects its temporary differences to reverse at lower tax rates than it had previously estimated. As a result, the Company changed its estimate of the effective income tax rate applied to its temporary differences, resulting in a decrease in deferred income tax liabilities and an income tax benefit of $21.1 million.*

(3) *The "Change in estimate of income tax basis" in 2008 resulted due to changes in the estimated income tax basis in connection with the preparation of 2006 and 2007 amended federal income tax returns.*

(4) *In the fourth quarter of 2008, the Company filed its federal and state income tax returns for 2007. The apportionment of the Company's income to state income tax jurisdictions in which the Company files income tax returns changed significantly as a result of (i) the sale of the Company's Gulf Coast properties at the end of 2007 and the reinvestment of those proceeds in 2008 in properties located in states with higher income tax rates; and (ii) the continued acquisition and development of properties located in states with higher income tax rates in 2008. Therefore, at December 31, 2008, the Company expected its temporary differences to reverse at higher income tax rates than it had previously estimated. As a result, the Company changed its estimate of the effective income tax rate*

applied to its temporary differences, resulting in an increase in deferred income tax liabilities and income tax expense of $64.8 million which is reflected in the "Change in state income tax rate" line in the table.