PETROHAWK ENERGY CORP
Form 10-K
February 25, 2009

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, 2008

Commission file number 001-33334

PETROHAWK ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

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

1000 Louisiana, Suite 5600, Houston, Texas 77002

(Address of principal executive offices including ZIP code)

(832) 204-2700

(Registrant s telephone number)

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

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

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

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

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

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

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

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

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

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

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

The aggregate market value of common stock, par value $.001 per share, held by non-affiliates (based upon the closing sales price on the New York Stock Exchange on June 30, 2008), the last business day of registrant s most recently completed second fiscal quarter was approximately $10.0 billion.

As of February 20, 2009, there were 252,448,890 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Information required by Part III, Items 10, 11, 12, 13 and 14, is incorporated by reference to portions of the registrant s definitive proxy statement for its 2009 annual meeting of stockholders which will be filed on or before April 30, 2009.

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Special note regarding forward-looking statements

This report on Form 10-K contains forward-looking statements within the meaning of the federal securities laws. All statements, other than statements of historical facts, concerning, among other things, planned capital expenditures, potential increases in oil and natural gas production, the number of anticipated wells to be drilled in the future, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as may, expect, estimate, project, plan, believe, intend, achievable, will, continue, potential, should, could and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. The 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 set forth in the forward-looking statements, including, but not limited to, the following factors:

- our ability to successfully develop our large inventory of undeveloped acreage primarily held in resource-style areas in Louisiana, Arkansas and Texas, including our resource-style plays such as the Haynesville, Fayetteville and Eagle Ford Shales;
- the volatility in commodity prices for oil and natural gas, including continued declines in prices;
- the possibility that the industry may be subject to future regulatory or legislative actions (including any additional taxes and changes in environmental regulation);
- the possibility that the United States economy is entering into a deflationary period, which would negatively impact the price of commodities, including oil and natural gas;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;
- the possibility that production decline rates in some of our resource-style plays are greater than we expect;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fully develop our undeveloped acreage positions;
- the ability to replace oil and natural gas reserves;
- environmental risks;
- drilling and operating risks;
- exploration and development risks;

competition, including competition for acreage in resource-style areas;

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

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

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

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

general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business, may be less favorable than expected, including the possibility that the current economic recession in the United States will be severe and prolonged, which could adversely affect the demand for oil and natural gas and make it difficult, if not impossible, to access financial markets;

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

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

Finally, our future results will depend upon various other risks and uncertainties, including, but not limited to, those detailed in the section entitled Risk Factors included in this report. All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

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PART I

ITEM 1. BUSINESS

Overview

We are an independent oil and natural gas company engaged in the exploration, development and production of predominately natural gas properties located onshore in the United States. Our properties are primarily located in Louisiana, Texas, Arkansas and Oklahoma. We organize our operations into two principal regions: the Mid-Continent, which includes our Louisiana and Arkansas properties; and the Western, which includes our Texas and Oklahoma properties.

At December 31, 2008, 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 1,418 billion cubic feet of natural gas equivalent (Bcfe), consisting of 14 million barrels (MMBbls) of oil, and 1,335 billion cubic feet (Bcf) of natural gas and natural gas liquids. Approximately 56% of our proved reserves were classified as proved developed. We maintain operational control of approximately 83% of our proved reserves. Production for our fourth quarter averaged 361 million cubic feet of natural gas equivalent per day (Mmcfe/d) and we exited the quarter producing approximately 400 Mmcfe/d. Full year 2008 production averaged 305 Mmcfe/d. Our total operating revenues for 2008 were $1.1 billion.

We seek to maintain a portfolio of long-lived, lower risk properties in resource-style plays, which typically are characterized by lower geological risk and a large inventory of identified drilling opportunities. We focus on properties within our core operating areas which we believe have significant development and exploration opportunities and where we can apply our technical experience and economies of scale to increase production and proved reserves while lowering lease operating costs. In late 2007 and throughout 2008, we sought to aggressively expand our leasehold position in resource-style natural gas plays within our core operating areas, particularly in the Haynesville Shale play in northern Louisiana and East Texas. We believe the steps we have taken will help us grow production and reserves in resource-style, tight-gas areas in North Louisiana, Arkansas and Texas.

Recent Developments

Haynesville Shale

The Haynesville Shale has become one of the most active natural gas plays in the United States. This area is defined by a shale formation located approximately 1,500 feet below the Cotton Valley formation at depths ranging from approximately 10,500 feet to 13,000 feet. The formation is as much as 300 feet thick and is composed of an organic rich black shale. It is located across numerous parishes in Northwest Louisiana, primarily in Caddo, Bossier, Red River, DeSoto, Webster and Bienville parishes and also in East Texas, primarily in Harrison, Panola and Shelby 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 300,000 net acres in the Haynesville Shale play. As of December 31, 2008, we had reported initial production tests from ten of our operated wells with an average initial production rate of 19.3 Mmcfe/d. We recently placed four additional wells online utilizing similar production practices. The initial production rates of these wells averaged 17.7 Mmcfe/d. Two additional Haynesville well completions experienced mechanical problems that resulted in lower than expected initial production rates. We currently estimate that the average rate of production will decline approximately 80% during the first twelve months of production. Actual decline rates may differ significantly. At year-end 2008, we had 11 operated horizontal drilling rigs in the Haynesville Shale.

Eagle Ford Shale

We recently announced our discovery of the Eagle Ford Shale play in South Texas. The Eagle Ford Shale is found at a depth of approximately 11,000 feet to 12,000 feet and has a thickness of approximately 250 feet. We currently have approximately 156,000 net acres leased in the play. Our first well had an initial production rate of 9.1 Mmcfe/d. We recently completed our second well at a rate of 8.3 Mmcfe/d. We are currently completing our third well and are drilling our fourth well.

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Senior Note Offering

On January 27, 2009, we completed a private placement offering to eligible purchasers of an aggregate principal amount of $600 million 10.5% senior notes due August 1, 2014. The notes were priced at 91.279% of the face value to yield 12.75% to maturity. Net proceeds from the offering were used to repay all outstanding borrowings on our Third Amended and Restated Senior Revolving Credit Agreement (the Senior Credit Agreement), and provides additional financial flexibility to fund our 2009 capital budget as well as potential acquisitions and further infrastructure expansion.

2009 Capital budget

The continued credit crisis and related turmoil in the global financial system and economic recession in the United States create financial challenges that will grow if conditions do not improve. In response to these crises and declining oil and natural gas prices during the last half of 2008, we reduced and refocused our 2009 capital budget on the development of non-proved locations in our Haynesville, Fayetteville and Eagle Ford Shale plays. We believe these projects offer the potential for the highest internal rates of return and reserve growth. Currently we plan to spend approximately $1.0 billion on drilling, completions, seismic and facilities during 2009, of which $690 million has been allocated to our Haynesville Shale properties, $100 million to our Fayetteville Shale properties and $50 million to our Eagle Ford Shale properties. We expect to fund our 2009 capital budget with cash and marketable securities on hand, additional borrowings under our Senior Credit Agreement and cash flows from operations. We also strive to maintain financial flexibility and may access capital markets as necessary to maintain substantial borrowing capacity under our Senior Credit Agreement, facilitate drilling on our large undeveloped acreage position and permit us to selectively expand our acreage position and infrastructure projects. In the event our cash flow is materially less than anticipated and other sources of capital we historically have utilized are not available on acceptable terms, we may be required to curtail our expected capital spending.

New Gathering Subsidiary Hawk Field Services, LLC

During 2008, we initiated construction of our own gathering systems to service our wells as well as third party production in the Fayetteville and Haynesville Shales. Operating under a new subsidiary, Hawk Field Services, LLC, we constructed approximately 110 miles of gathering lines in the Fayetteville Shale in 2008, and have approximately 150 miles of gathering lines currently in service, under construction or planned in the Haynesville Shale during 2009.

New Marketing Subsidiary HK Energy Marketing, LLC

During the fourth quarter of 2008, we began purchasing and selling third party natural gas produced from wells we operate. We report the revenues and expenses related to these marketing activities on a gross basis as part of our operating revenues and operating expenses. Marketing revenues are recorded at the time natural gas is physically delivered to third parties at a fixed or index price. Marketing expenses attributable to gas purchases are recorded as we take physical title to the natural gas and then transport the purchased volumes to the point of sale.

Business Strategy

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

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

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

Reduced operating costs We focus on reducing the per unit operating costs associated with our properties and have been successful in lowering our lease operating expenses from $0.73 per Mcfe in 2006 to $0.56 per Mcfe in 2007 and to $0.47 per Mcfe in 2008.

Divestment of non-resource and non-core properties We continually evaluate our property base to identify opportunities to divest non-core, higher cost or less productive properties with limited development potential. This strategy allows us to focus on a portfolio of core properties with significant potential to increase our proved reserves and production and reducing operating costs. We also continue to evaluate divestment opportunities for our non-resource-style properties located primarily in the Permian Basin.

Maintenance of financial flexibility We strive to maintain our financial flexibility by balancing our financial resources with our plans to develop our key properties and pursuit of opportunities for growth and expansion. We intend to maintain substantial borrowing capacity under our Senior Credit Agreement to facilitate drilling on our large undeveloped acreage position in resource-style plays, permit us to selectively expand our position in these plays and expand our infrastructure projects. We access capital markets as necessary to maintain our financial flexibility.

Monetize at an appropriate time with the goal of providing superior returns to stockholders The independent exploration and production industry has been consolidating for a number of years. Our business strategy embraces this trend. We seek to assemble and maintain within our core operating areas a high-quality, lower cost portfolio of operated properties with attractive production, reserve and development profiles that may be desirable to industry participants.

Oil and Natural Gas Reserves

The December 31, 2008 proved reserve estimates presented in this document were prepared by Netherland, Sewell. 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)*. Our reserves are sensitive to commodity prices and their effect on economic producing rates.

The reserves information in this Form 10-K represents only estimates. There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control, such as commodity pricing. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of 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 justify 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.

Proved reserve estimates are based on the December 31, 2008 West Texas Intermediate posted price of $41.00 per barrel (Bbl) for oil and natural gas liquids, adjusted by lease for quality, transportation fees, and regional price differentials and on a December 31, 2008 Henry Hub spot market price of $5.71 per million British thermal unit (MMbtu) for natural gas, as adjusted by lease for energy content, transportation fees, and regional

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price differentials. All prices and costs associated with operating wells were held constant in accordance with the United States Securities and Exchange Commission (SEC) guidelines. The following table presents certain information as of December 31, 2008. Shut-in wells currently not capable of production are excluded from producing well information.

	Mid-Continent Region	Western Region	Total
Proved Reserves at Year End (Bcfe) [1]			
Developed	599.3	192.7	792.0
Undeveloped	549.9	75.8	625.7
Total	1,149.2	268.5	1,417.7
Gross Wells	3,148	4,146	7,294
Net Wells [1]	1,354.4	1,283.7	2,638.1

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

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

Core Operating Regions

Mid-Continent Region

In the Mid-Continent Region, we concentrate our drilling program primarily in North Louisiana and in the Fayetteville Shale in the Arkoma Basin. We believe our Mid-Continent Region operations provide us with a solid base for future production and reserve growth. During 2008, we drilled 601 wells in this region with a success rate of 98%. In 2009, we plan to drill approximately 125 to 130 operated wells in this region. In 2008, we produced 85 Bcfe in this region, or 232 Mmcfe/d. As of December 31, 2008, approximately 81% of our proved reserves, or 1,149 Bcfe, were located in our Mid-Continent Region.

Elm Grove and Caspiana Field Located primarily in Bossier and Caddo Parishes of North Louisiana, our Elm Grove and Caspiana field produces from the Hosston and Cotton Valley formations. These zones are composed of low permeability sandstones that require fracture stimulation treatments to produce. We own varying working and net revenue interests in this field. We produced 44 Bcfe in 2008 in this field, or 119 Mmcfe/d. As of December 31, 2008, proved reserves for the Elm Grove/Caspiana field were approximately 685 Bcfe, of which approximately 49% were classified as proved undeveloped and approximately 14% proved developed non-producing.

During 2008, we drilled 143 wells, all of which were successful. Additionally, we have successfully utilized coiled tubing for recompletions to fracture stimulate and commingle the shallower Hosston formation with the existing Lower Cotton Valley formation, increasing the present value of the wells and reducing future capital expenditures. In 2009, we do not currently plan on drilling any operated wells as we focus our drilling efforts on our Haynesville Shale properties.

Fayetteville Shale We have assembled a position of approximately 157,000 net acres in the Fayetteville Shale, which we believe holds significant potential for production and reserve growth. The Fayetteville Shale is an unconventional gas reservoir located in the Arkoma Basin in Arkansas, at a depth of approximately 1,500 feet to 6,500 feet and ranging in thickness from 100 feet to 500 feet. The formation is a Mississippian-age shale that has similar geologic characteristics to the Barnett Shale in the Ft. Worth Basin of North Texas. Drilling in the play began in 2004 and has accelerated rapidly during the past three years. To date, the best results have been obtained by drilling horizontal wells with lateral lengths of 2,500 feet to 3,000 feet and utilizing slickwater fracture stimulation completions. Throughout 2008, we experienced significant operational improvements in the results of completions, primarily as a result of drilling longer laterals with cemented liners. We have increased our average lateral length from 2,286 feet during the first quarter of 2008 to 2,655 feet during the fourth quarter of

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2008 and our average number of fracture stages has increased from 6.0 during the first quarter of 2008 to 7.6 during the fourth quarter of 2008. As a result, our average state initial production test rates have increased from 1.9 Mmcfe/d in the first quarter of 2008 to 2.5 Mmcfe/d in the fourth quarter of 2008, a 28% increase. Our percentage of completions that tested greater than 3 Mmcfe/d increased from 12% in the first quarter of 2008 to 54% in the fourth quarter of 2008, with two wells in the second half of 2008 testing greater than 5 Mmcfe/d. We own varying working and net revenue interests in this area.

As of December 31, 2008, proved reserves for this field were approximately 173 Bcfe, of which approximately 31% were classified as proved undeveloped and approximately 4% proved developed non-producing. During 2008, we drilled 350 wells, 347 of which were successful for a rate of 99%. In 2009, we plan to drill approximately 50 wells in this area. We produced 18 Bcfe in 2008 in this area, or 49 Mmcfe/d.

To support the planned expansion of our operations in this area, we recently completed construction of six separate pipeline segments. Specifically, we built and currently operate approximately 110 miles of pipelines that gather natural gas from our wells and transport it to interconnects with various interstate pipelines. These systems consist of six-inch to 16-inch diameter pipelines with throughput capacity of approximately 200 million cubic feet (Mmcf) of natural gas per day with associated compression and gas dehydration facilities. These gathering systems provide us with a field-wide distribution network to major transportation pipelines and allow us to deliver a vast majority of our production directly into the recently completed Boardwalk Pipeline.

Haynesville Shale The Haynesville Shale has become one of the most active natural gas plays in the United States. This area is defined by a shale formation located approximately 1,500 feet below the base of the Cotton Valley formation at depths ranging from approximately 10,500 feet to 13,000 feet. The formation is as much as 300 feet thick and is composed of an organic rich black shale. It is located across numerous parishes in Northwest Louisiana, primarily in Caddo, Bossier, Red River, DeSoto, Webster and Bienville parishes and also in East Texas, primarily in Harrison, Panola and Shelby counties. In addition to the Haynesville Shale potential associated with this play, the Bossier Shale is also believed to be a prospective reservoir. It is situated above the Haynesville Shale in several distinct shale packages below the Lower Cotton Valley sands and appears potentially productive in areas of Northwest Louisiana and Northeast Texas. 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 300,000 net acres in the area we currently believe to be prospective for the Haynesville Shale. We own varying working and net revenue interests in this area.

Our current drilling and completion methodology focuses on completing wells with longer laterals and maximizing the number of fracture stages, spaced approximately 325 feet apart. The objective of this technique is to minimize the total number of wells required to effectively drain the reservoir, resulting in lower overall development costs. We are currently targeting lateral lengths between 4,300 feet and 4,600 feet with up to 15 fracture stages. At year-end 2008, we had 11 operated horizontal rigs in the Haynesville Shale. We currently expect spud-to-first sales to average approximately 90 days during 2009.

As of December 31, 2008, we had reported initial production tests from ten of our operated wells with an average initial production rate of 19.3 Mmcfe/d. We recently placed four additional wells online utilizing production practices consistent with previously reported wells. The initial production rates of these wells averaged 17.7 Mmcfe/d. Two additional Haynesville well completions experienced mechanical problems that resulted in lower than expected initial production rates. We currently estimate that average monthly rates of production will decline approximately 80% during the first twelve months of production. Actual decline rates may differ significantly.

In 2008, we produced 6 Bcfe in this area, or 17 Mmcfe/d. As of December 31, 2008, proved reserves for this field were approximately 163 Bcfe, of which approximately 62% were classified as proved undeveloped and approximately 10% proved developed non-producing. During 2008, we drilled 26

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wells, all of which were successful. We plan to drill approximately 75 operated wells in this area in 2009, with approximately six wells expected to be completed per month. We expect to operate an average of 12 rigs in the play in 2009, with an emphasis on growing production and reserves while at the same time holding our acreage position.

In this area, we are in the process of building high pressure gathering systems to transport our production to various intrastate and interstate pipelines. We have built or plan to build approximately 150 miles of primarily 16-inch diameter pipeline in several of our drilling areas that we expect will improve our operational control and access to natural gas markets. Total system capacity is planned to be approximately 1.0 Bcf per day and will include associated treating facilities.

Terryville Field Located in Lincoln Parish, Louisiana. The objective formations in this field include the Cotton Valley, Bossier and Gray sands. We own varying working and net revenue interests in this field. As of December 31, 2008, proved reserves for this field were approximately 112 Bcfe, of which approximately 44% were classified as proved undeveloped and approximately 9% proved developed non-producing. In 2008, we drilled 49 wells, all of which were successful. We do not currently plan on drilling any operated wells in 2009. We produced 15 Bcfe in 2008 in this field, or 42 Mmcfe/d.

During 2007 we acquired a 50 square mile 3-D seismic dataset over the field. Delivered late in the third quarter of 2007, the data identified several areas which we believe present significant drilling opportunities. Specifically, the data has been used to identify potential gas bearing Gray sand structures, and an area of Bossier expansion that we feel is indicative sand development. During the later part of 2007 we drilled a number of wells in this area of Bossier expansion and have verified that the area does contain Bossier sands that have resulted in production.

In late December 2007, we acquired approximately 8,000 net acres immediately west and contiguous to our Terryville leasehold. The area overlies a large untested structure in the Gray sand and Lower Cotton Valley sands. The majority of the production from the field has come from Upper Cotton Valley and Hosston sands. However, these sands appear to be underdeveloped, and we have identified numerous developmental drilling opportunities. We have finalized the acquisition of approximately 60-square miles of 3-D seismic data over the acreage that will be merged with our existing 3-D seismic data over Terryville and are hopeful that numerous exploration and exploitation opportunities will be identified with the data.

Western Region

Our principal properties in the Western Region include the Sawyer Canyon Field in Sutton County, Texas, Waddell Ranch Field in Crane County, Texas, Jalmat Field in Lea County, New Mexico, TXL Field in Ector County, Texas, East Texas area concentrated in Panola, Harrison, Shelby and Nacadoches Counties, Texas, WEHLU Field in Oklahoma County, Oklahoma and Eagle Ford Shale in South Texas. During 2008, we drilled 138 wells in this region, all of which were successful. In 2009, we plan to drill approximately 50 wells in this region. In 2008, we produced 27 Bcfe from this region, or 73 Mmcfe/d. As of December 31, 2008, approximately 19% of our proved reserves, or 269 Bcfe, were located in our Western Region fields.

Sawyer Canyon Field This field is located in Sutton County, Texas. Our ownership in the field is comprised of interest in approximately 50 sections, and during the past several years we have been developing gas bearing Canyon sandstone formations ranging in depths from 5,500 feet to 6,800 feet. We have a 92% to 100% working interest in most of the areas we are actively drilling. As of December 31, 2008, proved reserves for this field were approximately 55 Bcfe. Twenty-four wells were drilled in 2008. We produced 4 Bcfe in 2008 in this field, or 10 Mmcfe/d. In 2009, we do not currently plan to drill any wells.

Waddell Ranch Field This field is located in Crane County, Texas. The Waddell Ranch Field complex is comprised of 17,000 net acres and is productive from over 15 different reservoirs. The primary production is from the Queen, Grayburg, San Andres, Clearfork, and Ellenburger formations ranging in depth from 3,000 feet to 11,000 feet. We have a working interest in this non-operated field that ranges from 19% to 75% that is burdened by a significant net profits interest that reduces our average working interest and our average net revenue interest to 13%. As of December 31, 2008, proved reserves for this field were approximately 40 Bcfe. In 2008, eight wells were drilled. We produced 3 Bcfe in 2008 in this field, or 8 Mmcfe/d. In 2009, we plan to drill approximately 6 wells.

Jalmat Field An extensive review of Jalmat Field, located in Lea County, New Mexico, has resulted in the identification of over 45 recompletion/stimulation workovers in the Tansill, Yates and Seven Rivers and significant waterflood potential in the Seven Rivers-Queen zone. We own a 96% working interest and 79% net revenue interest in this field. As of December 31, 2008, proved reserves for this field were approximately 40 Bcfe. We produced 2 Bcfe in 2008 in this field, or 5 Mmcfe/d. In 2008, we did not drill any wells and in 2009, we do not currently plan to drill any wells.

TXL Field This waterflood is located in Ector County, Texas and is unitized in the Clearfork/Tubb formation at approximately 5,600 feet. We have a 20% working interest and a 25% net revenue interest in this non-operated property. Over 100 additional infill drill sites remain to be drilled in this property which we believe will lead to additional proved reserves as well as upside potential. As of December 31, 2008, proved reserves for this field were approximately 19 Bcfe. We drilled nine wells in 2008. We produced 1 Bcfe in 2008 in this field, or 3 Mmcfe/d. In 2009, we plan to drill five wells.

East Texas Area Our properties in the East Texas Basin have Haynesville Shale potential, as well as production from the Cotton Valley, Travis Peak and James Lime formations, which range in depth from approximately 6,500 feet to 10,000 feet. We own significant interests in the Joaquin, South Carthage, North Beckville and Blocker fields in Shelby, Panola and Harrison Counties, Texas. We own varying interests in these fields. In 2008, we actively acquired acreage in the developing James Lime horizontal play and in the Travis Peak vertical play in Nacogdoches and Shelby Counties, Texas. In the 3rd quarter of 2008 we entered into a Joint Venture with EOG Resources to jointly develop our acreage primarily in Nacogdoches and Shelby Counties, Texas. We have approximately 45% working interest under the Joint Venture. As of December 31, 2008, proved reserves for this area were approximately 18 Bcfe. During 2008 we drilled 12 wells, all of which were successful. We produced 2 Bcfe in 2008 in this area, or 4 Mmcfe/d. For 2009, approximately six operated wells are expected to be drilled.

WEHLU Field The West Edmond Hunton Lime Unit, or WEHLU, covers 29,000 net acres primarily in Oklahoma County, Oklahoma. The WEHLU field, originally discovered in 1942, is the largest Hunton Lime formation field in the state of Oklahoma. The field has 59 oil and natural gas wells (52 currently producing approximately 12 Mmcfe/d net) with stable production holding the entire unit. We own a 98% working interest and 80% net revenue interest in the majority of the field. Additionally, we have an agreement with a public company to jointly develop additional reserves and production in a portion of WEHLU. The area of mutual interest created by the agreement covers 5,680 acres located in the central northwest portion of the field and we own a 40% working interest and 33% net revenue interest in this area. As of December 31, 2008, proved reserves for this field were approximately 17 Bcfe. Thirteen successful horizontal wells were drilled in 2008. We produced 4 Bcfe in 2008 in this field, or 10 Mmcfe/d. In 2009, we plan to drill four wells.

Eagle Ford Shale We recently announced our discovery of the Eagle Ford Shale play in South Texas. The Eagle Ford Shale is found at a depth of approximately 11,000 feet to 12,000 feet and has a thickness of approximately 250 feet. We currently have approximately 156,000 net acres leased in the play. We own varying interests in the play. Our first well had an initial production rate of 9.1 Mmcfe/d. We recently completed our second well at a rate of 8.3 Mmcfe/d. The well was drilled to a true vertical depth of approximately 11,000 feet and had a lateral length of 4,300 feet with 12 stages of fracture stimulation. We are currently completing our third well and are drilling our fourth well. In 2008, we produced 0.1Bcfe in this area, or 0.4 Mmcfe/d. As of December 31, 2008, proved reserves for this field were approximately 1.0 Bcfe. During 2008, we drilled two wells, both of which were successful. In 2009, we plan to drill 10 to 12 wells in this area.

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Risk Management

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

We only enter into derivatives arrangements counterparties within our Senior Credit Agreement banking group that we believe are credit worthy as these arrangements expose us to the risk of financial loss if our counterparty is unable to satisfy its obligations. We will continue to evaluate the benefit of employing derivatives in the future. See Item 7A. *Quantitative and Qualitative Disclosures about Market Risk* for additional information.

Oil and Natural Gas Operations

Our principal properties consist of developed and undeveloped oil and natural gas leases and the reserves associated with these leases. Generally, developed oil and natural gas leases remain in force as long as production is maintained. Undeveloped oil and natural gas leaseholds are generally for a primary term of three to five years. In most cases, the term of our undeveloped leases can be extended by paying delay rentals or by producing oil and natural gas reserves that are discovered under those leases.

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

	Years Ended December 31,					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive [(1)]	555	183.0	292	127.4	178	71.2
Dry	12	2.0	12	5.6	19	6.0
Total Exploratory	567	185.0	304	133.0	197	77.2
Development Wells:						
Productive [(1)]	172	82.4	113	72.2	132	59.8
Dry			3	1.3	1	
Total Development	172	82.4	116	73.5	133	59.8
Total Wells:						
Productive [(1)]	727	265.4	405	199.6	310	131.0
Dry	12	2.0	15	6.9	20	6.0
Total	739	267.4	420	206.5	330	137.0

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

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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 or licenses that have varying terms. The following table presents a summary of our acreage interests as of December 31, 2008:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
State						
Alabama			27,389	13,965	27,389	13,965
Arkansas	49,584	32,864	189,313	129,298	238,897	162,162
Indiana			11,582	8,826	11,582	8,826
Kansas	16,663	7,846	812	497	17,475	8,343
Louisiana	135,978	68,410	247,920	198,384	383,898	266,794
New Mexico	16,388	11,957	240	240	16,628	12,197
Oklahoma	263,513	96,038	12,429	5,999	275,942	102,037
Texas	258,796	98,990	235,739	142,668	494,535	241,658
Total Acreage	740,922	316,105	725,424	499,877	1,466,346	815,982

At December 31, 2008, we had estimated proved reserves of approximately 1,418 Bcfe comprised of 1,335 Bcf of natural gas and natural gas liquids and 14 MMBbls of oil. The following table sets forth, at December 31, 2008, these reserves:

	Proved Developed	Proved Undeveloped	Total Proved
Gas (Bcf) [(1)]	737.4	597.3	1,334.7
Oil (MMBbls)	9.1	4.7	13.8
Equivalent (Bcfe)	792.0	625.7	1,417.7

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

The estimates of quantities of proved reserves above were made in accordance with the definitions contained in SEC Regulation S-X, Rule 4-10(a). For additional information on our oil and natural gas reserves, see Item 8. *Consolidated Financial Statements and Supplementary Data Supplementary Oil and Gas Information (Unaudited).*

We account for our oil and natural gas producing activities using the full cost method of accounting in accordance with SEC regulations. Accordingly, all costs incurred in the acquisition, exploration, and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of evaluated oil and natural gas properties are subject to a quarterly full cost ceiling test. We recorded a full cost ceiling impairment of approximately $1.0 billion at December 31, 2008, at which time the West Texas Intermediate posted price was $41.00 per barrel for oil and the Henry Hub spot market price was $5.71 per MMbtu for natural gas.

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Capitalized costs of our evaluated and unevaluated properties at December 31, 2008, 2007 and 2006 are summarized as follows:

	2008	December 31, 2007 (In thousands)	2006
Oil and gas properties (full cost method):			
Evaluated	$ 4,894,357	$ 3,247,304	$ 2,901,649
Unevaluated	2,287,968	677,565	537,611
Gross oil and gas properties	7,182,325	3,924,869	3,439,260
Less accumulated depletion	(2,111,038)	(769,197)	(379,017)
Net oil and gas properties	$ 5,071,287	$ 3,155,672	$ 3,060,243

Our oil and natural gas production volumes and average sales price are as follows:

	Years Ended December 31, 2008	2007	2006
Production:			
Gas production (Mmcf) [(1)]	102,273	99,506	63,643
Oil production (MBbl)	1,554	2,816	2,703
Equivalent production (Mmcfe)	111,597	116,402	79,863
Average Daily Production (Mmcfe)	305	319	219
Average price per unit: [(2)]			
Gas (per Mcf) [(1)]	$ 8.56	$ 6.92	$ 6.57
Oil (per Bbl)	95.16	68.84	62.27
Equivalent (per Mcfe)	9.17	7.58	7.34

(1) *Approximately 2%, 4% and 5% of natural gas production represents natural gas liquids (calculated with a 6:1 equivalent ratio) with an average price of $56.63 per Bbl, $43.70 per Bbl and $36.88 per Bbl for the years ended December 31, 2008, 2007 and 2006, respectively.*

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

The 2008, 2007 and 2006 average oil and natural gas sales prices above do not reflect the impact of cash paid on, or cash received from, settled derivative contracts as these amounts are reflected as other income and expenses in the consolidated statements of operations, consistent with our decision not to elect hedge accounting. Including this impact 2008, 2007 and 2006 average gas sales prices were $8.13, $7.41 and $6.75 per thousand cubic feet (Mcf) and our average oil sales prices were $74.82, $67.03 and $54.28 per barrel (Bbl), respectively.

Competitive Conditions in the Business

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater financial and other resources. Many of these companies explore for, produce and market oil and natural gas, as well as carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, obtaining sufficient rig availability, obtaining purchasers and transporters of the oil and natural gas we produce and hiring and retaining key employees. There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States. It is not possible to predict the nature of

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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 2008, two individual purchasers of our production each accounted for in excess of 10% of our total sales, collectively representing 30% of our total sales. In 2007, we had one purchaser of our production that accounted for 10% of our total sales. In 2006, we had no individual purchasers that accounted for more than 10% of our total sales. We do not believe the loss of any one of our purchasers would materially affect our ability to sell the oil and natural gas we produce. We believe other purchasers are available in our areas of operations.

Seasonality of Business

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

Operational Risks

Oil and natural gas exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that we will discover or acquire additional oil and natural gas in commercial quantities. Oil and natural gas operations also involve the risk that well fires, blowouts, equipment failure, human error and other circumstances 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 financial position and results of operations. For further discussion on risks see Item 1A. *Risk Factors.*

Regulations

Domestic exploration for, production and sale of, oil and natural gas are extensively regulated at the federal, state and local levels. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding on the oil and natural gas industry that often are costly to comply with and that carry substantial penalties for failure to comply. In addition, production operations are affected by changing tax and other laws relating to the oil and natural gas industry, constantly changing administrative regulations and possible interruptions or termination by government authorities.

State regulatory authorities have established rules and regulations requiring permits for drilling operations, drilling bonds and reports concerning operations. Most states in which we operate also have statutes and regulations governing a number of environmental and conservation matters, including the unitization or pooling of oil and natural gas properties and establishment of maximum rates of production from oil and natural gas

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wells. Many states also restrict production to the market demand for oil and natural gas. Such statutes and regulations may limit the rate at which oil and natural gas could otherwise be produced from our properties.

We are subject to extensive and evolving environmental laws and regulations. These regulations are administered by the United States Environmental Protection Agency and various other federal, state, and local environmental, zoning, health and safety agencies, many of which periodically examine our operations to monitor compliance with such laws and regulations. These regulations govern the release of waste materials into the environment, or otherwise relating to the protection of the environment, human, animal and plant health, and affect our operations and costs. In recent years, environmental regulations have taken a cradle to grave approach to waste management, regulating and creating liabilities for the waste at its inception to final disposition. Our oil and natural gas exploration, development and production operations are subject to numerous environmental programs, some of which include solid and hazardous waste management, water protection, air emission controls and situs controls affecting wetlands, coastal operations and antiquities. Further, each state in which we operate has laws and regulations governing solid waste disposal, water and air pollution. Many states also have regulations governing oil and natural gas exploration, development and production operations.

Environmental 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 request 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 emissions of certain gases, commonly referred to as greenhouse gases including carbon dioxide and methane, which according to recent studies may be contributing to the warming of the Earth s atmosphere. In response to these studies, President Obama has expressed support for, and it is anticipated that the current session of Congress will consider, legislation to restrict or regulate emissions of greenhouse gases. 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. Depending on the particular program, we could be required to purchase and surrender allowances for greenhouse gas emissions resulting from our operations. Also, the Environmental Protection Agency may regulate greenhouse gas emissions even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. In July 2008, EPA released an Advance Notice of Proposed Rulemaking regarding possible future regulation of greenhouse gas emissions under the Clean Air Act. Although the notice did not propose any specific, new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases.

We are also 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. We believe we are in compliance with these requirements in all material respects.

We may be required in the future to make substantial outlays to comply with environmental laws and regulations. The additional changes in operating procedures and expenditures required to comply with future laws dealing with the protection of the environment cannot be predicted.

Employees

As of December 31, 2008, we had 378 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.

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Access to Company Reports

We file periodic reports, proxy statements and other information with the SEC in accordance with the requirements of the Securities Exchange Act of 1934, as amended. We make our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and Forms 3, 4 and 5 filed on behalf of directors and officers, and any amendments to such reports available free of charge through our corporate website at *www.petrohawk.com* as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. In addition, our corporate governance guidelines, code of conduct, code of ethics for our chief executive officer (CEO) and senior financial officers, audit committee charter, compensation committee charter and nominating committee charter are available on our website. Within the time period required by the SEC and the New York Stock Exchange (NYSE), as applicable, we will post on our website any modifications to the code of conduct and the code of ethics for our CEO and senior financial officers and any waivers applicable to senior officers as defined in the applicable code, as required by the Sarbanes-Oxley Act of 2002. You may also read and copy any document we file with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, our reports, proxy and information statements, and our other filings are also available to the public over the internet at the SEC s website at *www.sec.gov*. Unless specifically incorporated by reference in this annual report on Form 10-K, information that you may find on our website is not part of this report.

ITEM 1A. RISK FACTORS

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

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

Further, access to adequate gathering systems or pipeline takeaway capacity and the availability of drilling rigs and other services may be more challenging in new or emerging plays. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and takeaway capacity or otherwise, and/or natural gas and oil prices decline, the return on our investment in these areas may not be as attractive as we anticipate and we could incur material writedowns of unevaluated properties and the value of our undeveloped acreage could decline in the future.

We have substantial indebtedness and may incur substantially more debt. Any failure to meet our debt obligations would adversely affect our business and financial condition.

We have incurred substantial debt amounting to approximately $2.3 billion as of December 31, 2008. As a result of our indebtedness, we will need to use a portion of our cash flow to pay interest, which will reduce the amount we will have available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Our indebtedness under our Senior Credit Agreement is at a variable interest rate, and so a rise in interest rates will generate greater interest expense to the extent we do not have applicable interest rate fluctuation hedges. The

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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. To the extent we incur additional indebtedness, other than under our Senior Credit Agreement, our borrowing base under our Senior Credit Agreement will be reduced by $0.25 for each additional dollar of new debt. On January 27, 2009, we completed a private placement of an aggregate principal amount of $600 million 10.5% senior notes due August 1, 2014. As a result of the offering, our borrowing base was decreased from $1.1 billion to $950 million. Our borrowing base is subject to semi-annual redeterminations and may also be redetermined periodically at the discretion of the banks. Our borrowing base is determined by the banks and is dependent upon our proved developed reserves and the outlook for oil and natural gas prices. If our borrowing base were reduced below the amount of outstanding borrowings, we would be required to repay the excess borrowings promptly. During the first quarter of 2009, we initiated a borrowing base redetermination of our Senior Credit Agreement. Our borrowing base of $950 million, along with our existing terms and pricing, were reaffirmed.

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

We may not be able to drill wells on a substantial portion of our potential resource play locations.

We may not be able to drill on a substantial portion of our potential resource play locations for various reasons. We may not generate or be able to raise sufficient capital to do so. Further deterioration in commodities pricing may also make drilling some resource play 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 on these potential locations may not be successful or result in our ability to 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.

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, 2008, we own leasehold interests in approximately 300,000 net acres in areas we believe are prospective for the Haynesville Shale. A large portion of the acreage is not currently held by production. Unless production in paying quantities is established on units containing these leases during their terms, these leases will expire. If our leases expire, we will lose our right to develop the related properties.

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

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

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

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

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

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

Our Senior Credit Agreement limits our borrowings to the lesser of the borrowing base and the total commitments. Our borrowing base is currently $950 million. The borrowing base is determined semi-annually, and may also be redetermined periodically at the discretion of the banks. Lower oil and natural gas prices may result in a reduction in our borrowing base at the next redetermination. During the first quarter of 2009, we initiated a borrowing base redetermination of our Senior Credit Agreement. Our borrowing base of $950 million, along with our existing terms and pricing, were reaffirmed. A reduction in our borrowing base could require us to repay any indebtedness in excess of the borrowing base. Additionally, the indentures governing our senior unsecured debt contain covenants limiting our ability to incur additional indebtedness, including borrowings under our Senior Credit Agreement, unless we meet one of two alternative tests. The first test applies to all indebtedness and requires that after giving effect to the incurrence of additional debt the ratio of our adjusted consolidated EBITDA (as defined in our indentures) to our adjusted consolidated interest expense over the trailing four fiscal quarters will be at least 2.5 to 1.0. The second test applies only to borrowings under our Senior Credit Agreement that do not meet the first test and it limits these borrowings to the greater of a fixed sum (the most restrictive indenture limit being $100 million) and a percentage (the most restrictive indenture limit being 20%) of our adjusted consolidated net tangible assets (as defined in all of our indentures), which is determined using discounted future net revenues from proved natural gas and oil reserves as of the end of each year. Currently, we are permitted to incur additional indebtedness under these incurrence tests, but may be limited in the future. Lower natural gas and oil prices in the future could reduce our adjusted consolidated EBITDA, as well as our adjusted consolidated net tangible assets, and thus could reduce our ability to incur additional indebtedness.

Additionally, our ability to complete future equity offerings is limited by the availability of authorized common stock under our certificate of incorporation and by general market conditions. If we are not able to

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borrow sufficient amounts under our Senior Credit Agreement and/or are unable to raise sufficient capital to fund our capital expenditures, we may be required to curtail our drilling, development, land acquisition and other activities, which could result in forfeiture of leasehold interests if we are unable or unwilling to renew them, and we could be forced to sell some of our assets on an untimely or unfavorable basis, all of which could have a material adverse effect on our results and future operations.

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

The continued credit crisis and related turmoil in the global financial system and economic recession in the United States create financial challenges that will grow if conditions do not improve. In response to these crises and declining oil and natural gas prices, we have reduced and refocused our 2009 capital budget. Although we believe our operating and capital budget for 2009 can be funded with internally generated cash flow and existing financial resources, our cash flow from operations, borrowings under our Senior Credit Agreement and cash on hand historically have not been sufficient to fund all of our expenditures, and we have relied on the capital markets and sales of non-core assets to provide us with additional capital. Our ability to access the capital markets has been restricted as a result of these crises and may continue to be restricted at a time when we would like, or need, to raise capital. If our cash flow from operations is less than anticipated and our access to capital is restricted, we may be required to further reduce our operating and capital budget, which could have a material adverse effect on our results and future operations. The financial crisis may also limit the number of participants or reduce the values we are able to realize in asset sales or other transactions we may engage in to raise capital, thus making these transactions more difficult to consummate and less economic. Additionally, the current economic situation has affected the demand for natural gas and oil and has resulted in lower prices for oil and natural gas, which could have a negative impact on our revenues. Lower prices and could also adversely affect the collectibility of our trade receivables and cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations.

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

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

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

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

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

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- 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.

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

In general, the volume of production from oil and natural gas properties declines as reserves are depleted. Our reserves will decline as they are produced unless we acquire properties with proved reserves or conduct successful development and exploration activities. Thus, our future oil and natural gas production and, therefore, our cash flow and income are highly dependent upon our level of success in finding or acquiring additional reserves. However, we cannot assure you that our future acquisition, development and exploration activities will result in any specific amount of additional proved reserves or that we will be able to drill productive wells at acceptable costs.

The successful acquisition of producing properties requires an assessment of a number of factors. These factors include recoverable reserves, future oil and natural gas prices, operating costs and potential environmental and other liabilities, title issues and other factors. Such assessments are inexact and their accuracy is inherently uncertain. In connection with such assessments, we perform a review of the subject properties that we believe is thorough. However, there is no assurance that such a review will reveal all existing or potential problems or allow us to fully assess the deficiencies and capabilities of such properties. We cannot assure you that we will be able to acquire properties at acceptable prices because the competition for producing oil and natural gas properties is intense and many of our competitors have financial and other resources that are substantially greater than those available to us.

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

This report on Form 10-K contains estimates of our proved oil and natural gas reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

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

At December 31, 2008, approximately 44% of our estimated reserves were classified as proved undeveloped. Estimates of proved undeveloped reserves are less certain than estimates of proved developed reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of these oil and natural gas reserves and the costs associated with

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development of these reserves in accordance with SEC regulations, actual capital expenditures will likely vary from estimated capital expenditures, development may not occur as scheduled and actual results may not be as estimated.

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

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

Our business is highly competitive.

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

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

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

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) in gas we produce;

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- 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.

Governmental and environmental regulations could adversely affect our business.

Our business is subject to federal, state and local laws and regulations on taxation, the exploration for and development, production and marketing of oil and natural gas and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, prevention of waste, unitization and pooling of properties and other matters. These laws and regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning our oil and natural gas wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could limit our revenues.

Our operations are also subject to complex environmental laws and regulations adopted by the various jurisdictions in which we have or expect to have oil and natural gas operations. We could incur liability to governments or third parties for any unlawful discharge of oil, natural gas or other pollutants into the air, soil or water, including responsibility for remedial costs. We could potentially discharge these materials into the environment in any of the following ways:

- from a well or drilling equipment at a drill site;
- from gathering systems, pipelines, transportation facilities and storage tanks;
- damage to oil and natural gas wells resulting from accidents during normal operations; and
- blowouts, hurricanes, cratering and explosions.

Because the requirements imposed by laws and regulations are frequently changed, we cannot assure you that laws and regulations enacted in the future, including changes to existing laws and regulations, will not adversely affect our business. In addition, because we acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage caused by the former operators.

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.

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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 financial position and results of operations. 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. A loss in connection with our oil and natural gas properties could have a materially adverse effect on our financial position and results of operations to the extent that the insurance coverage provided under our policies cover only a portion of any such loss.

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.

Our recent growth is due significantly to acquisitions of exploration and production companies, producing properties and undeveloped and unevaluated leaseholds. We expect acquisitions may also contribute to our future growth. 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 properties which we believe is generally consistent with industry practices. 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 preclosing 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, we may not be able to acquire oil and natural gas properties that contain economically recoverable reserves or be able to complete such acquisitions on acceptable terms.

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 in order 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, we cannot guarantee that all of our prospects will result in viable projects or that we will not abandon our initial investments. Additionally, we cannot guarantee that the leasehold acreage we acquire 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. We rely to a significant extent on 3-D seismic data and other advanced technologies in identifying leasehold acreage prospects and in conducting our exploration activities. The 3-D seismic data and other technologies we use do not allow us to know conclusively prior to our acquisition of leasehold acreage or drilling a well whether oil or natural gas is present or may be produced economically. The use of 3-D seismic data and other technologies also requires greater pre-drilling expenditures than traditional drilling strategies.

In addition, we may not be successful in controlling and reducing our drilling and production costs in order 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 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 rigs and the delivery of equipment;
- adverse weather conditions, including hurricanes; and
- compliance with governmental requirements.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. Increasing levels of exploration and production in response to strong prices of oil and natural gas, may increase the demand for oilfield services, and the costs of these services may increase, while the quality of these services may suffer. If the unavailability or high cost of drilling rigs, equipment, supplies or qualified personnel were particularly severe in Texas, Oklahoma, Arkansas and Louisiana, we could be materially and adversely affected because our operations and properties are concentrated in those areas. In order to secure drilling rigs in these areas, we have entered into certain contracts with drilling companies that extend over several years. If demand for drilling rigs subsides during the period covered by these contracts, the price we are required to pay may be significantly more than the market rate for similar services.

We depend on the skill, ability and decisions of third party operators to a significant extent.

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.

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 including KCS Energy, Inc., 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.

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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. SFAS No. 142, *Goodwill and Other Intangible Assets* (SFAS 142) 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. We completed our annual goodwill impairment test during the third quarters of 2008, 2007 and 2006 and no goodwill impairments were deemed necessary.

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 writedown 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.

At December 31, 2008, we recorded a full cost ceiling impairment of approximately $1.0 billion. The full cost ceiling calculation dictates that prices and costs in effect as of the last day of the quarter are held constant. As a result of the full cost ceiling impairment, we reviewed our goodwill for impairment as of December 31, 2008. Based on that review, no goodwill impairment was deemed necessary. Future adverse changes to any of these factors could lead to an impairment of all or a portion of our goodwill in future periods which could significantly reduce earnings during the period in which the impairment occurs, and would result in a corresponding reduction to goodwill and stockholders equity.

Hedging transactions may limit our potential gains and increase our potential losses.

In order to manage our exposure to price risks in the marketing of our oil and natural gas production, we have entered into oil and natural gas price hedging arrangements with respect to a portion of our anticipated production and we may enter into additional hedging transactions in the future. While intended to reduce the effects of volatile oil and natural gas prices, such transactions may limit our potential gains and increase our potential losses if oil and natural gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

- our production is less than expected;

- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement; or

- the counterparties to our hedging agreements fail to perform under the contracts.

The current economic crisis may have a negative impact on the liquidity of the counterparties to our hedging arrangements, which increases the risk of those counterparties failing to perform under those agreements. If those parties do fail to perform, we will be exposed to the price risks we had sought to mitigate and our operating results, financial position and cash flows may be materially and adversely affected.

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

We may be required under full cost accounting rules to writedown 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

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using prevailing oil and natural gas prices on the last day of the period or a subsequent higher price under certain limited circumstances. 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 writedown the book value of our oil and natural gas properties.

Costs associated with unevaluated properties, which were $2.3 billion at December 31, 2008, 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.

As of December 31, 2008, using the West Texas Intermediate posted price of $41.00 per Bbl for oil and the Henry Hub spot market price of $5.71 per MMbtu for natural gas, we recorded a pre-tax non-cash impairment charge of $1.0 billion as a result of full cost ceiling limitations. As ceiling test computations depend upon the prevailing oil and natural gas prices, as of a fixed date, it is impossible to predict the likelihood, timing and magnitude of any future impairments. Depending on the magnitude, a ceiling test writedown could negatively affect our results of operations.

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 *6, Commitments and Contingencies,* and is incorporated herein by reference.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of our stockholders during the fourth quarter of the fiscal year ended December 31, 2008.

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PART II.

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

Our common stock trades on the New York Stock Exchange under the symbol HK. The following table sets forth the quarterly high and low sales prices per share of our common stock as reported on the Nasdaq Stock Market through March 11, 2007 and on the New York Stock Exchange from March 12, 2007 through December 31, 2008.

	High	Low
2008		
First Quarter	$ 20.49	$ 14.00
Second Quarter	48.82	19.55
Third Quarter	54.49	17.55
Fourth Quarter	21.66	8.49
2007		
First Quarter	$ 13.46	$ 10.23
Second Quarter	17.50	12.87
Third Quarter	17.07	13.64
Fourth Quarter	19.11	15.55

We have never paid cash dividends on our common stock. We intend to retain earnings for use in the operation and expansion of our business and therefore do not anticipate declaring cash dividends on our common stock in the foreseeable future. Any future determination to pay dividends on common stock will be at the discretion of the board of directors and will be dependent upon then existing conditions, including our prospects, and such other factors, as the board of directors deems relevant. We are also restricted from paying cash dividends on common stock under our Senior Credit Agreement and our other long-term debt.

Approximately 533 stockholders of record as of December 31, 2008 held our common stock. In many instances, a registered stockholder is a broker or other entity holding shares in street name for one or more customers who beneficially own the shares.

Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

The following table sets forth certain information with respect to the surrender of our common stock by employees in exchange for the payment of certain tax withholding obligations during the three months ended December 31, 2008.

	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
October 2008	4,444	$ 14.32		
November 2008	1,058	16.90		
December 2008				

(1) *All of the shares were surrendered by employees in exchange for the payment of tax withholding upon the vesting of restricted stock awards. The acquisition of the surrendered shares was not part of a publicly announced program to repurchase shares of our common stock, nor were they considered as or accounted for as treasury shares.*

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Five-Year Stock Performance Graph

The following common stock performance graph shows the performance of Petrohawk common stock up to December 31, 2008. As required by applicable rules of the SEC, the performance graph shown below was prepared based on the following assumptions:

A $100 investment was made in Petrohawk common stock and each index on December 31, 2003.

All quarterly dividends were reinvested at the average of the closing stock prices at the beginning and end of the quarter.

The indices in the performance graph compare the annual cumulative total stockholder return on Petrohawk common stock with the cumulative total return of the Standard and Poor s 500 Index (S&P 500) and a peer group index comprised of 15 U.S. companies engaged in crude oil and natural gas operations whose stocks were traded on NASDAQ or the NYSE during the period from December 31, 2003 through December 31, 2008. The companies that comprise the peer group are Atlas America Inc. (ATLS), Berry Petroleum Corp. (BRY), Cabot Oil & Gas, Corp. (COG), Carrizo Oil & Gas Inc. (CRZO), Cimarex Energy Co. (XEC), Comstock Resources Inc. (CRK), Denbury Resources Inc. (DNR), EXCO Resources Inc. (XCO), Forest Oil Corp. (FST), Mariner Energy, Inc. (ME), Plains Exploration & Production Company (PXP), St. Mary Land & Exploration Co. (SM), Stone Energy Corp. (SGY), Swift Energy Co. (SFY) and Whiting Petroleum Corp. (WLL) collectively referred to as (Peer Group Index).

	12/31/2003	12/31/2004	12/31/2005	12/31/2006	12/31/2007	12/31/2008
Petrohawk	$ 100.00	$ 217.26	$ 335.53	$ 291.88	$ 439.34	$ 396.70
Peer Group Index	$ 100.00	$ 145.41	$ 209.31	$ 226.30	$ 305.06	$ 144.52
S&P 500	$ 100.00	$ 108.99	$ 112.26	$ 127.55	$ 132.06	$ 81.23

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ITEM 6. SELECTED FINANCIAL DATA

The following table presents selected historical financial data derived from our consolidated financial statements. The following data is only a summary and should be read with our historical consolidated financial statements and related notes contained in this document. Our acquisition of KCS Energy, Inc. in 2006 and Mission Resources Corporation in 2005, affects the comparability between the consolidated financial data for the periods presented.

	Years Ended December 31,				
	2008	2007	2006	2005	2004
	(In thousands, except per share data)				
Income Statement Data:					
Total operating revenues	$ 1,095,210	$ 883,405	$ 587,762	$ 258,039	$ 33,577
(Loss) income from operations [1]	(538,050)	250,649	154,540	103,890	4,699
Net (loss) income	(388,052)	52,897	116,563	(16,634)	8,117
Net (loss) income available to common stockholders	(388,052)	52,897	116,346	(17,074)	7,672
Net (loss) income per share of common stock: [2][3]					
Basic	$ (1.77)	$ 0.31	$ 0.95	$ (0.31)	$ 0.71
Diluted	$ (1.77)	$ 0.31	$ 0.92	$ (0.31)	$ 0.36

	As of December 31,				
	2008	2007	2006	2005	2004
	(In thousands)				
Balance sheet data:					
Working (deficit) capital	$ (77,880)	$ (171,304)	$ (85,307)	$ (37,905)	$ 8,856
Total assets	6,907,329	4,672,439	4,279,656	1,410,174	534,199
Total long-term debt [4]	2,283,874	1,595,127	1,326,239	495,801	239,500
Stockholders equity	3,404,910	2,008,897	1,928,344	526,458	247,091

(1) *2008 includes an approximate $1.0 billion full cost ceiling impairment charge recorded by the Company.*

(2) *Common stock share amounts have been restated to reflect a one-for-two stock split effective May 26, 2004.*

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

(4) *Amount excludes deferred premiums on derivatives which have been classified as current for all periods presented.*

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist in understanding our results of operations and our current financial condition. Our consolidated financial statements and the accompanying notes included elsewhere in this 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 independent oil and natural gas company engaged in the exploration, development and production of predominately natural gas properties located onshore in the United States. Our properties are primarily located in Louisiana, Texas, Arkansas and Oklahoma. We organize our operations into two principal regions: the Mid-Continent, which includes our Louisiana and Arkansas properties; and the Western, which includes our Texas and Oklahoma properties.

Historically, we have grown through acquisitions, with a focus on properties within our core operating areas which we believe have significant development and exploration opportunities and where we can apply our technical experience and economies of scale to increase production and proved reserves while lowering lease operating costs. In late 2007 and throughout 2008, we sought to aggressively expand our leasehold position in resource-style natural gas plays within our core operating areas, particularly in the Haynesville Shale play in northern Louisiana and East Texas. We currently own leasehold interests in approximately 300,000 net acres in the Haynesville Shale play. We also own leasehold interests covering approximately 157,000 net acres in the Fayetteville Shale in Arkansas, and, during 2008, we announced our discovery of the Eagle Ford Shale play in South Texas, where we currently own leasehold interests in approximately 156,000 net acres. The vast majority of our acreage in these plays is currently undeveloped. Typically, the leases we own require that production in paying quantities be established on units under the lease within the lease term (generally three to five years) or the lease will expire, although a significant percentage of the leases in the Haynesville Shale play are currently held by production from other producing zones. Lease expirations will be an important factor determining our capital expenditures focus over the next several years.

At December 31, 2008, our estimated total proved oil and natural gas reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell, were approximately 1,418 Bcfe, consisting of 14 MMBbls of oil, and 1,335 Bcf of natural gas and natural gas liquids. Approximately 56% of our proved reserves were classified as proved developed. We maintain operational control of approximately 83% of our proved reserves. Production for the fourth quarter averaged 361 Mmcfe/d and we exited the quarter producing 400 Mmcfe/d. Full year 2008 production was 305 Mmcfe/d. We drilled 739 gross wells (267.4 net wells) in 2008, 727 gross (265.4 net) of which were successful resulting in a success rate of 98%. We had total operating revenues of $1.1 billion compared to $883 million in 2007, an increase of almost 25%.

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, and secondarily upon our commodity price hedging activities. Accordingly, finding and developing oil and natural gas reserves at economical costs is critical to our long-term success.

During the second half 2008, oil and natural gas prices declined significantly in response to the credit crisis, the turmoil in the global financial system and the economic recession in the United States and in other developed

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and developing countries. In response to declining oil and natural gas prices during the last quarter of 2008, we reduced and refocused our 2009 capital budget on the development of non-proved locations in our Haynesville, Fayetteville and Eagle Ford Shale plays. We believe these projects offer the potential for the highest internal rates of return and reserve growth. Currently we plan to spend approximately $1 billion on drilling, completions, seismic and facilities during 2009, of which $690 million has been allocated to our Haynesville Shale properties, $100 million to our Fayetteville Shale properties and $50 million to our Eagle Ford Shale properties. Our future drilling plans are subject to change based upon various factors, some of which are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. To the extent these factors lead to reductions in our drilling plans and associated capital budgets in future periods, our financial position, cash flows and operating results could be adversely impacted.

Another consequence we face as a result of declining oil and natural gas prices is the possibility that we may be required to recognize a non-cash impairment expense under the full cost method of accounting, which we use to account for our oil and natural gas exploration and development activities. We recorded a full cost ceiling impairment of approximately $1.0 billion at December 31, 2008, at which time the West Texas Intermediate posted price was $41.00 per barrel for oil and the Henry Hub spot market price was $5.71 per MMbtu for natural gas. At times, oil and natural gas prices subsequent to year-end have been lower than they were at December 31, 2008. If oil and natural gas prices do not recover, we may be required to take additional impairment charges in the future.

Capital Resources and Liquidity

Our primary sources of capital resources and liquidity are internally generated cash flows from operations, availability under our Senior Credit Agreement, and access to capital markets, to the extent available. The capital markets, as they relate to us, have been adversely impacted by the current financial crisis, concerns about overall deflation and its effect on commodity prices, the possibility of a deepening world recession that may extend for a long period into the future, a lack of liquidity in the banking system and the unavailability and cost of credit. Continued volatility in the capital markets could adversely impact our ability to access the capital markets, which could reduce our ability to execute our development and acquisition plans, our ability to replace our reserves, and eventually, our production levels. During the first quarter of 2009, we initiated a borrowing base redetermination of our Senior Credit Agreement. Our borrowing base of $950 million, along with our existing terms and pricing, were reaffirmed. We will continue to monitor our liquidity and the capital markets.

Our future capital resources and liquidity may depend, in part, on our success in developing the leasehold interests that we acquired. Cash is required to fund capital expenditures necessary to offset inherent declines in production and proven reserves, which is typical in the capital-intensive oil and gas industry. Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding and acquiring additional reserves. During 2008 and to date in 2009, we have raised $1.3 billion of debt (net of expenses) and $1.8 billion of equity capital (net of discounts and expenses). We expect to fund our future capital requirements through internally generated cash flows, borrowings under our Senior Credit Agreement which gives us $950 million of borrowing capacity as of today, and additional future capital market issuances if necessary. Long-term cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the oil and natural gas industry. Oil and natural gas prices have continued to fall after December 31, 2008. If these prices hold for a prolonged period of time or continue to fall, our ability to fund capital expenditures, reduce debt, meet financial obligations and become profitable may be materially impacted. We also strive to maintain financial flexibility and may access capital markets as necessary to maintain substantial borrowing capacity under our Senior Credit Agreement, facilitate drilling on our large undeveloped acreage position and permit us to selectively expand our acreage position and infrastructure projects.

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Cash Flow

Our primary sources of cash in 2008, 2007 and 2006 were from operating and financing activities. Proceeds from the sale of common stock, the issuance of new senior debt and cash received from operations were offset by repayments of our Senior Credit Agreement and cash used in investing activities to fund our drilling program and acquisition activities, net of any divestiture activities. Operating cash flow fluctuations were substantially driven by changes in commodity prices and changes in our production volumes. Working capital was substantially influenced by these variables. Fluctuation in commodity prices and our overall cash flow may result in an increase or decrease in our future capital expenditures. Prices for oil and natural gas have historically been subject to seasonal influences characterized by peak demand and higher prices in the winter heating season; however, the impact of other risks and uncertainties have influenced prices throughout recent years. See Results of Operations below for a review of the impact of prices and volumes on sales.

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Cash flows provided by operating activities	$ 608,955	$ 605,045	$ 296,893
Cash flows used in investing activities	(3,030,450)	(876,696)	(972,566)
Cash flows provided by financing activities	2,426,566	267,870	668,355
Net increase (decrease) in cash	$ 5,071	$ (3,781)	$ (7,318)

Operating Activities. Net cash flows provided by operating activities were $609.0 million, $605.0 million and $296.9 million for the years ended December 31, 2008, 2007 and 2006, respectively. Key drivers of net operating cash flows are commodity prices, production volumes and operating costs.

Net cash provided by operating activities increased in 2008 primarily due to the 21% increase in our average realized natural gas equivalent price compared to the same period in the prior year, partially offset by a 4% decrease in production volumes due to the sale of our Gulf Coast properties during the fourth quarter of 2007. Production for the fourth quarter was 361 Mmcfe/d compared to 315 Mmcfe/d during the third quarter of 2008. We exited the quarter producing 400 Mmcfe/d. Full year 2008 production was 305 Mmcfe/d. We expect to continue to increase our production volumes in 2009 as a result of our capital program which is primarily focused on drilling opportunities in the Haynesville, Fayetteville and Eagle Ford Shales. However, we are unable to predict future production levels or future commodity prices, and, therefore, we cannot provide any assurance about future levels of net cash provided by operating activities.

Net cash flows provided by operating activities increased in 2007 primarily due to our 46% increase in production volumes primarily due to our merger with KCS in July 2006, as well as our 3% increase in our realized natural gas equivalent price.

As a result of significant declines in oil and natural gas prices, net cash flows provided by operating activities declined significantly in the fourth quarter 2008 compared to the third quarter despite significant increases in production.

Investing Activities. The primary driver of cash used in investing activities is capital spending, inclusive of acquisitions and net of divestitures. Cash used in investing activities was $3.0 billion, $876.7 million and $972.6 million for the years ended December 31, 2008, 2007 and 2006, respectively.

In 2008, we spent $3.1 billion on acquisitions of oil and gas properties and capital expenditures. Our acquisitions were partially funded by the remaining restricted cash that we had deposited with a qualified intermediary to facilitate like-kind exchange transactions following the sale of our Gulf Coast properties. We participated in the drilling of 739 gross wells in 2008. We spent an additional $164.8 million on other property and equipment during 2008 as well, primarily to fund the development of gathering systems primarily in the

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Fayetteville Shale in Arkansas and the beginning stages of the development of our gathering systems in the Haynesville Shale in Louisiana.

In 2008, we used a portion of the funds from our debt and equity offerings discussed below to purchase a net $123.0 million of marketable securities. These marketable securities have been classified and accounted for as trading securities and will be used primarily to fund a portion of our 2009 capital program.

In 2007, we spent $1.3 billion on acquisitions of oil and gas properties and capital expenditures. We spent $764.3 million on capital expenditures in conjunction with our drilling program. We participated in the drilling of 420 gross wells in 2007, of which 15 were dry holes, for a success rate of 96%. In addition, we spent $488.9 million primarily to acquire additional interests in the Fayetteville Shale in Arkansas and in both the Elm Grove and Terryville fields in Louisiana. Our program to acquire additional interests and acreage in these fields is ongoing.

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

During the third quarter of 2007, we closed our acquisition of One TEC, LLC, with properties primarily in Arkansas and Texas, for $39.9 million, net of $2.1 million cash acquired.

Cash used in investing activities in 2006 was $972.6 million. During the fourth quarter of 2006 we sold certain oil and natural gas assets in Michigan, Wyoming and California with total estimated reserves of approximately 49 Bcfe. The majority of these assets were acquired in our merger with KCS. Our proceeds from these three separate transactions totaled approximately $135 million, before customary closing adjustments. The proceeds received were used to pay down a portion of our Senior Credit Agreement.

On July 12, 2006, we merged with KCS Resources, Inc.. Total consideration for the shares of KCS common stock consisted of approximately $1.1 billion of our common stock, approximately $450 million in cash and the assumption of $275 million of KCS debt. In addition, all outstanding options to purchase KCS common stock and restricted shares of KCS common stock were converted into options to purchase our common stock or restricted shares of our common stock using an exchange ratio of 2.3706 shares of our common stock to one share of KCS common stock.

During the first quarter of 2006, we completed the acquisition of stock of Winwell Resources, Inc. for $208 million in cash after customary closing adjustments, and the acquisition of certain oil and natural gas properties for $86 million in cash after customary closing adjustments. In conjunction with these acquisitions, we deposited a total of $22.5 million in earnest money that was included in other non-current assets at December 31, 2005 and applied to the overall purchase price in January 2006.

We closed a $52.5 million divestment of substantially all of our properties in the Gulf of Mexico on March 21, 2006. The net proceeds received in this transaction were used to pay down a portion of our Senior Credit Agreement. We received an additional $12.6 million in proceeds from the sale of non-operated properties during the third quarter of 2006.

In 2006, we spent $483.4 million on acquisitions of oil and gas properties and capital expenditures. We spent $395.5 million on capital expenditures in conjunction with our drilling program. We participated in the drilling of 330 gross wells in 2006, of which 20 were dry holes, for a success rate of 94%.

We spent an additional $87.9 million primarily on the acquisition of oil and natural gas properties in North Louisiana as described above.

Financing Activities. The primary driver of cash provided by financing activities is proceeds from the issuance of common stock and long-term debt offset by repayments of long-term debt. Net cash flows provided by financing activities were $2.4 billion, $267.9 million and $668.4 million for the years ended December 31, 2008, 2007 and 2006, respectively.

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

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

On May 13, 2008, we issued $500 million aggregate principal amount of the 2015 Notes in a private placement under the Securities Act of 1933, as amended. The net proceeds from the sale of the 2015 Notes were approximately $490 million, after deducting the initial purchasers discounts and estimated offering expenses and commissions.

On June 19, 2008, we issued an additional $300 million aggregate principal amount of 2015 Notes in a private placement under the Securities Act of 1933, as amended. The net proceeds from the sale of the 2015 Notes were approximately $294 million, after deducting the initial purchasers discount and estimated offering expenses and commissions.

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

Capital financing and excess cash flow are used to repay debt to the extent available. In 2008, we had net borrowings of $677.7 million primarily due to the cash requirements of our drilling and acquisition activities in 2008 offset by sales of common stock and issuances of long term debt discussed above. On January 27, 2009, we completed a private placement offering to eligible purchasers of an aggregate principal amount of $600 million 10.5% senior notes due August 1, 2014. The notes were priced at 91.279% of the face value to yield 12.75% to maturity. As of December 31, 2008, the Senior Credit Agreement had a $1.1 billion borrowing base and we had $450 million outstanding, all of which was repaid in conjunction with the completion of the $600 million private placement on January 27, 2009. As a result of the offering, our borrowing base decreased from $1.1 billion to $950 million.

Cash flows provided by financing activities include net borrowings of $260.4 million and $569.5 million for the years ended December 31, 2007 and 2006, respectively, primarily due to our acquisitions activities discussed below as well as our ongoing drilling activities.

In connection with our merger with KCS, on July 12, 2006, we consummated a private placement of 9.125% senior notes. These notes were issued at 98.735% of the face amount of $650 million for gross proceeds of approximately $642.0 million, before estimated offering expenses and the initial purchasers discount. We applied a portion of the net proceeds to fund the $450 million that was paid to KCS stockholders in connection

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with the merger. On July 27, 2006, we issued an additional $125 million of these notes at 101.125% of the face amount. We applied the net proceeds from the sale of the additional 2013 Notes to repay indebtedness outstanding under our senior revolving credit facility.

In connection with the North Louisiana Acquisitions, on February 1, 2006, we issued and sold 13.0 million shares of our common stock for $14.50 per share, for gross proceeds of $188.5 million. Contemporaneously with the offering, we repurchased 3.3 million shares of our common stock for $46.2 million from EnCap Investments, L.P. and certain of its affiliates. We incurred a total of $10.9 million of offering costs during 2006.

Financing activities included $14.6 million of cash paid on settled derivative contracts that were acquired in conjunction with our acquisition activities in 2006 and $3.6 million of cash received on settled derivative contracts in 2007.

In April 2006, we initiated a buyback of our 8% cumulative convertible preferred stock for $9.25 per share, resulting in a $5.3 million use of cash in financing activities.

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 at December 31, 2008 by payment periods as of December 31, 2008.

	Payments Due by Period				
Contractual Obligations	**Total**	**2009**	**2010-2011** *(In thousands)*	**2012-2013**	**2014 and Beyond**
Senior revolving credit facility	$ 450,000	$	$	$ 450,000	$
7 $^{7}/8$% $800 million senior notes	800,000				800,000
9 $^{1}/8$% $775 million senior notes (1)	768,725			768,725	
7 $^{1}/8$% $275 million senior notes (2)	272,375			272,375	
9 $^{7}/8$% senior notes	254		254		
Interest expense on long-term debt (3)	848,802	166,543	333,068	259,941	89,250
Deferred premiums on derivatives (4)	15,193	9,426	5,767		
Rig commitments	433,035	147,303	237,186	48,546	
Other commitments (5)	507,795	89,033	78,134	77,587	263,041
Operating leases	28,668	5,125	9,081	8,642	5,820
Total contractual obligations	$ 4,124,847	$ 417,430	$ 663,490	$ 1,885,816	$ 1,158,111

(1) *Excludes $5.9 million of unamortized discount and $1.0 million of unamortized premium recorded in conjunction with the issuance of the notes. See 9.125% Senior Notes below for more details.*

(2) *Excludes a net $8.3 million discount recorded in conjunction with our merger with KCS. See 7.125% Senior Notes below for more details.*

(3) *Future interest expense was calculated based on interest rates and amounts outstanding at December 31, 2008 less required annual repayments.*

(4) *Approximately $9.4 million of this amount has been classified as current at December 31, 2008.*

(5) *Other commitments pertains to exploration, development and production activities including commitments for pipeline and well equipment, obtaining and processing seismic data and natural gas transportation space on various pipelines.*

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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 or the $600 million of 10.5% Senior Notes due 2014 that we issued during the first quarter of 2009. 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, 2008 is $28.6 million.

Senior Revolving Credit Facility

We entered into the Third Amended and Restated Senior Revolving Credit Agreement, dated as of September 10, 2008 (the Senior Credit Agreement), between 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 BMO Capital Markets Financing, Inc. as co-syndication agents for the Lenders, and JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A. and Fortis Capital Corp. as co-documentation agents for the Lenders., which amends and restates our $1 billion senior revolving credit agreement dated July 12, 2006. The Senior Credit Agreement provides for a $1.5 billion facility with a current borrowing base of $950 million that will be 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 gas properties, reserves, other indebtedness and other relevant factors. 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 notes that the Company may issue. During the first quarter of 2009, we initiated a borrowing base redetermination of our Senior Credit Agreement. Our borrowing base of $950 million, along with our existing terms and pricing, were reaffirmed.

Amounts outstanding under the Senior Credit Agreement bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.25% to 2.00% for Eurodollar loans or at specified margins over the Alternate Base Rate (ABR) of 0.00% to 0.50% for ABR loans. Such margins will fluctuate based on the utilization of the facility. Borrowings under the Senior Credit Agreement are secured by first priority liens on substantially all of our assets, including pursuant to the terms of the Third Amended and Restated Guarantee and Collateral Agreement, all of the assets of, and equity interests in, our subsidiaries. Amounts drawn down on the facility will mature on July 1, 2013.

The Senior Credit Agreement contains customary financial and other covenants, including minimum working capital levels (the ratio of current assets plus the unused commitment under the Senior Credit Agreement to current liabilities) of not less than 1.0 to 1.0 and minimum coverage of interest expenses of not less than 2.5 to 1.0. In addition, we are subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. At December 31, 2008, we were in compliance with all of our debt covenants under the Senior Credit Agreement.

10.5% Senior Notes

On January 27, 2009, we issued $600 million principal amount of our 10.5% senior notes due 2014 (the 2014 Notes). The 2014 Notes were issued under and are governed by an indenture dated January 27, 2009, between us, U.S. Bank National Association, as trustee, and our subsidiaries named therein as guarantors. The 2014 Notes bear interest at 10.5% per annum, payable semi-annually on February 1 and August 1 of each year, commencing on August 1, 2009. The 2014 Notes will mature on August 1, 2014. The 2014 Notes were priced at 91.279% of the face value to yield 12.75% to maturity. The 2014 Notes are senior unsecured obligations and rank equally with all of our current and future senior indebtedness.

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

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trustee, and our subsidiaries named therein as guarantors. The 2015 Notes bear interest at a rate of 7.875% per annum, payable semi-annually on June 1 and December 1 of each year, commencing December 1, 2008. The 2015 notes will mature on June 1, 2015. The 2015 Notes are senior unsecured obligations and rank equally with all of our current and future senior indebtedness. At December 31, 2008, we were in compliance with all of our debt covenants relating to the 2015 Notes. The 2015 Notes were issued at par value, with no discount or premium recorded.

9.125% Senior Notes

On July 12, 2006, we consummated a private placement of 9.125% senior notes, also referred to as the 2013 Notes, pursuant to an Indenture dated as of July 12, 2006 (2013 Indenture) and the First Supplemental Indenture to the 2013 Notes (the 2013 First Supplemental Indenture), among us, our subsidiaries named therein as guarantors, and U.S. Bank National Association, as trustee. The 2013 Notes were issued at 98.735% of the face amount for gross proceeds of approximately $642.0 million, before estimated offering expenses and the initial purchasers discount. We applied a portion of the net proceeds from the sale of the 2013 Notes to fund the cash paid by us to the KCS stockholders in connection with our merger with KCS and our repurchase of the 9.875% notes due 2011 (2011 Notes) pursuant to a tender offer we concluded in July 2006. At December 31, 2008 we were in compliance with all of our covenants relating to the 2013 Notes.

In conjunction with the issuance of the $650 million 2013 Notes, we recorded a discount of $8.2 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized discount was $5.9 million at December 31, 2008. In conjunction with the issuance of the additional $125 million 2013 Notes, we recorded a premium of $1.4 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized premium was $1.0 million at December 31, 2008.

7.125% Senior Notes

In our merger with KCS, we assumed (pursuant to the Second Supplemental Indenture relating to the 7.125% Senior Notes, also referred to as the 2012 Notes), all the obligations (approximately $275 million) of KCS under the 2012 Notes and the Indenture dated April 1, 2004 (the 2012 Indenture) among KCS, U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein, which governs the terms of the 7.125% senior notes due 2012. The 2012 Notes are guaranteed on an unsubordinated, unsecured basis by all of our current subsidiaries. Interest on the 2012 Notes is payable semi-annually, on each April 1 and October 1. At December 31, 2008, we were in compliance with all of the debt covenants under the 7.125% Senior Notes.

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 $8.3 million at December 31, 2008.

9.875% Senior Notes

On April 8, 2004, Mission Resources Corporation 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 for a premium of $14.9 million plus accrued interest of $3.5 million.

Off-Balance Sheet Arrangements

At December 31, 2008, we did not have any off-balance sheet arrangements.

Plan of Operation for 2009

Our 2009 capital budget is $1.0 billion. On January 27, 2009, we completed a private placement offering to eligible purchasers of an aggregate principal amount of $600 million 10.5% senior notes due August 1, 2014. We

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used proceeds from the offering to repay all outstanding borrowings under our Senior Credit Agreement. We believe that cash, marketable securities on hand at December 31, 2008 and additional borrowings under our Senior Credit Agreement will allow us to fund our 2009 capital budget. We also strive to maintain financial flexibility and may access capital markets as necessary to maintain substantial borrowing capacity under our Senior Credit Agreement, facilitate drilling on our large undeveloped acreage position and permit us to selectively expand our acreage position and infrastructure projects.

Critical Accounting Policies and Estimates

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

Oil and Natural Gas Activities

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

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and natural gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization expense and the full cost ceiling 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 period-end 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, 2008, 2007 and 2006 were prepared by Netherland, Sewell, an independent oil and natural gas reservoir engineering consulting firm. For more information regarding reserve estimation, including historical reserve revisions, refer to Item 8. *Consolidated Financial Statements and Supplementary Data Supplemental Oil and Gas Information (Unaudited).*

Depreciation, Depletion and Amortization

Our rate of recording depreciation, depletion and amortization expense (DD&A) is primarily dependent upon our estimate of proved reserves, which is utilized in our unit-of-production method calculation. If the estimates of proved reserves were to be reduced, the rate at which we record DD&A expense would increase, reducing net income. Such a reduction in reserves may result from 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 $0.18 and $0.19 per Mcfe, respectively.

Full Cost Ceiling 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 writedown 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 prices and costs in effect as of the last day of the quarter are held constant. However, we may not be subject to a writedown if prices increase subsequent to the end of a quarter in which a writedown might otherwise be required. If oil and natural gas prices decline, even if for only a short period of time, or if we have downward revisions to our estimated proved reserves, it is possible that writedowns of our oil and natural gas properties could occur in the future.

Future Development and Abandonment 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

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difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis. A five percent decrease or increase in future development and abandonment costs would decrease or increase the DD&A rate by approximately $0.06 per Mcfe.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and facilities associated with our oil and gas wells and our gathering systems, and to restore land at the end of oil and 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.

Allocation of Purchase Price in Business Combinations

As part of our business strategy, we periodically pursue the acquisition of oil and natural gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and natural gas reserves and unproved properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

Under Statement of Financial Accounting Standards (SFAS) SFAS No. 142, *Goodwill and Other Intangible Assets*, goodwill is not subject to amortization. Rather, goodwill of each reporting unit is tested for impairment on an annual basis, or more frequently if an event occurs or circumstances change that would reduce the fair value of the reporting unit below its carrying amount. The 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 impairment is charged against earnings.

Accounting for Derivative Instruments and Hedging Activities

We utilize derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our anticipated future oil and natural gas production. We generally hedge a substantial, but varying, portion of our anticipated oil and natural gas production for the next 12-36 months. We do not use derivative instruments for trading purposes. We have elected not to apply hedge accounting to our derivative contracts, which would potentially allow us to not record the change in fair value of our derivative contracts in the statement of operations. We carry our derivatives at fair value on our consolidated balance sheets, with the changes in the fair value included in our statements of operations in the period in which the change occurs. Our results of operations would potentially have been significantly different had we elected and qualified for hedge accounting on our derivative contracts.

Comparison of Results of Operations

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

We reported a net loss of $388.1 million for the year ended December 31, 2008 compared to net income of $52.9 million for the comparable period in 2007. The decrease in our net income of $440.9 million from the year ended December 31, 2007 was primarily driven by our full cost ceiling impairment of $1.0 billion before taxes offset by an increase in our oil and gas revenues as well as an increase in our net gain on derivative contracts. The following table summarizes key items of comparison and their related change for the periods indicated.

In thousands (except per unit and per Mcfe amounts)	Years Ended December 31, 2008	2007	Change
Net (loss) income available to common stockholders	$ (388,052)	$ 52,897	$ (440,949)
Operating revenues:			
Oil and gas	1,031,657	883,405	148,252
Marketing	63,553		63,553
Expenses:			
Marketing	58,581		58,581
Production:			
Lease operating	52,477	64,666	(12,189)
Workover and other	5,624	7,700	(2,076)
Taxes other than income	47,104	58,347	(11,243)
Gathering, transportation and other	47,309	33,015	14,294
General and administrative:			
General and administrative	62,500	58,327	4,173
Stock-based compensation	12,310	15,540	(3,230)
Depletion, depreciation and amortization			
Depletion Full cost	391,042	390,180	862
Depreciation Other	4,268	3,231	1,037
Accretion expense	1,246	1,750	(504)
Full cost ceiling impairment	950,799		950,799
Net gain (loss) on derivative contracts	156,870	(35,011)	191,881
Interest expense and other	(151,825)	(129,603)	(22,222)
Income tax benefit (provision)	144,953	(33,138)	178,091
Production:			
Natural Gas Mmcf[1]	102,273	99,506	2,767
Crude Oil MBbl	1,554	2,816	(1,262)
Natural Gas Equivalent Mmcfe	111,597	116,402	(4,805)
Average Daily Production Mmcfe	305	319	(14)
Average price per unit [2]:			
Natural gas price Mcf[1]	$ 8.56	$ 6.92	$ 1.64
Crude oil price Bbl	95.16	68.84	26.32
Equivalent Mcfe	9.17	7.58	1.59
Average cost per Mcfe:			
Production:			
Lease operating	0.47	0.56	(0.09)
Workover and other	0.05	0.07	(0.02)
Taxes other than income	0.42	0.50	(0.08)
Gathering, transportation and other	0.42	0.28	0.14
General and administrative:			
General and administrative	0.56	0.50	0.06
Stock-based compensation	0.11	0.13	(0.02)

Depletion	3.50	3.35	0.15

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

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

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For the year ended December 31, 2008, oil and natural gas revenues increased $148.3 million from the same period in 2007, to $1.0 billion, which was primarily due to an increase of $1.59 per Mcfe in our equivalent realized average price to $9.17 per Mcfe and resulted in an additional $177 million of revenues. The effect of the increase in price was partially offset by a decrease in production of 4,805 Mmcfe due to the sale of our Gulf Coast properties during the fourth quarter of 2007.

We had marketing revenues of $63.6 and marketing expenses of $58.6 million in 2008, resulting in a net margin of $5.0 million. During the fourth quarter of 2008, we began purchasing and selling third party natural gas produced from wells we operate. We report the revenues and expenses related to these marketing activities on a gross basis as part of our operating revenues and operating expenses. Marketing revenues are recorded at the time natural gas is physically delivered to third parties at a fixed or index price. Marketing expenses attributable to gas purchases are recorded as we take physical title to the natural gas and transport the purchased volumes to the point of sale.

Lease operating expenses decreased $12.2 million for the year ended December 31, 2008. On a per unit basis, lease operating expenses decreased from $0.56 per Mcfe in 2007 to $0.47 per Mcfe in 2008. This decrease on a per unit basis is primarily due to the sale of our higher lease operating cost Gulf Coast properties during the fourth quarter of 2007 and an increase in production from lower operating cost areas in Arkansas and Louisiana.

Workover expenses decreased $2.1 million for the year ended December 31, 2008 compared to the same period in 2007. The decrease was primarily due to the sale of our Gulf Coast properties during the fourth quarter of 2007 which historically had a higher amount of workover activity compared to our ongoing operations.

Taxes other than income decreased $11.2 million for the year ended December 31, 2008 as compared to the same period in 2007. The largest components of taxes other than income are production and severance taxes which are generally assessed as either a percentage of gross oil and natural gas sales or as a fixed rate based on production. As a percentage of oil and gas sales, taxes other than income decreased from 7% in 2007 to 5% in 2008. This decrease as a percentage of revenue is primarily attributable to the sale of our Gulf Coast properties and the increase in production associated with our Louisiana and Arkansas properties.

Gathering, transportation and other expense increased $14.3 million, or $0.14 per Mcfe, for the year ended December 31, 2008 as compared to the same period in 2007. This increase was primarily due to an increase in production in the Fayetteville Shale which has higher gathering, transportation and other costs.

General and administrative expense for the year ended December 31, 2008 increased $4.2 million as compared to the same period in 2007 to $62.5 million. This increase was primarily attributable to additional professional fees associated with the acquisition and development of our new resource-style plays in 2008. Also contributing to the increase in general and administrative expenses from the prior year was an increase in internal costs associated with our acquisition activities and related capital raises in 2008.

Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs associated with the evaluated properties plus future development costs based on the ratio of production volume for the current period to total estimated remaining reserve volume for the evaluated properties. Depletion expense increased $0.9 million for the year ended December 31, 2008 from the same period in 2007, to $391.0 million. Our 4% decrease in production attributable to the sale of our Gulf Coast properties during the fourth quarter of 2007 was more than offset by the increase on a per unit basis of $0.15 per Mcfe to $3.50 per Mcfe. This increase on a per unit basis is primarily attributable to the transfer of unevaluated costs to our full cost pool and an increase in our estimated future development costs.

We recorded a full cost ceiling impairment of approximately $1.0 billion for the year ended December 31, 2008. A variety of economic and other factors have recently caused significant declines in oil and natural gas prices. We utilize the full cost method of accounting to account for our oil and natural gas exploration and development activities. Under this method of accounting, we are required on a quarterly basis to determine

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whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the ceiling , based upon the expected after tax present value (discounted at 10%) of the future net cash flows from our proved reserves, calculated using prevailing oil and natural gas prices on the last day of the period, or a subsequent higher price under certain circumstances. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non-cash impairment expense. Our ceiling was calculated using prices of $41.00 per barrel of oil and $5.71 per MMbtu. Accordingly, at December 31, 2008, our costs exceeded our ceiling limitation by approximately $1.0 billion, resulting in an approximate $1.0 billion writedown of our oil and natural gas properties.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Consistent with the prior year, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the consolidated statement of operations. At December 31, 2008, we had a $224.5 million derivative asset, $201.1 million of which was classified as current. The Company recorded a net derivative gain of $156.9 million ($230.6 million net unrealized gain and $73.7 million net loss for cash paid on settled contracts) for the year ended December 31, 2008 compared to a net derivative loss of $35.0 million ($79.0 million unrealized loss net of a $44.0 million net gain for cash received on settled contracts) in the prior year. This increase in our net derivative gain is primarily attributable to the recent decrease in the forward strip pricing used to value our derivatives.

Interest expense and other was $151.8 million and $129.6 million for the years ended December 31, 2008 and 2007, respectively, increasing $22.2 million from the same period in 2007. Interest expense increased $37.5 million due to the issuance of $800 million of new long-term debt in 2008. In addition, we withdrew the proposed public offering of master limited partnership units during the second quarter of 2008 and expensed the related costs of $3.4 million which is included in interest expense and other on the consolidated statements of operations. These items were offset by a reduction in interest expense associated with the Senior Credit Agreement of $15.5 million from the prior year due to the decrease in our outstanding balance as well as interest income of $4.2 million primarily attributable to our investment of proceeds from the sale of our Gulf Coast properties as well as the proceeds we received from the issuance of common stock and long-term debt during 2008.

Income tax expense for the year ended December 31, 2008 decreased $178.1 million from the prior year resulting in a tax benefit of $145.0 million. The decrease in income tax expense from the prior year was primarily due to our pre-tax loss of $533.0 million for the year ended December 31, 2008 compared to our pre-tax income of $86.0 million in 2007. The effective tax rates for the years ended December 31, 2008 and 2007 were 27.2% (benefit) and 38.5%, respectively. The change in the effective tax rate from the prior year is primarily due to the benefit generated by the pre-tax loss reduced by an increase to the state effective rate due to increased operations in higher state tax jurisdictions.

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Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

We had net income of $52.9 million for the year ended December 31, 2007 compared to net income of $116.6 million for 2006. The decrease in net income is primarily due to our pre-tax loss on derivative contracts of $35.0 million in 2007 compared to a pre-tax gain on derivative contracts of $124.4 million in 2006. 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)	**2007**	**2006**	**Change**
Net income	$ 52,897	$ 116,563	$ (63,666)
Operating revenues:			
Oil and gas	883,405	587,762	295,643
Expenses:			
Production:			
Lease operating	64,666	58,029	6,637
Workover and other	7,700	8,118	(418)
Taxes other than income	58,347	45,547	12,800
Gathering, transportation and other	33,015	16,187	16,828
General and administrative:			
General and administrative	58,327	35,827	22,500
Stock-based compensation	15,540	8,242	7,298
Depletion, depreciation and amortization:			
Depletion Full cost	390,180	257,593	132,587
Depreciation Other	3,231	2,135	1,096
Accretion expense	1,750	1,544	206
Net (loss) gain on derivative contracts:	(35,011)	124,442	(159,453)
Interest expense and other	(129,603)	(89,884)	(39,719)
Income tax provision	(33,138)	(72,535)	39,397
Production:			
Natural Gas Mmcf [(1)]	99,506	63,643	35,863
Crude Oil MBbl	2,816	2,703	113
Natural Gas Equivalent Mmcfe	116,402	79,863	36,539
Average Daily Production Mmcfe	319	219	100
Average price per unit [(2)]:			
Gas price per Mcf [(1)]	$ 6.92	$ 6.57	$ 0.35
Oil price per Bbl	68.84	62.27	6.57
Equivalent per Mcfe	7.58	7.34	0.24
Average cost per Mcfe:			
Production:			
Lease operating	0.56	0.73	(0.17)
Workover and other	0.07	0.10	(0.03)
Taxes other than income	0.50	0.57	(0.07)
Gathering, transportation and other	0.28	0.20	0.08
General and administrative:			
General and administrative	0.50	0.45	0.05
Stock-based compensation	0.13	0.10	0.03
Depletion expense	3.35	3.23	0.12

(1) *Approximately 4% and 5% of natural gas production represents natural gas liquids (calculated with a 6:1 equivalent ratio) with an average price of $43.70 per Bbl and $36.88 per Bbl for the years ended December 31, 2007 and 2006, respectively.*

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

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For the year ended December 31, 2007, oil and natural gas sales increased $295.6 million, from the same period in 2006, to $883.4 million. The increase for the year was primarily due to the increase in production of 36,539 Mmcfe which was largely due to including a full year of production from properties acquired in our merger with KCS in July 2006. This increase in production led to an approximate $268.2 million increase in revenues from the prior year. The remaining increase of $27.4 million is due to the increase in commodity prices as our realized average price per Mcfe increased $0.24 per Mcfe in 2007 to $7.58 per Mcfe from $7.34 per Mcfe in 2006.

Lease operating expense increased $6.6 million from the prior year. However, on a per unit basis, lease operating expense decreased 23% from $0.73 per Mcfe in 2006 to $0.56 per Mcfe in 2007. The decrease is primarily due to our continued cost control efforts to lower our lease operating expense. We continue to identify divestment prospects which tend to be outlying, higher operating cost properties. Also contributing to the decline on a per unit basis was our acquisition of lower cost properties in our merger with KCS and properties acquired in the North Louisiana Acquisitions.

Workover and other expense decreased $0.4 million for the year ended December 31, 2007 as compared to 2006. The decrease was primarily due to the decrease in major maintenance activities in 2007. On a per unit basis, workover and other expense decreased $0.03 per Mcfe to $0.07 per Mcfe in 2007 compared to $0.10 per Mcfe in 2006.

Taxes other than income increased $12.8 million for the year ended December 31, 2007 as compared to the same period in 2006. The largest components of taxes other than income are production and severance taxes which are generally assessed as a percentage of gross oil and natural gas sales. On a per unit basis, taxes other than income decreased $0.07 per Mcfe to $0.50 per Mcfe in 2007 as compared to $0.57 per Mcfe in 2006. As a percentage of oil and natural gas sales, taxes other than income decreased from 8% in 2006 to 7% in 2007 primarily due to the receipt of tax refunds.

Gathering, transportation and other expense increased $16.8 million for the year ended December 31, 2007 as compared to the same period in 2006. On a per unit basis, gathering transportation and other increased $0.08 per Mcfe from $0.20 per Mcfe in 2006 to $0.28 per Mcfe in 2007. The overall increase is due to the inclusion of a full year of activity in 2007 associated with our merger with KCS in July 2006 as well as higher costs in the Fayetteville Shale associated with our higher production.

General and administrative expense for the year ended December 31, 2007 increased $22.5 million to $58.3 million compared to $35.8 million for the same period in 2006. This increase was primarily due to the sale of our Gulf Coast properties on November 30, 2007. In connection with the sale of the our Gulf Coast properties, the employment of certain employees was terminated, giving rise to termination benefits resulting in additional general and administrative expenses of $9.5 million recorded on November 30, 2007. Salaries and employee benefits increased by approximately $9.9 million with the inclusion of a full year of KCS employees and annual salary increases for existing employees. Office expenses increased approximately $3.1 million with the full year effect of the merger with KCS as well as new corporate office space in Houston and Tulsa.

Stock-based compensation increased $7.3 million for the year ended December 31, 2007 as compared to the same period in the prior year. This increase was primarily due to the sale of our Gulf Coast properties on November 30, 2007, as outstanding stock appreciation rights, stock options and restricted share awards to employees whose employment was terminated in connection with the sale were modified to accelerate the vesting of these awards and to extend the exercise period from 90 days to November 30, 2008. As a result of these two modifications, we recognized an additional $2.4 million of stock-based compensation expense in November 2007. The remaining increase of approximately $4.9 million is primarily due to additional equity awards that were issued during 2006 and 2007.

Depletion expense increased $132.6 million as compared to the same period in 2006 to $390.2 million for the year ended December 31, 2007. Depletion for oil and natural gas properties is calculated using the unit of

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production method, which essentially depletes the capitalized costs associated with the evaluated properties plus future development costs based on the ratio of production volume for the current period to total remaining proved reserve volume for the evaluated properties. On a per unit basis, depletion expense increased $0.12 per Mcfe to $3.35 per Mcfe from $3.23 per Mcfe. This increase is primarily due to our merger with KCS in July 2006 and the North Louisiana Acquisitions in January 2006 which substantially increased our future development costs.

We enter into derivative commodity instruments to hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Consistent with prior years, 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 valuation of these derivative contracts in the consolidated statement of operations. At December 31, 2007, we had a $12.4 million derivative asset, all of which was classified as current, and a $35.1 million derivative liability, $28.2 million of which was classified as current. We recorded a net derivative loss of $35.0 million ($79.0 million unrealized loss and a $44.0 million net gain for cash received on settled contracts) for the year ended December 31, 2007 compared to a net derivative gain of $124.4 million ($134.4 million unrealized gain and $10.0 million cash paid on settled contracts) for the year ended December 31, 2006. This decrease is due to the increase in commodity prices, primarily crude oil as the weighted average of the forward strip used to value our crude oil derivatives increased from $65.40 per Bbl at December 31, 2006 to $91.77 per Bbl at December 31, 2007. Also contributing to this decrease was the increase in the weighted average forward strip used to value our natural gas derivatives which increased from $7.29 per MMbtu at December 31, 2006 to $7.92 per MMbtu at December 31, 2007.

Interest expense and other increased $39.7 million for the year ended December 31, 2007 compared to the same period in 2006. This increase was primarily due to additional debt we incurred in conjunction with our merger with KCS in July 2006 and the closing of the North Louisiana Acquisitions in January 2006. Also contributing to this increase was the increase in our senior revolving credit facility in 2007 which was used to partially fund our acquisition and drilling activities as well as other general corporate purposes.

Income tax expense for the year ended December 31, 2007 decreased $39.4 million from the prior year. The decrease in income tax expense from prior year is primarily due to our pre-tax income of $86.0 million in 2007 compared to pre-tax income of $189.1 million in 2006. The effective tax rates for the years ended December 31, 2007 and 2006 were 38.5% and 38.4%, respectively.

Related Party Transactions

A description of our related party transactions is included in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 10*, Related Party Transactions,* and is incorporated herein by reference.

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 and natural gas prices decline significantly our ability to finance our capital budget and operations could be adversely impacted. We expect energy prices to remain volatile and unpredictable, therefore we have designed a risk management policy which provides for the use of derivative instruments to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the affect it could have on our operations. The types of derivative instruments that we typically utilize include collars, swaps, basis swaps and puts. The total volumes which we hedge through the use of our derivative instruments varies from period to period, however, generally our objective is to hedge approximately 65% to 70% of our current and anticipated production. Our hedge policies and objectives may change significantly as commodities prices or price futures change.

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We are exposed to market risk on our open hedged positions, to the extent our counterparties have liquidity issues and are unable to settle their obligations with us. The current economic crisis may have a negative impact on the liquidity of the counterparties to our hedging agreements, which increases the risk of those counterparties failing to perform under those agreements. If those parties default, we could be exposed to the price risks we had sought to mitigate and our financial condition and results of operations may be materially and adversely affected. Please refer to Item 8. *Consolidated Financial Statements and Supplementary Data* Note 7, *Derivative 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. As a result, we made the decision to implement a risk management policy to mitigate a portion of this risk as we expect interest rates to continue to be volatile and unpredictable. Our risk management policy provides for the use of interest rate swaps to reduce the exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. At December 31, 2008 we did not have any open interest rate swap positions. 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.

The Company accounts for its derivative activities under the provisions of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended. This statement, as amended, 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 Note 7, *Derivative and Hedging Activities* for more details.

Fair Market Value of Financial Instruments

The estimated fair values for financial instruments under Financial Accounting Standards Board Statement No. 107, *Disclosures about Fair Value of Financial Instruments*, are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, cash equivalents, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. Please refer to Fair Value of Financial Instruments in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 1, *Summary of Significant Events and Accounting Policies* for additional information.

Interest Sensitivity

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

At December 31, 2008, total debt was $2.3 billion, of which approximately 80% bears interest at a weighted average fixed interest rate of 8.3% per year. The remaining 20% of our total debt balance at December 31, 2008 bears interest at floating or market interest rates that at our option are tied to prime rate or LIBOR. Fluctuations in market interest rates will cause our annual interest costs to fluctuate. At December 31, 2008, the interest rate on our variable rate debt was 2.7% per year. If the balance of our variable rate debt at December 31, 2008 were to remain constant, a 10% change in market interest rates would impact our cash flow by approximately $0.3 million per quarter.

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ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Petrohawk Energy Corporation (the Company), including the Company s Chief Executive Officer and Chief 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 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, 2008.

Deloitte & Touche LLP, the Company s independent registered public accounting firm, has issued an attestation report on the effectiveness on our internal control over financial reporting as of December 31, 2008 which is included in Item 8. *Consolidated Financial Statements and Supplementary Data*.

/s/ FLOYD C. WILSON	/s/ MARK J. MIZE
Floyd C. Wilson	**Mark J. Mize**
Chairman of the Board, President	**Executive Vice President,**
and Chief Executive Officer	**Chief Financial Officer and Treasurer**

Houston, Texas

February 25, 2009

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of

Petrohawk Energy Corporation

Houston, Texas

We have audited the accompanying consolidated balance sheets of Petrohawk Energy Corporation and subsidiaries (the Company) as of December 31, 2008 and 2007, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2008. We also have audited the Company s internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company s management is responsible for these financial statements, 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 these financial statements and an opinion on the Company s internal control over financial reporting 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 and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting 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 audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

In our 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Houston, Texas

February 24, 2009

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PETROHAWK ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	Years Ended December 31,		
	2008	**2007**	**2006**
Operating revenues:			
Oil and gas	$ 1,031,657	$ 883,405	$ 587,762
Marketing	63,553		
Total operating revenues	1,095,210	883,405	587,762
Operating expenses:			
Marketing	58,581		
Production:			
Lease operating	52,477	64,666	58,029
Workover and other	5,624	7,700	8,118
Taxes other than income	47,104	58,347	45,547
Gathering, transportation and other	47,309	33,015	16,187
General and administrative	74,810	73,867	44,069
Depletion, depreciation and amortization	396,556	395,161	261,272
Full cost ceiling impairment	950,799		
Total operating expenses	1,633,260	632,756	433,222
(Loss) income from operations	(538,050)	250,649	154,540
Other income (expenses):			
Net gain (loss) on derivative contracts	156,870	(35,011)	124,442
Interest expense and other	(151,825)	(129,603)	(89,884)
Total other income (expenses)	5,045	(164,614)	34,558
(Loss) income before income taxes	(533,005)	86,035	189,098
Income tax benefit (provision)	144,953	(33,138)	(72,535)
Net (loss) income	(388,052)	52,897	116,563
Preferred dividends			(217)
Net (loss) income available to common stockholders	$ (388,052)	$ 52,897	$ 116,346
Net (loss) income per share of common stock:			
Basic	$ (1.77)	$ 0.31	$ 0.95
Diluted	$ (1.77)	$ 0.31	$ 0.92
Weighted average shares outstanding:			
Basic	218,993	168,006	122,452

Diluted	218,993	171,248	126,135

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

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PETROHAWK ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share amounts)

	December 31, 2008	December 31, 2007
Current assets:		
Cash	$ 6,883	$ 1,812
Marketable securities	123,009	
Accounts receivable	277,349	148,138
Current portion of deferred income taxes		5,855
Receivables from derivative contracts	201,128	12,369
Prepaids and other	40,063	21,019
Total current assets	648,432	189,193
Oil and gas properties (full cost method):		
Evaluated	4,894,357	3,247,304
Unevaluated	2,287,968	677,565
Gross oil and gas properties	7,182,325	3,924,869
Less accumulated depletion	(2,111,038)	(769,197)
Net oil and gas properties	5,071,287	3,155,672
Other operating property and equipment:		
Gas gathering systems and equipment	190,054	1,514
Other operating assets	20,271	17,426
Gross other operating property and equipment	210,325	18,940
Less accumulated depreciation	(11,106)	(6,838)
Net other operating property and equipment	199,219	12,102
Other noncurrent assets:		
Goodwill	933,058	933,945
Debt issuance costs, net of amortization	30,477	12,052
Receivables from derivative contracts	23,399	
Restricted cash (Note 2)		269,837
Note receivable (Note 2)		96,098
Other	1,457	3,540
Total assets	$ 6,907,329	$ 4,672,439
Current liabilities:		
Accounts payable and accrued liabilities	$ 639,432	$ 331,471
Current portion of deferred income taxes	77,454	
Liabilities from derivative contracts		28,198
Current portion of long-term debt	9,426	828

Total current liabilities	726,312	360,497
Long-term debt	2,283,874	1,595,127
Liabilities from derivative contracts		6,915
Asset retirement obligations	28,644	23,800
Deferred income taxes	460,913	674,968
Other noncurrent liabilities	2,676	2,235
Commitments and contingencies (Note 6)		
Stockholders equity:		
Common stock: 300,000,000 shares of $.001 par value authorized; 252,364,143 and 171,220,817 shares issued and outstanding at December 31, 2008 and 2007, respectively	252	171
Additional paid-in capital	3,655,500	1,871,516
(Accumulated deficit) retained earnings	(250,842)	137,210
Total stockholders equity	3,404,910	2,008,897
Total liabilities and stockholders equity	$ 6,907,329	$ 4,672,439

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

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PETROHAWK ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(In thousands)

	Preferred		Common		Additional		(Accumulated Deficit)	Total
	Shares	Amount	Shares	Amount	Paid-in Capital	Treasury Stock	Retained Earnings	Stockholders Equity
Balances at December 31, 2005	593	$ 1	73,566	$ 74	$ 558,452	$ (36)	$ (32,033)	$ 526,458
Equity compensation vesting					10,618			10,618
Common stock issued for purchase of KCS Energy, Inc.			83,862	84	1,146,518			1,146,602
Sale of common stock			13,000	13	188,487			188,500
Encap shares retired			(3,322)	(3)	(46,197)			(46,200)
Preferred stock dividends							(217)	(217)
Repurchase of preferred stock	(593)	(1)			(5,487)			(5,488)
Retirement of treasury shares			(8)		(36)	36		
Common stock issuances			1,389	1	2,449			2,450
Offering costs					(10,942)			(10,942)
Net income							116,563	116,563
Balances at December 31, 2006		$	168,487	$ 169	$ 1,843,862	$	$ 84,313	$ 1,928,344
Equity compensation vesting					22,230			22,230
Warrants exercised			575					
Common stock issuances			2,159	2	2,427			2,429
Tax benefit from exercise of stock options					2,997			2,997
Net income							52,897	52,897
Balances at December 31, 2007		$	171,221	$ 171	$ 1,871,516	$	$ 137,210	$ 2,008,897
Sale of common stock			78,200	78	1,831,872			1,831,950
Equity compensation vesting					16,279			16,279
Warrants exercised			1,222	1	883			884
Common stock issuances			1,874	2	13,661			13,663
Purchase of shares to cover individuals tax withholding			(153)		(3,798)			(3,798)
Reduction in shares to cover individuals tax withholding					(1,150)			(1,150)
Offering costs					(73,763)			(73,763)
Net loss							(388,052)	(388,052)
Balances at December 31, 2008		$	252,364	$ 252	$ 3,655,500	$	$ (250,842)	$ 3,404,910

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

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PETROHAWK ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31, 2008	2007	2006
Cash flows from operating activities:			
Net (loss) income	$ (388,052)	$ 52,897	$ 116,563
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depletion, depreciation and amortization	396,556	395,161	261,272
Full cost ceiling impairment	950,799		
Income tax (benefit) provision	(144,953)	33,138	72,535
Stock-based compensation	12,310	15,540	8,242
Net unrealized (gain) loss on derivative contracts	(230,640)	79,011	(134,428)
Net realized (gain) loss on derivative contracts acquired		(3,615)	14,646
Other	4,552	5,664	1,469
Change in assets and liabilities, net of acquisitions:			
Accounts receivable	(110,479)	18,554	(16,664)
Prepaid expenses and other	(19,044)	(3,372)	(6,373)
Accounts payable and accrued liabilities	135,382	11,846	(19,231)
Other	2,524	221	(1,138)
Net cash provided by operating activities	608,955	605,045	296,893
Cash flows from investing activities:			
Oil and gas capital expenditures	(3,121,736)	(1,253,180)	(483,372)
Acquisition of One Tec, LLC, net of cash acquired of $2,145		(39,910)	
Acquisition of KCS Energy, Inc., net of cash acquired of $8,260			(512,344)
Acquisition of Winwell Resources, Inc., net of cash acquired of $14,965			(177,264)
Proceeds received from sale of oil and gas properties	109,268	689,220	192,424
Marketable securities purchased	(3,777,427)		
Marketable securities redeemed	3,654,418		
Increase in restricted cash		(650,000)	
Decrease in restricted cash	269,837	380,163	
Other operating property and equipment expenditures	(164,810)	(2,998)	(2,773)
Other		9	10,763
Net cash used in investing activities	(3,030,450)	(876,696)	(972,566)
Cash flows from financing activities:			
Proceeds from exercise of options and warrants	14,438	6,058	2,850
Proceeds from issuance of common stock	1,831,950		188,500
Acquisition of common stock			(46,200)
Offering costs	(73,763)		(10,942)
Proceeds from borrowings	2,764,000	950,000	1,681,183
Repayment of borrowings	(2,086,266)	(689,601)	(1,111,644)
Debt issue costs	(23,793)	(834)	(14,438)
Net realized gain (loss) on derivative contracts acquired		3,615	(14,646)
Buyback of 8% cumulative preferred stock			(5,340)

Other		(1,368)	(968)
Net cash provided by financing activities	2,426,566	267,870	668,355
Net increase (decrease) in cash	5,071	(3,781)	(7,318)
Cash at beginning of period	1,812	5,593	12,911
Cash at end of period	$ 6,883	$ 1,812	$ 5,593

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

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PETROHAWK ENERGY CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

Petrohawk Energy Corporation (Petrohawk or the Company) is an independent oil and natural gas company engaged in the exploration, development and production of oil and natural gas properties located in onshore North America. The Company operates in one segment, oil and natural gas exploration and exploitation. The consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries. All intercompany accounts and transactions have been eliminated. Certain prior year amounts have been reclassified to conform to the current year presentation.

Use of Estimates

The preparation of the Company s consolidated financial statements in conformity with accounting principles generally accepted in the United States requires the Company s management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. These estimates include oil and natural gas proved reserve quantities which form the basis for the calculation of amortization of oil and natural gas properties. Management emphasizes that reserve estimates are inherently imprecise and that estimates of more recent reserve discoveries are more imprecise than those for properties with long production histories. Actual results may differ from the estimates and assumptions used in the preparation of the Company s consolidated financial statements.

Marketable Securities

During the second quarter of 2008, the Company made the decision to invest a portion of its cash in money market mutual funds which are highly liquid marketable securities. The Company accounts for marketable securities in accordance with Statement of Financial Accounting Standards (SFAS) No. 115, *Accounting for Certain Investments in Debt and Equity Securities* and classifies marketable securities as trading, available-for-sale, or held-to-maturity. The appropriate classification of its marketable securities is determined at the time of purchase and reevaluated at each balance sheet date.

At December 31, 2008, the Company held approximately $123.0 million of marketable securities which have been classified and accounted for as trading securities. Trading securities are recorded at fair value with realized gains and losses reported in interest expense and other in the consolidated statements of operations.

Allowance for Doubtful Accounts

The Company establishes provisions for losses on accounts receivable if it determines that it will not collect all or part of the outstanding balance. The Company regularly reviews collectibility and establishes or adjusts the allowance as necessary using the specific identification method. There is no significant allowance for doubtful accounts at December 31, 2008 or 2007.

Oil and Natural Gas Properties

The Company accounts for its oil and natural gas producing activities using the full cost method of accounting as prescribed by the United States Securities and Exchange Commission (SEC). Accordingly, all costs incurred in the acquisition, exploration, and development of proved oil and natural gas properties, including

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the costs of abandoned properties, dry holes, geophysical costs, and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of proved oil and natural gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%, net of tax considerations. In accordance with Staff Accounting Bulletin Topic 12.D.3.c., the Company utilizes the prices in effect on a date subsequent to the end of a reporting period when the full cost ceiling limitation was exceeded at the end of a reporting period and subsequent pricing exceeds pricing at the end of the reporting period.

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

Property, Plant and Equipment Other than Oil and Natural Gas Properties

Other operating property and equipment are recorded at cost. Depreciation is calculated using the straight-line method over the following estimated useful lives: pipelines, 30 years; auto, leasehold improvements, furniture and equipment, 5 years; and computers, 3 years. Upon sale, retirement, or otherwise disposed of, the cost and accumulated depreciation are removed from the accounts and any gains or losses are reflected in current operations. Maintenance and repair costs are charged to operating expense as incurred. Material expenditures, which increase the life of an asset, are capitalized and depreciated over the estimated remaining useful life of the asset.

The Company reviews its property and equipment in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS 144). SFAS 144 requires the Company to evaluate property and equipment as an event occurs or circumstances change that would more likely than not reduce the fair value of the property and equipment below the carrying amount. If the carrying amount of property and equipment is not recoverable from its undiscounted cash flows, then the Company would recognize an impairment loss for the difference between the carrying amount and the current fair value. Further, the Company evaluates the remaining useful lives of property and equipment at each reporting period to determine whether events and circumstances warrant a revision to the remaining depreciation periods.

Revenue Recognition

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

Marketing Revenue and Expense

During the fourth quarter of 2008, the Company began purchasing and selling third party natural gas produced from wells we operate. The revenues and expenses related to these marketing activities are reported on a gross basis as part of operating revenues and operating expenses. Marketing revenues are recorded at the time natural gas is physically delivered to third parties at a fixed or index price. Marketing expenses attributable to gas purchases are recorded as the Company takes physical title to natural gas and transports the purchased volumes to the point of sale.

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Concentrations of Credit Risk

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

The purchasers of the Company s oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. The Company has not experienced any significant losses from uncollectible accounts. In 2008, the Company had two individual purchasers each accounting for in excess of 10% of our total sales, collectively representing 30% of its total sales. In 2007, the Company had one individual purchaser accounting for 10% of its total sales. In 2006, the Company had no individual purchasers accounting for more than 10% of its total sales. The Company does not believe the loss of any one of its purchasers would materially affect the Company s ability to sell the oil and natural gas it produces. The Company believes other purchasers are available in the Company s areas of operations.

Risk Management Activities

The Company follows SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133), as amended. From time to time, the Company may hedge a portion of its forecasted oil and natural gas production. Derivative contracts entered into by the Company have consisted of transactions in which the Company hedges the variability of cash flow related to a forecasted transaction. The Company has elected to not designate any of its positions for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in net gain (loss) on derivative contracts on the consolidated statements of operations.

During the first quarter of 2008, the Company made the decision to mitigate a portion of its interest rate risk with interest rate swaps, which reduce the exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. These interest rate swaps converted a portion of the Company s Senior Credit Agreement (as defined in Note 4, *Long-term Debt*) to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. The Company elected to not designate any of its interest rate swap positions for hedge accounting. Accordingly, the Company recorded the net change in the mark-to-market valuation of these positions, as well as all payments and receipts on settled contracts, in net gain (loss) on derivatives contracts on the consolidated statements of operations. During the second quarter of 2008, the Company repaid all outstanding borrowings under its Senior Credit Agreement. As a result, the Company made the decision to settle all of its outstanding interest rate swap positions which resulted in a gain of $1.5 million during the second quarter of 2008 which is included in net gain (loss) on derivative contracts on the consolidated statements of operations.

Income Taxes

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

In July 2006, the Financial Accounting Standards Board (FASB) issued Financial Interpretation (FIN) 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB 109* (FIN 48). FIN 48 created a single

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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.

The evaluation of a tax position in accordance with FIN 48 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.

The Company includes interest and penalties relating to uncertain tax positions within interest expense and other on the Company s consolidated statements of operations.

The Company adopted the provisions of FIN 48 effective January 1, 2007 which did not have a material impact on the Company s operating results, financial position or cash flows. The Company did not record a cumulative effect adjustment related to the adoption of FIN 48.

Included in the Company s consolidated balance sheet at January 1, 2007 was approximately $2.1 million of liabilities associated with uncertain tax positions in the jurisdictions in which it conducts business offset by reductions to existing deferred tax liabilities. This amount included $0.1 million of accrued interest and penalties. No material amounts have been identified to date that would impact the Company s effective tax rate. The Company does not anticipate material changes to liabilities related to such uncertain tax positions within the next twelve months. Refer to Note 9, *Income Taxes* , for more details.

Generally, the Company s tax years 2005 through 2008 are either currently under audit or remain open and subject to examination by federal tax authorities or the tax authorities in Arkansas, Louisiana, New Mexico, Oklahoma and Texas, which are the jurisdictions in which the Company has its principal operations. In certain of these jurisdictions, the Company operates through more than one legal entity, each of which may have different open years subject to examination. Additionally, it is important to note that years are technically open for examination until the statute of limitations in each respective jurisdiction expires.

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

Asset Retirement Obligation

SFAS No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143) requires that the fair value of an asset retirement cost, and corresponding liability, should be recorded as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The Company has recorded an asset retirement obligation to reflect the Company s legal obligations related to future plugging and abandonment of its oil and natural gas wells and gas gathering systems. The Company estimated the expected cash flow associated with the obligation and discounted the amount using a credit-adjusted, risk-free interest rate. At least annually, the Company reassesses the obligation to determine whether a change in the estimated obligation is necessary. The Company evaluates whether there are indicators that suggest the estimated cash flows underlying the obligation have materially changed. Should those indicators suggest the estimated obligation may have materially changed on an interim basis (quarterly), the Company will accordingly update its

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assessment. Additional retirement obligations increase the liability associated with new oil and natural gas wells and gas gathering systems as these obligations are incurred.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in an acquisition. Goodwill decreased $0.9 million in 2008 due to the tax effects of the exercise of stock options and the sale of restricted stock in 2008 that were included in the Company s original purchase price allocations for the KCS Energy, Inc. and Mission Resources Corporation mergers. SFAS No. 142, *Goodwill and Other Intangible Assets* (SFAS 142) 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 Company completed its annual goodwill impairment test during the third quarters of 2008, 2007 and 2006 and no goodwill impairments were deemed necessary.

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 writedown is charged against earnings. The assumptions used by the Company in calculating its reporting unit fair value at the time of the test include the Company s 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 the Company s goodwill in future periods.

At December 31, 2008, the Company recorded a full cost ceiling impairment of approximately $1.0 billion. The full cost ceiling calculation dictates that prices and costs in effect as of the last day of the quarter are held constant. See Note 3, *Oil and Natural Gas Properties* for more details. As a result of the full cost ceiling impairment, the Company reviewed its goodwill for impairment as of December 31, 2008. Based on that review, no goodwill impairment was deemed necessary.

Fair Value of Financial Instruments

The estimated fair values for financial instruments under FASB Statement No. 107, *Disclosures about Fair Value of Financial Instruments*, are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, marketable securities, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of the Company s Senior Credit Agreement approximates carrying value because the facility s interest rate approximates current market rates. The following table presents the estimated fair values of the Company s fixed interest rate debt instruments as of December 31, 2008 and 2007:

	December 31, 2008		December 31, 2007	
Debt	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
		(In thousands)		
7 7/8% $800 million senior notes	$ 800,000	$ 591,040	$	$
9 1/8% $775 million senior notes	768,725	595,762	768,725	809,083
7 1/8% $275 million senior notes	272,375	223,348	272,375	260,799
9 7/8% senior notes	254	213	254	254
	$ 1,841,354	$ 1,410,363	$ 1,041,354	$ 1,070,136

The Company accounts for its derivative activities under the provisions of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended. This statement, as amended, 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 Note 7, *Derivative and Hedging Activities* for more details.

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Stock-Based Compensation

In January 2006, the Company adopted SFAS No. 123(R), *Share-Based Payment* (SFAS 123(R)). SFAS 123(R) revises SFAS No. 123, *Accounting for Stock-Based Compensation* (SFAS 123), and focuses on accounting for share-based payments for services provided by employee to employer. The statement requires companies to expense the fair value of employee stock options and other equity-based compensation at the grant date. The statement does not require a certain type of valuation model, and either a binomial or Black-Scholes model may be used. The Company used the modified prospective application method as detailed in SFAS 123(R).

401(k) Plan

The Company sponsors a 401(k) tax deferred savings plan, whereby the Company matches a portion of employees contributions in cash. Participation in the plan is voluntary and all employees of the Company who are 21 years of age are eligible to participate. The Company charged to expense plan contributions of $2.6 million in 2008 and 2007 and $1.7 million in 2006. The Company matches employee contributions dollar-for-dollar on the first 10% of an employee s pretax earnings.

Recently Issued Accounting Pronouncements

On December 31, 2008, the SEC published the final rules and interpretations updating its oil and gas reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include changes to the pricing used to estimate reserves utilizing a 12-month average price rather than a single day spot price which eliminates the ability to utilize subsequent prices to the end of a reporting period when the full cost ceiling was exceeded and subsequent pricing exceeds pricing at the end of a reporting period, the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, and permitting disclosure of probable and possible reserves. The SEC will require companies to comply with the amended disclosure requirements for registration statements filed after January 1, 2010, and for annual reports on Form 10-K for fiscal years ending on or after December 15, 2009. Early adoption is not permitted. The Company is currently assessing the impact that the adoption will have on the Company s disclosures, operating results, financial position and cash flows.

In March 2008, the FASB issued Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133* (SFAS 161). SFAS 161 requires entities that utilize derivative instruments to provide qualitative disclosures about their objectives and strategies for using such instruments, as well as any details of credit-risk-related contingent features contained within derivatives. SFAS 161 also requires entities to disclose additional information about the amounts and location of derivatives located within the financial statements, how the provisions of SFAS 133 have been applied, and the impact that hedges have on an entity s operating results, financial position or cash flows. SFAS 161 is effective for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. The Company is currently assessing the impact, if any, that the adoption of this pronouncement will have on the Company s disclosures.

In December 2007, the FASB issued SFAS No. 141, *Business Combinations* (SFAS 141R), and SFAS No. 160, *Accounting and Reporting of Noncontrolling Interest in Consolidated Financial Statements, an amendment of ARB No. 51* (SFAS 160). SFAS 141R and SFAS 160 will significantly change the accounting for and reporting of business combination transactions and noncontrolling (minority) interests in consolidated financial statements. SFAS 141R retains the fundamental requirements in Statement 141, *Business Combinations*, while providing additional definitions, such as the definition of the acquirer in a purchase and improvements in the application of how the acquisition method is applied. SFAS 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests, and classified as a component of equity. These Statements become simultaneously effective January 1, 2009. Early adoption is not permitted. The

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Company is currently assessing the impact, if any, that the adoption of this pronouncement will have on the Company s operating results, financial position or cash flows.

In April 2007, the FASB issued FSP No. FIN 39-1, *Amendment of FASB Interpretation No. 39*, (FIN 39-1) to amend FIN 39, *Offsetting of Amounts Related to Certain Contracts* (FIN 39). The terms conditional contracts and exchange contracts used in FIN 39 have been replaced with the more general term derivative contracts. In addition, FIN 39-1 permits the offsetting of recognized fair values for the right to reclaim cash collateral or the obligation to return cash collateral against fair values of derivatives under certain circumstances, such as under master netting arrangements. Additional disclosure is also required regarding a Company s accounting policy with respect to offsetting fair value amounts. The Company adopted FIN 39-1 on January 1, 2008 and elected not to offset fair value amounts as part of the adoption of this FASB Interpretation. There was no impact on the Company s operating results, financial position or cash flows.

In February 2007, the FASB issued SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115* (SFAS 159), which permits entities to choose to measure many financial instruments and certain other items at fair value (Fair Value Option). Election of the Fair Value Option is made on an instrument-by-instrument basis and is irrevocable. At the adoption date, unrealized gains and losses on financial assets and liabilities for which the Fair Value Option has been elected would be reported as a cumulative adjustment to beginning retained earnings. Following the election of the Fair Value Option for certain financial assets and liabilities, the Company would report unrealized gains and losses due to changes in fair value in earnings at each subsequent reporting date. The Company adopted SFAS 159 effective January 1, 2008 which did not have a material impact on the Company s operating results, financial position or cash flows as the Company did not elect the Fair Value Option for any of its financial assets or liabilities.

In September 2006, the FASB issued SFAS 157, *Fair Value Measurements* (SFAS 157), which defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. This pronouncement applies to other standards that require or permit fair value measurements. Accordingly, this statement does not require any new fair value measurements. The Company adopted the provisions of SFAS 157 on January 1, 2008. See Fair Value Measurements below for more details.

Fair Value Measurements

In September 2006, the FASB issued SFAS 157 which defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. The provisions of SFAS 157 are effective January 1, 2008. The FASB has also issued Staff Position (FSP) SFAS 157-2 (FSP No. 157-2), which delays the effective date of SFAS 157 for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008. Effective January 1, 2008, the Company adopted SFAS 157 as discussed above and has elected to defer the application thereof to nonfinancial assets and liabilities in accordance with FSP No. 157-2. Non-recurring nonfinancial assets and nonfinancial liabilities for which the Company has not applied the provisions of SFAS 157 include those measured at fair value in goodwill impairment testing, asset retirement obligations initially measured at fair value, and those initially measured at fair value in a business combination.

In October 2008, the FASB issued FSP SFAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active* (FSP No. 157-3), which clarifies the application of SFAS No. 157 in an inactive market and illustrates how an entity would determine fair value when the market for a financial asset is not active. The guidance provided by FSP No. 157-3 did not have a material impact on the Company s operating results, financial position or cash flows.

The Company utilizes derivative contracts to economically hedge against the variability in cash flows associated with the forecasted sale of its anticipated future oil and natural gas production. The Company generally economically hedges a substantial, but varying, portion of anticipated oil and natural gas production for

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the next 12-24 months. Derivatives are carried at fair value on the consolidated balance sheets, with the changes in the fair value included in the consolidated statements of operations for the period in which the change occurs.

Periodically, the Company utilizes marketable securities to invest a portion of its cash on hand. These securities are carried at fair value on the consolidated balance sheets, with the changes in the fair value included in the consolidated statements of operations for the period in which the change occurs.

As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs. SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

The three levels of the fair value hierarchy defined by SFAS 157 are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, marketable securities and listed equities.

Level 2 Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category generally include non-exchange-traded derivatives such as commodity swaps, interest rate swaps, options and collars.

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value.

The following table sets forth by level within the fair value hierarchy the Company s financial assets and liabilities that were accounted for at fair value as of December 31, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	December 31, 2008			
	Level 1	**Level 2**	**Level 3**	**Total**
	(In thousands)			
Assets				
Marketable securities	$ 123,009	$	$	$ 123,009
Receivables from derivative contracts		224,527		224,527
	$ 123,009	$ 224,527	$	$ 347,536
Liabilities				
Liabilities from derivative contracts	$	$	$	$

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Derivatives listed above include collars, swaps, basis swaps and puts that are carried at fair value. The fair value amounts in current period earnings associated with the Company s derivatives resulted from Level 2 fair value methodologies; that is, the Company is able to value the assets and liabilities based on observable market data for similar instruments. This observable data includes the forward curve for commodity prices based on quoted markets prices and prospective volatility factors related to changes in the forward curves.

As of December 31, 2008, the Company s derivative contracts were placed at major financial institutions with investment grade credit ratings which are believed to have a minimal credit risk. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above; however, the Company does not anticipate such nonperformance.

Marketable securities listed above are carried at fair value. The fair value amounts in current period earnings associated with the Company s marketable securities resulted from Level 1 fair value methodologies; that is, the Company is able to value the assets based on quoted fair values for identical instruments.

2. ACQUISITIONS AND DIVESTITURES

Acquisitions

KCS Energy, Inc.

On April 21, 2006, the Company and KCS Energy, Inc. (KCS) announced they had entered into a definitive agreement to merge the companies. This merger was consummated on July 12, 2006 and was consistent with management s goals of acquiring properties within the Company s core operating areas that have a significant proved reserve component and which management believes have additional development and exploration opportunities.

Upon the closing of the merger, KCS stockholders became entitled to receive a combination of $9.00 cash and 1.65 shares of Petrohawk common stock for each share of KCS common stock. At the time of the merger, there were approximately 50.0 million shares of unrestricted KCS common stock outstanding that converted into approximately 82.6 million shares of unrestricted Petrohawk common stock. Total consideration for the shares of KCS common stock was comprised of approximately $1.1 billion of Petrohawk common stock, calculated based on the five day average of Petrohawk s common stock around the merger announcement date, or $13.44, approximately $450 million of cash and the assumption of $275 million of KCS debt. In addition, all outstanding options to purchase KCS common stock and restricted shares of KCS common stock were converted into options to purchase the Company s common stock or restricted shares of the Company s common stock using an exchange ratio of 2.3706 shares of Petrohawk common stock to one share of KCS common stock.

The merger was accounted for using the purchase method of accounting under the accounting standards established in SFAS No. 141, *Business Combinations* (SFAS 141) and SFAS 142. As a result, the Company reflected the results of operations of KCS beginning July 12, 2006. The Company recorded the estimated fair values of the assets acquired and liabilities assumed at July 12, 2006, which primarily consisted of oil and natural gas properties of $1.6 billion, asset retirement obligations of $15.1 million, a deferred income tax liability of $421.6 million, a deferred income tax asset of $49.1 million and goodwill of $767.1 million. The deferred income tax liability recognizes the difference between the tax basis and the fair value of the acquired oil and natural gas properties. The recorded book value of the oil and natural gas properties was increased and goodwill was recorded to recognize this tax basis differential, none of which is deductible for tax purposes. The deferred income tax asset pertains to net operating loss carry-forwards and alternative minimum tax credits in the amounts of $44 million, net of tax, and $5.1 million, respectively.

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Other Transactions

Fayetteville Shale

On January 7, 2008, the Company entered into an agreement to purchase additional properties located in the Fayetteville Shale for $231.3 million after customary closing adjustments. The transaction closed on February 8, 2008. The acquired properties include interests primarily in Van Buren and Cleburne Counties, Arkansas. These properties are substantially undeveloped. During the second half of 2007, the Company completed three separate acquisitions for total cash consideration of approximately $409 million.

Elm Grove Field

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

One TEC, LLC

On August 3, 2007 the Company completed the acquisition of all of the membership interests of One TEC, LLC (One TEC) for approximately $42.0 million. The One TEC acquisition was accounted for using the purchase method of accounting under the accounting standards established in SFAS 141 and SFAS 142. As a result, the Company reflected the results of operations of One TEC beginning August 3, 2007. The Company recorded the estimated fair values of the assets acquired and liabilities assumed at August 3, 2007, which primarily consisted of oil and natural gas properties of $35.0 million.

North Louisiana Acquisitions

On January 27, 2006, the Company completed the acquisition of all of the issued and outstanding common stock of Winwell Resources, Inc. (Winwell). The aggregate consideration paid was approximately $208 million in cash after certain closing adjustments.

The Winwell acquisition was accounted for using the purchase method of accounting under the accounting standards established in SFAS 141 and SFAS 142. As a result, the Company reflected the results of operations of Winwell beginning January 27, 2006. The Company recorded the estimated fair values of the assets acquired and liabilities assumed at January 27, 2006, which primarily consisted of oil and natural gas properties of $219.8 million, asset retirement obligations of $0.5 million, a net deferred tax liability of $78.9 million, and goodwill of $33.5 million. The deferred income tax liability recognizes the difference between the tax basis and the fair value of the acquired oil and natural gas properties. The recorded book value of the oil and natural gas properties was increased and goodwill was recorded to recognize this tax basis differential, none of which is deductible for tax purposes.

Also on January 27, 2006, the Company completed the acquisition of certain oil and natural gas assets from Redley Company (together with the Winwell acquisition, the North Louisiana Acquisitions). The aggregate consideration paid in this asset acquisition was approximately $86.2 million, after certain closing adjustments. The Company reflected the results of operations of the acquired assets beginning January 27, 2006.

Divestitures

Gulf Coast Properties

In June 2007, the Company announced a strategic repositioning involving plans to sell its Gulf Coast properties and concentrate its efforts on developing and expanding the Company s resource-style assets, including tight-gas properties in North Louisiana and the Fayetteville Shale in central Arkansas. On November 30, 2007, the Company completed the sale of its Gulf Coast properties for $825 million, consisting of $700 million in cash and a $125 million note that the purchaser could redeem at any time prior to one year from

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November 30, 2007 for $100 million plus accrued and unpaid interest. If the redemption occurred prior to April 29, 2008, accrued interest would be waived. The economic effective date for the sale was July 1, 2007. Proceeds from the sale were recorded as a decrease to the Company s full cost pool. The note was recorded upon closing at $100 million less a discount of $4.8 million, or approximately $95.2 million. On April 28, 2008, the purchaser redeemed the note for $100 million.

In conjunction with the closing of this sale, the Company deposited $650 million with a qualified intermediary to facilitate potential like-kind exchange transactions, all of which was utilized for property acquisitions completed during the fourth quarter of 2007 and first quarter of 2008.

In connection with the sale of the Company s Gulf Coast properties, the employment of certain employees was terminated, giving rise to termination benefits resulting in additional general and administrative expenses of $9.5 million recorded by the Company on November 30, 2007. In addition, outstanding stock appreciation rights, stock options and restricted share awards to employees whose employment was terminated in connection with the sale were modified to extend the exercise period from 90 days to November 30, 2008, as well as to accelerate the vesting of those awards. As a result of these two modifications, the Company recognized an additional $2.4 million of stock-based compensation expense on November 30, 2007.

Michigan, Wyoming and California

During the fourth quarter of 2006 the Company sold certain of its oil and natural gas assets in Michigan, Wyoming and California. The majority of these assets were acquired in the Company s merger with KCS. Proceeds from these three separate transactions were approximately $135 million, before adjustments, and were recorded as a decrease to the Company s full cost pool.

Gulf of Mexico

On March 21, 2006, the Company completed the sale of substantially all of its Gulf of Mexico properties for $43.2 million, after certain closing adjustments. These proceeds were recorded as a decrease to the Company s full cost pool.

3. OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties as of December 31, 2008 and 2007 consisted of the following:

	December 31,	
	2008	**2007**
	(In thousands)	
Subject to depletion	$ 4,894,357	$ 3,247,304
Not subject to depletion:		
Exploration wells in progress	95,744	14,818
Other capital costs:		
Incurred in 2008	1,883,950	
Incurred in 2007	296,628	376,566
Incurred in 2006	8,655	272,060
Incurred in 2005 and prior	2,991	14,121
Total not subject to depletion	2,287,968	677,565
Gross oil and gas properties	7,182,325	3,924,869
Less accumulated depletion	(2,111,038)	(769,197)
Net oil and gas properties	$ 5,071,287	$ 3,155,672

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The Company uses the full cost method of accounting for its investment in oil and gas properties. Under this method of accounting, all costs of acquisition, exploration and development of oil and gas reserves (including such costs as leasehold acquisition costs, geological expenditures, dry hole costs, tangible and intangible development costs and direct internal costs) are capitalized as the cost of oil and gas properties when incurred. To the extent that capitalized costs of oil and gas properties, net of accumulated depletion exceed the discounted future net revenues of proved oil and gas reserves net of deferred taxes, such excess capitalized costs would be charged to expense. Full cost companies must use the prices in effect at the end of each accounting quarter to calculate the ceiling test value of their reserves. However, subsequent commodity price increases may be utilized to calculate the ceiling value and reserves.

The Company assesses all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value. The Company assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

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

At December 31, 2007, the Company s net capitalized costs of proved oil and natural gas properties did not exceed the estimated future net revenues discounted at 10%, net of tax considerations.

Decreases in product price levels, as well as changes in production rates, levels of reserves, the evaluation of costs excluded from amortization, future development costs, and service costs and other factors could result in significant future ceiling test impairments.

4. LONG-TERM DEBT

Long-term debt as of December 31, 2008 and 2007 consisted of the following:

	December 31, 2008	December 31, 2007
	(In thousands)	
Senior revolving credit facility	$ 450,000	$ 570,000
7.875% $800 million senior notes	800,000	
9.125% $775 million senior notes [(1)]	763,773	762,934
7.125% $275 million senior notes [(2)]	264,080	261,939
9.875% senior notes	254	254
Deferred premiums on derivatives [(3)]	5,767	
	$ 2,283,874	$ 1,595,127

(1) *This amount is comprised of the $650.0 million and $125.0 million private placements consummated in July 2006. These amounts include a $5.9 million and $6.9 million discount at December 31, 2008 and 2007,*

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respectively, recorded by the Company in conjunction with the issuance of the $650.0 million notes. Additionally, these amounts include a $1.0 million and a $1.1 million premium at December 31, 2008 and 2007, respectively, recorded by the Company in conjunction with the issuance of the $125.0 million notes. See 9.125% Senior Notes below for more details.

(2) *Amount includes a $8.3 million and $10.4 million discount at December 31, 2008 and 2007, respectively, recorded by the Company in conjunction with the assumption of the notes. See 7.125% Senior Notes below for more details.*

(3) *Amount excludes $9.4 million and $0.8 million of deferred premiums on derivatives which have been classified as current at December 31, 2008 and 2007, respectively.*

Senior Revolving Credit Facility

The Company entered into the Third Amended and Restated Senior Revolving Credit Agreement, dated as of September 10, 2008 (the Senior Credit Agreement), between the Company, each of the lenders from time to time party thereto (the Lenders), BNP Paribas, as administrative agent for the Lenders, Bank of America, N.A. and BMO Capital Markets Financing, Inc. as co-syndication agents for the Lenders, and JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A. and Fortis Capital Corp. as co-documentation agents for the Lenders., which amends and restates its $1 billion senior revolving credit agreement dated July 12, 2006. The Senior Credit Agreement provides for a $1.5 billion facility with an increased borrowing base of $1.1 billion that will be redetermined on a semi-annual basis, with the Company and the Lenders each having the right to one annual interim unscheduled redetermination, and adjusted based on the Company s oil and gas properties, reserves, other indebtedness and other relevant factors. The Company s borrowing base is subject to a reduction equal to the product of $0.25 multiplied by the stated principal amount (without regard to any initial issue discount) of any notes that the Company may issue. During the first quarter of 2009, the Company initiated a borrowing base redetermination of its Senior Credit Agreement. See Note 13, *Subsequent Events* , for more details.

Amounts outstanding under the Senior Credit Agreement will bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.25% to 2.00% for Eurodollar loans or at specified margins over the Alternate Base Rate (ABR) of 0.00% to 0.50% for ABR loans. Such margins will fluctuate based on the utilization of the facility. Borrowings under the Senior Credit Agreement will be secured by first priority liens on substantially all of the Company s assets, including pursuant to the terms of the Third Amended and Restated Guarantee and Collateral Agreement, all of the assets of, and equity interests in, the Company s subsidiaries. Amounts drawn down on the facility will mature on July 1, 2013.

The Senior Credit Agreement contains customary financial and other covenants, including minimum working capital levels (the ratio of current assets plus the unused commitment under the Senior Credit Agreement to current liabilities) of not less than 1.0 to 1.0 and minimum coverage of interest expenses of not less than 2.5 to 1.0. In addition, the Company is subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. At December 31, 2008, the Company was in compliance with all of its debt covenants under the Senior Credit Agreement.

On January 27, 2009, the Company completed a private placement offering to eligible purchasers of an aggregate principal amount of $600 million 10.5% senior notes due August 1, 2014. As a result of the offering, the Company s borrowing base was decreased from $1.1 billion to $950 million. See Note 13, *Subsequent Events* , for more details.

7.875% Senior Notes

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

The 2015 Notes bear interest at a rate of 7.875% per annum, payable semi-annually on June 1 and December 1 of each year, commencing December 1, 2008. The 2015 Notes will mature on June 1, 2015. The 2015 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness. The 2015 Notes are jointly and severally guaranteed on a senior unsecured basis by the Company s subsidiaries. Petrohawk, the issuer of the Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

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

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

Year	**Percentage**
2012	103.938
2013	101.969
2014	100.000

The Company may be required to offer to repurchase the 2015 Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined in the 2015 Indenture. The 2015 Indenture contains covenants that, among other things, restrict or limit the ability of the Company and its subsidiaries to: borrow money; pay dividends on stock; purchase or redeem stock or subordinated indebtedness; make investments; create liens; enter into transactions with affiliates; sell assets; and merge with or into other companies or transfer all or substantially all of the Company s assets. At December 31, 2008, the Company was in compliance with all of its debt covenants relating to the 2015 Notes.

9.125% Senior Notes

On July 12, 2006, the Company consummated its private placement of 9.125% Senior Notes, also referred to as the 2013 Notes, pursuant to an Indenture dated as of July 12, 2006 (2013 Indenture) and the First Supplemental Indenture to the 2013 Notes (the 2013 First Supplemental Indenture), among the Company, the Company s subsidiaries named therein as guarantors, and U.S. Bank National Association, as trustee. The 2013 Notes were issued at 98.735% of the face amount for gross proceeds of approximately $642.0 million, before estimated offering expenses and the initial purchasers discount. The Company applied a portion of the net proceeds from the sale of the 2013 Notes to fund the cash consideration paid by the Company to the KCS stockholders in connection with the Company s merger with KCS and the Company s repurchase of the 2011 Notes pursuant to a tender offer the Company concluded in July 2006.

The 2013 Notes bear interest at the rate of 9.125% per annum, payable semi-annually on January 15 and July 15 of each year, commencing January 15, 2007. The 2013 Notes mature on July 15, 2013. The 2013 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness, including the 2012 Notes. The 2013 Notes rank effectively subordinate to the Company s secured debt to the extent of the collateral, including secured debt under the Senior Credit Agreement, and senior to any future subordinated indebtedness. The 2013 Notes are jointly and severally guaranteed on a senior unsecured basis by the Company s subsidiaries, including, pursuant to the 2013 First Supplemental Indenture, the KCS subsidiaries acquired in the Company s merger with KCS. Petrohawk Energy Corporation, the issuer of the 2013 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

On or before July 15, 2009, the Company may redeem up to 35% of the aggregate principal amount of the 2013 Notes with the net cash proceeds of certain equity offerings at a redemption price of 109.13% of the principal amount plus accrued interest and unpaid interest to the redemption date provided that: (i) at least 65% in aggregate principal amount of the 2013 Notes originally issued under the 2013 Indenture remain outstanding immediately after the redemption (excluding 2013 Notes held by the Company and its subsidiaries); and (ii) each redemption must occur within 90 days of the date of the closing of the related equity offering.

In addition, on or before July 15, 2010, the Company may redeem all or part of the 2013 Notes upon not less than 30 nor more than 60 days notice, at a redemption price equal to the sum of (i) the principal amount, plus (ii) accrued and unpaid interest, if any, to the redemption date, plus (iii) the make whole premium at the redemption date.

On or after July 15, 2010, the Company may redeem some or all of the 2013 Notes at any time. If any of the 2013 Notes are redeemed during any 12-month period beginning on July 15 of the year indicated below, the Company must pay the following redemption prices (expressed as percentages of principal amount) plus accrued and unpaid interest thereon, if any, to the applicable redemption date:

Year	Percentage
2010	104.563
2011	102.281
2012	100.000

The Company may be required to offer to repurchase the 2013 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 2013 Indenture. Additionally, the Company may be required to offer to repurchase the 2013 Notes and, to the extent required by the terms thereof, all other indebtedness (as defined in the 2013 Indenture) that is pari passu with the 2013 Notes at a purchase price of 100% of the principal amount (or accreted value in the case of any such other pari passu indebtedness issued with a significant original issue discount) plus accrued and unpaid interest, if any, to the date of purchase, in the event net proceeds from assets sales are not applied as required by the 2013 Indenture.

The 2013 Indenture contains covenants that, among other things, restrict or limit the ability of the Company and its subsidiaries to: (i) borrow money; (ii) pay dividends on stock; (iii) purchase or redeem stock or subordinated indebtedness; (iv) make investments; (v) create liens; (vi) enter into transactions with affiliates; (vii) sell assets; and (viii) merge with or into other companies or transfer all or substantially all of the Company s assets.

The Company issued the 2013 Notes in two tranches, $650 million on July 12, 2006 and $125 million on July 27, 2006. The additional $125 million in 2013 Notes were issued pursuant to the same Indenture at 101.125% of the face amount. The Company applied the net proceeds from the sale of the additional 2013 Notes to repay indebtedness outstanding under its revolving credit facility. At December 31, 2008, the Company was in compliance with all of its debt covenants relating to the 2013 Notes.

In conjunction with the issuance of the $650 million 2013 Notes, the Company recorded a discount of $8.2 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The

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remaining unamortized discount was $5.9 million at December 31, 2008. In conjunction with the issuance of the $125 million 2013 Notes, the Company recorded a premium of $1.4 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized premium was $1.0 million at December 31, 2008.

7.125% Senior Notes

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

Year	Percentage
2009	101.784
2010	100.000
2011	100.000
2012	100.000

At December 31, 2008, the Company was in compliance with all of its debt covenants under the 7.125% Senior Notes.

In conjunction with the assumption of the 7.125% Senior Notes from KCS, the Company recorded a discount of $13.6 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized discount is $8.3 million at December 31, 2008.

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

9.875% Senior Notes

On April 8, 2004, Mission issued $130.0 million of its 9.875% senior notes due 2011 (the 2011 Notes). The Company assumed these notes upon the closing of the Company s merger with Mission. In conjunction with the Company s merger with KCS, the Company extinguished substantially all of its 2011 Notes for a premium of $14.9 million plus accrued interest of $3.5 million. There were approximately $0.3 million of the notes which were not redeemed and are still outstanding as of December 31, 2008. In connection with the extinguishment of substantially all of the 2011 Notes, the Company requested and received from the noteholders consent to eliminate most significant debt covenants associated with the 2011 Notes.

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Debt Maturities

Aggregate maturities required on long-term debt at December 31, 2008 are due in future years as follows (in thousands):

2009 (1)	$ 9,426
2010	5,767
2011	254
2012	272,375
2013	1,218,725
Thereafter	800,000
Total	$ 2,306,547

(1) *Amount represents deferred premiums on derivatives which have been classified as current at December 31, 2008.*

Debt Issuance Costs

The Company capitalizes certain direct costs associated with the issuance of long-term debt. The Company capitalized $23.8 million of debt issue costs in connection with the Company s issuance of 2015 Notes in May and June 2008 and in connection with the Company s amended and restated Senior Credit Agreement in September 2008. At December 31, 2008, the Company had approximately $30.5 million of debt issuance costs remaining that are being amortized over the lives of the respective debt.

5. ASSET RETIREMENT OBLIGATION

The Company records an asset retirement obligation (ARO) when the total depth of a drilled well is reached and the Company can reasonably estimate the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon costs. For gas gathering systems, the Company records an ARO when the system is placed in service and the Company can reasonably estimate the fair value of an obligation to perform site reclamation and other necessary work. The Company records the ARO liability on the consolidated balance sheets and capitalizes a portion of the cost in oil and natural gas properties or gas gathering systems and equipment during the period in which the obligation is incurred. In general, the amount of an ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date. This amount is then discounted back to the date that the abandonment obligation was incurred using an assumed cost of funds for the Company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds. The additional capitalized costs are depreciated on a unit-of-production basis or straight-line basis.

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The Company recorded the following activity related to the ARO liability for the years ended December 31, 2008 and 2007 (in thousands):

ARO liability at December 31, 2006	$ 45,326
Liabilities settled and divested [1]	(26,444)
Additions	2,754
Acquisitions [1]	414
Accretion expense	1,750
ARO liability at December 31, 2007	23,800
Liabilities settled and divested [1]	(339)
Additions	2,780
Acquisitions [1]	1,157
Accretion expense	1,246
ARO liability at December 31, 2008	$ 28,644

[1] *Refer to Note 2 Acquisitions and Divestitures for more details on the Company s acquisition and disposition activities.*

6. COMMITMENTS AND CONTINGENCIES

Contingencies

From time to time, the Company may be a plaintiff or defendant in a pending or threatened legal proceeding arising in the normal course of its business. All known liabilities are accrued based on the Company s best estimate of the potential loss. While the outcome and impact of currently pending legal proceedings cannot be predicted with certainty, the Company s management and legal counsel believe that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on the Company s consolidated operating results, financial position or cash flows.

Lease Commitments

The Company leases corporate office space in Houston, Texas and Tulsa, Oklahoma as well as a number of other field office locations. In addition, the Company also has lease commitments related to certain vehicles, machinery and equipment under long-term operating leases. Rent expense was $4.1 million, $3.3 million and $2.0 million for the years ended December 31, 2008, 2007, and 2006, respectively. As of December 31, 2008, future minimum lease payments for all non-cancelable operating leases are as follows (in thousands):

2009	$ 5,125
2010	4,661
2011	4,420
2012	4,300
2013	4,342
Thereafter	5,820
Total	$ 28,668

As of December 31, 2008, the Company has drilling rig commitments totaling $433.0 million as follows (in thousands):

2009	$ 147,303
2010	131,725
2011	105,461
2012	48,546
2013	
Thereafter	
Total	$ 433,035

The Company has various other contractual commitments pertaining to exploration, development and production activities. The Company has work related commitments for, among other things, pipeline and well equipment, obtaining and processing seismic data and natural gas transportation. As of December 31, 2008, the Company is obligated pay $507.8 million as follows (in thousands):

2009	$ 89,033
2010	39,475
2011	38,659
2012	37,146
2013	40,441
Thereafter	263,041
Total	$ 507,795

7. DERIVATIVE AND HEDGING ACTIVITIES

The Company enters into derivative commodity contracts to economically hedge its exposure to price fluctuations on a portion of its anticipated oil and natural gas production. It is the Company s policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Each of the counterparties to the Company s derivative contracts is a lender in the Company s Senior Credit Agreement. The Company did not post collateral under any of these contracts as they are secured under the Senior Credit Agreement.

At December 31, 2008 the Company has entered into collars, swaps, put options and basis swaps. Under a collar arrangement, the Company pays the counterparty the amount which the index price rises above the ceiling price and will receive receipts equal to the floor price when the index price falls below the floor price. Periodically, the Company may pay a fixed premium to increase the floor price above the existing market value at the time the Company enters into the arrangement. A swap requires the Company to make a payment to, or receive receipts from, the counterparty based upon the differential between a specified fixed price and a price related to those quoted on the New York Mercantile Exchange (NYMEX) for each respective period. In a put option, the Company pays a fixed premium to lock in a specified floor price. When the index price falls below the floor price, the Company receives from the counterparty receipts net of the fixed premium and pays the fixed premium when the index price rises above floor price. Under a basis swap, the Company makes a payment to or receives receipts from the counterparty based upon the differential between the index price adjusted for a fixed spread and the contract s settlement location price.

During the first quarter of 2008, the Company made the decision to mitigate a portion of its interest rate risk with interest rate swaps, which mitigate exposure to market rate fluctuations by converting variable interest rates (such as those on the Company s Senior Credit Agreement) to fixed interest rates. Under these swaps, the Company makes payments to, or receives payments from, the counterparties based upon the differential between

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a specified fixed price and a price related to the three-month LIBOR. The Company has elected to not designate any of its positions for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these positions, as well as all payments and receipts on settled contracts, in net gain (loss) on derivatives contracts on the consolidated statements of operations. During the second quarter of 2008, the Company repaid all outstanding borrowings under its Senior Credit Agreement. As a result, the Company made the decision to settle all of its outstanding interest rate swap positions which resulted in a gain of approximately $1.5 million during the second quarter of 2008. This gain is included in net gain (loss) on derivative contracts on the consolidated statements of operations.

At December 31, 2008, the Company had 69 open positions summarized in the tables below: 52 natural gas collar arrangements, two natural gas swap arrangements, one natural gas basis swap arrangement, 10 natural gas put options and four crude oil price arrangements. Derivative commodity contracts settle based on NYMEX West Texas Intermediate and Henry Hub prices which may differ from the actual price received by the Company. The Company s basis swap hedges the basis differential between NYMEX Henry Hub price and the Houston Ship Channel price. During 2008, 2007 and 2006 the Company did not elect to designate any positions as cash flow hedges for accounting purposes, and accordingly, recorded the net change in the mark-to-market valuation of these contracts, as well as all payments and receipts on settled contracts, in current earnings as a component of other income and expenses on the consolidated statements of operations.

At December 31, 2008, the Company had a $224.5 million derivative asset, which $201.1 million was classified as current. For the year ended December 31, 2008, the Company recorded a net derivative gain of $156.9 million ($230.6 million unrealized gain partially offset by a $73.7 million loss from net cash payments on settled contracts).

At December 31, 2007, the Company had 60 open positions summarized in the tables below: 36 natural gas collar arrangements, 12 natural gas swap arrangements, two natural gas put options, seven crude oil swap arrangements and three crude oil collar arrangements.

At December 31, 2007, the Company had a $12.4 million derivative asset, all of which was classified as current, and a $35.1 million derivative liability, $28.2 million of which was classified as current. For the year ended December 31, 2007 the Company recorded a net derivative loss of $35.0 million ($79.0 million unrealized loss partially offset by a $44.0 million gain for net cash received on settled contracts).

At December 31, 2006, the Company had 94 open positions summarized in the tables below: 73 natural gas price collar arrangements, six natural gas price swap arrangements, two natural gas put options, two crude oil price swap arrangements and 11 crude oil collar arrangements.

For the year ended December 31, 2006, the Company recorded a net derivative gain of $124.4 million ($134.4 million unrealized gain partially offset by a $10.0 million loss from cash payments on settled contracts).

Natural Gas

At December 31, 2008, the Company had the following natural gas collar positions:

		Collars			
		Floors		Ceilings	
Period	Volume in MMbtu s	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
January 2009 December 2009	75,730,000	$ 7.00 $10.00	$ 7.57	$ 9.60 $16.45	$ 11.79
January 2010 December 2010	29,200,000	$7.00	$ 7.00	$10.00	$ 10.00

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At December 31, 2008, the Company had the following natural gas swap positions:

Period	Volume in MMbtu s	Swaps Price / Price Range	Weighted Average Price
January 2009 December 2009	1,825,000	$ 8.43	$ 8.43
January 2010 December 2010	1,825,000	$ 8.22	$ 8.22

At December 31, 2008, the Company had the following natural gas basis swap position:

Period	Volume in MMbtu s	Basis Swaps Price / Price Range	Weighted Average Price
January 2009 December 2009	3,650,000	$ 0.33	$ 0.33

At December 31, 2008, the Company had the following natural gas put options:

Period	Puts Volume in MMbtu s	Weighted Average Price
January 2009 December 2009	14,600,000	$ 10.00

Crude Oil

At December 31, 2008, the Company had the following crude oil swap positions:

Period	Volume in Bbls	Swaps Price / Price Range	Weighted Average Price
January 2009 December 2009	273,750	$ 76.85 $77.30	$ 77.00
January 2010 December 2010	273,750	$ 75.15 $75.55	$ 75.28

8. STOCKHOLDERS EQUITY

On February 1, 2008, the Company sold an aggregate of 20.7 million shares of its common stock in an underwritten public offering. The gross proceeds from the sale were approximately $310 million, before deducting underwriting discounts and commissions and estimated expenses of $13 million.

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

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

In connection with the Company s merger with KCS on July 12, 2006, the Company issued 83.9 million shares of its common stock as consideration to the former stockholders of KCS.

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In connection with the North Louisiana Acquisitions, on February 1, 2006, the Company issued and sold 13.0 million shares of its common stock for $14.50 per share, for an aggregate offering amount of $188.5 million. The Company received $180.4 million in net proceeds from the offering. Contemporaneously with the offering, the Company agreed to repurchase, and EnCap Investments, L.P., and certain of its affiliates, agreed to sell, 3.3 million shares for $46.2 million, which represents a price equal to the net proceeds received for those 3.3 million shares by the Company from the offering. The common stock was offered and sold pursuant to private placement exemptions from registration provided by Rule 506 of Regulation D, under Section 4(2) of the Act, Regulation S of the Act and similar exemptions under state law. Shares of the common stock were offered and sold only to accredited investors (as defined in Rule 501(a) of the Act) and non-United States persons pursuant to the offers and sales outside the United States within the meaning of Regulation S under the Act. The placement agents received a cash payment of $7.7 million as compensation for services provided in connection with the offering and to reimburse them for certain expenses.

For the years ended December 31, 2008, 2007 and 2006, respectively, the Company has recognized $12.3 million, $15.5 million and $8.2 million, respectively, of non-cash stock compensation expense.

Incentive Plans

The Company s Incentive Plans include the Third Amended and Restated 2004 Employee Incentive Plan (2004 Employee Plan), Second Amended and Restated 2004 Non-Employee Director Incentive Plan (2004 Non-Employee Director Plan), Mission Resources Corporation 1994 Stock Incentive Plan (Mission 1994 Plan), Mission Resources Corporation 1996 Stock Incentive Plan (Mission 1996 Plan) and Mission Resources Corporation 2004 Incentive Plan (Mission 2004 Plan), KCS Energy, Inc. 2001 Employee and Directors Stock Plan (KCS 2001 Plan) and the KCS Energy, Inc. 2005 Employee and Directors Stock Plan (KCS 2005 Plan) as of December 31, 2008.

Warrants, Options and Stock Appreciation Rights

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

The weighted average grant date fair value of options granted in 2008, 2007 and 2006 was $6.1 million, $5.4 million and $30.7 million, respectively. At December 31, 2008, 2007 and 2006, the unrecognized compensation expense related to non-vested stock options totaled $3.9 million, $3.1 million and $5.1 million, respectively, and will be recognized on a straight line basis over the weighted average remaining vesting period of 0.9 years for 2008, and 1.8 years for 2007 and 2006, respectively. There were 11,559 options, 11,650 options and 500 options which expired in 2008, 2007 and 2006, respectively.

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The following table sets forth the warrants, options and stock appreciation rights transactions for the years ended December 31, 2008, 2007 and 2006 (in thousands, except share and per share amounts).

	Number	Weighted Average Exercise Price Per Share	Aggregate Intrinsic Value [1]	Weighted Average Remaining Contractual Life (Years)
Outstanding at December 31, 2005	5,698,547	$ 6.16	$ 40,232	5.6
KCS options assumed in merger	2,585,950	3.96		
Granted	1,877,270	11.97		
Exercised	(507,342)	6.08		
Forfeited	(428,212)	14.83		
Outstanding at December 31, 2006	9,226,213	$ 6.34	$ 47,607	6.0
Granted	1,494,100	11.84		
Exercised	(2,378,593)	4.90		
Forfeited	(196,072)	11.96		
Outstanding at December 31, 2007	8,145,648	$ 7.64	$ 78,779	4.9
Granted	1,102,800	19.02		
Exercised	(3,036,031)	7.03		
Forfeited	(71,795)	13.19		
Outstanding at December 31, 2008	6,140,622	$ 9.92	$ 45,390	6.3

(1) *The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option. The aggregate intrinsic value of stock options exercised during the years ended December 31, 2008, 2007 and 2006 was approximately $47.5 million, $29.5 million and $2.8 million, respectively.*

Warrants, options and stock appreciation rights outstanding at December 31, 2008 consisted of the following:

Range of Grant Prices Per Share		Outstanding Number	Outstanding Weighted Average Exercise Price per share	Weighted Average Remaining Contractual Life (Years)	Exercisable Number	Exercisable Weighted Average Exercise Price per share
$0.73	5.62	1,534,169	$ 2.84	2.6	1,534,169	$ 2.84
5.72	10.22	1,567,665	8.04	6.0	1,564,665	8.04
10.23	13.61	1,533,286	11.24	7.8	727,799	11.06
$13.86	47.16	1,505,502	17.73	8.7	257,286	14.26

During the second quarter of 2004, and in connection with the recapitalization of the Company by PHAWK, LLC transaction, the Company issued PHAWK, LLC 5.0 million five-year common stock purchase warrants at a price of $3.30 per share. The warrants are exercisable at any time and expire on May 25, 2009. On July 8, 2005, shares and warrants held by PHAWK, LLC were distributed to its members, including certain members of our management. The Company had 1.4 million and 0.7 million warrants exercised and a net 1.2 million and 0.6 million shares of company stock issued during the years ended December 31, 2008 and 2007, respectively. These exercises were included within the options and warrants transactions table above.

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Restricted Stock

From time to time, the Company grants shares of restricted stock to employees of the Company. Employee shares vest over a three-year period at a rate of one-third on the annual anniversary date of the grant and the non-employee directors shares vest six-months from the date of grant. The weighted average grant date fair value of the shares granted in 2008, 2007 and 2006 was $11.4 million, $10.8 million and $18.3 million, respectively. At December 31, 2008, 2007 and 2006, the unrecognized compensation expense related to non-vested restricted stock totaled $6.8 million, $7.5 million and $10.4 million, respectively, and will be recognized on a straight line basis over the weighted average remaining vesting period of 1.4 years, 1.7 years and 1.9 years, respectively.

The following table sets forth the restricted stock transactions for the years ended December 31, 2008, 2007 and 2006 (in thousands, except share and per share amounts).

	Number of Shares	Weighted Average Grant Date Fair Value Per Share	Aggregate Intrinsic Value (1)
Unvested outstanding shares at December 31, 2005	73,334	$ 10.87	$ 969
KCS shares assumed in merger	616,238	13.44	
Granted	888,888	11.72	
Vested	(116,121)	11.52	
Forfeited	(19,494)	10.72	
Unvested outstanding shares at December 31, 2006	1,442,845	$ 12.38	$ 16,593
Granted	867,100	12.52	
Vested	(822,597)	12.23	
Forfeited	(80,505)	12.46	
Unvested outstanding shares at December 31, 2007	1,406,843	$ 12.75	$ 24,352
Granted	570,549	19.90	
Vested	(730,964)	22.14	
Forfeited	(38,286)	15.05	
Unvested outstanding shares at December 31, 2008	1,208,142	$ 15.31	$ 20,930

(1) *The intrinsic value of restricted stock was calculated as the closing market price on December 31, 2008, 2007 and 2006 of the underlying stock multiplied by the number of restricted shares.*

Performance Shares

In conjunction with the Company s merger with KCS, the Company assumed the KCS 2005 Plan under which performance share awards had been granted. The performance awards provide for a contingent right to receive shares of common stock. The grantee earns between 0% and 200% of the target amount of performance shares upon the achievement of pre-determined objectives over a three-year performance period. The objectives relate to the Company s total stockholder return (as defined in the form of performance share agreement) as compared to the total stockholder return of a group of peer companies during the performance period.

The fair value of the awards using a monte carlo technique was $10.89 per share. The Company will recognize compensation cost of $1.5 million over the expected service life of the performance share awards whether or not the threshold is achieved. The Company recognized $0.7 million, $0.5 million and $0.3 million in compensation cost for the years ended December 31, 2008, 2007 and 2006, respectively. During the year ended December 31, 2007, approximately 19,000 net shares of restricted stock were issued as a result of the termination of certain employees with the sale of the Company s Gulf Coast properties. At December 31, 2008, the performance period was completed. A total of 200,864 shares were issued on February 16, 2009 which was equal to 200% of the target amount.

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2004 Employee Incentive Plan

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

On July 12, 2006, the Company and its stockholders approved an amendment to the 2004 Plan Employee to increase the number of shares available for issuance thereunder from 4.25 million shares to 7.05 million shares. On July 18, 2007, the Company and its stockholders approved an amendment to the 2004 Employee Plan to increase the number of shares available for issuance thereunder from 7.05 million shares to 12.55 million shares.

At December 31, 2008, 5.7 million shares were available under the 2004 Employee Plan for future issuance.

2004 Non-Employee Director Incentive Plan

In July 2004 the Company adopted the 2004 Non-Employee Director Plan covering 0.20 million shares. The plan provides for the grant of both incentive stock options and restricted shares of the Company s stock. This plan was designed to attract and retain the services of directors. At the adoption of the plan, each non-employee director received 7,500 restricted shares of the Company s common stock and each new non-employee director would receive 7,500 shares of the Company s common stock. Additional grants of 5,000 restricted shares of the Company s common stock were issued to each non-employee director on each anniversary of his or her service. Effective August, 2006, the annual equity grant to both new and existing non-employee directors increased to 10,000 shares of restricted stock, with the vice chairman of the board of directors to receive 15,000 shares of restricted stock annually. Effective June 2008, the annual compensation awarded to new and existing non-employee directors changed to $150,000, as well as an additional $75,000 for the Vice Chairman. The annual compensation awards were granted in the form of restricted stock, which totaled 5,900 shares for non-employee directors and 8,900 shares for the Vice Chairman for the year-end December 31, 2008. These shares vest over a six-month period from the date of grant. Shares were issued under this plan for the years ended December 31, 2008, 2007 and 2006, were 50,200, 85,000 shares, and 72,500 shares, respectively and there had been no forfeited or cancelled shares.

On July 12, 2006, the Company and its stockholders approved an amendment to the Company s 2004 Non-Employee Director Plan to increase the number of shares available for issuance thereunder from 0.4 million to 0.6 million shares. At December 31, 2008, 0.3 million shares were available under the Plan for future issuance. At December 31, 2008, all non-employee director grants have been fully vested.

KCS and Mission Incentive Plans

Upon consummation of the Company s merger with KCS, the Company assumed the KCS 2001 Plan, as amended, the KCS 2005 Plan, as amended, and associated obligations relating to grants of restricted stock, stock options and performance shares under those plans which were granted prior to the closing of the Company s merger with KCS. At December 31, 2008, no options were available under the Plan for future issuance.

No options were issued in 2008 under the KCS 2005 Plan. In 2007, the Company granted stock appreciation rights covering 0.4 million shares of common stock to employees of the Company under the KCS 2005 Plan. The stock appreciation rights have an exercise price of $11.64 with a weighted average price of $11.64. These stock appreciation rights vest over a three year period at a rate of one-third on the annual anniversary date of the grant and expire ten years from the grant date.

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

8% Cumulative Convertible Preferred Stock

On June 29, 2001 the Company completed its Private Placement Offering of 8% cumulative convertible preferred stock and common stock purchase warrants, offered as units of one preferred share and one-half of one warrant at $9.25 per unit.

In April 2006, the Company initiated a buyback of the preferred stock for $9.25 per unit. On June 9, 2006, the Company sent the holders of the preferred shares notice of redemption as set forth in the certificate of designation for the preferred stock. On July 10, 2006, the Company completed the redemption of the preferred stock. As of December 31, 2008, there were no remaining preferred shares outstanding. All Class A and Class B warrants associated with the preferred stock expired on June 29, 2006.

Treasury Stock

In August 2004, the Company s Board of Directors terminated the stock repurchase program. During the quarter ended September 30, 2006, the Company retired its 8,382 treasury shares.

Assumptions

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

	Years Ended December 31,		
	2008	**2007**	**2006** [(1)]
Weighted average value per option granted during the period	$ 5.52	$ 3.63	$ 6.95
Assumptions [(2)(3)(4)]:			
Stock price volatility	39.6%	38.0%	39.0%
Risk free rate of return	2.0%	4.4%	4.9%
Expected term	3.0 years	3.0 years	2.9 years

(1) *Includes assumptions from valuation related to the Company s merger with KCS.*
(2) *The Company s estimated future forfeiture is 5% based on the Company s historical forfeiture rate.*
(3) *Calculated using the Black-Scholes fair value based method.*
(4) *The Company does not pay dividends on its common stock.*

Rights Plan

On October 14, 2008, the board of directors of the Company adopted a rights plan (Rights Plan), pursuant to which it declared and paid a dividend distribution of one preferred stock purchase right (a Right) for each outstanding share of common stock of the Company to stockholders of record on October 25, 2008. The Rights Plan is designed to enable stockholders of the Company to realize maximum value for their shares of the Company by giving the board of directors of the Company time to properly evaluate various alternatives and preserve the board of directors bargaining power and flexibility to deal with third party inquiries.

Each Right entitles the holder to purchase from the Company under certain circumstances one one-thousandth of a share of the Company s Series A Junior Participating Preferred Stock (the Preferred Stock) at a price of $60.00, subject to adjustment. Shares of Preferred Stock purchasable upon exercise of the Rights are

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generally entitled to dividend, voting and liquidation preferences equal to 1,000 times the corresponding rights on one share of the common stock, which is protected by customary anti-dilution provisions. Accordingly, the value of the one one-thousandth interest in a share of Preferred Stock purchasable upon exercise of each Right should approximate the value of one share of common stock. A Rights Agreement between the Company and American Stock Transfer & Trust Company, as Rights Agent, governs the Rights.

The Rights are not exercisable (and are transferable only with the common stock) until a Distribution Date occurs (or they are earlier redeemed or expire), which generally will occur on the tenth day following a public announcement that a person or group of affiliated or associated persons (Acquiring Person) has acquired beneficial ownership of 15% or more of the outstanding shares of the common stock or after the commencement or announcement of a tender offer or exchange offer which would result in any such person or group of persons acquiring beneficial ownership of 15% or more of the outstanding shares of common stock. Until a Right is exercised, the holder thereof, as such, has no rights as a stockholder of the Company, including, without limitation, the right to vote or to receive dividends. The Rights will expire on October 14, 2009, unless extended or earlier redeemed or exchanged by the Company. The Rights are redeemable by the Company, in whole, but not in part, under certain circumstances at a price of $.001 per Right.

Subject to the Company s ability to amend the terms of the Rights Plan, redeem the Rights or exchange the Rights in connection with a transaction that the board of directors determines to be in the best interests of the stockholders of the Company, in the event that any person or group of affiliated or associated person becomes an Acquiring Person, the Rights Plan provides that each holder of a Right, other than Rights that are beneficially owned by the Acquiring Person (which will thereafter be void), will have the right to receive upon exercise a number of shares of common stock having a market value of two times the exercise price of the Right.

9. INCOME TAXES

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

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Current:			
Federal	$ 10,148	$ (11,011)	$ (2,069)
State	5,053	(998)	(65)
	15,201	(12,009)	(2,134)
Deferred:			
Federal	176,558	(19,300)	(66,337)
State	(46,806)	(1,829)	(4,064)
	129,752	(21,129)	(70,401)
Total benefit (provision)	$ 144,953	$ (33,138)	$ (72,535)

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

	Years Ended December 31, 2008	2007	2006
		(In thousands)	
Expected tax benefit (provision)	$ 186,551	$ (30,112)	$ (66,184)
State taxes, net	24,651	(1,385)	(3,818)
Change in state tax rate[(1)]	(64,796)		
Other	(1,453)	(1,641)	(2,533)
Total benefit (provision)	$ 144,953	$ (33,138)	$ (72,535)

(1) *In the fourth quarter of 2008, the Company filed its federal and state tax returns for 2007. The apportionment of the Company s income to state tax jurisdictions in which the Company files tax returns changed significantly as a result of (i) the sale of the Company s Gulf Coast properties at the end of 2007 and the reinvestment of those proceeds in 2008 in properties located in states with higher income tax rates; and (ii) the continued acquisition and development of properties located in states with higher income tax rates in 2008. Therefore, the Company now expects its temporary differences to reverse at higher tax rates than it had previously estimated. As a result the Company changed its estimate of the effective tax rate applied to its temporary differences, resulting in an increase in deferred tax liabilities and income tax expense of $64.8 million.*

The components of net deferred tax assets and (liabilities) recognized are as follows:

	December 31, 2008	2007
	(In thousands)	
Deferred current tax assets:		
Unrealized hedging transactions	$	$ 5,855
Deferred current tax assets	$	$ 5,855
Deferred current tax liabilities:		
Unrealized hedging transactions	$ (77,454)	$
Deferred current tax liabilities	$ (77,454)	$
Deferred noncurrent tax assets:		
Net operating loss carry-forwards	$ 331,315	$ 125,215
Stock-based compensation expense	8,547	9,499
Unrealized hedging transactions		2,558
Alternative minimum tax credit carryforwards	8,882	18,438
Other	6,988	1,031
Gross deferred noncurrent tax assets	355,732	156,741
Valuation allowance	(825)	(692)
Deferred noncurrent tax assets	$ 354,907	$ 156,049

Deferred noncurrent tax liabilities:		
Book-tax differences in property basis	$ (806,809)	$ (831,017)
Unrealized hedging transactions	(9,011)	
Deferred noncurrent tax liabilities	$ (815,820)	$ (831,017)
Net noncurrent deferred tax liabilities	$ (460,913)	$ (674,968)

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FIN 48 prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of tax positions taken or expected to be taken in a tax return. For those benefits to be recognized, a tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. There was not a material impact on the company s operating results, financial position or cash flows as a result of the adoption of the provisions of FIN 48. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	Liability for Unrecognized Tax Benefits *(In thousands)*
Balance at January 1, 2007	$ 2,100
Additions for tax positions of prior years	1,260
Reductions for tax positions of prior years	(274)
Balance at December 31, 2007	3,086
Additions for tax positions of prior years	1,773
Reductions for tax positions of prior years	(561)
Lapse of statute of limitations	(1,111)
Balance at December 31, 2008	$ 3,187

Generally, the Company s tax years 2005 through 2008 remain open and subject to examination by Federal tax authorities or the tax authorities in Arkansas, Louisiana, New Mexico, Oklahoma and Texas which are the jurisdictions where Petrohawk has its principal operations. In certain jurisdictions the Company operates through more than one legal entity, each of which may have different open years subject to examination. The Internal Revenue Service completed its examination of the Federal return filed by KCS Energy Inc. for the tax year ending December 31, 2005 making no adjustments to the return filed. The Company has not been notified of any other potential examinations. No material amounts of the unrecognized tax benefits have been identified to date that would impact the Company s effective tax rate.

Petrohawk recognizes interest and penalties accrued to unrecognized benefits in interest expense and other in its statements of operations. For the year ended December 31, 2008, Petrohawk recognized no interest and penalties while recognizing $0.1 million for the tax year ending December 31, 2007. The Company had approximately $0.1 million, $0.2 million and $0.1 million for the payment of interest and penalties accrued as December 31, 2008, 2007 and 2006, respectively.

As of December 31, 2008, the Company had available, to reduce future taxable income, a U.S. federal regular net operating loss (NOL) carryforward of approximately $927.1 million (net of excess tax benefits not recognized of $2.8 million), which expire in the years 2018 through 2028. Utilization of NOL carryforwards is subject to annual limitations due to stock ownership changes. The tax net operating loss carryforward may be limited by other factors as well. The Company also has various state NOL carryforwards, reduced by the valuation allowance for losses that the Company anticipates will expire before they can be utilized, totaling approximately $176.4 million, (net of Texas credit for business loss carryforwards) at December 31, 2008, with varying lengths of allowable carryforward periods ranging from five to 20 years that can be used to offset future state taxable income. It is expected that these deferred tax benefits will be utilized prior to their expiration.

10. RELATED PARTY TRANSACTIONS

In February 2006, the Company repurchased approximately 3.3 million shares of its common stock held by EnCap Investments, L.P., and certain of its affiliates, at a price per share equal to the net proceeds per share that the Company received from a private offering of 13.0 million of its common shares that closed on the same day as the EnCap purchase. The 3.3 million shares were repurchased for $46.2 million.

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11. NET (LOSS) INCOME PER COMMON SHARE

The following represents the calculation of net (loss) income per common share:

	Years Ended December 31, 2008	2007	2006
	(In thousands, except per share amounts)		
Basic			
Net (loss) income	$ (388,052)	$ 52,897	$ 116,563
Less: preferred dividends			(217)
Net (loss) income available to common stockholders	$ (388,052)	$ 52,897	$ 116,346
Weighted average basic number of shares outstanding	218,993	168,006	122,452
Basic net (loss) income per share	$ (1.77)	$ 0.31	$ 0.95
Diluted			
Net (loss) income	$ (388,052)	$ 52,897	$ 116,346
Plus: preferred dividends			217
Net (loss) income available to common stockholders	$ (388,052)	$ 52,897	$ 116,563
Weighted average basic number of shares outstanding	218,993	168,006	122,452
Common stock equivalent shares representing shares issuable upon exercise of stock options and stock appreciation rights	Anti-dilutive	1,406	989
Common stock equivalent shares representing shares issuable upon exercise of warrants	Anti-dilutive	971	1,251
Common stock equivalent shares representing shares included upon vesting of restricted shares	Anti-dilutive	865	1,443
Weighted average diluted number of shares outstanding	218,993	171,248	126,135
Diluted net (loss) income per share	$ (1.77)	$ 0.31	$ 0.92

Common stock equivalents, including stock options, SARS, restricted stock and warrants, totaling 7.3 million shares were not included in the computation of diluted net (loss) income per share because the effect would have been anti-dilutive due to the net loss for the year ended December 31, 2008. Common stock equivalents, including stock options, SARS, restricted stock and warrants, totaling 0.1 million and 0.9 million shares were not included in the computation of diluted net (loss) income per share for the years ended December 31, 2007 and 2006, respectively, because the grant prices were greater than the average market price of the common shares and the effect would have been anti-dilutive.

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12. ADDITIONAL FINANCIAL STATEMENT INFORMATION

Certain balance sheet amounts are comprised of the following:

	December 31, 2008	December 31, 2007
	(In thousands)	
Accounts receivable:		
Oil and gas sales	$ 98,536	$ 77,033
Gas marketing sales	36,476	
Joint interest accounts	96,485	52,210
Income taxes receivable	35,535	1,788
Advances receivable		15,906
Other	10,317	1,201
	$ 277,349	$ 148,138
Prepaids and other:		
Prepaid insurance	$ 2,315	$ 2,690
Prepaid drilling costs	35,739	13,937
Other	2,009	4,392
	$ 40,063	$ 21,019
Accounts payable and accrued liabilities:		
Trade payables	$ 82,028	$ 25,751
Revenues and royalties payable	145,828	90,967
Accrued capital costs	264,888	117,748
Accrued interest expense	42,548	37,557
Prepayment liabilities	59,234	10,977
Accrued lease operating expenses	7,017	6,373
Accrued ad valorem taxes payable	4,029	5,578
Accrued employee compensation	11,723	3,468
Accrued hedging settlements		2,028
Other	22,137	31,024
	$ 639,432	$ 331,471

Certain cash and non-cash related items:

	Years Ended December 31, 2008	2007	2006
		(In thousands)	
Cash payments:			
Interest payments	$ 144,241	$ 128,769	$ 43,714
Income tax payments (refunds)	22,274	(931)	4,847
Non-cash items excluded from the statements of cash flows:			
Accrued capital expenditures	147,140	6,496	87,642

13. SUBSEQUENT EVENTS

On January 27, 2009, the Company completed a private placement offering to eligible purchasers of an aggregate principal amount of $600 million 10.5% senior notes due August 1, 2014. The notes are priced at 91.279% of the face value to yield 12.75% to maturity. Net proceeds from the offering were used to repay all outstanding borrowings on Petrohawk s Senior Credit Agreement, which will provide additional financial flexibility to fund a portion of its 2009 capital budget, to fund potential acquisitions, to provide for further infrastructure expansion and for general corporate purposes.

During the first quarter of 2009, the Company initiated a borrowing base redetermination of its Senior Credit Agreement. The Company s borrowing base of $950 million, along with its existing terms and pricing, were reaffirmed.

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SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Natural Gas Reserves

Users of this information should be aware that the process of estimating quantities of proved and proved developed oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Proved reserves represent estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions in effect when the estimates were made. Proved developed reserves are proved reserves expected to be recovered through wells and equipment in place and under operating methods used when the estimates were made.

Estimates of proved reserves at December 31, 2008, 2007 and 2006 were prepared by Netherland, Sewell & Associates, Inc. (Netherland, Sewell), the Company s independent consulting petroleum engineers. All proved reserves are located in the United States.

The following table illustrates the Company s estimated net proved reserves, including changes, and proved developed reserves for the periods indicated, as estimated by Netherland, Sewell. Natural gas liquids are included in natural gas reserves. Oil and natural gas liquids are based on the December 31, 2008 and 2007 West Texas Intermediate posted price of $41.00 per barrel and $92.50 per barrel, and posted price of $57.75 per barrel on December 31, 2006 which are adjusted by lease for quality, transportation fees, and regional price differentials. Gas prices are based on a December 31, 2008, 2007 and 2006 Henry Hub spot market price of $5.71 per MMbtu, $6.80 per MMbtu and $5.63 per MMbtu and are adjusted by lease for energy content, transportation fees, and regional price differentials. All prices are held constant in accordance with SEC guidelines.

		Proved Reserves	
	Oil (MBbls)	**Gas (Mmcf)**	**Equivalent (Mmcfe)**
Proved reserves, December 31, 2005	21,467	308,467	437,269
Extensions and discoveries	4,109	270,526	295,180
Purchase of minerals in place	8,597	485,270	536,852
Production	(2,703)	(63,645)	(79,863)
Sale of minerals in place	(6,528)	(40,653)	(79,821)
Revision of previous estimates	(531)	(30,311)	(33,497)
Proved reserves, December 31, 2006	24,411	929,654	1,076,120
Extensions and discoveries (1)	4,912	296,816	326,288
Purchase of minerals in place	184	42,587	43,691
Production	(2,816)	(99,506)	(116,402)
Sale of minerals in place	(11,553)	(204,093)	(273,411)
Revision of previous estimates	2,601	(10,305)	5,301
Proved reserves, December 31, 2007	17,739	955,153	1,061,587
Extensions and discoveries (1)	1,293	456,817	464,575
Purchase of minerals in place	147	94,406	95,288
Production	(1,554)	(102,273)	(111,597)
Sale of minerals in place	(210)	(2,342)	(3,602)
Revision of previous estimates	(3,577)	(67,076)	(88,538)

Proved reserves, December 31, 2008	13,838	1,334,685	1,417,713

(1) *Includes infill reserves in existing proved fields of 204,787 Mmcfe and 232,065 Mmcfe at December 31, 2008 and 2007, respectively.*

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	Proved Developed Reserves		
	Oil (Mbls)	Gas (Mmcf)	Equivalent (Mmcfe)
December 31, 2006	17,944	566,024	673,688
December 31, 2007	12,142	533,902	606,754
December 31, 2008	9,099	737,368	791,962

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

The following table illustrates the total amount of capitalized costs relating to oil and natural gas producing activities and the total amount of related accumulated depreciation, depletion and amortization.

	December 31,		
	2008	2007	2006
		(In thousands)	
Evaluated properties [(1)]	$ 5,084,726	$ 3,249,484	$ 2,903,763
Unevaluated properties	2,287,968	677,565	537,611
	7,372,694	3,927,049	3,441,374
Accumulated depletion, depreciation and amortization [(1)]	(2,114,024)	(770,288)	(379,984)
	$ 5,258,670	$ 3,156,761	$ 3,061,390

(1) *Amounts include costs and associated accumulated depletion, depreciation and amortization for our gas gathering systems and related support equipment.*

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

Costs incurred in property acquisition, exploration and development activities were as follows:

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Property acquisition costs, proved	$ 214,315	$ 165,614	$ 1,406,489
Property acquisition costs, unproved	1,965,429	356,348	517,695
Exploration and extension well costs	679,887	372,438	337,076
Development costs	582,575	379,749	152,335
Total costs	$ 3,442,206	$ 1,274,149	$ 2,413,595

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves

The following information has been developed utilizing SFAS 69, *Disclosures about Oil and Gas Producing Activities*, (SFAS 69) procedures and based on oil and natural gas reserve and production volumes estimated by the Company s engineering staff. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flow be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account when reviewing the following information:

future costs and selling prices will probably differ from those required to be used in these calculations;

due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations;

a 10% discount rate may not be reasonable as a measure of the relative risk inherent in realizing future net oil and natural gas revenues; and

future net revenues may be subject to different rates of income taxation.

Under the Standardized Measure, future cash inflows were estimated by applying year-end oil and natural gas prices to the estimated future production of year-end proved reserves. Estimates of future income taxes are computed using current statutory income tax rates including consideration for estimated future statutory depletion and tax credits. The resulting net cash flows are reduced to present value amounts by applying a 10% discount factor. Use of a 10% discount rate and year-end prices are required by SFAS 69.

The Standardized Measure is as follows:

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Future cash inflows	$ 8,145,908	$ 8,434,767	$ 6,492,900
Future production costs	(1,971,585)	(2,004,206)	(1,703,787)
Future development costs	(1,631,050)	(1,227,874)	(1,044,147)
Future income tax expense	(1,058,344)	(1,549,136)	(1,004,896)
Future net cash flows before 10% discount	3,484,929	3,653,551	2,740,070
10% annual discount for estimated timing of cash flows	(1,651,056)	(1,728,055)	(1,170,023)
Standardized measure of discounted future net cash flows	$ 1,833,873	$ 1,925,496	$ 1,570,047

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves

The following is a summary of the changes in the Standardized Measure of discounted future net cash flows for the Company s proved oil and natural gas reserves during each of the years in the three year period ended December 31, 2008.

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Beginning of year	$ 1,925,496	$ 1,570,047	$ 1,023,719
Sale of oil and gas produced, net of production costs	(879,143)	(719,677)	(459,881)
Purchase of minerals in place	220,929	84,889	1,484,511
Sales of minerals in place	(9,962)	(903,165)	(265,315)
Extensions and discoveries	782,998	708,563	353,392
Changes in income taxes, net	294,484	(188,388)	(84,094)
Changes in prices and costs	(1,086,271)	817,610	(791,504)
Development costs incurred	582,575	379,749	152,335
Revisions of previous quantities	(135,634)	12,855	(48,142)
Accretion of discount	275,394	198,275	225,683
Changes in production rates and other	(136,993)	(35,262)	(20,657)
End of year	$ 1,833,873	$ 1,925,496	$ 1,570,047

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SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

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

	Quarters Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(In thousands, except per share amounts)			
2008				
Total operating revenues	$ 214,938	$ 304,633	$ 304,960	$ 270,679
Income (loss) from operations	82,239	161,593	147,870	(929,752)
Net (loss) income [(1)]	(55,612)	(92,766)	305,465	(545,139)
(Loss) earnings per share of common stock:				
Basic	$ (0.30)	$ (0.45)	$ 1.30	$ (2.18)
Diluted	$ (0.30)	$ (0.45)	$ 1.28	$ (2.18)
2007				
Total operating revenues	$ 209,243	$ 233,482	$ 213,337	$ 227,343
Income from operations	58,677	72,804	55,931	63,237
Net (loss) income [(1)]	(19,415)	45,631	26,795	(114)
(Loss) earnings per share of common stock:				
Basic	$ (0.12)	$ 0.27	$ 0.16	$ (0.00)
Diluted	$ (0.12)	$ 0.27	$ 0.16	$ (0.00)

[(1)] *The volatility in net (loss) income is substantially due to the Company s accounting policy to mark derivative positions to market and not apply cash flow hedge accounting as well as the Company s full cost ceiling impairment recorded during the fourth quarter of 2008. See Note 7, Derivative and Hedging Activities and Note 3, Oil and Natural Gas Properties for additional information.*

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Management s Evaluation of Disclosure Controls and Procedures

In accordance with Exchange Act Rule 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2008 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management s Report on Internal Control over Financial Reporting

Management has assessed, and our independent registered public accounting firm, Deloitte & Touche LLP, has audited, our internal control over financial reporting as of December 31, 2008. The unqualified reports of management and Deloitte & Touche LLP thereon are included in Item 8 of this Annual Report on Form 10-K and are incorporated by reference herein.

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting that occurred during the three months ended December 31, 2008 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2009 annual meeting under the heading Directors, Executive Officers and Corporate Governance.

ITEM 11. EXECUTIVE COMPENSATION

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2009 annual meeting under the heading Executive Compensation.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2009 annual meeting under the heading Principal Stockholders and Security Ownership of Management and Related Stockholder Matters.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2009 annual meeting under the heading Certain Transactions.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2009 annual meeting under the heading Ratification of Appointments of Independent Auditors.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(1) Consolidated Financial Statements:
The consolidated financial statements of the Company and its subsidiaries and report of independent registered public accounting firm listed in Section 8 of this Form 10-K are filed as a part of this Form 10-K.

(2) Consolidated Financial Statements Schedules:
All schedules are omitted because they are inapplicable or because the required information is contained in the financial statements or included in the notes thereto.

(3) Exhibits:
The following documents are included as exhibits to this Form 10-K. Those exhibits incorporated by reference are so indicated by the information supplied with respect thereto. Those exhibits which are not incorporated by reference are attached hereto.

Exhibit No	Description
2.1	Agreement and Plan of Merger, dated April 3, 2005 (and as amended through June 8, 2005), by and among Petrohawk Energy Corporation, Petrohawk Acquisition Corporation, and Mission Resources Corporation (Incorporated by reference to Annex A of our Registration Statement on Form S-4/A filed on June 22, 2005).
2.2	Agreement and Plan of Merger, dated October 13, 2004, among Petrohawk Energy Corporation, Wynn-Crosby Energy, Inc., Ronald W. Crosby and Paige L. Crosby (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed on November 24, 2004).
2.3	Agreement and Plan of Mergers, dated October 13, 2004, among Petrohawk Energy Corporation, Wynn-Crosby Energy, Inc., Wynn-Crosby 1994, Ltd.; Wynn-Crosby 1995, Ltd.; Wynn-Crosby 1996, Ltd.; Wynn-Crosby 1997, Ltd.; Wynn-Crosby 1998, Ltd.; Wynn-Crosby 1999, Ltd.; Wynn-Crosby 2000, Ltd.; Wynn-Crosby 2002, Ltd.; WCOG Properties, Ltd.; Kara Nicole Limited; Kristen Lee Limited; Eric Wynn Limited; Christopher David Limited; Paige Lee Limited; Bernadien Wynn Limited; Roger Lee Limited; and George Heaps Limited, and Ronald W. Crosby (Incorporated by reference to Exhibit 2.2 of our Current Report on Form 8-K filed on November 24, 2004).
2.4	Amendment to Agreement and Plan of Mergers among Petrohawk Energy Corporation, Wynn-Crosby Energy, Inc., Wynn-Crosby 1994, Ltd.; Wynn-Crosby 1995, Ltd.; Wynn-Crosby 1996, Ltd.; Wynn-Crosby 1997, Ltd.; Wynn-Crosby 1998, Ltd.; Wynn-Crosby 1999, Ltd.; Wynn-Crosby 2000, Ltd.; Wynn-Crosby 2002, Ltd.; WCOG Properties, Ltd.; Kara Nicole Limited; Kristen Lee Limited; Eric Wynn Limited; Christopher David Limited; Paige Lee Limited; Bernadien Wynn Limited; Roger Lee Limited; and George Heaps Limited, and Ronald W. Crosby, dated October 26, 2004 (Incorporated by reference to Exhibit 2.3 of our Current Report on Form 8-K filed on November 24, 2004).
2.5	Stock Purchase Agreement among Winwell Resources, Inc. and all of its Shareholders, as Sellers, and Petrohawk Energy Corporation, as Buyer, dated as of December 14, 2005 (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed December 20, 2005).
2.6	Asset Purchase Agreement among Redley Company, Burris Run Company and Red Clay Minerals, collectively as Seller, and Petrohawk Energy Corporation, as Buyer, dated as of December 14, 2005 (Incorporated by reference to Exhibit 2.2 of our Current Report on Form 8-K filed December 20, 2005).

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Exhibit No	Description
2.7	First Amendment to Asset Purchase Agreement among Redley Company, Burris Run Company and Red Clay Minerals, collectively as Seller, and Petrohawk Energy Corporation, as Buyer, effective as of December 14, 2005 (Incorporated by reference to Exhibit 2.7 of our Annual Report on Form 10-K filed March 14, 2006).
2.8	Assignment Agreement between Petrohawk Properties, L.P. and Petrohawk Energy Corporation effective January 27, 2006 (Incorporated by reference to Exhibit 2.8 of our Annual Report on Form 10-K filed March 14, 2006).
2.9	Amended and Restated Agreement and Plan of Merger executed as of May 16, 2006, and effective as of April 20, 2006 by and among KCS Energy, Inc., Petrohawk Energy Corporation and Hawk Nest Corporation (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed May 18, 2006).
3.1	Certificate of Incorporation for Petrohawk Energy Corporation (Incorporated by reference to Exhibit 3.1 to our Form S-8 (File No. 333-117733) filed on July 29, 2004).
3.2	Certificate of Amendment to Certificate of Incorporation for Petrohawk Energy Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on November 24, 2004).
3.3	Certificate of Amendment of Certificate of Incorporation of Petrohawk Energy Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on August 3, 2005).
3.4	Amended and Restated Bylaws of Petrohawk Energy Corporation effective as of July 12, 2006 (Incorporated by reference to Exhibit 3.2 of our Current Report on Form 8-K filed on July 17, 2006).
3.5	Certificate of Amendment to Certificate of Incorporation of Petrohawk Energy Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on July 17, 2006).
3.6	Certificate of Designations of Series A Junior Preferred Stock of Petrohawk Energy Corporation effective as of October 15, 2008 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on October 16, 2008)
4.1	Indenture dated as of April 8, 2004, among Mission Resources Corporation, the Guarantors named therein and The Bank of New York, as Trustee, relating to Petrohawk Energy Corporation s 9.125% Senior Notes due 2011 (Incorporated by reference to Exhibit 4.1 to Mission Resources Corporation s Current Report on Form 8-K/A filed on April 15, 2004).
4.2	First Supplemental Indenture dated as of July 28, 2005, among Petrohawk Energy Corporation, the successor by way of merger to Mission Resources Corporation, the parties named therein as Existing Subsidiary Guarantors, the parties named therein as Additional Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as successor trustee to The Bank of New York (Incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed on August 3, 2005).
4.3	Second Supplemental Indenture dated as of July 12, 2006, among Petrohawk Energy Corporation, as successor by merger to Mission Resources Corporation, the parties named therein as subsidiary guarantors, and The Bank of New York Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed on July 17, 2006).
4.4	Indenture dated April 1, 2004 among KCS Energy, Inc., U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein, relating to KCS Energy, Inc. s 7.125% senior notes due 2012 (Incorporated by reference to Exhibit 4.1 to KCS Energy, Inc. s Quarterly Report on Form 10-Q filed on May 10, 2004).

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4.5	First Supplemental Indenture, dated as of April 8, 2005, to Indenture dated as of April 1, 2004, among KCS Energy, Inc., certain of its subsidiaries and U.S. Bank National Association (Incorporated by reference to Exhibit 4.1 of KCS Energy, Inc. s Form 8-K filed on April 11, 2005).
4.6	Second Supplemental Indenture dated July 12, 2006 among Petrohawk Energy Corporation, the successor by way of merger to KCS Energy, Inc., the parties named therein as guarantors, and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.4 to our Current Report on Form 8-K filed July 17, 2006).
4.7	Third Supplemental Indenture dated as of July 12, 2006 among Petrohawk Energy Corporation, the successor by way of merger to KCS Energy, Inc., the parties named therein as existing guarantors, the parties named therein as new guarantors, and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.5 to our Current Report on Form 8-K filed July 17, 2006).
4.8	Fourth Supplemental Indenture dated as of August 3, 2007 among Petrohawk Energy Corporation, the successor by way of merger to KCS Energy, Inc., the parties named therein as existing guarantors, the parties named therein as new guarantors, and The Law Debenture Trust Company of New York, as the successor to U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.12 to our Quarterly Report on Form 10-Q filed on November 6, 2008).
4.9*	Fifth Supplemental Indenture dated as of November 28, 2008 among Petrohawk Energy Corporation, HK Energy Marketing, LLC, the parties named therein as guarantors, and The Law Debenture Trust Company of New York, as the successor to U.S. Bank National Association, as trustee.
4.10*	Sixth Supplemental Indenture dated as of January 26, 2009 among Winwell Resources, L.L.C., KCS Resources, LLC, Petrohawk Energy Corporation, the parties named therein as guarantors, and The Law Debenture Trust Company of New York, as the successor to U.S. Bank National Association, as trustee.
4.11	Indenture dated July 12, 2006 among Petrohawk Energy Corporation, U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein, relating to Petrohawk Energy Corporation s 9.875% senior notes due 2013 (Incorporated by reference to Exhibit 4.6 to our Current Report on Form 8-K filed July 17, 2006).
4.12	First Supplemental Indenture dated July 12, 2006 among Petrohawk Energy Corporation, U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein (Incorporated by reference to Exhibit 4.7 to our Current Report on Form 8-K filed July 17, 2006).
4.13	Second Supplemental Indenture dated August 3, 2007 among Petrohawk Energy Corporation, One TEC, LLC, One TEC Operating, LLC, Bison Ranch, LLC, the parties named therein as existing guarantors and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.10 to our Quarterly Report on Form 10-Q filed November 8, 2007).
4.14*	Third Supplemental Indenture dated as of November 28, 2008 among Petrohawk Energy Corporation, HK Energy Marketing, LLC, the parties named therein as guarantors, and U.S. Bank National Association, as trustee.
4.15*	Fourth Supplemental Indenture dated as of January 26, 2009 among Winwell Resources, L.L.C., KCS Resources, LLC, Petrohawk Energy Corporation, the parties named therein as guarantors, and U.S. Bank National Association, as trustee.
4.16	Indenture, dated May 13, 2008, among Petrohawk Energy Corporation, the subsidiary guarantors named therein, and U.S. Bank Trust National Association (Incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed May 15, 2008).

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4.17*	First Supplemental Indenture dated as of November 28, 2008 among Petrohawk Energy Corporation, HK Energy Marketing, LLC, and parties named therein as guarantors, and U.S. Bank Trust National Association, as trustee.
4.18*	Second Supplemental Indenture dated as of January 26, 2009 among Winwell Resources, L.L.C., KCS Resources, LLC, Petrohawk Energy Corporation, the parties named therein as guarantors, and U.S. Bank Trust National Association, as trustee.
4.19	Rights Agreement, dated as of October 14, 2008, between Petrohawk Energy Corporation and American Stock Transfer & Trust Company, as Rights Agent (Incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed October 16, 2008).
4.20	Registration Rights Agreement, dated May 13, 2008, among the Company, the subsidiary guarantors named therein, and Lehman Brothers Inc., on behalf of Lehman Brothers Inc., J.P. Morgan Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, BNP Paribas Securities Corp., Credit Suisse Securities (USA) LLC, Banc of America Securities LLC, Citigroup Global Markets Inc., BMO Capital Markets Corp., RBC Capital Markets Corporation, and Wells Fargo Securities, LLC. (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed on May 15, 2008).
4.21	Indenture, dated January 27, 2009, among the Company, the subsidiary guarantors named therein, and U.S. Bank Trust National Association (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed on January 28, 2009).
4.22	Registration Rights Agreement, dated January 27, 2009, among the Company, the subsidiary guarantors named therein, and J.P. Morgan Securities Inc., on behalf of J.P. Morgan Securities Inc., BNP Paribas Securities Corp., Wachovia Capital Markets, LLC, Banc of America Securities LLC, BMO Capital Markets Corp., Barclays Capital Inc., Fortis Securities LLC, Calyon Securities (USA) Inc., RBC Capital Markets Corporation, Capital One Southcoast, Inc., Wedbush Morgan Securities Inc., Natixis Bleichroeder Inc., Citigroup Global Markets Inc., BBVA Securities, Inc., and Piper Jaffray & Co. (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed on January 28, 2009).
10.1	Third Amended and Restated Senior Revolving Credit Agreement dated September 10, 2008, among Petrohawk Energy Corporation, each of the Lenders from time to time party thereto, BNP Paribas, as administrative agent for the Lenders, Bank of America, N.A. and BMO Capital Markets Financing, Inc., as syndication agents for the Lenders, and JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A. and Fortis Capital Corp. as co-documentation agents for the Lenders (Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed September 15, 2008).
10.2	Third Amended and Restated Guarantee and Collateral Agreement dated September 10, 2008, made by Petrohawk Energy Corporation and each of its subsidiaries, as Grantors, in favor of BNP Paribas, as Administrative Agent (Incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed September 15, 2008).
10.3	Purchase Agreement dated January 22, 2009, among the Company and J.P. Morgan Securities Inc., on behalf of J.P. Morgan Securities Inc., BNP Paribas Securities Corp., Wachovia Capital Markets, LLC, Banc of America Securities LLC, BMO Capital Markets Corp., Barclays Capital Inc., Fortis Securities LLC, Calyon Securities (USA) Inc., RBC Capital Markets Corporation, Capital One Southcoast, Inc., Wedbush Morgan Securities Inc., Natixis Bleichroeder Inc., Citigroup Global Markets Inc., BBVA Securities, Inc., and Piper Jaffray & Co. (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed January 28, 2009).
10.4	The Petrohawk Energy Corporation Amended and Restated 1999 Incentive and Nonstatutory Stock Option Plan (Incorporated by reference to Exhibit 99.3 of our Current Report on Form 8-K filed on August 18, 2004).

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10.5	Form of Director and Officer Indemnity Agreement (Incorporated by reference to Exhibit 10.11 of our Annual Report on Form 10-K filed on March 31, 2005).
10.6	The Petrohawk Energy Corporation Second Amended and Restated 2004 Non-Employee Director Incentive Plan (Incorporated by reference to Exhibit 4.1 to our Registration Statement No. 333-117733 on Form S-8 filed July 29, 2005).
10.7	First Amendment to the Petrohawk Energy Corporation Second Amended and Restated 2004 Non-Employee Director Incentive Plan (Incorporated by reference to Exhibit 10.8 to our Quarterly Report on Form 10-Q filed August 9, 2006).
10.8	Form of Stock Option Agreement for the Second Amended and Restated 2004 Non-Employee Director Incentive Plan (Incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q filed August 11, 2005).
10.9	Form of Restricted Stock Agreement for the Second Amended and Restated 2004 Non-Employee Director Incentive Plan (Incorporated by reference to Exhibit 10.4 of our Second Quarter 2005 Form 10-Q filed on August 11, 2005).
10.10	Form of Incentive Stock Agreement for the Second Amended and Restated 2004 Non-Employee Director Incentive Plan (Incorporated by reference to Exhibit 10.5 of our Second Quarter 2005 Form 10-Q filed on August 11, 2005).
10.11	The Petrohawk Energy Corporation Third Amended and Restated 2004 Employee Incentive Plan (Incorporated by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q filed May 10, 2007).
10.12	Amendment No. 1 to the Petrohawk Energy Corporation Third Amended and Restated 2004 Employee Incentive Plan (Incorporated by reference to our Registration Statement on Form S-8 (File No. 333-148434) filed January 2, 2008).
10.13	Form of Stock Option Agreement for the Third Amended and Restated 2004 Employee Incentive Plan (Incorporated by reference to Exhibit 10.3 of our Annual Report on Form 10-K filed March 14, 2006).
10.14	Form of Restricted Stock Agreement for the Third Amended and Restated 2004 Employee Incentive Plan (Incorporated by reference to Exhibit 10.8 of our Second Quarter 2005 Form 10-Q filed on August 11, 2005).
10.15	Form of Incentive Stock Agreement for the Third Amended and Restated 2004 Employee Incentive Plan (Incorporated by reference to Exhibit 10.9 of our Second Quarter 2005 Form 10-Q filed on August 11, 2005).
10.16	Form of Stock Appreciation Rights Agreement Annual Vesting Awards under the Petrohawk Energy Corporation Third Amended and Restated 2004 Employee Incentive Plan (Incorporated by reference to Exhibit 10.3 of our Quarterly Report on Form 10-Q filed May 10, 2007).
10.17	KCS Energy, Inc. 2001 Employee and Directors Stock Plan (Incorporated by reference to Exhibit (10)iii to KCS Energy, Inc. s Annual Report on Form 10-K filed April 2, 2001), as amended by the Amendment to the KCS Energy, Inc. 2001 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.4 to KCS Energy, Inc. s Current Report on Form 8-K filed April 25, 2006).
10.18	Amendment No. 2 to the KCS Energy, Inc. 2001 Employees and Directors Stock Plan (Incorporated by reference to Exhibit 10.44 of our Annual Report on Form 10-K filed February 28, 2007).
10.19	Form of Supplemental Stock Option Agreement under KCS Energy, Inc. 2001 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.6 of KCS Energy, Inc s Quarterly Report on Form 10-Q filed November 9, 2004).

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Exhibit No	Description
10.20	Form of Directors Supplemental Stock Option Agreement under KCS Energy, Inc. 2001 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.7 of KCS Energy, Inc. s Quarterly Report on Form 10-Q filed November 9, 2004).
10.21	Form of Restricted Stock Award Agreement under KCS Energy, Inc. 2001 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.8 of KCS Energy, Inc. s Quarterly Report on Form 10-Q filed November 9, 2004).
10.22	Form of Restricted Stock Award Agreement (with accelerated vesting provision) under 2001 KCS Energy, Inc. Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.9 of KCS Energy, Inc. s Quarterly Report on Form 10-Q filed November 9, 2004).
10.23	Form of Amendment to Restricted Stock Agreement under the KCS Energy, Inc. 2001 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.5 to KCS Energy, Inc. s Current Report on Form 8-K filed April 25, 2006).
10.24	Form of Amendment to Supplemental Stock Option Agreement under KCS Energy, Inc. s 2001 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.5 to KCS Energy, Inc. s Current Report on Form 8-K filed April 25, 2006).
10.25	KCS Energy, Inc. 2005 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 4.8 to KCS Energy, Inc s Registration Statement on Form S-8 (File No. 333-125690) filed June 10, 2005), as amended by the First Amendment to KCS Energy, Inc. 2005 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.1 to KCS Energy, Inc. s Current Report on Form 8-K filed May 19, 2005).
10.26	Amendment No. 2 to the KCS Energy, Inc. 2005 Employees and Directors Stock Plan (Incorporated by reference to Exhibit 10.43 of our Annual Report on Form 10-K filed February 28, 2007).
10.27	Amendment No. 3 to the KCS Energy, Inc. 2005 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.2 of our Quarterly Report on Form 10-Q filed May 10, 2007).
10.28	Form of Supplemental Stock Option Agreement under KCS Energy, Inc. 2005 Employee and Directors Stock Plan and related Stock Option Exercise Agreement (Incorporated by reference to Exhibit 10.3 of KCS Energy, Inc. s Current Report on Form 8-K filed June 16, 2005).
10.29	Form of Supplemental Stock Option Agreement for Non-Employee Directors under KCS Energy, Inc. 2005 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.4 of KCS Energy, Inc s Current Report on Form 8-K filed June 16, 2005).
10.30	Form of Restricted Stock Award Agreement under KCS Energy, Inc. 2005 Employee and Directors Stock Plan (without accelerated vesting provision) and related Restricted Stock Award Certificate (Incorporated by reference to Exhibit 10.5 of KCS Energy, Inc s Current Report on Form 8-K filed June 16, 2005).
10.31	Form of Restricted Stock Award Agreement under KCS Energy, Inc. 2005 Employee and Directors Stock Plan (with accelerated vesting provision) and related Restricted Stock Award Certificate (Incorporated by reference to Exhibit 10.6 of KCS Energy, Inc. s Current Report on Form 8-K filed June 16, 2005).
10.32	Form of Amended and Restated Performance Share Award Certificate under KCS Energy, Inc. 2005 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.19 to our Quarterly Report on Form 10-Q filed November 3, 2006).
10.33	Form of Restricted Stock Award Certificate under the KCS Energy, Inc. 2005 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.4 of our Quarterly Report on Form 10-Q filed May 10, 2007).

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Exhibit No	Description
10.34	Form of Restricted Stock Award Agreement pursuant to the KCS Energy, Inc. 2005 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.5 of our Quarterly Report on Form 10-Q filed May 10, 2007).
10.35	Form of Stock Appreciation Rights Agreement Annual Vesting Awards under the KCS Energy, Inc. 2005 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.6 of our Quarterly Report on Form 10-Q filed May 10, 2007).
10.36	Executive Employment Agreement Form A for certain executives and Petrohawk Energy Corporation (Incorporated by reference to Exhibit 10.41 of our Annual Report on Form 10-K filed February 28, 2007).
10.37	Executive Employment Agreement Form B for certain executives and Petrohawk Energy Corporation (Incorporated by reference to Exhibit 10.42 of our Annual Report on Form 10-K filed February 28, 2007).
10.38	Form Amendment to Employment Agreement entered into on September 1, 2007 with Floyd C. Wilson, Larry L. Helm, Mark J. Mize, Stephen W. Herod and Richard K. Stoneburner (Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed September 7, 2007).
10.39	Employment Agreement entered into August 14, 2007 effective August 1, 2007 by and between Petrohawk Energy Corporation and David S. Elkouri (Incorporated by reference to Exhibit 10.4 to our Quarterly Report on Form 10-Q filed November 8, 2007).
10.40	Agreement of Sale and Purchase by and among Petrohawk Properties, LP, Petrohawk Energy Corporation, KCS Resources, Inc. and One TEC, LLC collectively, as Seller and Milagro Development I, LP as Purchaser dated October 15, 2007 (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed December 7, 2007).
10.41*	Assumption Agreement dated November 21, 2008 by and among HK Energy Marketing, LLC in favor of BNP Paribas, as administrative agent for the banks and other financial institutions parties to the Third Amended and Restated Senior Revolving Credit Agreement, dated as of September 10, 2008.
10.42*	Assumption Agreement dated January 20, 2009 by and among KCS Resources, LLC in favor of BNP Paribas, as administrative agent for the banks and other financial institutions parties to the Third Amended and Restated Senior Revolving Credit Agreement, dated as of September 10, 2008.
10.43*	Assumption Agreement dated as of January 20, 2009 by and among Winwell Resources, L.L.C. in favor of BNP Paribas, as administrative agent for the banks and other financial institutions parties to the Third Amended and Restated Senior Revolving Credit Agreement, dated as of September 10, 2008.
12.1*	Computation of Ratio of Earnings to Combined Fixed Charges and Preference Dividends.
14.1	Code of Ethics for CEO and Senior Financial Officers (Incorporated by reference to Form 10-K/A filed on April 30, 2007).
21.1*	Subsidiaries of the Registrant.
23.1*	Consent of Deloitte & Touche LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certificate of Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certificate of Chief Financial Officer under Section 302 of Sarbanes-Oxley Act of 2002

Exhibit No	Description
32*	Certifications required by Rule 13a-14(b) or Rule 15d-14(b) under the Securities and Exchange Act of 1934 and 18 U.S.C. Section 1350.
99.1*	Netherland, Sewell & Associates, Inc. Reserve Report.

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

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

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SIGNATURES

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

PETROHAWK ENERGY CORPORATION

Date: February 25, 2009

By: /s/ FLOYD C. WILSON
Floyd C. Wilson
Chairman of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ FLOYD C. WILSON **Floyd C. Wilson**	Chairman of the Board, President and Chief Executive Officer	February 25, 2009
/s/ MARK J. MIZE **Mark J. Mize**	Executive Vice President, Chief Financial Officer and Treasurer	February 25, 2009
/s/ C. BYRON CHARBONEAU **C. Byron Charboneau**	Vice President, Chief Accounting Officer and Controller	February 25, 2009
/s/ JAMES W. CHRISTMAS **James W. Christmas**	Vice Chairman and Director	February 25, 2009
/s/ TUCKER S. BRIDWELL **Tucker S. Bridwell**	Director	February 25, 2009
/s/ THOMAS R. FULLER **Thomas R. Fuller**	Director	February 25, 2009
/s/ JAMES L. IRISH III **James L. Irish III**	Director	February 25, 2009
/s/ GARY A. MERRIMAN **Gary A. Merriman**	Director	February 25, 2009

/s/ ROBERT G. RAYNOLDS **Robert G. Raynolds**	Director	February 25, 2009
/s/ ROBERT C. STONE, JR. **Robert C. Stone, Jr.**	Director	February 25, 2009
/s/ CHRISTOPHER A. VIGGIANO **Christopher A. Viggiano**	Director	February 25, 2009