PETROHAWK ENERGY CORP
Form 10-K
February 23, 2010
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF

THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2009

Commission file number 001-33334

PETROHAWK ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

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

1000 Louisiana, Suite 5600, Houston, Texas 77002

(Address of principal executive offices including ZIP code)

(832) 204-2700

(Registrant s telephone number)

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

Title of each class	**Name of each exchange on which registered**

Common Stock, par value $.001 per share	**New York Stock Exchange**

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

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

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 ¨ No x

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 x No ¨

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

Indicate by check mark 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. ¨

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 x	Accelerated filer ¨	Non-accelerated filer ¨	Smaller reporting company ¨

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

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, 2009), the last business day of registrant s most recently completed second fiscal quarter was approximately $6.0 billion.

As of February 17, 2010, there were 301,209,109 shares of common stock outstanding.

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 2010 annual meeting of stockholders which will be filed on or before April 30, 2010.

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Special note regarding forward-looking statements

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

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

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

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

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

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

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

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

At December 31, 2009, 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 2,750 billion cubic feet of natural gas equivalent (Bcfe), consisting of 8 million barrels (MMBbls) of oil, and 2,700 billion cubic feet (Bcf) of natural gas and natural gas liquids. Approximately 33% of our proved reserves were classified as proved developed. We maintain operational control of approximately 84% of our proved reserves. Approximately 93% of our proved reserves are in the Haynesville Shale, Eagle Ford Shale, Fayetteville Shale and Elm Grove/Caspiana Fields. Production for the fourth quarter of 2009 averaged 598 million cubic feet of natural gas equivalent (Mmcfe) per day (Mmcfe/d). Full year 2009 production averaged 502 Mmcfe/d compared to 305 Mmcfe/d in 2008. Our total operating revenues for 2009 were approximately $1.1 billion.

We seek to maintain a portfolio of long-lived, lower risk properties in resource-style plays, which typically are characterized by lower geological risk and a large inventory of identified drilling opportunities. 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 lease operating costs. We continue to expand our leasehold position in resource-style natural gas plays within our core operating areas, particularly in the Haynesville and Bossier Shales in North Louisiana and East Texas and the Eagle Ford Shale in South Texas. We expect to continue to grow our production and reserves predominantly in resource-style, tight-gas areas.

Recent Developments

Permian Basin Sale

On October 30, 2009, we closed the previously announced sale of our Permian Basin properties for $376 million in cash, before customary 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 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.

Senior Revolving Credit Facility

On October 14, 2009, we entered into our Fourth Amended and Restated Senior Revolving Credit Agreement (the Fourth Amendment), which amended and restated our senior revolving credit agreement (Senior Credit Agreement). The Fourth Amendment is a $2.0 billion facility with a borrowing base of $1.5 billion, $1.2

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billion of which relates to our oil and natural gas business and up to $300 million (currently limited as described below) of which relates to our midstream business. The $1.2 billion borrowing base attributable to our oil and natural gas properties was reduced $200 million to $1.0 billion upon the closing of the sale of the Permian Basin properties on October 30, 2009. The portion of the borrowing base which relates to our oil and natural gas business will be redetermined on a semi-annual basis (we and the lenders also each have the right to one annual interim unscheduled redetermination) and adjusted based on our oil and natural gas reserves, other indebtedness and other relevant factors. The component of the borrowing base related to our midstream business is limited to the lesser of $300 million or 3.5 times our midstream segment EBITDA (as defined in the Senior Credit Agreement), and is determined quarterly. Amounts outstanding under the Fourth Amendment bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 2.25% to 3.25% for Eurodollar loans or at specified margins over the Alternative Base Rate (ABR) of 0.75% to 1.75% for ABR loans. The margins fluctuate based upon our utilization of the facility. Our Senior Credit Agreement has a borrowing base of $1.2 billion at December 31, 2009.

2010 Capital budget

Our 2010 capital budget is focused on the development of non-proved reserve locations in our Haynesville, Bossier, Eagle Ford and Fayetteville Shale plays so that we can hold our acreage in these areas. We also believe these projects offer us the potential for high internal rates of return and reserve growth. Currently we plan to spend approximately $1.45 billion on drilling and completions during 2010, of which $900 million has been allocated to our Haynesville and Bossier Shale properties, $350 million to our Eagle Ford Shale properties, $100 million to our Fayetteville Shale properties and $100 million to our remaining properties. Our midstream segment will have an estimated capital program of $250 million. Additionally, we expect to spend between $100 million and $300 million on ongoing leasing activities. Our future drilling plans are subject to change based upon various factors, some of which are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals.

We expect to fund our 2010 capital budget with cash flows from operations, proceeds from potential asset dispositions, and additional 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.

Bossier Shale

We have been evaluating the Bossier Shale in North Louisiana and East Texas as a viable shale gas reservoir using an extensive data set that includes digital well logs, core analysis, and, most recently, the results of well tests by industry partners. As a result of this evaluation we currently believe that the area of prospective commercial production within our current leasehold acreage is approximately 122,000 net acres and that the rock quality is similar to that of the Haynesville Shale in a limited area of the formation.

Pending technological advances that would allow multiple zones to be completed with a single horizontal wellbore, the Bossier Shale will require wellbores independent of the Haynesville Shale. We expect to spud our first Bossier Shale horizontal well, in late first quarter 2010. Initial results from that test well should be available late in the second quarter. We are also participating in a Lower Bossier Shale test well through our joint venture in the East Texas portion of the play. The well has reached total depth and should begin completion operations shortly. We anticipate that these activities, along with an industry-wide increase in Bossier Shale drilling, should provide support for expansion of drilling activities in the Bossier Shale play.

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Business Strategy

Our primary objective is to increase stockholder value by focusing on the continued development of our existing properties and selectively increasing our position within our core operating areas, with a special emphasis on expanding our resource-style properties. Our strategy emphasizes:

Concentrated portfolio of natural gas properties We focus on natural gas properties within our core operating areas which we believe have significant development and exploration opportunities and where we can apply our technical experience and economies of scale. Our properties are located primarily in North Louisiana, East Texas, South Texas, and the Arkoma Basin of Arkansas.

Attractive undeveloped reserves We seek to maintain a portfolio of long-lived, lower risk properties focused on resource-style plays within our core operating areas. Resource-style plays are typically characterized by lower geological risk and a large inventory of identified drilling opportunities, and include the Haynesville and Bossier Shales in North Louisiana and East Texas, the Fayetteville Shale in Arkansas and the Eagle Ford Shale in South Texas. We believe these properties have the potential to contribute significant 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 lease operating expenses from $0.56 per Mcfe in 2007 to $0.47 per Mcfe in 2008 and $0.43 per Mcfe in 2009.

Divestment of non-core properties We continually evaluate our property base to identify opportunities to divest non-core, higher cost or less productive properties with limited development potential. This strategy allows us to focus on a portfolio of core properties with significant potential to increase our proved reserves and production and reduce our operating costs. To allow us to concentrate on our core properties and further enhance our liquidity position, we sold our Permian Basin assets during the fourth quarter of 2009 and we have identified several potential asset dispositions during 2010, which may include a transaction involving our midstream business, divesting our Terryville Field in northwest Louisiana, divesting our interest in the West Edmond Hunton Lime Unit in central Oklahoma, as well as divesting other non-core assets.

Maintenance of financial flexibility We strive to maintain financial flexibility by balancing our financial resources with our plans to develop our key properties and pursuit of 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-style plays, permit us to selectively expand our position in these plays and expand our infrastructure projects. We may access capital markets as necessary to maintain substantial borrowing capacity under our Senior Credit Agreement.

Oil and Natural Gas Reserves

Estimates of proved reserves at December 31, 2009, 2008, and 2007 were prepared by Netherland, Sewell & Associates, Inc. (Netherland, Sewell), our independent consulting petroleum engineers. The technical persons responsibile 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 reserve committee composed of three outside directors, all of whom have experience in energy company reserve evaluations. The reserve committee is charged with ensuring the integrity of the process of selection and engagement of the independent engineering firm.

The reserves information in this Form 10-K 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

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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).*

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, 2009. Average prices as of that date were as follows: West Texas Intermediate (WTI) posted price of $57.65 per barrel (Bbl) for oil and natural gas liquids, adjusted by lease for quality, transportation fees, and regional price differentials and a Henry Hub spot market price of $3.87 per million British thermal unit (Mmbtu) for natural gas, as adjusted by lease 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, 2009.

	Mid-Continent Region	Western Region	Total
Proved Reserves at Year End (Bcfe) [(1)]			
Developed	802.1	103.0	905.1
Undeveloped	1,583.0	262.0	1,845.0
Total	2,385.1	365.0	2,750.1

(1) *Oil and natural gas liquids are converted to equivalent gas reserves with a 6:1 equivalent ratio.*

The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2009 and 2008. Shut-in wells currently not capable of production are excluded from producing well information.

	Years Ended December 31,			
	2009		2008	
	Gross	Net[(1)]	Gross	Net[(1)]
Oil	343.0	72.8	2,196.0	317.9
Natural Gas	4,687.0	1,703.2	5,098.0	2,320.2
Total	5,030.0	1,776.0	7,294.0	2,638.1

(1) *Net wells represent our working interest share of each well. The term net as used in 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.*

Oil and Natural Gas Segment

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 and midstream. A further description of our operating segments is included in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 13, *Segments* .

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Core Operating Regions

Mid-Continent Region

In the Mid-Continent Region, we concentrate our drilling program primarily in North Louisiana, East Texas and in the Fayetteville Shale in the Arkoma Basin. We believe our Mid-Continent Region operations provide us with a solid base for future production and reserve growth. During 2009, we drilled 573 wells in this region (of which 111 were operated and 462 were non-operated), and all but one well in the Fayetteville Shale was successful. In 2010, we plan to drill approximately 170 to 180 operated wells in this region and an additional 500 - 600 non-operated wells which are dependent upon other operators for execution. In 2009, we produced 152 Bcfe in this region, or 416 Mmcfe/d. As of December 31, 2009, approximately 87% of our proved reserves, or 2,385 Bcfe, were located in our Mid-Continent Region.

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 360,000 net acres in the area 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, spaced approximately 325 feet apart. 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 2009, we had 12 operated horizontal rigs in the Haynesville Shale. Spud-to-first sales averaged approximately 60 days during 2009.

As of December 31, 2009, we had approximately 70 operated wells on production in North Louisiana producing approximately 480 Mmcfe/d gross. With the exception of two wells that had mechanical issues, the average initial production of these wells was approximately 18 Mmcfe/d. Actual decline rates may differ significantly.

In 2009, we produced 77 net Bcfe, or 211 Mmcfe/d. As of December 31, 2009, proved reserves for this field were approximately 1,529 Bcfe, of which approximately 19% were classified as proved developed and approximately 81% as proved undeveloped. The proved reserves include 160 proved developed wells and 419 proved undeveloped locations. During 2009, we drilled 184 wells (73 operated and 111 non-operated), all of which were successful. We plan to drill 110 to 120 operated wells in this area in 2010, with nine to ten wells expected to be completed per month. We have preliminarily budgeted for an additional 200 non-operated wells in 2010 which will be dependent upon other operators for execution. We expect to operate an average of 17 rigs in the play in 2010, with an emphasis on growing production and reserves while at the same time holding our acreage position.

Bossier Shale During 2009, the combination of wells we have drilled in the Haynesville Shale and wells drilled by other operators provided sufficient petrophysical and geochemical data to support the premise that there are potentially significant reserves in the Bossier Shale. The 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 122,000 net acres in the area that we currently believe to be prospective for the Bossier Shale. We have not drilled a horizontal well in the Bossier Shale yet, but other operators have completed a number of wells that have helped further determine the level of prospectivity and overall area that could prove to result in commercially viable gas reserves. We intend

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to drill a number of Bossier Shale horizontal wells during 2010. We own varying working and net revenue interests in this area. As of December 31, 2009, we did not have any proved reserves for the Bossier Shale.

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 own varying working and net revenue interests in these fields. We produced 35 Bcfe in 2009 in these fields, or 96 Mmcfe/d. As of December 31, 2009, proved reserves for the Elm Grove/Caspiana fields were approximately 444 Bcfe, of which approximately 64% were classified as proved developed, and 36% was classified as proved undeveloped. The proved reserves include 1,039 proved developed wells and 360 proved undeveloped locations.

During 2009, we drilled one operated well and 13 non-operated wells, all of which were successful. While this area still comprises a significant portion of our reserves and production, the vast majority of the capital that we previously committed to these fields was allocated to the Haynesville Shale during 2009 as part of our plan to hold our Haynesville Shale acreage. For 2010, we have budgeted capital to drill approximately 60 wells, which includes vertical wells targeting the Hosston and Cotton Valley Sands and horizontal wells in the Cotton Valley Sands.

Fayetteville Shale We have assembled a position of approximately 157,000 net acres in the Fayetteville Shale, which we believe holds significant potential for production and reserve growth. The Fayetteville Shale is located in the Arkoma Basin in Arkansas, at a depth of approximately 1,500 feet to 6,500 feet and ranging in thickness from 100 feet to 500 feet. The formation is a Mississippian-age shale that has similar geologic characteristics to the Barnett Shale in the Fort Worth Basin of North Texas. Drilling in the play began in 2004 and has accelerated rapidly during the past five years. Currently, we are drilling horizontal wells with lateral lengths of 2,500 feet to 3,000 feet and utilizing slickwater fracture stimulation completions. During 2009 the amount of non-operated activity increased significantly. While we have continued to achieve results that were in line with previous years, there were nine times more non-operated wells (327) than operated wells (35) in 2009. Additionally, of the 79 Mmcfe/d that we were producing during the fourth quarter of 2009, the amount of operated versus non-operated net production was approximately equal. We own varying working and net revenue interests in this area.

As of December 31, 2009, proved reserves for this field were approximately 299 Bcfe, of which approximately 54% were classified as proved developed and approximately 46% as proved undeveloped. The proved reserves include 863 proved developed wells and 394 proved undeveloped locations. During 2009, we drilled 362 wells, 361 of which were successful. In 2010, we plan to drill approximately 370 wells in this area (15 operated and 355 non-operated). We produced 28 Bcfe in 2009 in this area, or 77 Mmcfe/d.

Western Region

The majority of the Western Region assets at the end of 2009 were in the Hawkville Field which is located in the Eagle Ford Shale play in South Texas. The Western Region also contains property that is located in Oklahoma plus other properties located in the Anadarko and Arkoma Basins. We believe our Eagle Ford Shale properties provide us with future production and reserve growth. Including the contribution from the Permian Basin properties that were sold in October 2009, net production from the region was 31 Bcfe (86 Mmcfe/d) in 2009. During 2009 we drilled 53 productive wells (24 operated and 29 non-operated) with no dry holes. As of December 31, 2009, the proved reserves for the region were approximately 365 Bcfe, or 13% of our total proved reserves. There are 82 operated wells budgeted for 2010 and an additional 20 to 30 non-operated wells.

Eagle Ford Shale We have approximately 310,000 net acres under lease or option to lease in the Eagle Ford Shale in the Hawkville Field, located in LaSalle and McMullen Counties, Texas and the Red Hawk area located in Zavala County, Texas. Our working interest and net revenue interest for the

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majority of the operated wells are 90% and 68%, respectively. The working interest for the non-operated wells range from 10% to 45% and will average over 35% for the majority of the non-op program.

We have 20 operated and four non-operated producing wells plus four additional wells that are pending completion and three wells that were drilling at year-end in this field. Our Eagle Ford Shale wells have averaged a true vertical depth that ranges from 10,850 feet to 12,150 feet. We have encountered a formation that has an average pay thickness of over 200 feet. Our wells have been drilled with a horizontal section that is averaging approximately 4,000 feet in length. The wells are cased hole completed and fracture stimulated with an average of fourteen stages. Nine of the current completions produce no condensate and they had an average initial production rate of 9.5 million cubic feet of natural gas per day (Mmcf/d). Thirteen of the current completions produce condensate and these wells had an average initial production rate of 7 Mmcf/d and 280 barrels of oil per day (Bo/d), or 8.7 Mmcfe/d.

Gross operated production from the Eagle Ford Shale is currently 57 Mmcf/d and 1,600 Bo/d (40 Mmcfe/d net). During 2009, we produced 7 Bcfe or 20 Mmcfe/d from this field. As of December 31, 2009, the proved reserves for this field were approximately 288 Bcfe of which approximately 14% were classified as proved developed and approximately 86% as proved undeveloped. The proved reserves include 28 proved developed wells and 136 proved undeveloped locations. Twenty four operated and two non-operated Hawkville wells were drilled in 2009 and 60 operated plus 22 non-operated Hawkville wells are budgeted for 2010.

Permian Basin Properties We sold our Permian Basin properties on October 30, 2009 for $376 million before customary closing adjustments. The Waddell Ranch Complex, Crane County, Texas, Sawyer Field, Sutton County, Texas, Jalmat Field, Lea County, New Mexico and TXL North Unit, Ector County, Texas accounted for 83% of the proved reserves and 81% of the net production from our Permian Basin properties. In 2009, 11 wells were drilled with a 100% success rate and the combined production from the fields was 10 Bcfe or 27 Mmcfe/d. The Permian Basin properties had estimated proved reserves of approximately 168 Bcfe.

Midstream Segment

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 and midstream. A further description of our operating segments is included in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 13, *Segments* .

In 2008, through our subsidiary, Hawk Field Services, we initiated construction of our own gathering systems and treating facilities to service our operated wells and third party production from the Fayetteville and Haynesville Shales. Throughout 2009, we have continued to expand our facilities serving this area and initiated the development of a gathering system and treating facilities serving the Eagle Ford Shale. Our midstream business allows us to potentially improve our returns by providing greater control over the completion of our wells and the transportation of our production for delivery into major intrastate or interstate pipelines. Also, to allow producers to maximize price realizations, we have designed our systems to provide access to multiple pipeline interconnects.

Haynesville Shale We are building high pressure gathering systems to transport our production to various intrastate and interstate pipelines and we are constructing several centralized treating facilities to remove carbon dioxide (CO_2) before it is delivered into those pipelines connected to our system. As of December 31, 2009, we had constructed approximately 150 miles of primarily 16-inch diameter pipeline in several of our drilling areas that we expect will optimize our operational control and access to natural gas markets. Our Haynesville Shale system throughput was 445 Mmcf/d with a capacity of 1.4 billion cubic feet of natural gas per day (Bcf/d) and a treating capacity of 735 Mmcf/d as of

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December 31, 2009. We expect to have 375 miles of pipelines completed by the end of 2010 with a total system throughput capacity of approximately 2.0 Bcf/d with associated treating capacity of 1.1 Bcf/d.

Eagle Ford Shale During 2009, we initiated construction of a high pressure gathering system to transport our production to various intrastate and interstate pipelines. As of December 31, 2009, we had built approximately 62 miles of primarily 16-inch diameter pipeline in several of our drilling areas that we expect will optimize our operational control and access to natural gas markets. Our Eagle Ford Shale system has a throughput capacity of 550 Mmcf/d and a treating capacity of 100 Mmcf/d as of December 31, 2009. We expect to have 88 miles completed by the end of 2010 with a total system throughput capacity of approximately 550 Mmcf/d with associated treating capacity of 250 Mmcf/d.

Fayetteville Shale To support our operations, we completed construction of three separate gathering systems which represent approximately 106 miles of pipelines that gather natural gas from our operated wells and transport it to interconnects with various interstate pipelines. As of December 31, 2009, our Fayetteville system consists of six-inch to 16-inch diameter pipelines with throughput capacity of approximately 200 Mmcf/d. We expect to have 112 miles completed by the end of 2010 with a total system throughput capacity of approximately 270 Mmcf/d with associated treating capacity of 55 Mmcf/d.

Risk Management

We have designed a risk management policy to provide 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 and natural gas production. We hedge a substantial, but varying, portion of anticipated oil and natural gas production for the next 12-36 months. Periodically, we enter 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.

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 oil and natural gas price collars, 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 and natural gas 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* 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

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production is maintained. Undeveloped oil and natural gas leaseholds are generally for a primary term of three to five years. In most cases, the term of our undeveloped leases can be extended by paying delay rentals or by producing oil and natural gas reserves that are discovered under those leases.

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

	Years Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive [(1)]	601	156.8	555	183.0	292	127.4
Dry	1	0.2	12	2.0	12	5.6
Total Exploratory	602	157.0	567	185.0	304	133.0
Development Wells:						
Productive [(1)]	24	5.1	172	82.4	113	72.2
Dry					3	1.3
Total Development	24	5.1	172	82.4	116	73.5
Total Wells:						
Productive [(1)]	625	161.9	727	265.4	405	199.6
Dry	1	0.2	12	2.0	15	6.9
Total	626	162.1	739	267.4	420	206.5

(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 exploratory wells where there is no production history.*

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, 2009:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
State						
Alabama			22,604	18,836	22,604	18,836
Arkansas	68,375	50,955	164,266	125,363	232,641	176,318
Indiana			7,676	6,984	7,676	6,984
Kansas	14,555	9,802	699	385	15,254	10,187
Louisiana	144,194	95,150	249,415	217,132	393,609	312,282
Oklahoma	226,447	86,957	9,855	4,193	236,302	91,150
Texas	149,590	72,220	431,037	299,262	580,627	371,482
Total Acreage	603,161	315,084	885,552	672,155	1,488,713	987,239

At December 31, 2009, we had estimated proved reserves of approximately 2,750 Bcfe comprised of 2,700 Bcf of natural gas and natural gas liquids and 8 MMBbls of oil. The following table sets forth, at December 31, 2009, these reserves:

	Proved Developed	Proved Undeveloped	Total Proved
Gas (Bcf) [(1)]	887.6	1,812.4	2,700.0
Oil (MMBbls)	2.9	5.4	8.3
Equivalent (Bcfe)	905.1	1,845.0	2,750.1

(1) *Amounts include natural gas liquids (calculated with a 6:1 equivalent ratio).*

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At December 31, 2009, our estimated proved undeveloped (PUD) reserves were approximately 1,845 Bcfe, a significant increase over the previous year s estimate of 626 Bcfe. The net increase of 1,219 Bcfe is comprised of additions of 1,509 Bcfe, primarily attributable to drilling in the Haynesville, Eagle Ford, and Fayetteville Shales, and partially offset by a net reduction of approximately 290 Bcfe, primarily relating to the effect of lower gas prices on the previous year s PUD reserves and the sale of our Permian Basin properties. During 2009, the majority of our total drilling and completion capital was allocated to drilling unproved leases in the Haynesville Shale to hold acreage. Approximately $34 million in drilling and completion capital expenditures went toward developing approximately 15 Bcfe of PUD reserves. As of December 31, 2009 all of our PUD reserves have been included in the reserve report for less than five years and over 90 percent have been included for less than two years.

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. We recorded a full cost ceiling 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 West Texas Intermediate posted price was $49.66 and $41.00 per barrel for oil and the Henry Hub spot market price was $3.63 and $5.71 per Mmbtu for natural gas. 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 impairment before income taxes of approximately $106 million and $65 million after taxes.

Capitalized costs of our evaluated and unevaluated properties at December 31, 2009, 2008 and 2007 are summarized as follows:

	2009	December 31, 2008 (In thousands)	2007
Oil and natural gas properties (full cost method):			
Evaluated	$ 5,984,765	$ 4,894,357	$ 3,247,304
Unevaluated	2,512,453	2,287,968	677,565
Gross oil and natural gas properties	8,497,218	7,182,325	3,924,869
Less accumulated depletion	(4,329,485)	(2,111,038)	(769,197)
Net oil and natural gas properties	$ 4,167,733	$ 5,071,287	$ 3,155,672

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The following table summarizes our oil and natural gas 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,		
	2009	2008	2007
Production:			
Natural gas Mmcf [1]:			
Haynesville Shale	77,117	6,243	
Elm Grove / Caspiana	34,254	42,599	33,862
Other	62,665	53,431	65,644
Total	174,036	102,273	99,506
Oil MBbl			
Haynesville Shale			
Elm Grove / Caspiana	133	151	152
Other	1,387	1,403	2,664
Total	1,520	1,554	2,816
Natural gas equivalent Mmcfe	183,156	111,597	116,402
Average daily production Mmcfe	502	305	319
Average sales price per unit: [2]			
Natural Gas per Mcf [1]	$ 3.70	$ 8.56	$ 6.92
Oil per Bbl	56.15	95.16	68.84
Natural gas equivalent per Mcfe	3.99	9.17	7.58
Average cost per Mcfe:			
Production:			
Lease operating	$ 0.43	$ 0.47	$ 0.56
Workover and other	0.02	0.05	0.07
Taxes other than income	0.32	0.42	0.50
Gathering, transportation and other:			
Oil and natural gas	0.38	0.39	0.28
Midstream	0.11	0.03	

(1) *Approximately 1%, 2% and 4% of natural gas production represents natural gas liquids (calculated with a 6:1 equivalent ratio) with an average price of $28.20 per Bbl, $56.63 per Bbl and $43.70 per Bbl for the years ended December 31, 2009, 2008 and 2007, respectively.*

(2) *Amounts exclude the impact of cash paid or received on settled commodities derivative contracts as we did not elect to apply hedge accounting.*

The 2009, 2008 and 2007 average oil and natural gas 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 *Other income (expenses)* in the consolidated statements of operations, consistent with our decision not to elect hedge accounting. Including this impact 2009, 2008 and 2007 average natural gas sales prices were $5.83, $8.13 and $7.41 per thousand cubic feet (Mcf) and our average oil sales prices were $58.86, $74.82 and $67.03 per Bbl, respectively.

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

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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 rig availability, 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. 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 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. In 2007, we had one purchaser of our production that accounted for 10% 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*.

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

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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, rendering a person liable for environmental damages and cleanup costs without regard to negligence or fault on the part of that person. Strict adherence with these regulatory requirements increases our cost of doing business and consequently affects our profitability.

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.

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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.

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. On June 9, 2009, companion bills entitled the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act of 2009 were introduced in the United States Senate (Senate Bill number 1215) and House of Representatives (House Bill number 2766). These bills would repeal the exemption for hydraulic fracturing from the SDWA, which would have the effect of allowing the EPA to promulgate regulations requiring permits and implementing potential new requirements of hydraulic fracturing under the SDWA. This could, in turn, require state regulatory agencies in states with programs delegated under the SDWA to impose additional requirements on hydraulic fracturing operations. Sponsors of the bills have asserted that chemicals used in the fracturing process may be adversely impacting drinking water supplies. The bills would require persons using hydraulic fracturing to disclose the chemical constituents of their fracturing fluids to a

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regulatory agency, which would make the information public via the internet. This could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process are impairing groundwater or causing other damage. These bills, if adopted, could establish an additional level of regulation at the federal or state level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business. Certain states have adopted, or are considering, similar disclosure legislation.

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. The EPA proposed in a consent decree, which has not been approved by a federal court, that it will issue by January 31, 2011 a proposal to revise its national emissions standards for hazardous air pollution for crude oil and natural gas production, as well as gas transmission and storage and 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 published on a register to be made available on the Internet. These regulations may apply to our operations. The EPA has proposed two other rules that would regulate GHGs, one of which would regulate GHGs from stationary sources, and may affect sources in the oil and natural gas exploration and production industry and the pipeline industry. The EPA s finding, the greenhouse gas reporting rule, and the proposed rules to regulate the emissions of greenhouse gases would result in federal regulation of carbon dioxide emissions and other greenhouse gases, and may affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry.

On June 26, 2009, the United States House of Representatives approved adoption of the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey cap-and-trade legislation or ACESA. On November 5, 2009 the Senate Committee on Environment and Public Works approved the Clean Energy Jobs and American Power Act of 2009, authored by John Kerry and Barbara Boxer, that is similar in many ways to ACESA. One of the purposes of these bills is to control and reduce emissions of greenhouse gases in the United States. These

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bills would establish an economy-wide cap on emissions of GHGs in the United States and would require an overall reduction in GHG emissions of 17% to 20% (from 2005 levels) by 2020, and by over 80% by 2050. Under these bills, most sources of GHG emissions would be required to obtain GHG emission allowances corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet the overall emission reduction goals of the bills. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The net effect of these bills would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. President Obama has indicated that he is in support of the adoption of legislation such as the two bills discussed above, and the White House is expending significant efforts to push for the legislation.

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. 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. In another case filed in the Texas District Court in Austin on October 6, 2009, a citizens group sued the Texas Commission on Environmental Quality (TCEQ) asserting that the agency was required to regulate carbon dioxide emissions from parties applying for permits under the Texas Clean Air Act. The result of this lawsuit could impose additional regulations on our operations, if the Texas courts require the TCEQ to regulate carbon dioxide and perhaps other GHGs such as methane, and these rules are applied to our operations in Texas. We may be subject to the EPA GHG monitoring and reporting rule, and potentially new EPA permitting rules if adopted to apply GHG permitting obligations and emissions limitations under the federal Clean Air Act. Even if no federal greenhouse gas regulations are enacted, or if the EPA issues regulations, 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

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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 oil, wastes, hazardous substances or other regulated materials, and may seek natural resources damages.

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, 2009, we had 469 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 About Us 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 CEO 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 annual report on Form 10-K, information that you may find on our website is not part of this report.

ITEM 1A. RISK FACTORS

We have substantial indebtedness and may incur substantially more debt. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.

We have incurred substantial debt amounting to approximately $2.6 billion as of December 31, 2009. As a result of our indebtedness, we will need to use a portion of our cash flow to pay interest, which will reduce the amount we will have available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Our indebtedness under our Senior Credit Agreement is at a variable interest rate, and so a rise in interest rates will generate greater interest expense to the extent we do not have applicable interest rate fluctuation hedges. The amount of our debt may also cause us to be more vulnerable to economic downturns and adverse developments in our business.

We may incur substantially more debt in the future. The indentures governing our outstanding senior notes contain restrictions on our incurrence of additional indebtedness. These restrictions, however, are subject to a number of qualifications and exceptions, and under certain circumstances, we could incur substantial additional indebtedness in compliance with these restrictions. Moreover, these restrictions do not prevent us from incurring obligations that do not constitute indebtedness under the indentures. Our Senior Credit Agreement is a $2.0 billion facility with a borrowing base of $1.5 billion, $1.2 billion of which relates to our oil and natural gas properties and up to $300 million of which relates to our midstream assets. The $1.2 billion borrowing base attributable to our oil and natural gas properties was reduced $200 million to $1.0 billion upon the closing of the sale of the Permian Basin properties on October 30, 2009. As of December 31, 2009, we had $203 million of debt outstanding under this facility and $1.0 billion of additional borrowing capacity.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or sell additional shares of common stock on terms that we may not find attractive if it may be done at all. Further, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under that indebtedness, which could adversely affect our business, financial condition and results of operations.

We may not be able to drill wells on a substantial portion of our acreage.

We may not be able to drill on a substantial portion of our acreage for various reasons. We may not generate or be able to raise sufficient capital to do so. Future deterioration in commodities pricing may also make drilling some acreage uneconomic. Our actual drilling activities and future drilling budget will depend on drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, lease expirations, gathering system and pipeline transportation constraints, regulatory approvals and other factors. In addition, any drilling activities we are able to conduct may not be successful or add additional proved reserves to our overall proved reserves, which could have a material adverse effect on our future business, financial condition and results of operations.

Part of our strategy involves drilling in new or emerging shale formations using horizontal drilling and completion techniques. The results of our planned drilling program in these formations are subject to more uncertainties than conventional drilling programs in more established formations and may not meet our expectations for reserves or production.

The results of our drilling in new or emerging formations, such as the Haynesville, Bossier and Eagle Ford Shales, are more uncertain than drilling results in areas that are developed and have established production. Because new or emerging formations have limited or no production history, we are less able to use past drilling results in those areas to help predict our future drilling results. Further, part of our drilling strategy to maximize recoveries from the Haynesville, Bossier and Eagle Ford Shales involves the drilling of horizontal wells using completion techniques that have proven to be successful in other shale formations. Our experience with horizontal drilling in these areas to date, as well as the industry s drilling and production history, while growing, is limited. The ultimate success of these drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and production profiles are better established.

Further, access to adequate gathering systems or pipeline takeaway capacity and the availability of drilling rigs and other services may be more challenging in new or emerging areas. If our drilling results are less than

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anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and takeaway capacity or otherwise, and/or natural gas and oil prices decline, our investment in these areas may not be as attractive as we anticipate and we could incur material writedowns of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

As of December 31, 2009, we own leasehold interests in approximately 360,000 net acres in areas we believe are prospective for the Haynesville Shale and approximately 310,000 net acres in areas we believe are prospective for the Eagle Ford Shale. A large portion of the acreage is not currently held by production. Unless production in paying quantities is established on units containing these leases during their terms, these leases will expire. If our leases expire, we will lose our right to develop the related properties.

Our drilling plans for these areas are subject to change based upon various factors, including factors that are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals. Further, some of this acreage is located in sections where we do not hold the majority of the acreage and therefore it is likely that we will not be named operator of these sections. As a non-operating leaseholder we have less control over the timing of drilling and there is therefore additional risk of expirations occurring in sections where we are not the operator.

Increased drilling in the Haynesville Shale may cause pipeline and gathering system capacity constraints that may limit our ability to sell natural gas and/or receive market prices for our natural gas.

The Haynesville Shale has become one of the more active natural gas plays in the United States and the wells drilled to date have reported very high initial production rates, implying potentially large reserves. If drilling in the Haynesville Shale continues to be successful, the amount of gas being produced in the area from these new wells, as well as gas produced from other existing wells, could exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available. If this occurs it will be necessary for new interstate and intrastate pipelines and gathering systems to be built.

Because of the recent volatility in natural gas prices and the current economic climate, certain pipeline projects that are planned for the Haynesville Shale area may not occur on schedule or at all because the prospective owners of these pipelines may be unable to secure the necessary financing. In addition, capital constraints could limit our ability to build intrastate gathering systems necessary to transport our natural gas to interstate pipelines. In such event, this could result in wells being shut-in awaiting a pipeline connection or capacity and/or natural gas being sold at much lower prices than those quoted on New York Mercantile Exchange (NYMEX) or than we currently project, which would adversely affect our results of operations.

We may have difficulty financing our planned capital expenditures which could adversely affect our growth.

We have experienced, and expect to continue to experience, substantial capital expenditure and working capital needs, primarily as a result of our drilling program, particularly in the Haynesville, Bossier, and Eagle Ford Shales. We intend to continue to selectively increase our acreage position in the Haynesville, Bossier, and Eagle Ford Shales, which would require additional capital in addition to the capital necessary to drill on our existing acreage. We expect to use borrowings under our Senior Credit Agreement, proceeds from potential asset dispositions and proceeds from potential future capital markets transactions, if necessary, to fund capital expenditures that are in excess of our cash flow and cash on hand.

Our Senior Credit Agreement limits our borrowings to the lesser of the borrowing base and the total commitments. Our borrowing base related to our oil and natural gas properties is $1.0 billion. Our borrowing

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base is determined semi-annually, and may also be redetermined periodically at the discretion of the banks. Lower oil and natural gas prices may result in a reduction in our borrowing base at the next redetermination. A reduction in our borrowing base could require us to repay any indebtedness in excess of the borrowing base. Additionally, the indentures governing our senior unsecured debt contain covenants limiting our ability to incur additional indebtedness, including borrowings under our Senior Credit Agreement, unless we meet one of two alternative tests. The first test applies to all indebtedness and requires that after giving effect to the incurrence of additional debt the ratio of our adjusted consolidated EBITDA (as defined in our indentures) to our adjusted consolidated interest expense over the trailing four fiscal quarters will be at least 2.5 to 1.0. The second test applies only to borrowings under our Senior Credit Agreement that do not meet the first test and it limits these borrowings to the greater of a fixed sum (the most restrictive indenture limit being $100 million) and a percentage (the most restrictive indenture limit being 20%) of our adjusted consolidated net tangible assets (as defined in all of our indentures), which is determined using discounted future net revenues from proved natural gas and oil reserves as of the end of each year. Currently, we are permitted to incur additional indebtedness under these incurrence tests, but may be limited in the future. Lower natural gas and oil prices in the future could reduce our adjusted consolidated EBITDA, as well as our adjusted consolidated net tangible assets, and thus could reduce our ability to incur additional indebtedness.

Additionally, our ability to complete future equity offerings is limited by the availability of authorized common stock under our certificate of incorporation and by general market conditions. If we are not able to borrow sufficient amounts under our Senior Credit Agreement and/or are unable to raise sufficient capital to fund our capital expenditures, we may be required to curtail our drilling, development, land acquisition and other activities, which could result in a decrease in our production of oil and natural gas, forfeiture of leasehold interests if we are unable or unwilling to renew them, and could force us to sell some of our assets on an untimely or unfavorable basis, each of which could have a material adverse effect on our results and future operations.

Oil and natural gas prices are volatile, and low prices could have a material adverse impact on our business.

Our revenues, profitability and future growth and the carrying value of our properties depend substantially on prevailing oil and natural gas prices. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we will be able to borrow under our Senior Credit Agreement will be subject to periodic redetermination based in part on current oil and natural gas prices and on changing expectations of future prices. Lower prices may also reduce the amount of oil and natural gas that we can economically produce and have an adverse effect on the value of our properties.

Historically, the markets for oil and natural gas have been volatile, and they are likely to continue to be volatile in the future. Among the factors that can cause volatility are:

- the domestic and foreign supply of oil and natural gas;
- the ability of members of the Organization of Petroleum Exporting Countries and other producing countries to agree upon and maintain oil prices and production levels;
- political instability, armed conflict or terrorist attacks, whether or not in oil or natural gas producing regions;
- the level of consumer product demand;
- the growth of consumer product demand in emerging markets, such as China;
- labor unrest in oil and natural gas producing regions;

weather conditions, including hurricanes and other natural occurrences that affect the supply and/or demand of oil and natural gas;

the price and availability of alternative fuels;

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- the price of foreign imports;
- worldwide economic conditions; and
- the availability of liquid natural gas imports.

These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of oil and natural gas.

The current economic and financial crisis has negatively impacted the prices for our oil and natural gas production, limited access to the credit and equity markets, increased the cost of capital, and may have other negative consequences that we cannot predict.

The current economic and financial crisis in the United States and globally creates financial challenges that will grow if conditions do not improve. Although we believe our operating and capital budget for 2010 can be funded with internally generated cash flow and existing financial resources, our cash flow from operations, borrowings under our Senior Credit Agreement and cash on hand historically have not been sufficient to fund all of our expenditures, and we have relied on the capital markets and sales of non-core assets to provide us with additional capital. Our ability to access the capital markets has, at times, been limited as a result of these crises and may be restricted at a time when we would like, or need, to raise capital. If our cash flow from operations is less than anticipated or we are not able to successfully complete a portion of our potential asset dispositions in 2010 and our access to capital is restricted, we may be required to reduce our operating and capital budget, which could have a material adverse effect on our results and future operations. Economic and financial conditions may also limit the number of participants or reduce the values we are able to realize in asset sales or other transactions we may engage in to raise capital, thus making these transactions more difficult to consummate and less economic. Additionally, the current economic situation has affected the demand for oil and natural gas and has resulted in lower prices for oil and natural gas, which could have a negative impact on our revenues. Lower prices could also adversely affect the collectibility of our trade receivables.

Unless we replace our reserves, our reserves and production will decline, which would adversely affect our financial condition, results of operations and cash flows.

Producing natural gas and oil reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Decline rates are typically greatest early in the productive life of a well. For instance, we currently estimate that our Haynesville Shale wells will decline approximately 80 85% during the first twelve months of production. Estimates of the decline rate of an oil or natural gas well are inherently imprecise, and are less precise with respect to new or emerging oil and natural gas formations with limited production histories than for more developed formations with established production histories. Our production levels and the reserves that we currently expect to recover from our wells will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future natural gas and oil reserves and production and, therefore, our cash flow and results of operations are highly dependent upon our success in efficiently developing and exploiting our current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, our cash flows and the value of our reserves may decrease, adversely affecting our business, financial condition and results of operations.

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

This report on Form 10-K contains estimates of our proved oil and natural gas reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of

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estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

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

At December 31, 2009, approximately 67% of our estimated reserves were classified as proved undeveloped. Estimates of proved undeveloped reserves are less certain than estimates of proved developed reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of these oil and natural gas reserves and the costs associated with development of these reserves in accordance with SEC regulations, actual capital expenditures will likely vary from estimated capital expenditures, development may not occur as scheduled and actual results may not be as estimated.

We depend substantially on the continued presence of key personnel for critical management decisions and industry contacts.

Our success depends upon the continued contributions of our executive officers and key employees, particularly with respect to providing the critical management decisions and contacts necessary to manage and maintain growth within a highly competitive industry. Competition for qualified personnel can be intense, particularly in the oil and natural gas industry, and there are a limited number of people with the requisite knowledge and experience. Under these conditions, we could be unable to attract and retain these personnel. The loss of the services of any of our executive officers or other key employees for any reason could have a material adverse effect on our business, operating results, financial condition and cash flows.

Our business is highly competitive.

The oil and natural gas industry is highly competitive in many respects, including identification of attractive oil and natural gas properties for acquisition, drilling and development, securing financing for such activities and obtaining the necessary equipment and personnel to conduct such operations and activities. In seeking suitable opportunities, we compete with a number of other companies, including large oil and natural gas companies and other independent operators with greater financial resources, larger numbers of personnel and facilities, and, in some cases, with more expertise. There can be no assurance that we will be able to compete effectively with these entities.

Our oil and natural gas activities are subject to various risks which are beyond our control.

Our operations are subject to many risks and hazards incident to exploring and drilling for, producing, transporting, marketing and selling oil and natural gas. Although we may take precautionary measures, many of these risks and hazards are beyond our control and unavoidable under the circumstances. Many of these risks or hazards could materially and adversely affect our revenues and expenses, the ability of certain of our wells to produce oil and natural gas in commercial quantities, the rate of production and the economics of the development of, and our investment in the prospects in which we have or will acquire an interest. Any of these risks and hazards could materially and adversely affect our financial condition, re