PETROHAWK ENERGY CORP
Form 10-K
February 28, 2012

Use these links to rapidly review the document

Table of Contents

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, 2011

Commission file number 001-33334

PETROHAWK ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

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

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

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

The registrant is a wholly owned subsidiary of BHP Billiton Limited and meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this Form with the reduced disclosure format as permitted by Instruction I(2).

There is no market for the registrant's common stock, par value $0.001 per share. As of February 24, 2012, there were 100 shares of common stock outstanding.

TABLE OF CONTENTS

Table of Contents

Special note regarding forward-looking statements

This Annual Report on Form 10-K contains, and we may from time to time otherwise make in other public filings, forward-looking statements within the meaning of the federal securities laws. All statements, other than statements of historical facts, concerning, among other things, planned capital expenditures, potential increases in oil and natural gas production, the number and location of wells to be drilled in the future, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "believe," "intend," "achievable," "anticipate," "will," "continue," "potential," "should," "could" and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Actual results could differ materially from those anticipated in these forward-looking statements. One should consider carefully the statements under the "Risk Factors" section of 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 integrate our business with affiliates of BHP Billiton Limited;
- our ability to retain key members of senior management and key technical employees;
- 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 changes in tax law 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 replace oil and natural gas reserves;
- environmental risks;
- drilling and operating risks;
- exploration and development risks;
- competition, including competition for acreage in resource play areas;
- management's ability to execute our plans to meet our goals;
- the cost and availability of goods and services, such as drilling rigs, fracture stimulation services and tubulars;

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

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

our ability to secure firm transportation and other marketing outlets for the natural gas, natural gas liquids and crude oil and condensate we produce and to sell these products at market prices;

general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business, may be less favorable than expected, including the possibility that economic conditions in the United States will worsen and that capital markets are disrupted, which could adversely affect demand for oil and natural gas;

Table of Contents

- social unrest, political instability, armed conflict, or acts of terrorism or sabotage in oil and natural gas producing regions, such as the Middle East, or our markets; and

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

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

Table of Contents

PART I

ITEM 1. BUSINESS

Overview

We are an oil and natural gas company engaged in the exploration, development and production of predominately natural gas properties located in the United States. As further discussed under the heading "*Merger*" below, on August 25, 2011, BHP Billiton Limited, a corporation organized under the laws of Victoria, Australia (BHP Billiton Limited), acquired 100% of our outstanding shares of common stock through the merger of a wholly owned subsidiary of BHP Billiton Petroleum (North America) Inc., a Delaware corporation and wholly owned subsidiary of BHP Billiton Limited, with and into Petrohawk, with Petrohawk continuing as the surviving entity. At the date of this report, Petrohawk remains an indirect, wholly owned subsidiary of BHP Billiton Limited.

Our oil and natural gas properties are concentrated in three premier domestic shale plays that we believe have decades of future development potential. We organize our oil and natural gas operations into two principal regions: the Mid-Continent, which includes our Louisiana, East Texas and West Texas properties; and the Western, which includes our South Texas properties.

At December 31, 2011, 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 4,044 billion cubic feet of natural gas equivalent (Bcfe), consisting of 3,355 billion cubic feet (Bcf) of natural gas, 58 million barrels (MMBbls) of oil, and 57 MMBbls of natural gas liquids. Approximately 39% of our proved reserves were classified as proved developed. We maintain operational control of approximately 78% of our proved reserves. Production for the fourth quarter of 2011 averaged 1,086 million cubic feet of natural gas equivalent (Mmcfe) per day (Mmcfe/d). Full year 2011 production averaged 977 Mmcfe/d compared to 675 Mmcfe/d in 2010. Our total operating revenues for 2011 were approximately $2.1 billion.

We focus on properties within our core operating areas that we believe have significant development and exploration opportunities and where we can apply our technical experience and economies of scale to increase production and proved reserves. We continue to selectively expand our leasehold position in our existing resource plays in the Haynesville Shale in Northern Louisiana and East Texas, the Eagle Ford Shale in South Texas and the Permian Basin in West Texas. We expect to continue to grow our production and reserves from these existing areas, with a near-term focus on holding our acreage positions and growing our crude oil and natural gas liquids production. We also expect to continue to evaluate entry into new prospective resource plays where we can capitalize on our expertise and extensive experience.

Recent Developments

Merger

On July 14, 2011, we entered into an agreement and plan of merger (Merger Agreement) with BHP Billiton Limited (Guarantor), BHP Billiton Petroleum (North America) Inc. (Parent), a Delaware corporation and a wholly owned subsidiary of Guarantor, and North America Holdings II Inc., a Delaware corporation (Purchaser) and a wholly owned subsidiary of Parent. Pursuant to the Merger Agreement, on August 20, 2011, Purchaser accepted for payment all of the outstanding shares of our common stock, par value $0.001 per share, validly tendered and not validly withdrawn pursuant to the tender offer for $38.75 per share, net to the seller in cash. Additionally, and pursuant to the Merger Agreement, on August 25, 2011, Purchaser merged with and into Petrohawk, with Petrohawk continuing as the surviving corporation in the merger and as a wholly owned subsidiary of Parent (the BHP Merger).

Table of Contents

At Parent's request and direction and as an inducement to Parent's willingness to enter into the Merger Agreement, we entered into retention agreements (Retention Agreements) with certain of our executive officers contemporaneously with the execution of the Merger Agreement. The Retention Agreements continued the employment of each executive with us for a period of time following the closing. Floyd C. Wilson also entered into a consulting agreement (Consulting Agreement) with us beginning after the retention date specified in Mr. Wilson's Retention Agreement and ending six months thereafter under which Mr. Wilson will provide services to us and pursuant to which he will be entitled to separately specified compensation. Additional information regarding the Merger Agreement, Retention Agreements and Consulting Agreement is set forth in our Form 8-K filed on July 20, 2011.

Midstream Transactions

On July 1, 2011, we along with our subsidiaries Hawk Field Services, LLC (Hawk Field Services) and EagleHawk Field Services LLC (EagleHawk), closed previously announced transactions with KM Gathering LLC (KM Gathering) and KM Eagle Gathering LLC (Eagle Gathering), each of which is an affiliate of Kinder Morgan Energy Partners, L.P. (Kinder Morgan), a publicly traded master limited partnership, in which Hawk Field Services transferred (i) its remaining 50% membership interest in KinderHawk Field Services LLC (KinderHawk) to KM Gathering and (ii) a 25% interest in EagleHawk to Eagle Gathering, in exchange for aggregate cash consideration of approximately $836 million. In conjunction with the closing of these transactions, our remaining capital commitment to KinderHawk was relieved. This remaining capital commitment was approximately $41.4 million as of July 1, 2011. Our commitment to deliver certain minimum annual quantities of natural gas through the Haynesville gathering system through May 2015 was not relieved in the transfer of our remaining 50% membership interest in KinderHawk.

EagleHawk, which is managed by Hawk Field Services, engages in the natural gas midstream business in the Eagle Ford Shale in South Texas. At the closing of the transactions, EagleHawk holds our gathering and treating assets and business serving our Hawkville and Black Hawk Fields in the Eagle Ford Shale. EagleHawk has agreements with us covering gathering and treating and pursuant to which we dedicate our production from our Eagle Ford Shale leases.

Senior Revolving Credit Facility

On April 29, 2011, we amended our existing credit facility, the Fifth Amended and Restated Senior Revolving Credit Agreement (the Senior Credit Agreement), as amended on November 8, 2010 and December 22, 2010, by entering into the Third Amendment to the Fifth Amended and Restated Senior Revolving Credit Agreement (the Third Amendment), among us, each of the lenders from time to time party thereto (the Lenders), BNP Paribas, as administrative agent for the Lenders, Bank of America, N.A. and Bank of Montreal as co-syndication agents for the Lenders, and JPMorgan Chase Bank, N.A. and Wells Fargo Bank, N.A., as co-documentation agents for the Lenders. Among other things, the Third Amendment: (a) increased our borrowing base to $1.9 billion, $1.8 billion of which related to our oil and natural gas properties and $100 million of which related to our midstream assets (limited as described below); (b) reduced interest rates such that amounts outstanding under the Senior Credit Agreement will bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.50% to 2.50% for Eurodollar loans or at specified margins over the Alternate Base Rate (ABR) of 0.50% to 1.50% for ABR loans, which margins will fluctuate based on the utilization of the facility; (c) extended the maturity date of the facility from July 1, 2014 to July 1, 2016; and (d) increased the amount of the facility from $2.0 billion to $2.5 billion.

On July 1, 2011, we amended our Senior Credit Agreement, as amended on November 8, 2010, December 22, 2010 and April 29, 2011, by entering into the Fourth Amendment to the Fifth Amended and Restated Senior Revolving Credit Agreement (the Fourth Amendment), among us and the Lenders. Among other things, the Fourth Amendment permitted Hawk Field Services to convey its

Table of Contents

Eagle Ford Shale gathering and treating business in South Texas to EagleHawk; transfer a 25% equity interest in EagleHawk to Kinder Morgan; enter into and abide by the terms of the operative documents governing the formation and operation of EagleHawk, and reaffirmed the oil and gas component of our borrowing base under the Senior Credit Agreement at $1.8 billion, while reducing to zero the midstream component of our borrowing base. The portion of the Senior Credit Agreement's borrowing base which relates to our oil and natural gas properties is redetermined on a semi-annual basis (with us and the lenders each having the right to one annual interim unscheduled redetermination) and adjusted based on our oil and natural gas properties, reserves, other indebtedness and other relevant factors. Our ability to utilize the full amount of our borrowing capacity is influenced by a variety of factors, including redeterminations of our borrowing base, and covenants under our Senior Credit Agreement and our senior unsecured debt indentures. Additionally, our borrowing base is subject to a reduction equal to the product of $0.25 multiplied by the stated principal amount (without regard to any initial issue discount) of any unsecured senior or senior subordinated notes that we may issue.

Effective October 3, 2011, we reduced the borrowing capacity under our Senior Credit Agreement from $2.5 billion to $25 million. At December 31, 2011, we had a $3.0 million letter of credit outstanding with a vendor, no borrowings outstanding and $22.0 million of borrowing capacity available under the Senior Credit Agreement. Effective February 1, 2012, the $3.0 million letter of credit was terminated. Refer to Item 8. *Consolidated Financial Statements and Supplementary Data Note 4, "Long-term Debt*" for more details.

Our Senior Credit Agreement contains customary financial and other covenants, including minimum working capital levels (the ratio of current assets plus the unused commitment under the Senior Credit Agreement to current liabilities) of not less than 1.0 to 1.0 and minimum coverage of interest expenses (as defined in the Senior Credit Agreement) of not less than 2.5 to 1.0. We are subject to additional covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. Effective September 27, 2011, our compliance obligations with respect to the aforementioned minimum working capital level and minimum coverage of interest expense covenants, as well as our compliance obligations with respect to certain other covenants in the Senior Credit Agreement including reserve report and other information delivery, were suspended until March 31, 2012. 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, under the most restrictive indentures, 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 limits these borrowings to the greater of a fixed sum of, under the most restrictive indentures, $1 billion and 30% of our adjusted consolidated net tangible assets (as defined in all of our indentures), which is largely calculated based upon the discounted future net revenues from our proved oil and natural gas reserves as of the end of each year.

2019 Notes Issuance

On May 20, 2011, we issued $600 million aggregate principal amount of our 6.25% senior notes due 2019 (the 2019 Notes). The net proceeds from the sale of the 2019 Notes were approximately $589 million (after deducting offering fees and expenses). The proceeds from the 2019 Notes were utilized to repay borrowings outstanding under our Senior Credit Agreement and for working capital for general corporate purposes.

Table of Contents

2012 Note Refinancing

On January 31, 2011, we completed the issuance of an additional $400 million aggregate principal amount of our 7.25% senior notes due 2018 (the additional 2018 Notes). The net proceeds from the sale of the additional 2108 Notes were approximately $400.5 million (after deducting offering fees and expenses). A portion of the proceeds of the additional 2018 Notes were utilized to redeem our $275 million 7.125% senior notes due 2012 (the 2012 Notes).

Business Strategy

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

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

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

Reduce operating costs We focus on reducing the per unit operating costs associated with our properties and have been successful in lowering our unit lease operating expenses from $0.43 per Mcfe in 2009 to $0.26 in 2010 and $0.17 per Mcfe in 2011.

Oil and Natural Gas Reserves

Estimates of proved reserves at December 31, 2011, 2010 and 2009 were prepared by Netherland, Sewell, our independent consulting petroleum engineers. Netherland, Sewell is a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. Netherland, Sewell was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within Netherland, Sewell, the technical persons primarily responsible for preparing the estimates set forth in the Netherland, Sewell reserve report incorporated herein are Mr. Thomas J. Tella and Mr. William J. Knights. Mr. Tella has been practicing consulting petroleum engineering at Netherland, Sewell since 1978. Mr. Tella is a Licensed Professional Engineer in the State of Texas and has over 35 years of practical experience in petroleum engineering, with over 30 years experience in the estimation and evaluation of reserves. He graduated from Texas Tech University in 1972 with a Bachelor of Science Degree in Chemical Engineering. Mr. Knights has been practicing consulting petroleum geology at Netherland, Sewell since 1991. Mr. Knights is a Licensed Professional Geoscientist in the State of Texas, Geology and has over

30 years of practical experience in petroleum geosciences, with over 20 years experience in the estimation and evaluation of reserves. He graduated from Texas Christian University with a Bachelor of Science Degree in Geology in 1981 and with a Master of Science Degree in Geology in 1984. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying Securities and Exchange Commission (SEC) and other industry reserves definitions and guidelines.

Historically, our board of directors had established an independent reserves committee composed of three outside directors, all of whom had experience in energy company reserve valuations. In conjunction with the closing of the BHP Merger, this committee was eliminated and our independent consulting petroleum engineers currently report to our Principal Reserves Officer who is charged with ensuring the integrity of the process of selection and engagement of the independent consulting petroleum engineers and in making a recommendation to our board of directors as to whether to accept the report prepared by our independent consulting petroleum engineers. Ms. Tina S. Obut, our Principal Reserves Officer, is a Registered Petroleum Engineer and has held reservoir engineering positions since 1989. Ms. Obut has served as our Principal Reserves Officer in the role of Senior Vice President Corporate Reserves since May 15, 2008. Ms. Obut served as Vice President Corporate Reserves from March 2007 to May 15, 2008. Ms. Obut initially joined the Company in April 2006 as Manager of Corporate Reserves. Prior to joining us, Ms. Obut was employed by El Paso Production Company as Manager of Reservoir Engineering Evaluations from July 2004 until April 2006. From 2001 to 2004, Ms. Obut was Planning and Asset Manager at Mission Resources. From 1992 to 2001, Ms. Obut was a Vice President with Ryder Scott Company, and from 1989 to 1992, she worked as a reservoir engineer with Chevron.

The reserves information in this Annual Report on 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 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, 2011. Average prices for the 12-month period were as follows: West Texas Intermediate (WTI) spot price of $96.19 per barrel (Bbl) for oil and natural gas liquids, adjusted by lease or field for quality, transportation fees, and regional price differentials and a Henry Hub spot market price of $4.12 per million British thermal unit (Mmbtu) for natural gas, as adjusted by lease or field for energy content, transportation fees, and regional price differentials. All prices and costs associated with operating wells were held constant in accordance with the amended Securities and Exchange Commission (SEC) guidelines which were effective for financial

Table of Contents

statements for periods ending on or after December 31, 2009. The following table presents certain information as of December 31, 2011.

	Mid-Continent Region	Western Region	Total
Proved Reserves at Year End (Bcfe)[1]			
Developed	1,265.2	329.8	1,595.0
Undeveloped	1,262.9	1,186.2	2,449.1
Total	2,528.1	1,516.0	4,044.1

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

The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2011 and 2010. Shut-in wells currently not capable of production are excluded from producing well information.

	Years Ended December 31,			
	2011		2010	
	Gross	Net[1]	Gross	Net[1]
Oil	13.0	10.2	2.0	1.8
Natural Gas	3,092.0	1,484.2	2,814.0	1,281.7
Total	3,105.0	1,494.4	2,816.0	1,283.5

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

Core Operating Regions

Mid-Continent Region

In the Mid-Continent Region, we concentrate our drilling program primarily in North Louisiana and East Texas and the Permian Basin in West Texas. We believe our Mid-Continent Region operations provide us with a solid base for future production and reserve growth. During 2011, we drilled 294 wells in this region (of which 87 were operated and 207 were non-operated), and all were successful. In 2011, we produced 269 Bcfe in this region, or 740 Mmcfe/d. As of December 31, 2011, approximately 63% of our proved reserves, or 2,528 Bcfe, were located in our Mid-Continent Region, which included 1,265 Bcfe of proved developed reserves.

Haynesville Shale The Haynesville Shale is 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 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 345,000 net acres in the area that we currently believe to be prospective for the Haynesville Shale. We own varying working and net revenue interests in this area.

Table of Contents

Our current drilling and completion methodology focuses on completing wells with longer laterals and maximizing the number of fracture stages, averaging approximately 430 feet in length. The objective of this technique is to minimize the total number of wells required to effectively drain the reservoir, resulting in lower overall development costs. We are currently targeting lateral lengths between 4,300 feet and 4,800 feet with up to 11 fracture stages. At year-end 2011, we had seven operated horizontal rigs running in the Haynesville Shale. Spud-to-first sales averaged approximately 110 days during 2011.

As of December 31, 2011, we had approximately 258 operated wells on production in North Louisiana producing approximately 984 Mmcfe/d gross. We have changed our production practice in the Haynesville Shale from one that typically produced at initial rates ranging from 18 Mmcfe/d to 24 Mmcfe/d to a typical range from 7 Mmcfe/d to 10 Mmcfe/d in an effort to maintain higher surface flowing pressures and lessen the rate of pressure decline, which we believe better maintains the permeability in the reservoir and ultimately allows for higher ultimate recovery of gas from each well. We had three operated wells that were pending completion and six operated wells that were drilling in this area at December 31, 2011.

In 2011, we produced 244 Bcfe, or 668 Mmcfe/d. As of December 31, 2011, proved reserves for the Haynesville Shale were approximately 2,252 Bcfe, of which approximately 44% were classified as proved developed and approximately 56% as proved undeveloped. The proved reserves include 796 proved developed wells and 552 proved undeveloped locations. During 2011, we drilled 275 wells (74 operated and 201 non-operated), all of which were successful.

Lower Bossier Shale During 2011, 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 Lower Bossier Shale. The Lower Bossier Shale is located approximately 200 feet to 400 feet above the Haynesville Shale. The net thickness of the Shale is approximately the same as the Haynesville Shale and it also has many of the same reservoir parameters as the Haynesville Shale, particularly in the southern area of the Haynesville Shale trend. We currently own leasehold interests in approximately 150,000 net acres in the area that we currently believe to be prospective for the Lower Bossier Shale. We participated in five Lower Bossier Shale wells as a non-operator during 2011. We produced 4 Bcfe, or 12 Mmcfe/d in 2011 in this area. We own varying working and net revenue interests in this area. As of December 31, 2011, proved reserves for this reservoir were approximately 14 Bcfe, all of which were classified as proved developed. No proved undeveloped reserves were recorded for the Lower Bossier Shale because the proved undeveloped locations for this area are not scheduled to be drilled within the next five years.

Elm Grove and Caspiana Fields Located primarily in Bossier and Caddo Parishes of North Louisiana, our Elm Grove and Caspiana fields produce from the Hosston and Cotton Valley formations. These zones are composed of low permeability sandstones that require fracture stimulation treatments to produce. We currently own leasehold interests in approximately 32,000 net acres in the area that we currently believe to be prospective for Cotton Valley and/or Hosston formations. We own varying working and net revenue interests in these fields. We produced 19 Bcfe in 2011 in these fields, or 53 Mmcfe/d. As of December 31, 2011, proved reserves for the Elm Grove/Caspiana Fields were approximately 250 Bcfe, all of which were classified as proved developed. No proved undeveloped reserves were recorded for the Elm Grove/Caspiana Fields because the proved undeveloped locations for this area are not scheduled to be drilled within the next five years. The proved reserves include 946 proved developed wells and no proved undeveloped locations. We owned an interest in 589 operated, producing wells in the Elm Grove and Caspiana Fields as of December 31, 2011.

Table of Contents

Permian Basin We began building an acreage position in the Permian Basin of West Texas in the second half of 2010, and have now acquired or have committed to acquire approximately 325,000 net acres at an average cost of approximately $1,524/acre with over 80% expected to be operated. Our core position includes acreage in both the Midland Basin, where the primary target is the Lower Wolfcamp Shale, which is approximately 900 feet thick, and the Delaware Basin, where the primary targets are the Avalon Shale, Bone Springs Sands and the Wolfcamp Shale, which are collectively approximately 3,000 feet thick. We own varying working and net revenue interests in these areas. During 2011, we drilled 12 operated wells, all of which were successful. In 2011, we produced 87 Mmcfe, or 14.5 barrels of oil equivalent. As of December 31, 2011, proved reserves for the Permian Basin were approximately 10 Bcfe, or 1.6 million barrels of oil equivalent (Mmboe), all of which were classified as proved developed. We are still in the exploratory phase for our Permian acreage and in 2012 we intend to concentrate on developing a future development plan for this area. As such, no proved undeveloped reserves were recorded for the Permian Basin as of December 31, 2011.

Western Region

Our Western Region assets are focused primarily in the Hawkville Field and Black Hawk Field in the Eagle Ford Shale play in South Texas. We believe our Eagle Ford Shale properties provide us with opportunities for future growth in oil, natural gas, and natural gas liquids (NGL) production and reserves. Net production from the region was 87 Bcfe (239 Mmcfe/d) in 2011. During 2011, we drilled 147 operated wells and 12 non-operated wells with a 100% success rate. As of December 31, 2011, the proved reserves for the region were approximately 1,516 Bcfe of which 330 Bcfe were classified as proved developed and 1,186 Bcfe as proved undeveloped. Also included in our Western Region is the management of our investment in EagleHawk. During the fourth quarter of 2011 and as a result of the BHP Merger, we realigned the management of our midstream operations in the Eagle Ford Shale with the management of our oil and natural gas operations in the Eagle Ford Shale.

Hawkville Field We have approximately 224,000 net acres under lease that are located in LaSalle, McMullen and Live Oak Counties, Texas. Our average working interest and net revenue interest in 103 operated wells are approximately 89% and 67%, respectively. Our average working interest and net revenue interest in 24 non-operated wells are approximately 33% and 24%, respectively.

The Hawkville Eagle Ford Shale pay thickness is up to 300 feet. The wells have an average true vertical depth that ranges from 10,500 feet to 12,500 feet and they are drilled with horizontal laterals currently ranging from 5,000 feet to 7,000 feet. The wells are cased hole completed and are currently being fracture stimulated with an average of 18 stages. There are currently 45 wells which produce condensate with yields ranging from 342 barrels per million cubic feet (Bbls/Mmcf) to 16 Bbls/Mmcf and with natural gas liquids yields ranging from 133 Bbls/Mmcf to 42 Bbls/Mmcf that had an average initial producing rate of 334 barrels of oil per day (Bo/d) and 5 million cubic feet of natural gas per day (Mmcf/d). There are currently 45 wells which produce natural gas that have an average NGL yield of 40 Bbls/Mmcf with no condensate that had an initial producing rate of 8 Mmcf/d. We had 11 operated wells and two non-operated wells that were pending completion and six wells that were drilling in this Field at year-end.

The gross operated production from this Field is currently 199 Mmcf/d plus 7,425 Bo/d. As of December 31, 2011, the proved reserves were approximately 1,085 Bcfe of which approximately 20% were classified as proved developed and 867 Bcfe as proved undeveloped. The proved reserves include 127 proved developed wells and 284 proved undeveloped locations. During 2011, we drilled 52 operated wells and 8 non-operated wells with no dry holes.

Table of Contents

Black Hawk Field We have approximately 58,000 net acres under lease that are located in DeWitt, Karnes and Gonzales Counties, Texas. For approximately 90% of the Field, Petrohawk is the operator during the drilling and completion phase of the wells and a private company is the operator after the wells are placed on production. Our average working interest and net revenue interest in 123 wells are approximately 49% and 37%, respectively.
The Black Hawk Eagle Ford Shale pay thickness is up to 170 feet. The wells have an average true vertical depth that ranges from 12,000 feet to 13,500 feet and they are drilled with horizontal laterals currently averaging over 5,500 feet. The wells are cased hole completed and are currently being fracture stimulated with an average of 18 stages. There are currently 97 wells which produce condensate with yields ranging from 1,193 Bbls/Mmcf to 21 Bbls/Mmcf and with NGL yields ranging from 183 Bbls/Mmcf to 1 Bbls/Mmcf that had an average initial producing rate of 809 Bo/d and 3 Mmcf/d. We had 23 operated wells that were pending completion and nine wells that were drilling in this Field at December 31, 2011. The gross production from this Field is currently 103 Mmcf/d plus 37,515 Bo/d. As of December 31, 2011, proved reserves were approximately 431 Bcfe, or 71.8 Mmboe, of which approximately 26% were classified as proved developed and 319 Bcfe, or 53.2 Mmboe, as proved undeveloped. The proved reserves include 123 proved developed wells and 221 proved undeveloped locations. During 2011, we drilled 96 wells with no dry holes.

EagleHawk Field Services During June 2009, we initiated construction of a high pressure gathering system in the Eagle Ford Shale to transport our production to various intrastate and interstate pipelines through the access of multiple interconnects. Our Eagle Ford Shale midstream activities have evolved into two separate midstream systems serving the Hawkville and Black Hawk areas, which are now owned by EagleHawk. We own a 75% membership interest in EagleHawk.
In the Hawkville area, EagleHawk's gathering and treating system currently consists of approximately 172 miles of 6-inch to 16-inch diameter pipeline and three treating plants. EagleHawk's Hawkville area system had a throughput capacity of 550 Mmcf/d and treating capacity of 550 GPM as of December 31, 2011.

In the Black Hawk area, EagleHawk's system consists of approximately 131 miles of 6-inch to 16-inch diameter gas pipeline and approximately 106 miles of 4-inch to 12-inch diameter liquid pipeline. EagleHawk's Black Hawk area system had a throughput capacity of 250 Mmcf/d of natural gas and 100,000 barrels per day (Bbls/d) of condensate as of December 31, 2011.

Risk Management

As a result of the BHP Merger, we no longer plan to enter into derivative contracts to hedge our commodity price variability. Historically, we had a risk management policy for the use of derivative instruments to provide partial protection against certain risks relating to our ongoing business operations, such as commodity price risk and interest rate risk. Derivative contracts were utilized to economically hedge our exposure to price fluctuations and reduce the variability in our cash flows associated with anticipated sales on future oil, natural gas and natural gas liquids production. We hedged a substantial, but varying, portion of anticipated oil, natural gas, and natural gas liquids production. Periodically, we also entered into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates (such as those on our Senior Credit Agreement) to fixed interest rates.

The decision we made on the quantity and price at which we chose to hedge our production was based in part on our view of current and future market conditions. While there were many different types of derivatives available, we typically used collar agreements, swap agreements and put options to attempt to manage price risk more effectively. The collar agreements were put and call options used to

Table of Contents

establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. Periodically, we paid a fixed premium to increase the floor price above the existing market value at the time we entered into the arrangement. All collar agreements provided for payments to counterparties if the index price exceeded the ceiling and payments from the counterparties if the index price was below the floor. The price swaps called for payments to, or receipts from, counterparties based on whether the market price of oil, natural gas, and natural gas liquids for the period was greater or less than the fixed price established for that period when the swap was put in place. Under put options, we paid a fixed premium to lock in a specified floor price. If the index price fell below the floor price, the counterparty paid us net of the fixed premium. If the index price rose above floor price, we paid the fixed premium.

It was our policy to enter into derivative contracts, including interest rate swaps, only with counterparties that were creditworthy financial institutions deemed by management as competent and competitive market makers. Each of the counterparties to our derivative contracts was a lender in our Senior Credit Agreement.

On December 20, 2011, we entered into a Master Transaction Agreement (the MTA) with Barclays Bank PLC (Barclays) in order to facilitate the termination of a portion of our existing derivative positions. As part of the MTA, we entered into certain derivative transactions with Barclays with equal and opposite economic terms from the majority of our existing derivative positions (Mirror Trades) at the time of the MTA in order to limit our exposure to future price movements. The Mirror Trades were entered into in December 2011 and are cancellable if certain events do not take place by March 16, 2012. We plan to novate the existing derivative positions to Barclays once certain terms and conditions are met. Once these existing derivative positions have been novated to Barclays, as between us and Barclays, the existing derivative positions as well as the Mirror Trades will terminate and Barclays will pay us a negotiated settlement amount which represents the approximate closeout value as of the dates stipulated in the Agreement of our original existing derivative contracts. We recorded an approximate $20 million loss in "*Net gain on derivative contracts"* at December 31, 2011 representing the change in the fair value of the Mirror Trades from December 20, 2011 to December 31, 2011. In addition, during the first quarter of 2012, we received $68.5 million for the termination of our outstanding derivative positions with BNP Paribas.

We will evaluate the benefit of employing derivatives in the future and may look to create new risk management policy should facts or circumstances warrant such a change. 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 production is maintained. Undeveloped oil and natural gas leaseholds are typically for a primary term of three to five years within which we are generally required to develop the property or the lease will expire. In some cases, the primary term of our undeveloped leases can be extended by option payments; the payments and time extended vary by lease.

Table of Contents

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

	Years Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive[1]	2	2.0	2	1.9		
Dry						
Total Extension	2	2.0	2	1.9		
Extension Wells:						
Productive[1]	414	184.7	827	192.0	601	156.8
Dry			2	0.6	1	0.2
Total Extension	414	184.7	829	192.6	602	157.0
Development Wells:						
Productive[1]	37	11.1	75	23.8	24	5.1
Dry						
Total Development	37	11.1	75	23.8	24	5.1
Total Wells:						
Productive[1]	453	197.8	904	217.7	625	161.9
Dry			2	0.6	1	0.2
Total	453	197.8	906	218.3	626	162.1

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

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

We own interests in developed and undeveloped oil and natural gas acreage in the locations set forth in the table below. These ownership interests generally take the form of working interests in oil and natural gas leases that have varying terms. The following table presents a summary of our acreage interests as of December 31, 2011:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
State	Gross	Net	Gross	Net	Gross	Net
Alabama			27,298	22,747	27,298	22,747
Indiana			311	286	311	286
Louisiana	206,833	172,824	52,181	48,771	259,014	221,595
Oklahoma	40	20	91,630	51,960	91,670	51,980
Texas	196,678	134,746	929,293	680,936	1,125,971	815,682
Total Acreage	403,551	307,590	1,100,713	804,700	1,504,264	1,112,290

The table below reflects our net undeveloped and mineral acreage as of December 31, 2011 that will expire each year if we do not establish production in paying quantities on the units in which such

15

Table of Contents

acreage is included or do not pay (or do not have the contractual right to pay) delay rentals or other extensions to maintain the lease.

Year	Percentage Expiration
2012	19%
2013	33%
2014	31%
2015	8%
2016	8%
2017 & beyond	1%
	100%

At December 31, 2011, we had estimated proved reserves of approximately 4.0 trillion cubic feet of natural gas equivalent (Tcfe) comprised of 3,355 Bcf of natural gas, 57 MMBbls of natural gas liquids, and 58 MMBbls of oil. The following table sets forth, at December 31, 2011, these reserves:

	Proved Developed	Proved Undeveloped	Total Proved
Natural Gas (Bcf)	1,434.4	1,920.7	3,355.1
Oil (MMBbls)	13.2	44.5	57.7
Natural Gas Liquids (MMBbls)	13.5	43.6	57.1
Equivalent (Bcfe)[1]	1,595.0	2,449.1	4,044.1

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

At December 31, 2011, our estimated proved undeveloped (PUD) reserves were approximately 2,449 Bcfe, a 242 Bcfe net increase over the previous year's estimate of 2,207 Bcfe. The net increase is comprised of additions of 1,107 Bcfe, primarily attributable to drilling in the Haynesville and Eagle Ford Shales. The increase was partially offset by a reduction of approximately 894 Bcfe, which primarily relates to PUD reserves estimated as of December 31, 2010 that are currently scheduled for development at least five years from December 31, 2011 due to changes in the development timing of new and existing PUD reserves, and to the sale of certain non-core properties. During 2011, the majority of our total drilling and completion capital was allocated to drilling undeveloped leases in the Haynesville Shale to hold acreage. As of December 31, 2011, all of our PUD reserves included in the reserve report are less than five years in age and over 99% are less than three years in age. The following table summarizes the amount of PUD reserves that have been developed in each of the last three years using the amount of PUD reserves that we reported in the prior year:

	2011	2010	2009
PUD reserves at beginning of year (Bcfe)	2,207.4	1,845.0	625.8
PUD reserves developed (Bcfe)	70.8	109.2	22.0
% PUD reserves developed	3%	6%	4%

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 "Supplemental 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,

Table of Contents

exploration, and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of evaluated oil and natural gas properties are subject to a quarterly full cost ceiling test. At December 31, 2011 the ceiling test value of our reserves was calculated based on the first day average of the 12-months ended December 31, 2011 of the WTI spot price of $96.19 per barrel, adjusted by lease or field for quality, transportation fees, and regional price differentials, and the first day average of the 12-months ended December 31, 2011 of the Henry Hub price of $4.12 per Mmbtu, adjusted by lease or field for energy content, transportation fees, and regional price differentials. Using these prices, our net book value of oil and natural gas properties at December 31, 2011, did not exceed the ceiling amount. At December 31, 2010 the ceiling test value of our reserves was calculated based on the first day average of the 12-months ended December 31, 2010 of the WTI spot price of $79.43 per barrel, adjusted by lease or field for quality, transportation fees, and regional price differentials, and the first day average of the 12-months ended December 31, 2010 of the Henry Hub price of $4.38 per Mmbtu, adjusted by lease or field for energy content, transportation fees, and regional price differentials. Using these prices, our net book value of oil and natural gas properties at December 31, 2010, did not exceed the ceiling amount. 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 of the 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 of the Henry Hub price of $3.87 per Mmbtu in accordance with SEC Release No. 33-8995, *Modernization of Oil and Gas Reporting*. As a result, we recorded a full cost ceiling test impairment before income taxes of approximately $106 million and $65 million after taxes. We recorded a full cost ceiling test impairment before income taxes of approximately $1.7 billion at March 31, 2009, at which time the WTI posted price was $49.66 per barrel for oil and the Henry Hub spot market price was $3.63 per Mmbtu for natural gas.

Capitalized costs of our evaluated and unevaluated properties at December 31, 2011, 2010 and 2009 are summarized as follows:

	December 31,		
	2011	**2010**	**2009**
		(In thousands)	
Oil and natural gas properties (full cost method):			
Evaluated	$ 10,509,954	$ 7,520,446	$ 5,984,765
Unevaluated	2,502,435	2,387,037	2,512,453
Gross oil and natural gas properties	13,012,389	9,907,483	8,497,218
Less accumulated depletion	(5,598,420)	(4,774,579)	(4,329,485)
Net oil and natural gas properties	$ 7,413,969	$ 5,132,904	$ 4,167,733

Table of Contents

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

	Years Ended December 31,		
	2011	**2010**	**2009**
Production:			
Natural gas Mmcf			
Haynesville Shale	243,648	153,813	77,117
Eagle Ford Shale	42,508	15,047	6,688
Elm Grove / Caspiana	18,803	23,324	34,254
Other	6,219	42,354	54,237
Total	311,178	234,538	172,296
Crude oil MBbl			
Haynesville Shale			
Eagle Ford Shale	4,596	893	124
Elm Grove / Caspiana	72	83	133
Other	47	292	1,263
Total	4,715	1,268	1,520
Natural gas liquids MBbl			
Haynesville Shale			
Eagle Ford Shale	2,839	660	
Elm Grove / Caspiana			
Other	4	21	290
Total	2,843	681	290
Production:			
Natural gas equivalent Mmcfe[1]	356,526	246,232	183,156
Average daily production Mmcfe[1]	977	675	502
Average price per unit:[2]			
Natural gas price Mcf	$ 3.87	$ 4.18	$ 3.69
Crude oil price Bbl	89.75	76.98	56.15
Natural gas liquids price Bbl	49.89	38.03	28.20
Natural gas equivalent price Mcfe[1]	4.96	4.49	3.99
Average cost per Mcfe:			
Production:			
Lease operating	$ 0.17	$ 0.26	$ 0.43
Workover and other	0.05	0.07	0.02
Taxes other than income	0.18	0.04	0.31
Gathering, transportation and other	0.49	0.40	0.44

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

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

Table of Contents

The 2011, 2010 and 2009 average oil, natural gas, and natural gas liquids sales prices above do not reflect the impact of cash paid on, or cash received from, settled derivative contracts as these amounts are reflected as "*Net gain on derivative contracts*" in the consolidated statements of operations, consistent with our decision not to elect hedge accounting. Including this impact 2011, 2010 and 2009 average crude oil sales prices were $89.03, $76.90 and $58.86 per Bbl and average natural gas sales prices were $4.76, $5.22 and $5.83 per Mcf. During 2010 we began hedging a portion of our natural gas liquids production for the first time. Including the impact of these hedges, our average natural gas liquids sales price for 2011 and 2010 was $49.37 and $37.10 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. Many of these companies explore for, produce and market oil and natural gas, as well as carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, obtaining sufficient availability of drilling and completion equipment and services, obtaining purchasers and transporters of the oil and natural gas we produce and hiring and retaining key employees. There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States and the states in which our properties are located. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation.

Other Business Matters

Markets and Major Customers

In 2011, none of the individual purchasers of our production accounted for in excess of 10% of our total sales. Four individual purchasers of our production collectively represented approximately 28% of our total sales. In 2010, none of the individual purchasers of our production accounted for in excess of 10% of our total sales. Three individual purchasers of our production each accounted for approximately 9% of our total sales, collectively representing approximately 27% of our total sales. In 2009, two individual purchasers of our production each accounted for in excess of 10% of our total sales, collectively representing 25% of our total sales. 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, oil and 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. Demand for oil also tends to improve in advance of the winter heating oil and summer driving months. 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.

Table of Contents

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

Environmental Regulations

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

Table of Contents

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, underground injection of waste material and the regulation of hydraulic fracturing. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have a material adverse effect on our financial condition and results of operations.

Comprehensive Environmental Response, Compensation and Liability Act and Hazardous Substances

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

The Solid Waste Disposal Act and Waste Management

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

The Clean Water Act, wastewater and storm water discharges

Our operations are also subject to the federal Clean Water Act and analogous state laws. Under the Clean Water Act, the EPA has adopted regulations concerning discharges of storm water runoff. This program requires covered facilities to obtain individual permits, or seek coverage under a general permit. Some of our properties may require permits for discharges of storm water runoff and, as part of our overall evaluation of our current operations, we will apply for storm water discharge permit coverage and updating storm water discharge management practices at some of our facilities. We

Table of Contents

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 (SDWA) and the Underground Injection Control (UIC) program promulgated under the SDWA 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 SDWA 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. Currently, hydraulic fracturing that does not use diesel fuel is not subject to regulation under the SDWA. Certain states have adopted and are considering laws that require the disclosure of the chemical constituents in hydraulic fracturing fluids. In addition, in 2010, the EPA began conducting a study on the environmental effects of hydraulic fracturing. The study is expected to be completed in 2012. Additional disclosure requirements could result in increased regulation, operational delays, and increased operating costs that could make it more difficult to perform hydraulic fracturing.

The Clean Air Act

The federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed and continues to develop stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Our operations, or the operations of service companies engaged by us, may in certain circumstances and locations be subject to permits and restrictions under these statutes for emissions of air pollutants.

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, governments have begun adopting domestic and international climate change regulations that requires reporting and reductions of the emission of greenhouse gases. 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. Internationally, the United Nations Framework Convention on Climate Change, and the Kyoto Protocol address greenhouse gas emissions, and several countries including those comprising the European Union have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs or have begun considering adopting greenhouse gas regulatory programs.

The EPA has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and required reporting by regulated facilities by March 2011 and annually thereafter. In November 2010, the EPA issued a final rule requiring companies to report certain greenhouse gas emissions from oil and natural gas facilities. On July 19, 2011, the EPA amended the oil and natural gas facility greenhouse gas reporting rule to require reporting beginning in September 2012. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding serves as a first step to issuing regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities. On July 28, 2011, the EPA proposed four new regulations that, if finalized, could affect our business. The regulations would establish new source performance standards for volatile organic compounds (VOCs) and sulfur dioxide and establish an air toxic standard for oil and natural gas production, transmission, and storage. The proposed regulations would apply to wells that are hydraulically fractured, or refractured, and to storage tanks and other equipment, and limit methane emissions from those sources. The EPA is in the process of accepting public comments on the proposed regulations, and expects to take final action by April 3, 2012.

In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions control systems, and additional compliance costs.

The National Environmental Policy Act

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

Threatened and endangered species, migratory birds, and natural resources

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

Table of Contents

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 and in some cases, criminal penalties.

Hazard communications and community right to know

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

Occupational Safety and Health Act

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

Employees

As of December 31, 2011, we had 862 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, and 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 practical after such reports are filed with, or furnished to, the SEC. You may also read and copy any document we file with the SEC at the SEC's Public Reference Room at 100 H Street, N.E., Washington, D.C. 20549. You may obtain information on the operations 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.

Table of Contents

ITEM 1A. RISK FACTORS

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 have access to 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 shale formations, some of which are new and emerging, using horizontal drilling and completion techniques. The results of our drilling program using these techniques may be subject to more uncertainties than conventional drilling programs, especially in areas that are new and emerging. These uncertainties could result in an inability to meet our expectations for reserves and production.

The results of our drilling in new or emerging formations, such as the Lower Bossier Shale, the Permian Basin and certain areas of the Eagle Ford Shale, are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history and consequently we are less able to predict future drilling results in these areas. In addition, the use of horizontal drilling and completion techniques used in all of our shale formations involve certain risks and complexities that do not exist in conventional wells. Our experience, as well as that of the industry as a whole, is significant but still growing in this area. 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.

If our drilling results are less than anticipated our investment in these areas may not be as attractive as we anticipate and we could incur material write downs 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, 2011, we own leasehold interests in approximately 345,000 net acres in areas we believe are prospective for the Haynesville Shale, approximately 332,000 net acres in areas we believe are prospective for the Eagle Ford Shale, approximately 150,000 net acres in areas we believe are prospective for the Lower Bossier Shale and approximately 325,000 net acres in areas we believe are prospective for the Permian Basin. A large portion of our 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, many 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. Further, some of our 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.

Table of Contents

Availability of adequate gathering systems and transportation take-away capacity may hinder our access to suitable oil and natural gas markets or delay our production.

Our ability to bring natural gas, natural gas liquids and crude oil production to market depends on a number of factors including the availability and proximity of pipelines and processing facilities. The recent growth in production in the Eagle Ford Shale, especially of oil and natural gas liquids production, has limited the availability of transportation take-away capacity for these products. If we are unable to obtain adequate amounts of take-away capacity to meet our growing production levels, we may have to delay initial production or shut in our wells awaiting a pipeline connection or capacity and/or sell our production at significantly lower prices than those quoted on NYMEX or than we currently project, which could adversely affect our results of 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 may impact our ability to access additional capital. 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;
- social unrest and political instability, particularly in oil and natural gas producing regions, such as the Middle East, and 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;
- 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.

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 $3.2 billion as of December 31, 2011. 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

Table of Contents

industry in which we operate. 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 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 or sell assets. 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.

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 oil and natural gas 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. 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 oil and natural gas 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 Annual 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 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.

Table of Contents

At December 31, 2011, approximately 61% of our estimated reserves were classified as proved undeveloped. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of these oil and natural gas reserves and the costs associated with development of these reserves in accordance with SEC regulations, actual capital expenditures will likely vary from estimated capital expenditures, development may not occur as scheduled and actual results may not be as estimated.

We 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 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. In addition current and prospective employees may experience uncertainty about their future roles with the Company as our operations are integrated into BHP Billiton Limited. These conditions, may materially and adversely affect our ability to attract and retain qualified personnel. The loss of the services of any of our 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, 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 that may have larger numbers of personnel and facilities, more expertise and, in some cases, access to greater financial resources. 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, results of operations and cash flows. Such risks and hazards include:

- human error, accidents, labor force and other factors beyond our control that may cause personal injuries or death to persons and destruction or damage to equipment and facilities;
- blowouts, fires, hurricanes, pollution and equipment failures that may result in damage to or destruction of wells, producing formations, production facilities and equipment;
- unavailability of materials and equipment;
- engineering and construction delays;
- unanticipated transportation costs and delays;
- unfavorable weather conditions;

Table of Contents

- hazards resulting from unusual or unexpected geological or environmental conditions;
- environmental regulations and requirements;
- accidental leakage of toxic or hazardous materials, such as petroleum liquids or drilling fluids, into the environment;
- hazards resulting from the presence of hydrogen sulfide (H_2S) or other contaminants in gas we produce;
- changes in laws and regulations, including laws and regulations applicable to oil and natural gas activities or markets for the oil and natural gas produced;
- fluctuations in supply and demand for oil and natural gas causing variations of the prices we receive for our oil and natural gas production; and
- the availability of alternative fuels and the price at which they become available.

As a result of these risks, expenditures, quantities and rates of production, revenues and operating costs may be materially adversely affected and may differ materially from those anticipated by us.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Companies that explore for and develop, produce, sell and transport oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax and environmental, health and safety laws and the corresponding regulations, and are required to obtain various permits and approvals from federal, state and local agencies. If these permits are not issued or unfavorable restrictions or conditions are imposed on our drilling activities, we may not be able to conduct our operations as planned. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

- water discharge and disposal permits for drilling operations;
- drilling bonds;
- drilling permits;
- reports concerning operations;
- air quality, noise levels and related permits;
- spacing of wells;
- rights-of-way and easements;

unitization and pooling of properties;

pipeline construction;

gathering, transportation and marketing of oil and natural gas;

taxation; and

waste transport and disposal permits and requirements.

Failure to comply with these laws may result in the suspension or termination of operations and subject us to liabilities under administrative, civil and criminal penalties. Compliance costs can be significant. Moreover, these laws or the enforcement thereof could change in ways that substantially increase the costs of doing business. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our business, financial condition and results of

Table of Contents

operations. Under these laws and other environmental health and safety laws and regulations, we could be held liable for personal injuries, property damage (including site clean-up and restoration costs) and other damages. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties, including the assessment of natural resource damages. Some laws and regulations may impose strict as well as joint and several liability for environmental contamination, which could subject us to liability for the conduct of others or for our own actions that were in compliance with all applicable laws at the time such actions were taken. Environmental and other governmental laws and regulations also increase the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects. Part of the regulatory environment in which we operate includes, in some cases, federal requirements for performing or preparing environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to the regulation by oil and natural gas-producing states relating to conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. Delays in obtaining regulatory approvals or necessary permits, the failure to obtain a permit or the receipt of a permit with excessive conditions or costs could have a material adverse effect on our ability to explore on, develop or produce our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability.

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

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. We routinely apply hydraulic-fracturing techniques in our drilling and completion programs. While hydraulic fracturing has historically been regulated by state oil and natural-gas commissions, the EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities involving diesel under the Safe Drinking Water Act (SDWA). The EPA has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, legislation has been introduced before Congress, called the Fracturing Responsibility and Awareness of Chemicals Act, to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process.

Certain states, including Texas, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas (RCT) and the public of certain information regarding the components used in the hydraulic-fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

Table of Contents

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic-fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic-fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic-fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. In addition, the U.S. Department of Energy is conducting an investigation into practices which the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Additionally, certain members of the Congress have called for further agency studies. Among these are the following: the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the U.S. Securities and Exchange Commission to investigate the natural-gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural-gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural-gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These on-going or proposed studies, depending on their scope and results, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory programs.

Further, on July 28, 2011, the EPA issued proposed rules that would subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA proposed rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion techniques developed in EPA's Natural Gas STAR program along with pit flaring of gas not sent to the gathering line. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under NESHAPS include maximum achievable control technology (MACT) standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. Final action on the proposed rules is expected no later than April 3, 2012.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs and time, which could adversely affect our business.

Possible regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and natural gas.

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, governments have begun adopting domestic and international climate change regulations that requires reporting and reductions of the emission of greenhouse gases. 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. Internationally, the United Nations Framework Convention on Climate Change, and the Kyoto Protocol address greenhouse gas emissions, and several countries including those comprising the

Table of Contents

European Union have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs or have begun considering adopting greenhouse gas regulatory programs.

The EPA has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and required reporting by regulated facilities by March 2011 and annually thereafter. In November 2010, the EPA issued a final rule requiring companies to report certain greenhouse gas emissions from oil and natural gas facilities. On July 19, 2011, the EPA amended the oil and natural gas facility greenhouse gas reporting rule to require reporting beginning in September 2012. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding serves as a first step to issuing regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities. On July 28, 2011, the EPA proposed four new regulations that, if finalized, could affect our business. The regulations would establish new source performance standards for volatile organic compounds (VOCs) and sulfur dioxide and establish an air toxic standard for oil and natural gas production, transmission, and storage. The proposed regulations would apply to wells that are hydraulically fractured, or refractured, and to storage tanks and other equipment, and limit methane emissions from those sources. The EPA is in the process of accepting public comments on the proposed regulations, and expects to take final action by April 3, 2012.

In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions control systems, and additional compliance costs.

Recent federal legislation could have an adverse impact on our ability to use derivative instruments to reduce the effects of commodity prices, interest rates and other risks associated with our business.

Historically, we have entered into a number of commodity derivative contracts in order to hedge a portion of our oil and natural gas production and, periodically, interest expense. On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act which requires the SEC, the Commodity Futures Trading Commission (or CFTC) to promulgate rules and regulations implementing the new legislation. The CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and to establish minimum capital requirements, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the Dodd-Frank Act. The Dodd-Frank Act may also require compliance with margin requirements and with certain clearing and trade-execution requirements in connection with certain derivative activities, although the application of those provisions is uncertain at this time. The legislation may also require the counterparties to our commodity derivative contracts to spinoff some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty, or cause the entity to comply with the capital requirements, which could result in increased costs to counterparties such as us.

Table of Contents

The new legislation and any new regulations could significantly increase the cost of some commodity derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of some commodity derivative contracts, reduce the availability of some derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing commodity derivative contracts and potentially increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the new legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. If the new legislation and regulations result in lower commodity prices, our revenues could be adversely affected. Any of these consequences could adversely affect our business, financial condition and results of operations.

The proposed United States federal budget for fiscal year 2012 and other pending legislation contain certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

The Obama administration's budget proposal for fiscal year 2012 contains numerous proposed tax changes, and legislation has been introduced that would enact many of these proposed changes. The proposed budget and legislation would repeal many tax incentives and deductions that are currently used by U.S. oil and gas companies and impose new taxes. Among others, the provisions include: elimination of the ability to deduct intangible drilling costs fully in the year incurred; repeal of the percentage depletion deduction for oil and gas properties; repeal of the domestic manufacturing tax deduction for oil and gas companies; increase in the geological and geophysical amortization period for independent producers; and implementation of a fee on non-producing leases located on federal lands. Should some or all of these provisions become law, our taxes could increase, potentially significantly, after net operating losses are exhausted, which would have a negative impact on our results of operations and cash flows. This also could reduce our drilling activities. We do not know the ultimate impact these proposed changes may have on our business.

We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and natural gas activities.

We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

- personal injury;
- bodily injury;
- third party property damage;
- medical expenses;
- legal defense costs;
- pollution in some cases;
- well blowouts in some cases; and
- workers compensation.

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

33

premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations and cash flows. There can be no assurance that the insurance coverage that we maintain will be sufficient to cover every claim made against us in the future.

Title to the properties in which we have an interest may be impaired by title defects.

We generally obtain title opinions on significant properties that we drill or acquire. However, there is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. Generally, under the terms of the operating agreements affecting our properties, any monetary loss is to be borne by all parties to any such agreement in proportion to their interests in such property. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

Assets we acquire may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities.

We have grown significantly through acquisitions of exploration and production companies, producing properties and undeveloped and unevaluated leaseholds. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, future oil and natural gas prices, operating and capital costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired companies and properties; however, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. We are generally not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. As a result of these factors, the value of properties we acquire may be less than we expect, less than we paid, and we may not acquire oil and natural gas properties that contain economically recoverable reserves.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns.

We require significant amounts of undeveloped leasehold acreage to further our development efforts. Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, there is no assurance that our leasehold acreage will be profitably developed, that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target results are dependent upon the current and future market prices for oil and natural gas, costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost.

In addition, we may not be successful in controlling our drilling and production costs to improve our overall return. The cost of drilling, completing and operating a well is often uncertain and cost factors can adversely affect the economics of a project. We cannot predict the cost of drilling and

Table of Contents

completing a well, and we may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents and shortages or delays in the availability of drilling and completion equipment and services;
- adverse weather conditions, including hurricanes; and
- compliance with governmental requirements.

We depend on the skill, ability and decisions of third party operators of the oil and natural gas properties in which we have a non-operated working interest.

The success of the drilling, development and production of the oil and natural gas properties in which we have or expect to have a non-operating working interest is substantially dependent upon the decisions of such third-party operators and their diligence to comply with various laws, rules and regulations affecting such properties. The failure of any third-party operator to make decisions, perform their services, discharge their obligations, deal with regulatory agencies, and comply with laws, rules and regulations, including environmental laws and regulations in a proper manner with respect to properties in which we have an interest could result in material adverse consequences to our interest in such properties, including substantial penalties and compliance costs. Such adverse consequences could result in substantial liabilities to us or reduce the value of our properties, which could negatively affect our results of operations.

We do not own all of the land on which our transportation pipelines and gathering and treating systems are located, which could disrupt our operations.

We do not own all of the land on which our gathering and treating systems have been constructed, and we are therefore subject to the possibility of increased costs to retain necessary land use. We obtain the rights to construct and operate our gathering and treating systems on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations and financial condition.

We may be required to take non-cash asset write downs if oil and natural gas prices decline.

We may be required under full cost accounting rules to write down the carrying value of oil and natural gas properties if oil and natural gas prices decline or if there are substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our exploration results. We utilize the full cost method of accounting for oil and natural gas exploration and development activities. Under full cost accounting, we are required by SEC regulations to perform a ceiling test each quarter. The ceiling test is an impairment test and generally establishes a maximum, or "ceiling," of the book value of oil and natural gas properties that is equal to the expected after tax present value (discounted at 10%) of the future net cash flows from proved reserves, including the effect of cash flow hedges when hedge accounting is applied, calculated using the unweighted arithmetic average of the first day of each month for the 12-month period ending at the balance sheet date. If the net book value of oil and natural gas properties (reduced by any related net deferred income tax liability and asset retirement obligation) exceeds the ceiling limitation, SEC regulations require us to impair or "write down" the book value of our oil and natural gas properties.

Table of Contents

As of December 31, 2011, our net book value of oil and natural gas properties did not exceed our ceiling amount using the WTI unweighted 12-month average price $96.19 per Bbl for oil and natural gas liquids and the Henry Hub unweighted 12-month average of $4.12 per Mmbtu for natural gas. As of December 31, 2010, our net book value of oil and natural gas properties did not exceed our ceiling amount using the WTI unweighted 12-month average price $79.43 per Bbl for oil and natural gas liquids and the Henry Hub unweighted 12-month average of $4.38 per Mmbtu for natural gas. As of December 31, 2009, using $57.65 per Bbl for oil and $3.87 per Mmbtu for natural gas, our net book value of oil and natural gas properties exceeded the ceiling amount. As a result, we recorded a full cost ceiling test impairment before income taxes of approximately $106 million, $65 million after taxes. We also recorded full cost ceiling test impairments before tax at March 31, 2009 of $1.7 billion. As ceiling test computations depend upon the calculated unweighted arithmetic average prices, it is impossible to predict the likelihood, timing and magnitude of any future impairments. Depending on the magnitude, a ceiling test write down could negatively affect our results of operations.

Costs associated with unevaluated properties, which were $2.5 billion at December 31, 2011, are not initially subject to the ceiling test limitation. Rather, we assess all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value based upon our intentions with respect to drilling on such properties, the remaining lease term, geological and geophysical evaluations, drilling results, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. These factors are significantly influenced by our expectations regarding future commodity prices, development costs, and access to capital at acceptable cost. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization and the ceiling test limitation. Accordingly, a significant change in these factors, many of which are beyond our control, may shift a significant amount of cost from unevaluated properties into the full cost pool that is subject to amortization and the ceiling test limitation.

Our results of operations could be adversely affected as a result of non-cash goodwill impairments.

In conjunction with the recording of the purchase price allocation for several of our acquisitions, we recorded goodwill which represents the excess of the purchase price paid by us for those companies plus liabilities assumed, including deferred taxes recorded in connection with the respective acquisitions, over the estimated fair market value of the tangible net assets acquired.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is included in Item 1. *Business* and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our business, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our business. We believe that our properties are adequate and suitable for us to conduct business in the future.

ITEM 3. LEGAL PROCEEDINGS

A description of our legal proceedings is included in Item 8. *Consolidated Financial Statements and Supplementary Data* Note *7, "Commitments and Contingencies,"* and is incorporated herein by reference.

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

Subsequent to our execution of the Merger Agreement discussed above, we and the members of our board prior to the BHP Merger were named as defendants in purported class action lawsuits brought by our stockholders challenging the proposed transaction (the Stockholder Actions). The Stockholder Actions were filed in: the Court of Chancery of the State of Delaware, Astor BK Realty Trust v. Petrohawk Energy Corp., et al., C.A. No. 6675-CS, Grossman v. Petrohawk Energy Corp., et al., C.A. No. 6688-CS, Marina Gincherman, IRA v. Petrohawk Energy Corp., et al., C.A. No. 6700, and Binkowski v. Petrohawk Energy Corp., et al., C.A. No. 6706; in the District of Harris County, Texas, Iron Workers District Counsel of Tennessee Valley & Vicinity Pension Plan v. Petrohawk Energy Corp., et al., C.A. No. 42124, Iron Workers Mid-South Pension Fund v. Petrohawk Energy Corp., et al., C.A. No. 42590, and L.A. Murphy v. Wilson, et al., C.A. No. 42772; and in United States District Court for the Southern District of Texas, Rob Barrett v. Floyd C. Wilson, et al., C.A. No. 4:11-cv-02852. The Stockholder Actions seek certification of a class of our former stockholders and generally allege, among other things, that: (i) each member of the board prior to the BHP Merger breached his fiduciary duties in connection with the transactions contemplated by the Merger Agreement by failing to maximize stockholder value, agreeing to preclusive deal protection provisions, and failing to protect against conflicts of interest; (ii) we aided and abetted our directors' purported breaches of their fiduciary duties; and/or (iii) the Guarantor, Parent and Purchaser parties aided and abetted the purported breaches of fiduciary duties by our directors. The Stockholder Actions seek, among other relief, rescission of the consummated transactions, damages, and attorneys' fees and costs.

Barrett has been settled and dismissed by the Southern District of Texas with prejudice. Guarantor agreed to pay $125,000 to Plaintiff's counsel for the attorney's fees and expenses incurred. On August 11, 2011, the parties to the Stockholder Actions entered into a Memorandum of Understanding wherein the Defendants acknowledged that the Stockholder Actions were a causal factor leading to the issuance of certain supplemental disclosures included in the Company's supplemental form 14D-9, filed on August 10, 2011. The parties executed a Stipulation and Agreement of Compromise, Settlement, and Release ("Stipulation"), dated November 30, 2011, that provides that, subject to court approval, the Stockholder Actions shall be dismissed on the merits with prejudice. The Stipulation further includes an agreement to pay, subject to court approval, $775,000 to Plaintiffs' counsel for their attorneys' fees and reimbursement of expenses. On December 30, 2011, the court preliminarily approved the Stipulation. The court scheduled a settlement hearing, which will be held on Monday, March 19, 2012, in part to determine whether the court should grant final approval of the Stipulation.

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

In 2008, the United States Fish and Wildlife Service (USFWS) opened an investigation into the activities of Hawk Field Services and the Company in the Fayetteville Shale play. The investigation focused on the pipeline stream crossings and potential impacts on the Speckled Pocketbook. On April 22, 2009, we received a letter from the United States Attorney's Office for the Eastern District of Arkansas and the Environmental Crimes Section of the United States Department of Justice notifying us that we were under criminal investigation for alleged violations of the Federal Clean Water Act and the Federal Endangered Species Act with respect to the endangered Speckled Pocketbook. Hawk Field Services sold its gathering and treating assets serving the Fayetteville Shale in conjunction with the Company's disposition of its Fayetteville Shale natural gas properties and, as a consequence, neither the Company nor Hawk Field Services currently have ongoing operations in Arkansas. The Company and the United States Department of Justice entered into a plea agreement and Hawk Field Services has pleaded guilty to three misdemeanor counts of violating the Endangered Species Act. Under the plea agreement, the Company agreed to pay a $350,000 fine and contribute $150,000 toward environmental conservation efforts in the Fayetteville Shale area. The United States District Court for the Eastern District of Arkansas accepted the plea agreement on September 14, 2011, and the Company paid the fine and contribution during the third quarter of 2011.

We are also involved in natural gas exploration in the Haynesville Shale in Louisiana. On July 27, 2009, we received a Cease and Desist Order from the Corps of Engineers alleging violations of the Federal Clean Water Act for unauthorized land clearing and discharges of dredged or fill material into wetlands associated with the development of three gas wells in Bossier, Caddo, and Red River Parishes in Louisiana. On approximately December 14, 2009, the EPA informed us that it would be acting as lead enforcement agency regarding these alleged violations. We have identified additional well sites on which work may have been conducted without required authorizations under the Clean Water Act. Information related to these well sites has been disclosed to the Corps of Engineers and the EPA. We are working with Corps to obtain the necessary authorizations for each of these well sites. The Company has negotiated a consent agreement and final order with EPA, whereby the Company has agreed to pay a $177,500 administrative penalty to resolve all liability for the alleged violations, which the Company paid in the first quarter of 2011.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

Table of Contents

PART II.

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

We are a wholly owned subsidiary of BHP Billiton Limited and there is no market for our common stock.

ITEM 7. MANAGEMENT'S NARRATIVE ANALYSIS OF THE RESULTS OF OPERATIONS

The following discussion is intended to assist in understanding our results of operations and our current financial condition. Our consolidated financial statements and the accompanying notes included elsewhere in this Annual Report on Form 10-K contain additional information that should be referred to when reviewing this material.

Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, including those discussed below, which could cause actual results to differ from those expressed.

Overview

We are an oil and natural gas company engaged in the exploration, development and production of predominately natural gas properties located in the United States. As further discussed in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 1 "*Summary of Significant Events and Accounting Policies,*" on August 25, 2011, BHP Billiton Limited, a corporation organized under the laws of Victoria, Australia, acquired 100% of our outstanding shares of common stock through the merger of a wholly owned subsidiary of BHP Billiton Petroleum (North America) Inc., a Delaware corporation and wholly owned subsidiary of BHP Billiton Limited, with and into Petrohawk, with Petrohawk continuing as the surviving entity. At the date of this report, Petrohawk remains an indirect, wholly owned subsidiary of BHP Billiton Limited.

Our oil and natural gas properties are concentrated in three premier domestic shale plays that we believe have decades of future development potential. We organize our oil and natural gas production operations into two principal regions: the Mid-Continent, which includes our Louisiana, East Texas and West Texas properties; and the Western, which includes our South Texas properties.

Historically, we have grown through acquisitions of proved oil and natural gas reserves and undeveloped acreage, with a focus on properties within our core operating areas that we believe have significant development and exploration opportunities. In the past few years, we significantly expanded our leasehold position in resource plays, particularly in the Haynesville Shale play in Northern Louisiana and East Texas, the Eagle Ford Shale play in South Texas and in the Permian Basin in West Texas, where we believe we can apply our technical experience and economies of scale to increase production and proved reserves. The vast majority of our acreage in these plays is currently undeveloped. Typically, the leases we own require that production in paying quantities be established on units under the lease within the primary lease term (generally three to five years) or the lease will expire.

At December 31, 2011, our estimated total proved oil and natural gas reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell, were approximately 4,044 Bcfe, consisting of 3,355 Bcf of natural gas, 58 MMBbls of oil and 57 MMBbls of natural gas liquids. Approximately 39% of our proved reserves were classified as proved developed. We maintain operational control of approximately 78% of our proved reserves. Production for the fourth quarter of 2011 averaged 1,086 Mmcfe/d. Full year 2011 production averaged 977 Mmcfe/d compared to 675 Mmcfe/d in 2010. Our total operating revenues for 2011 were approximately $2.1 billion.

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

Our 2011 capital budget emphasized the development of our extensive condensate-rich properties, largely in the Eagle Ford Shale, and shifted away from dry gas development in our core areas. Our drilling and completion budget for 2011 was based on our objective of accelerating development of certain areas of our Eagle Ford Shale position and our desire to reduce capital allocated to pure natural gas drilling once our Haynesville Shale lease-holding activities were effectively completed. During late 2010 and early 2011, we began acquiring acreage in the Permian Basin of West Texas. We have acquired or committed to acquire approximately 325,000 net acres in the Midland and Delaware Basins.

On December 22, 2011, we completed the acquisition of CEU Hawkville, LLC (CEU Hawkville), in which we purchased all of the outstanding membership interests in CEU Hawkville for $90 million, before customary closing adjustments. CEU Hawkville's assets consist primarily of interests in oil and natural gas properties in the Hawkville Field of the Eagle Ford Shale. The transaction had an effective date of October 1, 2011. Upon the closing of the transaction, we changed the name of CEU Hawkville LLC to South Texas Shale LLC.

On July 1, 2011, we along with our subsidiaries Hawk Field Services and EagleHawk, closed previously announced transactions with KM Gathering and Eagle Gathering, each of which is an affiliate of Kinder Morgan, a publicly traded master limited partnership, in which Hawk Field Services transferred (i) its remaining 50% membership interest in KinderHawk to KM Gathering and (ii) a 25% interest in EagleHawk to Eagle Gathering, in exchange for aggregate cash consideration of approximately $836 million. In conjunction with the closing of these transactions, our remaining capital commitment to KinderHawk was relieved. The remaining capital commitment was approximately $41.4 million as of July 1, 2011. Our commitment to deliver certain minimum annual quantities of natural gas through the Haynesville gathering system through May 2015 was not relieved in the transfer of our remaining 50% membership interest in KinderHawk.

EagleHawk, which is managed by Hawk Field Services, engages in the natural gas midstream business in the Eagle Ford Shale in South Texas. At the closing of the transactions, EagleHawk holds our gathering and treating assets and business serving our Hawkville and Black Hawk Fields in the Eagle Ford Shale. EagleHawk has agreements with us covering gathering and treating and pursuant to which we dedicate our production from our Eagle Ford Shale leases.

On March 11, 2011 an independent third party exercised their option to acquire a portion of our interest in oil and natural gas properties in the Black Hawk Field of the Eagle Ford Shale. Proceeds from this transaction were approximately $74 million and were recorded as a reduction to the carrying value of our full cost pool with no gain or loss recorded. The effective date of the transaction was March 1, 2011. On January 7, 2011, we completed the sale of our midstream assets in the Fayetteville Shale for approximately $75 million in cash, before customary closing adjustments. The transaction had an effective date of October 1, 2010.

On May 20, 2011, we issued $600 million aggregate principal amount of our 6.25% senior notes due 2019. The net proceeds from the sale of the 2019 Notes were approximately $589 million (after deducting offering fees and expenses). The proceeds from the 2019 Notes were utilized to repay borrowings outstanding under our senior revolving credit facility and for working capital for general corporate purposes.

On January 31, 2011, we completed the issuance of an additional $400 million aggregate principal amount of our 7.25% senior notes due 2018. The net proceeds from the sale of the additional 2018

Table of Contents

Notes were approximately $400.5 million (after deducting offering fees and expenses). A portion of the proceeds of the additional 2018 Notes were utilized to redeem our $275 million 7.125% senior notes due 2012.

On April 29, 2011, we amended our Senior Credit Agreement, the Fifth Amended and Restated Senior Revolving Credit Agreement, as amended on November 8, 2010 and December 22, 2010, by entering into the Third Amendment to the Fifth Amended and Restated Senior Revolving Credit Agreement, among us, each of the lenders from time to time party thereto (the Lenders), BNP Paribas, as administrative agent for the Lenders, Bank of America, N.A. and Bank of Montreal as co-syndication agents for the Lenders, and JPMorgan Chase Bank, N.A. and Wells Fargo Bank, N.A., as co-documentation agents for the Lenders. Among other things, the Third Amendment: (a) increased our borrowing base to $1.9 billion, $1.8 billion of which related to our oil and natural gas properties and $100 million of which related to our midstream assets (limited as described below); (b) reduced interest rates such that amounts outstanding under the Senior Credit Agreement will bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.50% to 2.50% for Eurodollar loans or at specified margins over the Alternate Base Rate (ABR) of 0.50% to 1.50% for ABR loans, which margins will fluctuate based on the utilization of the facility; (c) extended the maturity date of the facility from July 1, 2014 to July 1, 2016; and (d) increased the amount of the facility from $2.0 billion to $2.5 billion.

On July 1, 2011, we amended our Senior Credit Agreement, as amended on November 8, 2010, December 22, 2010 and April 29, 2011, by entering into the Fourth Amendment to the Fifth Amended and Restated Senior Revolving Credit Agreement, among us and the Lenders. Among other things, the Fourth Amendment permitted Hawk Field Services to convey its Eagle Ford Shale gathering and treating business in South Texas to EagleHawk; transfer a 25% equity interest in EagleHawk to Kinder Morgan; enter into and abide by the terms of the operative documents governing the formation and operation of EagleHawk, and reaffirmed the oil and gas component of our borrowing base under the Senior Credit Agreement at $1.8 billion, while reducing to zero the midstream component of our borrowing base. The portion of the Senior Credit Agreement's borrowing base which relates to our oil and natural gas properties is redetermined on a semi-annual basis (with us and the lenders each having the right to one annual interim unscheduled redetermination) and adjusted based on our oil and natural gas properties, reserves, other indebtedness and other relevant factors. Our ability to utilize the full amount of our borrowing capacity is influenced by a variety of factors, including redeterminations of our borrowing base, and covenants under our Senior Credit Agreement and our senior unsecured debt indentures. Additionally, our borrowing base is subject to a reduction equal to the product of $0.25 multiplied by the stated principal amount (without regard to any initial issue discount) of any unsecured senior or senior subordinated notes that we may issue. Effective October 3, 2011, we reduced the borrowing capacity under our Senior Credit Agreement from $2.5 billion to $25 million. At December 31, 2011, we had a $3.0 million letter of credit outstanding with a vendor, no borrowings outstanding and $22.0 million of borrowing capacity available under the Senior Credit Agreement. Effective February 1, 2012, the $3.0 million letter of credit was terminated. Refer to Item 8. *Consolidated Financial Statements and Supplementary Data Note 4, "Long-term Debt"* for more details.

Our Senior Credit Agreement contains customary financial and other covenants, including minimum working capital levels (the ratio of current assets plus the unused commitment under the Senior Credit Agreement to current liabilities) of not less than 1.0 to 1.0 and minimum coverage of interest expenses (as defined in the Senior Credit Agreement) of not less than 2.5 to 1.0. We are subject to additional covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. Effective September 27, 2011, our compliance obligations with respect to the aforementioned minimum working capital level and minimum coverage of interest expense covenants, as well as our compliance obligations with respect to certain other covenants in the Senior Credit Facility including reserve report and other information delivery, were suspended until March 31, 2012. Additionally, the indentures

Table of Contents

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, under the most restrictive indentures, 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 limits these borrowings to the greater of a fixed sum of, under the most restrictive indentures, $1 billion and 30% of our adjusted consolidated net tangible assets (as defined in all of our indentures), which is largely calculated based upon the discounted future net revenues from our proved oil and natural gas reserves as of the end of each year.

Our cash flows are subject to a number of variables including our level of oil and natural gas production and commodity prices, as well as various economic conditions that have historically affected the oil and natural gas industry. If natural gas prices remain at their current levels for a prolonged period of time or if oil and natural gas prices decline, our ability to fund our capital expenditures, reduce debt, meet our financial obligations and become profitable may be materially impacted. Our primary sources of capital and liquidity have historically been internally generated cash flows from operations, proceeds from asset sales and availability our Senior Credit Agreement. Our future capital resources and liquidity will be from internally generated cash flows from operations and funding from our Parent.

Contractual Obligations

We believe we have a significant degree of flexibility to adjust the level of our future capital expenditures as circumstances warrant. Our level of capital expenditures will vary in future periods depending on the success we experience in our acquisition, developmental and exploration activities, oil and natural gas price conditions and other related economic factors. Currently no sources of liquidity or financing are provided by off-balance sheet arrangements or transactions with unconsolidated, limited-purpose entities. The following table summarizes our contractual obligations and commitments by payment periods as of December 31, 2011.

	Payments Due by Period				
Contractual Obligations	**Total**	**2012**	**2013 - 2014**	**2015 - 2016**	**2017 and Beyond**
			(In thousands)		
6.25% $600 million senior notes[(1)]	$ 600,000	$	$	$	$ 600,000
7.25% $1.2 billion senior notes[(2)]	1,225,000				1,225,000
10.5% $600 million senior notes[(3)]	589,640		589,640		
7.875% $800 million senior notes[(4)]	799,611			799,611	
Interest expense on long-term debt[(5)]	1,247,232	250,629	475,462	278,795	242,346
Deferred premiums on derivatives[(6)]	17,520	17,520			
Rig commitments	302,601	160,406	134,895	7,300	
Gathering and transportation contracts	2,317,461	214,641	453,598	447,433	1,201,789
Pipeline and well equipment	54,935	54,935			
Other commitments[(7)]	30,619	30,619			
Operating leases	34,292	10,887	16,590	5,732	1,083
Total contractual obligations	$ 7,218,911	$ 739,637	$ 1,670,185	$ 1,538,871	$ 3,270,218

(1) On May 20, 2011, we issued $600 million principal amount of our 6.25% senior notes due 2019. See "6.25% Senior Notes" below for more details.

Table of Contents

(2) On August 17, 2010 and January 31, 2011, we issued an initial $825 million principal amount and an additional $400 million principal amount, respectively, of our 7.25% senior notes due 2018. The amount excludes a $6.8 million unamortized premium at December 31, 2011, which was recorded in conjunction with the issuance of the additional 2018 Notes. See "7.25% Senior Notes", below for further details.

(3) Excludes $28.4 million unamortized discount recorded in conjunction with the issuance of the notes and $10.4 million of the notes that were repurchased in the fourth quarter of 2011. See "10.5% Senior Notes" below for further details.

(4) Excludes $0.4 million of the notes that were repurchased in the fourth quarter of 2011. See "7.875% Senior Notes" below for further details.

(5) Future interest expense was calculated based on interest rates and amounts outstanding at December 31, 2011 less required annual repayments.

(6) This amount has been classified as current at December 31, 2011.

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

The contractual obligations table does not include obligations to taxing authorities due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations. In addition, amounts related to our asset retirement obligations are not included in the table above given the uncertainty regarding the actual timing of such expenditures. The total amount of asset retirement obligations at December 31, 2011 is $52.3 million.

On May 21, 2010, we created a joint venture with Kinder Morgan, KinderHawk, which engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville and Lower Bossier Shales. As part of this transaction, we were committed to fund up to an additional $41.4 million, as of June 30, 2011, in capital during 2011 in the event KinderHawk required capital to finance its planned capital expenditures. On July 1, 2011, in conjunction with the closing of the transfer of our remaining 50% membership interest in KinderHawk, the balance of our capital commitment to KinderHawk was relieved. In addition to the capital commitment, we are obligated to deliver to KinderHawk agreed upon minimum annual quantities of natural gas from our operated wells producing from the Haynesville and Lower Bossier Shales in North Louisiana through May 2015, or in the alternative, pay an annual true-up fee to KinderHawk if such minimum annual quantities are not delivered. This obligation is not reflected in the amounts shown in the table above. Our obligation to deliver minimum annual quantities of natural gas to KinderHawk through May 2015 remains in effect following the transfer of our remaining 50% membership interest in KinderHawk on July 1, 2011. We pay to KinderHawk negotiated gathering and treating fees, subject to an annual inflation adjustment factor.

One of our gathering and transportation commitments is our obligation to deliver to KinderHawk agreed upon minimum annual quantities of natural gas from our operated wells producing from the Haynesville and Lower Bossier Shales, within specified acreage in Northwest Louisiana through May 2015, or in the alternative, pay an annual true-up fee to KinderHawk if such minimum annual quantities are not delivered. This minimum annual quantities commitment is not included in the table above. Our obligation to deliver minimum annual quantities of natural gas to KinderHawk through

Table of Contents

May 2015 remains in effect following the transfer of our remaining 50% membership interest in KinderHawk on July 1, 2011. The minimum annual quantities per contract year are as follows:

Contract Year	Minimum Annual Quantity (Bcf)
Year 1 (partial) 2010	81.090
Year 2 2011	152.899
Year 3 2012	238.595
Year 4 2013	324.047
Year 5 2014	368.614
Year 6 (partial) 2015	143.066

These volumes represent 50% of our anticipated production from the specified acreage at the time we entered into the contract. Production from this acreage has been significantly in excess of these volumes during 2011 and 2010, and we have not been obligated to pay a true-up fee to date.

We pay KinderHawk negotiated gathering and treating fees, subject to an annual inflation adjustment factor. The gathering fee at the time we entered into the contract was equal to $0.34 per thousand cubic feet (Mcf) of natural gas delivered at KinderHawk's receipt points. The treating fee is charged for gas delivered containing more than 2% by volume of carbon dioxide. For gas delivered containing between 2% and 5.5% carbon dioxide, the treating fee is between $0.030 and $0.345 per Mcf, and for gas containing over 5.5% carbon dioxide, the treating fee starts at $0.365 per Mcf and increases on a scale of $0.09 per Mcf for each additional 1% of carbon dioxide content. In the event that annual natural gas deliveries are ever less than the minimum annual quantity per contract year set forth in the table above, our true-up fee obligation would be determined by subtracting the quantity delivered from the minimum annual quantity for the applicable contract year and multiplying the positive difference by the sum of the gathering fee in effect on the last day of such year plus the average monthly treating fees for such year. For example, if the quantity of natural gas delivered in 2011 were 50 Bcf less than the minimum annual quantity for such year and the year-end gathering fee was $0.34 per Mcf and the average treating fee for the period was $0.345 per Mcf, the true-up fee would be $34.3 million.

The KinderHawk joint venture is accounted for as a failed sale of in substance real estate in accordance with ASC Subtopic 360-20, *Property, Plant and Equipment Real Estate Sales* (ASC 360-20). The gathering agreement entered into with the formation of KinderHawk, which requires us to deliver natural gas from dedicated leases through the Haynesville Shale gathering and treating system for the life of the leases, constitutes extended continuing involvement under ASC 360-20. Thus, it has been determined that the contribution of our Haynesville Shale gathering and treating system to form KinderHawk is accounted for as a failed sale of in substance real estate. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 2,*"Acquisitions and Divestitures"* for more details regarding the KinderHawk joint venture arrangement and for discussion of the accounting treatment related to the arrangement. As a result of the failed sale, we recorded a financing obligation, representing the proceeds received, under the financing method of real estate accounting. The financing obligation of approximately $1.7 billion as of December 31, 2011, is recorded on the consolidated balance sheets in "*Payable on financing arrangements.*" Reductions to the obligation and the non cash interest on the obligation are tied to the gathering and treating services, as we deliver natural gas through the Haynesville Shale gathering and treating system. Interest and principal are determined based upon the allocable income to Kinder Morgan, and interest is limited up to an amount that is calculated based upon our weighted average cost of debt as of the date of the transaction. Allocable income in excess of the calculated value is reflected as reductions of principal. Interest is recorded in *"Interest expense and other"* on the consolidated statements of operations. This obligation is not reflected in the amounts shown in the table above.

Table of Contents

Our transfer of a 25% interest in EagleHawk to Kinder Morgan, on July 1, 2011, is accounted for as a failed sale of in substance real estate in accordance with ASC 360-20. Due to the gathering agreements which constitute extended continuing involvement under ASC 360-20, that were either entered into in conjunction with the closing of the EagleHawk transaction or assigned to EagleHawk at the closing of the transaction, it has been determined that the transfer of our Eagle Ford Shale gathering and treating systems to EagleHawk is accounted for as a failed sale of in substance real estate. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 2,*"Acquisitions and Divestitures"* for more details regarding the EagleHawk joint venture arrangement and for discussion of the accounting treatment related to the arrangement. As a result of the failed sale, we recorded a financing obligation, representing the proceeds received, under the financing method of real estate accounting. The financing obligation of approximately $141 million as of December 31, 2011, is recorded on the consolidated balance sheets in "*Payable on financing arrangements."* Reductions to the obligation and the non cash interest on the obligation are tied to the gathering and treating services, as we deliver our production through the Eagle Ford Shale gathering and treating systems. Interest and principal are determined based upon the allocable income to Kinder Morgan, and interest is limited up to an amount that is calculated based upon our weighted average cost of debt as of the date of the transaction. Allocable income in excess of the calculated value is reflected as reductions of principal. Interest is recorded in *"Interest expense and other"* on the consolidated statements of operations. This obligation is not reflected in the amounts shown in the table above.

The total balance of our financing obligations as of December 31, 2011, was approximately $1.8 billion, of which approximately $17.6 million was classified as current.

Senior Revolving Credit Facility

On April 29, 2011, we amended our Senior Credit Agreement, the Fifth Amended and Restated Senior Revolving Credit Agreement, as amended on November 8, 2010 and December 22, 2010, by entering into the Third Amendment to the Fifth Amended and Restated Senior Revolving Credit Agreement, among us and the Lenders. Among other things, the Third Amendment: (a) increased our borrowing base to $1.9 billion, $1.8 billion of which related to our oil and natural gas properties and $100 million of which related to our midstream assets (limited as described below); (b) reduced interest rates such that amounts outstanding under the Senior Credit Agreement will bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.50% to 2.50% for Eurodollar loans or at specified margins over the Alternate Base Rate (ABR) of 0.50% to 1.50% for ABR loans, which margins will fluctuate based on the utilization of the facility; (c) extended the maturity date of the facility from July 1, 2014 to July 1, 2016; and (d) increased the amount of the facility from $2.0 billion to $2.5 billion.

On July 1, 2011, we amended our Senior Credit Agreement, as amended on November 8, 2010, December 22, 2010 and April 29, 2011, by entering into the Fourth Amendment to the Fifth Amended and Restated Senior Revolving Credit Agreement, among us, each of the Lenders, BNP Paribas, as administrative agent for the Lenders, Bank of America, N.A. and Bank of Montreal as co-syndication agents for the Lenders, and JPMorgan Chase Bank, N.A. and Wells Fargo Bank, N.A., as co-documentation agents for the Lenders. Among other things, the Fourth Amendment permitted Hawk Field Services to convey its Eagle Ford Shale gathering and treating business in South Texas to EagleHawk; transfer a 25% equity interest in EagleHawk to Kinder Morgan; enter into and abide by the terms of the operative documents governing the formation and operation of EagleHawk, and reaffirmed the oil and gas component of our borrowing base under the Senior Credit Agreement at $1.8 billion, while reducing to zero the midstream component of our borrowing base. The portion of the Senior Credit Agreement's borrowing base which relates to our oil and natural gas properties is redetermined on a semi-annual basis (with us and the lenders each having the right to one annual interim unscheduled redetermination) and adjusted based on our oil and natural gas properties, reserves, other indebtedness and other relevant factors. Our ability to utilize the full amount of our borrowing capacity is influenced by a variety of factors, including redeterminations of our borrowing base, and covenants under our Senior Credit Agreement and our senior unsecured debt indentures. Additionally, our borrowing base is subject to a reduction equal to the product of $0.25 multiplied by the stated principal amount (without regard to any initial issue discount) of any unsecured senior or senior subordinated notes that we may issue. Effective October 3, 2011, we reduced the borrowing capacity under our Senior Credit Agreement from $2.5 billion to $25 million. At December 31, 2011, we had a $3.0 million letter of credit outstanding with a vendor, no borrowings outstanding and $22.0 million of borrowing capacity available under the Senior Credit Agreement. Effective February 1, 2012, the $3.0 million letter of credit was terminated. Refer to Item 8. *Consolidated Financial Statements and Supplementary Data Note 4, "Long-term Debt*" for more details.

Our Senior Credit Agreement contains customary financial and other covenants, including minimum working capital levels (the ratio of current assets plus the unused commitment under the Senior Credit Agreement to current liabilities) of not less than 1.0 to 1.0 and minimum coverage of interest expenses (as defined in the Senior Credit Agreement) of not less than 2.5 to 1.0. We are subject to additional covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. Effective September 27, 2011, our compliance obligations with respect to the aforementioned minimum working capital level and minimum coverage of interest expense covenants, as well as our compliance obligations with respect to certain other covenants in the Senior Credit Agreement including reserve report and other information delivery, were suspended until March 31, 2012. 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, under the most restrictive indentures, 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 limits these borrowings to the greater of a fixed sum of, under the most restrictive indentures, $1 billion and 30% of our adjusted consolidated net tangible assets (as defined in all of our indentures), which is largely calculated based upon the discounted future net revenues from our proved oil and natural gas reserves as of the end of each year.

6.25% Senior Notes

On May 20, 2011, we completed a private placement offering to eligible purchasers of an aggregate principal amount of $600 million of our 6.25% senior notes due 2019. The 2019 Notes were issued under and are governed by an indenture dated May 20, 2011, between us, U.S. Bank Trust National Association, as trustee, and our subsidiaries named therein as guarantors (the 2019 Indenture). The 2019 Notes were sold to investors at 100% of the aggregate principal amount of the 2019 Notes. The net proceeds from the sale of the 2019 Notes were approximately $589 million (after deducting offering fees and expenses). The proceeds were used to repay borrowings outstanding under our Senior Credit Agreement and for working capital for general corporate purposes.

The 2019 Notes bear interest at a rate of 6.25% per annum, payable semi-annually on June 1 and December 1 of each year, commencing on December 1, 2011. The 2019 Notes will mature on June 1, 2019. The 2019 Notes are senior unsecured obligations of ours and rank equally with all of our current and future senior indebtedness. The 2019 Notes are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by our subsidiaries, with the exception of two subsidiaries, as discussed in Item 8. *Consolidated Financial Statements and Supplementary Data Note 13, "EagleHawk*

Table of Contents

Field Services". Petrohawk Energy Corporation, the issuer of the 2019 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

We are required to offer to repurchase the 2019 Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined in the 2019 Indenture that is followed by a decline within 90 days in the ratings of the 2019 Notes published by either Moody's Investor Service, Inc. (Moody's) or Standard & Poor's Rating Services (S&P). Our credit rating did not decline in the allotted period of time after the change of control with the closing of the BHP merger. As a result, no such offer was made. Additionally, during the fourth quarter of 2011, an Investment Grade Rating Event (as defined in the 2019 Indenture) occurred that resulted in certain covenants in the 2019 Indenture, including covenants relating to incurrence of indebtedness, restricted payments, asset sales and affiliate transactions, being terminated.

7.25% Senior Notes

On August 17, 2010, we completed a private placement offering to eligible purchasers of an aggregate principal amount of $825 million of our 7.25% senior notes due 2018 (the initial 2018 Notes) at a purchase price of 100% of the principal amount of the initial 2018 Notes. The initial 2018 Notes were issued under and are governed by an indenture dated August 17, 2010, between us, U.S. Bank Trust National Association, as trustee, and our subsidiaries named therein as guarantors (the 2018 Indenture). We applied the net proceeds from the sale of the initial 2018 Notes to redeem our $775 million 9.125% senior notes due 2013.

On January 31, 2011, we completed the issuance of an additional $400 million aggregate principal amount of our 7.25% senior notes due 2018 in a private placement to eligible purchasers. The additional 2018 Notes are issued under the same Indenture and are part of the same series as the initial 2018 Notes. The additional 2018 Notes together with the initial 2018 Notes are collectively referred to as the 2018 Notes (the 2018 Notes).

The additional 2018 Notes were sold to Barclays Capital Inc. at 101.875% of the aggregate principal amount of the additional 2018 Notes plus accrued interest. The net proceeds from the sale of the additional 2018 Notes were approximately $400.5 million (after deducting offering fees and expenses). A portion of the proceeds of the additional 2018 Notes were utilized to redeem all of our outstanding $275 million 7.125% senior notes due 2012.

Interest on the 2018 Notes is payable on February 15 and August 15 of each year, beginning on February 15, 2011. Interest on the 2018 Notes accrued from August 17, 2010, the original issuance date of the series. The 2018 Notes will mature on August 15, 2018. The 2018 Notes are senior unsecured obligations of ours and rank equally with all of our current and future senior indebtedness. The 2018 Notes are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by our subsidiaries, with the exception of two subsidiaries, as discussed in Item 8. *Consolidated Financial Statements and Supplementary Data Note 13, "EagleHawk Field Services"*. Petrohawk Energy Corporation, the issuer of the 2018 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

We are required to offer to repurchase the 2018 Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined in the 2018 Indenture that is followed by a decline within 90 days in the ratings of the 2018 Notes published by either Moody's or S&P. Our credit rating did not decline in the allotted period of time after the change of control with the closing of the BHP merger. As a result, no such offer was made. Additionally, during the fourth quarter of 2011, an Investment Grade Rating Event (as defined in the 2018 Indenture) occurred that resulted in certain covenants in the 2018

Table of Contents

Indenture, including covenants relating to incurrence of indebtedness, restricted payments, asset sales and affiliate transactions, being terminated.

In conjunction with the issuance of the additional 2018 Notes, we recorded a premium of $7.5 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized premium was $6.8 million at December 31, 2011.

10.5% Senior Notes

On January 27, 2009, we completed a private placement offering to eligible purchasers of an aggregate principal amount of $600 million of our 10.5% senior notes due 2014 (the 2014 Notes). The 2014 Notes were issued under and are governed by an indenture dated January 27, 2009, between us, U.S. Bank Trust National Association, as trustee, and our subsidiaries named therein as guarantors (the 2014 Indenture).

The 2014 Notes bear interest at a rate of 10.5% per annum, payable semi-annually on February 1 and August 1 of each year. The 2014 Notes will mature on August 1, 2014. We are required to offer to repurchase the 2014 Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined in the 2014 Indenture. On September 16, 2011, we initiated an offer to repurchase the 2014 Notes, in accordance with the terms of the 2014 Indenture, due to the change of control resulting from the acquisition of Petrohawk Energy Corporation by BHP Billiton Limited. The holders of the 2014 Notes had until November 9, 2011 to tender their 2014 Notes. On November 14, 2011, we paid principal and interest of $10.8 million to repurchase a portion of the 2014 Notes at the request of the bondholders. The 2014 Notes are senior unsecured obligations of ours and rank equally with all of its current and future senior indebtedness. The 2014 Notes are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by our subsidiaries, with the exception of two subsidiaries, as discussed in Item 8. *Consolidated Financial Statements and Supplementary Data Note 13, "EagleHawk Field Services"*. Petrohawk Energy Corporation, the issuer of the 2014 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

In conjunction with the issuance of the 2014 Notes, we recorded a discount of $52.3 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized discount was $28.4 million at December 31, 2011.

7.875% Senior Notes

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

The 2015 Notes bear interest at a rate of 7.875% per annum, payable semi-annually on June 1 and December 1 of each year. The 2015 Notes will mature on June 1, 2015. We are required to offer to repurchase the 2015 Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined in the 2015 Indenture. On September 16, 2011, we initiated an offer to repurchase the 2015 Notes, in accordance with the terms of the 2015 Indenture, due to the change of control resulting from the acquisition of Petrohawk Energy Corporation by BHP Billiton Limited. The holders of the 2015 Notes had until November 9, 2011 to tender their 2015 Notes. On November 14, 2011, we paid principal and interest of $0.4 million to repurchase a portion of the 2015 Notes at the request of the bondholders. The 2015 Notes are senior unsecured obligations of ours and rank equally with all of our current and future senior indebtedness. The 2015 Notes are jointly and severally, fully and unconditionally

Table of Contents

guaranteed on a senior unsecured basis by our subsidiaries, with the exception of two subsidiaries, as discussed in Item 8. *Consolidated Financial Statements and Supplementary Data Note 13, "EagleHawk Field Services"*. Petrohawk Energy Corporation, the issuer of the 2015 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

7.125% Senior Notes

In our merger with KCS Energy, Inc. (KCS), we assumed (pursuant to the Second Supplemental Indenture relating to the 7.125% senior notes, also referred to as the 2012 Notes), all the obligations (approximately $275 million) of KCS under the 2012 Notes and the Indenture dated April 1, 2004 (the 2012 Indenture) among KCS, U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein, which governs the terms of the 7.125% senior notes due 2012. The 2012 Notes are guaranteed on an unsubordinated, unsecured basis by all of our current subsidiaries, with the exception of two subsidiaries, as discussed in Item 8. *Consolidated Financial Statements and Supplementary Data Note 13, "EagleHawk Field Services"*. Interest on the 2012 Notes is payable semi-annually, on each April 1 and October 1.

In conjunction with the assumption of the 7.125% Notes from KCS, we recorded a discount of $13.6 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized discount was zero at December 31, 2011.

On March 17, 2011, we redeemed all of the outstanding 2012 Notes with a portion of the proceeds received from the issuance of the additional 2018 Notes.

9.875% Senior Notes

On April 8, 2004, Mission Resources Corporation (Mission) issued $130.0 million of its 9.875% senior notes due 2011 (the 2011 Notes). We assumed these notes upon the closing of our merger with Mission. In conjunction with our merger with KCS, we extinguished substantially all of the 2011 Notes. On April 1, 2011, we repaid the $0.2 million of the 2011 Notes that were still outstanding.

Off-Balance Sheet Arrangements

At December 31, 2011, we did not have any material off-balance sheet arrangements.

Critical Accounting Policies and Estimates

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

Table of Contents

Oil and Natural Gas Activities

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

Full Cost Method

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

Proved Oil and Natural Gas Reserves

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

Our estimated proved reserves for the years ended December 31, 2011, 2010 and 2009 were prepared by Netherland, Sewell, an independent oil and natural gas reservoir engineering consulting firm. For more information regarding reserve estimation, including historical reserve revisions, refer to

Table of Contents

Item 8. Consolidated Financial Statements and Supplementary Data "*Supplemental Oil and Gas Information (Unaudited).*"

Depreciation, Depletion and Amortization

Our rate of recording depreciation, depletion and amortization expense (DD&A) is primarily dependent upon our estimate of proved reserves, which is utilized in our unit-of-production method calculation. If the estimates of proved reserves were to be reduced, the rate at which we record DD&A expense would increase, reducing net income. Such a reduction in reserves may result from calculated lower market prices, which may make it non-economic to drill for and produce higher cost reserves. A five percent positive or negative revision to proved reserves would decrease or increase the DD&A rate by approximately $0.13 per Mcfe.

Full Cost Ceiling Test Limitation

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

If the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ended December 31, 2011 had been 10% lower while all other factors remained constant, the net book value of oil and natural gas properties would have been impaired by approximately $690 million before income taxes and $444 million after income taxes.

Our parent, BHP Billiton Limited, prepares its consolidated financial statements in accordance with International Financial Reporting Standards (IFRS). For a discussion of BHP Billiton's accounting policies, please see the BHP Billiton 2011 Annual Report. For the avoidance of doubt, the impairment amounts listed above are not indicative of the potential results of any future BHP Billiton Limited impairment review under IFRS.

Future Development Costs

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

Table of Contents

increase in future development and abandonment costs would decrease or increase the DD&A rate by approximately $0.07 per Mcfe.

Asset Retirement Obligations

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

Accounting for Derivative Instruments and Hedging Activities

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

Goodwill

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

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

Table of Contents

In September 2011, the Financial Accounting Standards Board issued ASU No. 2011-08, *Testing for Goodwill Impairment* (ASU 2011-08) to simplify how companies test goodwill for impairment. ASU 2011-08 simplifies testing for goodwill impairments by allowing entities to first assess qualitative factors to determine whether the facts or circumstances lead to the conclusion that it is more likely than not that the fair value of a reporting unit is less than the carrying amount. If the entity concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then the entity does not have to perform the two-step impairment test. However, if that same conclusion is not reached, the company is required to perform the first step of the two-step impairment test. ASU 2011-08 also allows a company to bypass the qualitative assessment and proceed directly with performing the two-step goodwill impairment test. We opted to bypass the qualitative assessment and proceeded with the two-step goodwill impairment test when performing the annual goodwill impairment test in the third quarter of 2011.

Income Taxes

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

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

Accounting for KinderHawk and EagleHawk Joint Ventures

The KinderHawk and EagleHawk joint ventures are accounted for as failed sales of in substance real estate under the provisions of ASC 360-20. ASC 360-20 establishes standards for recognition of profit on all real estate sales transactions other than retail land sales, without regard to the nature of the seller's business. In making the determination of whether a transaction qualifies, in substance, as a sale of real estate, the nature of the entire real estate being sold is considered, including the land plus the property improvements and the integral equipment. The Haynesville Shale and Eagle Ford Shale gathering and treating systems consist of right of ways, pipelines and processing facilities. Due to the gathering agreements, entered into with the formation of KinderHawk and Eagle Hawk, which

Table of Contents

constitute extended continuing involvement under ASC 360-20, it has been determined that the contribution of our Haynesville Shale gathering and treating system to KinderHawk and our contribution of our Eagle Ford Shale gathering and treating system to EagleHawk should be accounted for as failed sales of in substance real estate. As a result of the failed sales, we account for the continued operations of the gas gathering systems and reflect financing obligations, representing the proceeds received, under the financing method of real estate accounting. Under the financing method, the historical cost of the Haynesville Shale and Eagle Ford Shale gas gathering systems contributed to KinderHawk and EagleHawk, respectively, are carried at the full historical basis of the assets on the consolidated balance sheets in *"Gas gathering systems and equipment"* and depreciated over the remaining useful life of the assets. The financing obligations of $1.8 billion as of December 31, 2011, are recorded on the consolidated balance sheets in *"Payable on financing arrangements."* Reductions to the obligations and the non cash interest on the obligations are tied to the gathering and treating services, as we deliver natural gas through the Haynesville Shale and Eagle Ford Shale gathering and treating systems. Interest and principal are determined based upon the allocable income to Kinder Morgan, and interest is limited up to an amount that is calculated based upon our weighted average cost of debt as of the date of the transactions. Allocable income in excess of the calculated value will be reflected as reductions of principal. Interest is recorded in *"Interest expense and other"* on the consolidated statements of operations. Additionally we record EagleHawk's revenues and through July 1, 2011 we recorded KinderHawk's revenues, net of eliminations for intercompany amounts associated with gathering and treating services provided to us, and expenses on the consolidated statements of operations in *"Midstream revenues," "Taxes other than income," "Gathering, transportation and other," "General and administrative," "Interest expense and other"* and *"Depletion, depreciation and amortization."*

On July 1, 2011, we closed a transaction with KM Gathering in which we transferred our remaining 50% membership interest in KinderHawk to KM Gathering. Upon the closing of the transfer of our remaining 50% interest in KinderHawk, we no longer include KinderHawk's revenues and expenses on the consolidated statements of operations. In accordance with ASC 360-20, the historical cost of the Haynesville Shale gas gathering system is carried at the full historical basis of the assets on the consolidated balance sheets in *"Gas gathering systems and equipment"* and depreciated over the remaining useful life of the assets, as discussed above. As a result of the transfer on July 1, 2011, we recorded an increase in our financing obligation associated with KinderHawk of approximately $743.0 million.

Table of Contents

Comparison of Results of Operations

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

We reported income from continuing operations, net of income taxes, of $177.2 million for the year ended December 31, 2011 compared to income from continuing operations, net of income taxes, of $135.9 million for the comparable period in 2010. The following table summarizes key items of comparison and their related change for the periods indicated.

	Years Ended December 31,		
In thousands (except per unit and per Mcfe amounts)	**2011**	**2010**	**Change**
Income from continuing operations, net of income taxes	$ 177,227	$ 135,905	$ 41,322
Operating revenues:			
Oil and natural gas	1,779,738	1,107,401	672,337
Marketing	296,006	475,030	(179,024)
Midstream	23,648	18,216	5,432
Operating expenses:			
Marketing	322,232	521,378	(199,146)
Production:			
Lease operating	62,295	64,744	(2,449)
Workover and other	17,853	18,119	(266)
Taxes other than income	63,617	9,543	54,074
Gathering, transportation and other	175,494	99,375	76,119
General and administrative:			
General and administrative	228,964	132,264	96,700
Stock-based compensation	53,203	23,229	29,974
Depletion, depreciation and amortization:			
Depletion Full cost	823,841	445,094	378,747
Depreciation Midstream	22,888	13,843	9,045
Depreciation Other	10,869	5,054	5,815
Accretion expense	2,126	1,979	147
Other income (expenses):			
Net gain on derivative contracts	363,714	301,121	62,593
Interest expense and other	(403,952)	(336,307)	(67,645)
Income from continuing operations before income taxes	275,772	230,839	44,933
Income tax provision	(98,545)	(94,934)	(3,611)
Production:			
Natural gas Mmcf	311,178	234,538	76,640
Crude oil MBbl	4,715	1,268	3,447
Natural gas liquids MBbl	2,843	681	2,162
Natural gas equivalent Mmcfe(1)	356,526	246,232	110,294
Average daily production Mmcfe(1)	977	675	302
Average price per unit(2):			
Natural gas price Mcf	$ 3.87	$ 4.18	$ (0.31)
Crude oil price Bbl	89.75	76.98	12.77
Natural gas liquids price Bbl	49.89	38.03	11.86
Natural gas equivalent price Mcfe(1)	4.96	4.49	0.47
Average cost per Mcfe:			
Production:			
Lease operating	0.17	0.26	(0.09)
Workover and other	0.05	0.07	(0.02)
Taxes other than income	0.18	0.04	0.14
Gathering, transportation and other	0.49	0.40	0.09
General and administrative:			
General and administrative	0.64	0.54	0.10
Stock-based compensation	0.15	0.09	0.06
Depletion	2.31	1.81	0.50

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

Table of Contents

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

For the year ended December 31, 2011, oil and natural gas revenues increased $672.3 million from the same period in 2010, to $1.8 billion. The increase was primarily due to the increase in our production of 110,294 Mmcfe, or 45% over 2010, primarily due to our drilling successes in resource plays in Louisiana and Texas. Increased production contributed approximately $495 million in revenues for the year ended December 31, 2011. Also contributing to this increase was an increase of $0.47 per Mcfe in our realized average price to $4.96 per Mcfe from $4.49 per Mcfe in the prior year period which was positively impacted by a higher percentage of our production being composed of oil and natural gas liquids. The increase per Mcfe led to an increase in oil and natural gas revenues of approximately $177 million.

We had marketing revenues of $296.0 million and marketing expenses of $322.2 million for the year ended December 31, 2011, resulting in a loss before income taxes of $26.2 million as compared to a loss before income taxes of $46.4 million for the same period in 2010. Prior to July 1, 2011, a subsidiary of ours purchased and sold our own and third party natural gas produced from wells which we and third parties operate. Effective July 1, 2011, our marketing subsidiary ceased its marketing operations. The revenues and expenses related to these marketing activities were reported on a gross basis as part of operating revenues and operating expenses in historical periods. Marketing revenues were recorded at the time natural gas was physically delivered to third parties at a fixed or index price. Marketing expenses attributable to gas purchases were recorded as our subsidiary took physical title to natural gas and transported the purchased volumes to the point of sale. Subsequent to July 1, 2011, we no longer bought or sold third party volumes from wells we and third parties operated. As a result, certain items previously recorded to "*Marketing revenues*" will no longer be reported while others will now be recorded to "*Oil and natural gas revenues*" on the consolidated statements of operations. In addition, certain charges previously reported in "*Marketing expenses*" will no longer be reported while others will now be recorded to "*Gathering, transportation and other*" on the consolidated statements of operations. Our loss before income taxes of $26.2 million is primarily attributable to decreased margins and increases in our transportation costs.

We had gross revenues from our midstream business of $87.3 million for the year ended December 31, 2011 compared to the same period in 2010 of $82.2 million, an increase of $5.1 million. The increase in gross revenues from our midstream business primarily relates to increased volumes from our gathering and treating system in the Eagle Ford Shale. In accordance with the financing method for a failed sale of in substance real estate we record EagleHawk's revenues, and through July 1, 2011 we recorded KinderHawk's revenues, net of eliminations for intercompany amounts associated with gathering and treating services provided to us on the consolidated statements of operations. For the year ended December 31, 2011, approximately $16.4 million in revenues, after intercompany eliminations, from KinderHawk and EagleHawk were reported in midstream revenues on the consolidated statements of operations. Gross revenues of $87.3 million also included $63.7 million of intercompany revenues that were eliminated in consolidation. On a net basis, we had revenues of $23.6 million for the year ended December 31, 2011, an increase of $5.4 million from the prior year. This increase is attributed to increased volumes from our gathering and treating system in the Eagle Ford Shale offset by the transfer of our remaining 50% membership interest in KinderHawk on July 1, 2011.

Lease operating expenses decreased $2.4 million for the year ended December 31, 2011 as compared to the same period in 2010. The decrease was primarily due to our continued cost control efforts as well as the sale of our higher cost properties in 2010. On a per unit basis, lease operating expenses decreased $0.09 per Mcfe to $0.17 per Mcfe in 2011 from $0.26 per Mcfe in 2010. The decrease on a per unit basis is primarily due to the increase in production during 2011 from our resource plays which historically have a lower per unit operating cost. Additionally, the sale of our

Table of Contents

Terryville Field, West Edmond Hunton Lime Unit Field and Fayetteville Shale properties in 2010, contributed to a decrease in costs for the year ended December 31, 2011 over the same period in 2010 as these properties historically operated with higher operating costs per unit.

Taxes other than income increased $54.1 million for year ended December 31, 2011 as compared to the same period in 2010. The largest components of taxes other than income are production and severance taxes which are generally assessed as either a fixed rate based on production or as a percentage of gross oil and natural gas sales. Our increase in production in the current year was partially offset by severance tax refunds related to drilling incentives for horizontal wells in the Haynesville and Eagle Ford Shales. For the year ended December 31, 2011, we recorded severance tax refunds totaling $16.6 million compared to $47.7 million in the prior year. On a per unit basis, excluding the severance tax refunds, taxes other than income remained flat at $0.23 per Mcfe in 2011 and 2010.

Gathering, transportation and other expense increased $76.1 million for the year ended December 31, 2011 as compared to the same period in 2010. On a per unit basis, gathering transportation and other increased $0.09 per Mcfe from $0.40 per Mcfe in 2010 to $0.49 per Mcfe in 2011. The overall increase is due to our increased production from our drilling successes in resource plays in Louisiana and Texas.

General and administrative expense for the year ended December 31, 2011 increased $96.7 million as compared to the same period in 2010. The increase is primarily attributable to costs associated with the BHP Merger as well as an increase in normal payroll and employee costs associated with increases in our work force as a result of our continued growth. An advisory service fee paid in conjunction with the BHP Merger accounted for $30.2 million of the increase over the prior year period. Payroll and employee costs increased approximately $53.2 million for items including employee retention and bonus payments and associated payroll taxes related to the BHP Merger and normal increases in payroll and employee costs due to our growth over the prior year. We also incurred professional and legal fees of approximately $8.5 million related to the BHP Merger during 2011.

Stock-based compensation expense for the year ended December 31, 2011 increased $30.0 million compared to the same period in 2010. On August 25, 2011, BHP Billiton Limited acquired 100% of our outstanding shares of common stock through the merger of a wholly owned subsidiary of BHP Billiton Petroleum (North America) Inc. with and into us. In conjunction with the merger, we cancelled all unexercised stock options and stock appreciation rights, both vested and unvested, outstanding under our employee and nonemployee equity incentive plans in exchange for a cash payment equal to $38.75 for each share of common stock underlying such option or stock appreciation right, less the applicable exercise price per share and net of withholding taxes, which resulted in our recognition of additional stock-based compensation expense in 2011.

Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs associated with evaluated properties plus future development costs based on the ratio of production volume for the current period to total remaining reserve volume for the evaluated properties. Depletion expense increased $378.7 million for the year ended December 31, 2011 from the same period in 2010, to $823.8 million. On a per unit basis, depletion expense increased $0.50 per Mcfe to $2.31 per Mcfe. The increase on a per unit basis is primarily due to our 2010 asset sales as well as the impact of our 2010 and 2011 capital expenditures program.

Depreciation expense associated with our gas gathering systems increased $9.0 million to $22.9 million for the year ended December 31, 2011 as compared to the same period in 2010. The increase was due to the growth in our midstream operations from capital spending over the course of the year, as well as the contribution of the gas gathering systems and treating facilities in the Haynesville Shale to KinderHawk and the transfer of a 25% interest in EagleHawk to Eagle Gathering. The KinderHawk and EagleHawk joint ventures are accounted for in accordance with the financing method for a failed

Table of Contents

sale of in substance real estate. Under the financing method, the historical costs of the Haynesville Shale and Eagle Ford Shale gas gathering systems are carried at the full historical basis of the assets on the consolidated balance sheets and depreciated over the remaining useful life of the assets. We depreciate our gas gathering systems over a 30 year useful life commencing on the estimated placed in service date.

Historically, we have entered into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil, natural gas, and natural gas liquids production. Consistent with the prior year, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the consolidated statements of operations. At December 31, 2011, we had a $376.7 million derivative asset, $371.6 million of which was classified as current, and a $40.7 million derivative liability, all of which was classified as current. We recorded a net derivative gain of $363.7 million ($90.1 million net unrealized gain and $273.6 million net gain for cash received on settled contracts) for the year ended December 31, 2011 compared to a net derivative gain of $301.1 million ($58.1 million net unrealized gain and a $243.0 million gain for cash received on settled contracts) in the same period in 2010.

Interest expense and other increased $67.6 million for the year ended December 31, 2011 compared to the same period in 2010. The increase is primarily the result of our accounting for the KinderHawk and EagleHawk joint ventures under the financing method for a failed sale of in substance real estate. For the year ended December 31, 2011, we recorded approximately $116.4 million of interest expense on the financing obligations compared to $40.5 million in the prior year. This increase for the period ended December 31, 2011 was offset by a decrease in interest expense on our Senior Notes due to the refinancing of our 2012 Notes and 2013 Notes and lower outstanding balances on our Senior Credit Agreement.

We had an income tax provision of $98.5 million for the year ended December 31, 2011 due to our income from continuing operations before income taxes of $275.8 million compared to an income tax provision of $94.9 million due to our income from continuing operations before income taxes of $230.8 million in the prior year. The effective tax rate for the year ended December 31, 2011 was 35.7% compared to 41.1% for the year ended December 31, 2010. The decrease in our effective tax rate in the current year is primarily due to the impact of the acceleration of certain equity awards as a result of the BHP Merger.

Investment in EagleHawk

EagleHawk had gross revenues of $26.1 million related to its Eagle Ford Shale gathering and treating systems in the Hawkville and Black Hawk Fields from July 1, 2011, the date of inception, to December 31, 2011. Gross revenues of $26.1 million included $14.1 million of intercompany revenues that were eliminated in consolidation. Total operating expenses for EagleHawk from July 1, 2011 to December 31, 2011 of $13.9 million included $7.7 million in gathering, transportation and other expenses and $4.7 million in depreciation expense. Gathering, transportation and other expenses for EagleHawk consist of costs to operate the pipelines, such as treating, processing, measuring and transporting expenses. Depreciation expense on EagleHawk's gathering and treating systems is calculated based on a 30 year useful life commencing on the estimated placed in service date.

Recently Issued Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Derivative Instruments and Hedging Activity

We are exposed to various risks including energy commodity price risk. When oil, natural gas, and natural gas liquids prices decline significantly our ability to finance our capital budget and operations could be adversely impacted. We expect energy prices to remain volatile and unpredictable, however, as a result of the BHP Merger, we no longer plan to enter into derivative contracts. Historically, we designed a risk management policy which provided for the use of derivative instruments to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the affect it could have on our operations. Collars, swaps and puts were the typical derivative instruments that we utilized. We generally hedged a substantial, but varying, portion of anticipated oil, natural gas and natural gas liquids production. On December 20, 2011, we entered into a Master Transaction Agreement with Barclays in order to facilitate the termination of a portion of our existing derivative positions. As part of the Master Transaction Agreement, we entered into certain derivative transactions with Barclays with equal and opposite economic terms from the majority of our existing derivative positions (Mirror Trades) at the time of the Master Transaction Agreement in order to limit our exposure to future price movements. The Mirror Trades were entered into in December 2011 and are cancellable if certain events do not take place by March 16, 2012. We plan to novate the existing derivative positions to Barclays once certain terms and conditions are met. Once these existing derivative positions have been novated to Barclays, as between us and Barclays, the existing derivative positions as well as the Mirror Trades will terminate and Barclays will pay us a negotiated settlement amount which represents the approximate closeout value as of the dates stipulated in the Agreement of our original existing derivative contracts. We recorded an approximate $20 million loss in "*Net gain on derivative contracts*" at December 31, 2011 representing the change in the fair value of the Mirror Trades from December 20, 2011 to December 31, 2011. In addition, during the first quarter of 2012, the Company received $68.5 million for the termination of its outstanding derivative positions with BNP Paribas.

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

We have also been exposed to interest rate risk on our variable interest rate debt. If interest rates increase, our interest expense would increase and our available cash flow would decrease. Periodically, we may look to utilize interest rate swaps to reduce the exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. At December 31, 2011, we did not have any open positions that converted our variable interest rate debt to fixed interest rates. We continue to monitor our risk exposure as we incur future indebtedness at variable interest rates and will look to continue our risk management policy as situations present themselves.

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

Fair Market Value of Financial Instruments

The estimated fair values for financial instruments under ASC 825, *Financial Instruments*, (ASC 825) are determined at discrete points in time based on relevant market information. These estimates involve

Table of Contents

uncertainties and cannot be determined with precision. The estimated fair value of cash, cash equivalents, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 5, "*Fair Value Measurements"* for additional information.

Interest Sensitivity

Historically, we have been exposed to interest rate exposure primarily from fluctuations in short-term rates, which are LIBOR and ABR based. The fluctuations can cause reductions of earnings or cash flows due to increases in the interest rates that we have historically paid on these obligations. At December 31, 2011, total debt excluding related discounts and premiums was $3.2 billion which bears interest at a weighted average fixed interest rate of 7.8% per year. At December 31, 2011, we did not have any amounts drawn under our Senior Credit Agreement. We do not currently have any long-term debt that bears interest at floating or market interest rates. If we incur future indebtedness which bears interest at variables rates, fluctuations in market interest rates could cause our annual interest costs to fluctuate.

Table of Contents

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Table of Contents

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Petrohawk Energy Corporation (the Company), including the Company's Principal Executive Officer and Principal Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. The Company's internal control system was designed to provide reasonable assurance to the Company's Management and Board of Directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Petrohawk Energy Corporation's internal control over financial reporting was effective as of December 31, 2011.

KPMG LLP, the Company's independent registered public accounting firm, has issued an attestation report on the effectiveness on the Company's internal control over financial reporting as of December 31, 2011 which is included in Item 8. *Consolidated Financial Statements and Supplementary Data*.

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

Houston, Texas
February 28, 2012

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholder
Petrohawk Energy Corporation:

We have audited the accompanying consolidated balance sheet of Petrohawk Energy Corporation and subsidiaries (the Company) as of December 31, 2011, and the related consolidated statements of operations, stockholders' equity, and cash flows for the year then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Petrohawk Energy Corporation and subsidiaries as of December 31, 2011, and the results of their operations and their cash flows for the year then ended in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Petrohawk Energy Corporation's internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2012 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP
Houston, Texas
February 28, 2012

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholder
Petrohawk Energy Corporation:

We have audited Petrohawk Energy Corporation's internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Petrohawk Energy Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Petrohawk Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Petrohawk Energy Corporation and subsidiaries as of December 31, 2011, and the related consolidated statements of operations, stockholders' equity, and cash flows for the year then ended, and our report dated February 28, 2012 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
Houston, Texas
February 28, 2012

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

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

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

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

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
December 5, 2011

Table of Contents

PETROHAWK ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands)

	Years Ended December 31,		
	2011	**2010**	**2009**
Operating revenues:			
Oil and natural gas	$ 1,779,738	$ 1,107,401	$ 732,137
Marketing	296,006	475,030	320,121
Midstream	23,648	18,216	18,418
Total operating revenues	2,099,392	1,600,647	1,070,676
Operating expenses:			
Marketing	322,232	521,378	316,987
Production:			
Lease operating	62,295	64,744	78,700
Workover and other	17,853	18,119	2,749
Taxes other than income	63,617	9,543	57,360
Gathering, transportation and other	175,494	99,375	79,982
General and administrative	282,167	155,493	111,009
Depletion, depreciation and amortization	859,724	465,970	391,609
Full cost ceiling impairment			1,838,444
Total operating expenses	1,783,382	1,334,622	2,876,840
Income (loss) from operations	316,010	266,025	(1,806,164)
Other income (expenses):			
Net gain on derivative contracts	363,714	301,121	260,248
Interest expense and other	(403,952)	(336,307)	(229,419)
Total other income (expenses)	(40,238)	(35,186)	30,829
Income (loss) from continuing operations before income taxes	275,772	230,839	(1,775,335)
Income tax (provision) benefit	(98,545)	(94,934)	753,006
Income (loss) from continuing operations, net of income taxes	177,227	135,905	(1,022,329)
Loss from discontinued operations, net of income taxes	(3,079)	(45,984)	(3,122)
Net income (loss)	$ 174,148	$ 89,921	$ (1,025,451)

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

Table of Contents

PETROHAWK ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share amounts)

	December 31,	
	2011	**2010**
Current assets:		
Cash	$ 174,436	$ 1,591
Accounts receivable	410,115	356,597
Receivables from derivative contracts	371,584	217,018
Prepaids and other	42,060	62,831
Total current assets	998,195	638,037
Oil and natural gas properties (full cost method):		
Evaluated	10,509,954	7,520,446
Unevaluated	2,502,435	2,387,037
Gross oil and natural gas properties	13,012,389	9,907,483
Less accumulated depletion	(5,598,420)	(4,774,579)
Net oil and natural gas properties	7,413,969	5,132,904
Other operating property and equipment:		
Gas gathering systems and equipment	918,810	593,388
Other operating assets	108,077	55,315
Gross other operating property and equipment	1,026,887	648,703
Less accumulated depreciation	(61,363)	(27,635)
Net other operating property and equipment	965,524	621,068
Other noncurrent assets:		
Goodwill	932,802	932,802
Other intangible assets, net of amortization	78,289	89,342
Debt issuance costs, net of amortization	45,528	45,941
Deferred income taxes	326,878	316,546
Receivables from derivative contracts	5,147	41,721
Restricted cash	34,736	
Assets held for sale		74,448
Other	11,859	6,944
Total assets	$ 10,812,927	$ 7,899,753
Current liabilities:		
Accounts payable and accrued liabilities	$ 963,701	$ 787,238
Deferred income taxes	79,748	45,815
Liabilities from derivative contracts	40,673	5,820
Payable to KinderHawk Field Services LLC		976
Payable on financing arrangements	17,631	7,052
Long-term debt	17,520	14,790
Total current liabilities	1,119,273	861,691
Long-term debt	3,192,641	2,612,852
Other noncurrent liabilities		

Liabilities from derivative contracts		13,575
Asset retirement obligations	52,317	31,741
Payable on financing arrangements	1,799,881	933,811
Other	640	544
Commitments and contingencies (Note 7)		
Stockholders' equity:		
Common stock: 100 and 500,000,000 shares of $.001 par value authorized; 100 and 302,489,501 shares issued and outstanding at December 31, 2011 and 2010, respectively		302
Additional paid-in capital	5,660,399	4,631,609
Accumulated deficit	(1,012,224)	(1,186,372)
Total stockholders' equity	4,648,175	3,445,539
Total liabilities and stockholders' equity	$ 10,812,927	$ 7,899,753

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

Table of Contents

PETROHAWK ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(In thousands)

	Common Shares	Common Amount	Additional Paid-in Capital	(Accumulated Deficit) Retained Earnings	Total Stockholders' Equity
Balances at January 1, 2009	252,364	$ 252	$ 3,655,500	$ (250,842)	$ 3,404,910
Sale of common stock	47,000	47	956,453		956,500
Equity compensation vesting					