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

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

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

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

For the fiscal year ended December 31, 2010

Commission file number 001-33334

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

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

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

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

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

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

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

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

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

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

(Check one):

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

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

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

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

DOCUMENTS INCORPORATED BY REFERENCE

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

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Explanatory Note

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

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

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

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

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

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Special note regarding forward-looking statements

This Amendment No. 1 to the Annual Report on Form 10-K contains forward-looking statements within the meaning of the federal securities laws. All statements, other than statements of historical facts, concerning, among other things, planned capital expenditures, potential increases in oil and natural gas production, the number and location of wells to be drilled in the future, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "believe," "intend," "achievable," "anticipate," "will," "continue," "potential," "should," "could" and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Actual results could differ materially from those anticipated in these forward-looking statements. One should consider carefully the statements under the "Risk Factors" section of the previously filed Annual Report on Form 10-K, as well as sections of this report which describe factors that could cause our actual results to differ from those anticipated in the forward-looking statements, including, but not limited to, the following factors:

- our ability to successfully develop our large inventory of undeveloped acreage in our resource plays such as the Haynesville, Lower Bossier and Eagle Ford Shales;
- volatility in commodity prices for oil and natural gas;
- the possibility that the industry may be subject to future regulatory or legislative actions (including any additional taxes and changes in environmental regulation);
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;
- the potential for production decline rates for our wells to be greater than we expect;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fully develop our undeveloped acreage positions;
- our ability to replace oil and natural gas reserves;
- environmental risks;
- drilling and operating risks;
- exploration and development risks;
- competition, including competition for acreage in resource play holdings;
- management's ability to execute our plans to meet our goals;

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

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

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

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

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

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

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

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

Finally, our future results will depend upon various other risks and uncertainties, including, but not limited to, those detailed in the section entitled "Risk Factors" included in the previously filed Annual Report on Form 10-K. All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

PART I

ITEM 1. BUSINESS

Overview

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

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

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

Recent Developments

2012 Note Refinancing

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

Senior Revolving Credit Facility

Effective August 2, 2010, we amended and restated our existing credit facility dated October 14, 2009 by entering into the Fifth Amended and Restated Senior Revolving Credit Agreement (the Senior Credit Agreement), among us, each of the lenders from time to time party thereto (the Lenders), BNP Paribas, as administrative agent for the Lenders, Bank of America, N.A. and Bank of Montreal as co-syndication agents for the Lenders, and JPMorgan Chase Bank, N.A. and Wells Fargo Bank, N.A.,

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as co-documentation agents for the Lenders. The Senior Credit Agreement provides for a $2.0 billion facility. As of December 31, 2010, the borrowing base was approximately $1.65 billion, $1.55 billion of which related to our oil and natural gas properties and up to $100 million (currently limited as described below) related to our midstream assets. The portion of the borrowing base relating to our oil and natural gas properties is redetermined on a semi-annual basis (with us and the Lenders each having the right to one annual interim unscheduled redetermination) and adjusted based on our oil and natural gas properties, reserves, other indebtedness and other relevant factors. The component of the borrowing base relating to our midstream assets is limited to the lesser of $100 million or 3.5 times midstream earnings before interest, taxes, depreciation and amortization (EBITDA), and is calculated quarterly. As of December 31, 2010, the midstream component of the borrowing base was limited to approximately $38 million based on midstream EBITDA. Our borrowing base is subject to a reduction equal to the product of $0.25 multiplied by the stated principal amount (without regard to any initial issue discount) of any unsecured senior or senior subordinated notes that we may issue. In January 2011, we issued an additional $400 million aggregate principal amount of our 7.25% senior notes, a portion of the proceeds of which will be used to redeem all of our 7.125% $275 million senior notes, which have been called for redemption. Accordingly, our borrowing base was reduced to approximately $1.6 billion.

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

Fayetteville Shale Divestiture

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

2013 Note Refinancing

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

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

Mid-Continent Properties Divestiture

On September 29, 2010, we completed the sale of our interest in certain Mid-Continent properties in Texas, Oklahoma and Arkansas for $123 million in cash, before customary closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of our full cost pool with no gain or loss recorded. The transaction had an effective date of July 1, 2010.

Hawk Field Services, LLC Joint Venture

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

We are obligated to deliver to KinderHawk agreed upon minimum annual quantities of natural gas from our operated wells producing from the Haynesville and Lower Bossier Shales, within specified acreage in Northwest Louisiana through May 2015, or in the alternative, pay an annual true-up fee to KinderHawk if such minimum annual quantities are not delivered. We pay KinderHawk negotiated gathering and treating fees, subject to an annual inflation adjustment factor. The gathering fee is equal to $0.34 per thousand cubic feet (Mcf) of natural gas delivered at KinderHawk's receipt points. The treating fee is charged for gas delivered containing more than 2% by volume of carbon dioxide. For gas delivered containing between 2% and 5.5% carbon dioxide, the treating fee is between $0.030 and $0.345 per Mcf, and for gas containing over 5.5% carbon dioxide, the treating fee starts at $0.365 per Mcf and increases on a scale of $0.09 per Mcf for each additional 1% of carbon dioxide content.

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

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

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

Terryville Divestiture

On May 12, 2010, we completed the sale of our interest in the Terryville Field, located in Lincoln and Claiborne Parishes, Louisiana for $320 million in cash, before customary closing adjustments. As of December 31, 2009, we had approximately 100 Bcfe of proved reserves associated with the Terryville Field. Production from the Terryville Field as of the sale date was approximately 20 Mmcfe/d. Proceeds from the sale were recorded as a reduction to the carrying value of our full cost pool with no gain or loss recorded. The transaction had an effective date of January 1, 2010.

West Edmond Hunton Lime Unit Divestiture

On April 30, 2010, we completed the sale of our interest in the West Edmond Hunton Lime Unit (WEHLU) Field in Oklahoma County, Oklahoma for $155 million in cash, before customary closing adjustments. As of December 31, 2009, we had approximately 23 Bcfe of proved reserves associated with the WEHLU Field. Production from the WEHLU Field as of the sale date was approximately 12 Mmcfe/d. Proceeds from the sale were recorded as a reduction to the carrying value of our full cost pool with no gain or loss recorded. The transaction had an effective date of April 1, 2010.

Acreage Acquisitions

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

2011 Capital budget

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

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

Business Strategy

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

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

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

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

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

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

Oil and Natural Gas Reserves

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

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

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

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

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

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

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

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

Operating Segments

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

Oil and Natural Gas Production

Core Operating Regions

Mid-Continent Region

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

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

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

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

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

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

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

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

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

Western Region

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

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

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

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

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

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

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

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

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Midstream Operations

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

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

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

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

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

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

Risk Management

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

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

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

It is our policy to enter into derivative contracts, including interest rate swaps, only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Each of the counterparties to our derivative contracts is a lender in our Senior Credit Agreement. We will continue to evaluate the benefit of employing derivatives in the future. See Item 7A. *Quantitative and Qualitative Disclosures about Market Risk* in our Annual Report on Form 10-K filed on February 22, 2011 for additional information.

Oil and Natural Gas Operations

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

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

	Years Ended December 31,					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive[1]	2	1.9			2	1.8