HALCON RESOURCES CORP
Form 10-K
February 28, 2013

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2012

Commission File Number: 001-35467

Halcón Resources Corporation

(Exact name of registrant as specified in its charter)

Delaware	**20-0700684**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

1000 Louisiana Street, Suite 6700, Houston, TX 77002
(Address of principal executive offices)
(832) 538-0300
(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 $.0001 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 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 (or for such shorter period that the registrant was required to file such reports) 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 (§229.405 of this chapter) 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.

Large accelerated filer o Accelerated filer ý 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

As of February 25, 2013, there were 366,928,463 shares outstanding of registrant's $.0001 par value common stock. Based upon the closing price for the registrant's common stock on the New York Stock Exchange as of June 30, 2012, the aggregate market value of shares of common stock held by non-affiliates of the registrant was approximately $573.0 million.

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 2013 annual meeting of stockholders which will be filed no later than 120 days after December 31, 2012.

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Special note regarding forward-looking statements

This 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 this report and other sections of this report which describe factors that could cause our actual results to differ from those anticipated in the forward-looking statements, including, but not limited to, the following factors:

- our ability to successfully integrate acquired oil and natural gas businesses and operations;
- the possibility that acquisitions may involve unexpected costs or delays, will not achieve intended benefits and will divert management's time and energy, which could have an adverse effect on our financial position, results of operations, or cash flows;
- risks in connection with potential acquisitions and the integration of significant acquisitions;
- we have substantial indebtedness and may incur more debt; higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business;
- our ability to successfully develop our large inventory of undeveloped acreage in our resource plays;
- access to and availability of water and other treatment materials to carry out planned fracture stimulations in our resource plays;
- 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;
- access to adequate gathering systems and transportation take-away capacity, necessary to fully execute our capital program;
- constraints in the Williston Basin and Utica areas with respect to gathering, transportation and processing facilities and marketing;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fully develop our undeveloped acreage positions;
- volatility in commodity prices for oil and natural gas;
- our ability to replace oil and natural gas reserves;

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 retain key members of senior management and key technical employees;

competition, including competition for acreage in resource play holdings;

environmental risks;

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- drilling and operating risks;
- exploration and development risks;
- the possibility that the industry may be subject to future regulatory or legislative actions (including any additional taxes and changes in environmental regulation);
- 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 major oil and natural gas producing regions outside the United States, such as the Middle East, and armed conflict or acts of terrorism or sabotage;
- other economic, competitive, governmental, regulatory, legislative, including federal, state and tribal regulations and laws, geopolitical and technological factors that may negatively impact our business, operations or pricing;
- the insurance coverage maintained by us will adequately cover all losses that may be sustained in connection will all oil and natural gas activities;
- title to the properties in which we have an interest may be impaired by title defects;
- management's ability to execute our plans to meet our goals;
- the cost and availability of goods and services, such as drilling rigs, fracture stimulation services and tubulars; and
- we depend on the skill, ability and decisions of third party operators of the oil and natural gas properties in which we have a non-operated working interest.

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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Glossary of Oil and Natural Gas Terms

The definitions set forth below apply to the indicated terms as used in this report. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

Boe. Barrels of oil equivalent in which six Mcf of natural gas equals one Bbl of oil. 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.

Boe/d. Barrels of oil equivalent per day.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Completion. The installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Development well. A well drilled within the proved areas of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Extension well. A well drilled to extend the limits of a known reservoir.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MBoe. One thousand Boe.

MMBoe. One million Boe.

Mcf. One thousand cubic feet of natural gas.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBtu. One million Btus.

MMcf. One million cubic feet of natural gas.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

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Operator. The individual or company responsible for the exploration, exploitation and production of an oil or natural gas well or lease.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Proved developed producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production.

Proved developed reserves. Proved reserves that are expected to be recovered from existing wellbores, whether or not currently producing, without drilling additional wells. Production of such reserves may require a recompletion.

Proved reserves. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation.

Proved undeveloped location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Recompletion. The completion for production of an existing wellbore in another formation from that in which the well has been previously completed.

Reserve-to-production ratio or Reserve life. A ratio determined by dividing our estimated existing reserves determined as of the stated measurement date by production from such reserves for the prior twelve month period.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

3-D seismic. The method by which a three dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do conventional surveys and contribute significantly to field appraisal, exploitation and production.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover. Operations on a producing well to restore or increase production.

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PART I

ITEM 1. BUSINESS

Overview

We have included definitions of technical terms important to an understanding of our business under "Glossary of Oil and Natural Gas Terms."

Unless the context otherwise requires, all references in this report to "Halcón," "our," "us," and "we" refer to Halcón Resources Corporation (formerly known as RAM Energy Resources, Inc.) and its subsidiaries, as a common entity. On February 10, 2012, we completed a one-for-three reverse stock split of our common stock. All share and per share information in this report has been adjusted to reflect the reverse stock split.

We are an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich oil and natural gas assets in the United States. We were incorporated in Delaware on February 5, 2004 and were recapitalized on February 8, 2012, as described more fully herein. Historically, our producing properties have been located in basins with long histories of oil and natural gas operations. During 2012 we focused our efforts on the acquisition of unevaluated leasehold and producing properties in selected prospect areas and now have an extensive drilling inventory in multiple basins that we believe allows for multiple years of profitable production growth and provides us with broad flexibility to direct our capital resources to projects with the greatest potential returns.

At December 31, 2012, 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 108.8 million barrels of oil equivalent (MMBoe), consisting of 87.4 million barrels (MMBbls) of oil, 5.4 MMBbls of natural gas liquids, and 96.1 billion cubic feet (Bcf) of natural gas. Approximately 47% of our proved reserves were classified as proved developed. We maintain operational control of approximately 93% of our proved reserves.

Our oil and natural gas assets consist of a combination of undeveloped acreage positions in unconventional liquids-rich basins/fields and mature liquids-weighted reserves and production in more conventional basins/fields. We have mature oil and natural gas reserves located primarily in Texas, North Dakota, Louisiana, Oklahoma and Montana. We have acquired acreage and may acquire additional acreage in the Utica / Point Pleasant formations in Ohio and Pennsylvania, the Woodbine / Eagle Ford formations in East Texas, the Bakken / Three Forks formations in North Dakota and Montana, the Tuscaloosa Marine Shale formation in Louisiana, the Midway / Navarro formations in Southeast Texas and the Wilcox formation in Texas and Louisiana as well as several other areas.

Our total operating revenues for 2012 were approximately $247.9 million. Production for the fourth quarter of 2012 averaged 18,348 barrels of oil equivalent per day (Boe/d). Full year 2012 production averaged 9,404 Boe/d compared to 4,121 Boe/d in 2011, resulting in a 128% year over year increase in our average daily production. The increase in production compared to the prior year was driven by our acquisitions of GeoResources, Inc. (GeoResources), the East Texas Assets (defined below) and the Williston Basin Assets (defined below), partially offset by a slight production decline from existing properties. The acquisition of GeoResources, the East Texas Assets and the Williston Basin Assets combined to contribute approximately 5,320 Boe/d of the increase. In 2012, we participated in the drilling of 192 gross (88.2 net) wells of which 189 gross (85.3 net) wells were completed and capable of production, and 3 gross (2.9 net) wells were dry holes. We also drilled and completed 6 gross (5.0 net) salt water disposal wells.

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Recent Developments

Acquisition of Williston Basin Assets

On December 6, 2012, we completed the acquisition of entities owning approximately 81,000 net acres prospective for the Bakken / Three Forks formations primarily located in Williams, Mountrail, McKenzie and Dunn Counties, North Dakota (the Williston Basin Assets), from two affiliated privately held companies, Petro-Hunt, L.L.C. and Pillar Energy, LLC (the Petro-Hunt parties) for a total adjusted purchase price of approximately $1.5 billion, consisting of approximately $756.1 million in cash and approximately $695.2 million in newly issued shares of our preferred stock. We issued a total of approximately 10,880 shares of our 8% Automatically Convertible Preferred Stock, par value $0.0001 per share. Following the approval by our stockholders, on January 18, 2013 each outstanding share of our preferred stock converted into 10,000 shares of our common stock at an effective conversion price of approximately $7.45 per share based on the liquidation preference. Accordingly, on that date an aggregate of 108.8 million shares of our common stock was issued to the Petro-Hunt parties. No cash dividends were paid on the convertible preferred stock as it converted into common stock before April 6, 2013. No proceeds were received by us upon conversion of the preferred stock.

The borrowing base for our Senior Credit Agreement was increased to $850.0 million after the closing of the Williston Basin Assets acquisition. Refer to Item 8. *Consolidated Financial Statements and Supplementary Data* Note 5,"*Acquisitions and Divestitures,*" for additional information regarding our acquisition of the Williston Basin Assets.

Merger with GeoResources, Inc.

On August 1, 2012, we acquired GeoResources by merger (the Merger) for a total purchase price of $854.4 million. As consideration, we paid a combination of $20.00 in cash, and issued 1.932 shares of our common stock, for each share of GeoResources' common stock that was issued and outstanding on the closing date and also assumed GeoResources' outstanding warrants. We issued a total of approximately 51.3 million shares of common stock and paid approximately $531.5 million in cash to former GeoResources stockholders in exchange for their shares of GeoResources common stock. GeoResources' oil and natural gas properties include acreage in the Bakken / Three Forks formations in North Dakota and Montana, the Austin Chalk trend and Eagle Ford Shale in Texas. The acquisition expanded our presence in these areas as well as added properties in Oklahoma and Louisiana, which added oil and natural gas reserves and production to our existing asset base. GeoResources' production for the year ended December 31, 2011 was 1.9 MMBoe. Prior to the Merger, we and GeoResources operated as separate companies. GeoResources' results of operations are reflected in our results from and after August 1, 2012. Accordingly, the comparison to prior period results of operations and financial condition set forth below relate solely to us. Refer to Item 8. *Consolidated Financial Statements and Supplementary Data* Note 5,"*Acquisitions and Divestitures,*" for additional information regarding the Merger.

East Texas Assets Acquisition

In early August 2012, we acquired an operated interest in 20,628 net acres of oil and natural gas leaseholds in East Texas (the East Texas Assets) from several private oil and natural gas entities for consideration of $426.8 million comprised of approximately $296.1 million in cash and 20.8 million shares of our common stock, subject to normal closing adjustments. The properties consist of producing and nonproducing acreage believed to be prospective for the Woodbine, Eagle Ford and other formations. The East Texas Assets results of operations are reflected in our results from and after August 1, 2012. Refer to Item 8. *Consolidated Financial Statements and Supplementary Data* Note 5,"*Acquisitions and Divestitures,*" for additional information regarding the East Texas Assets acquisition.

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Acquisition of Unevaluated Acreage

On June 28, 2012, we acquired a working interest in acreage in Eastern Ohio that we believe is prospective for the Utica / Point Pleasant formations. The purchase price in the transaction was approximately $164.0 million. We funded the acquisition with cash on hand.

Other Recent Developments

Offering of Additional 8.875% Senior Notes

On January 14, 2013, we completed the issuance of an additional $600.0 million aggregate principal amount of our 8.875% senior unsecured notes due 2021 (the Additional 2021 Notes). The Additional 2021 Notes were issued at 105% of par and provided net proceeds of approximately $619.5 million (after deducting offering fees). The net proceeds from this offering were used to repay all of the outstanding borrowings under our Senior Credit Agreement and for general corporate purposes, including funding a portion of our 2013 capital expenditures program. There was no borrowing base reduction to our Senior Credit Agreement as a result of the issuance of the Additional 2021 Notes.

Common Stock Purchase Agreement

On December 6, 2012, we received net proceeds of approximately $294.0 million from the private placement of 41.9 million shares of our common stock with Canada Pension Plan Investment Board (CPPIB), which acquired the shares for a purchase price of approximately $7.16 per share.

Offering of 8.875% Senior Notes

On November 6, 2012, we completed a private offering of $750.0 million aggregate principal amount of our 8.875% senior notes due 2021 (the 2021 Notes). The 2021 Notes were issued at 99.247% of par and provided net proceeds of approximately $725.6 million (after deducting offering fees and expenses). The net proceeds from this offering were used to fund a portion of the cash consideration paid in our acquisition of the Williston Basin Assets.

Offering of 9.75% Senior Notes

On July 16, 2012, we completed a private offering of $750.0 million aggregate principal amount of 9.75% senior unsecured notes due 2020 (the 2020 Notes). The 2020 Notes were issued at 98.646% of par and provided net proceeds of approximately $723.1 million (after deducting offering fees and expenses). The net proceeds from this offering were used to fund a portion of the cash consideration paid in the Merger and East Texas Assets acquisition.

Preferred Stock Offering

On March 5, 2012, we sold in a private placement 4,444.4511 shares of 8% automatically convertible preferred stock (Preferred Stock), par value $0.0001 per share, each share of which automatically converted into 10,000 shares of our common stock on April 17, 2012. We received gross proceeds of approximately $400.0 million, or $9.00 per share of common stock, before offering expenses. No cash dividends were paid on the Preferred Stock as it converted into common stock before May 31, 2012. Refer to Item 8. *Consolidated Financial Statements and Supplementary Data* Note 12,"*Preferred Stock and Stockholders' Equity,*" for additional information regarding the offering and subsequent conversion.

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Recapitalization

On February 8, 2012, HALRES LLC, formerly, Halcón Resources, LLC (HALRES), a newly-formed limited liability company led by Floyd C. Wilson, recapitalized us with a $550.0 million investment structured as the purchase of $275.0 million in new common stock, a $275.0 million five-year 8.0% convertible note and warrants for the purchase of an additional 36.7 million shares of our common stock at an exercise price of $4.50 per share (Recapitalization). Information regarding our Recapitalization is set forth under Item 8. *Consolidated Financial Statements and Supplementary Data* Note 3,*"Recapitalization."*

Senior Revolving Credit Agreement

In connection with the closing of the Recapitalization, we entered into a senior secured revolving credit agreement (the Senior Credit Agreement) with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders on February 8, 2012. Initially, the Senior Credit Agreement provided for a $500.0 million facility with an initial borrowing base of $225.0 million. Amounts borrowed under the Senior Credit Agreement will mature on February 8, 2017. The borrowing base will be redetermined semi-annually, with us and the lenders each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations. The borrowing base takes into account our oil and natural gas properties, proved reserves, total indebtedness, and other relevant factors consistent with customary oil and natural gas lending criteria. The 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 future notes or other long-term debt securities that we may issue. Funds advanced under the Senior Credit Agreement may be paid down and re-borrowed during the five-year term of the revolver. Amounts outstanding under the Senior Credit Agreement bear interest at specified margins over the base rate of 0.50% to 1.50% for ABR-based loans or at specified margins over LIBOR of 1.50% to 2.50% for Eurodollar-based loans. Advances under the Senior Credit Agreement are secured by liens on substantially all of our properties and assets. The Senior Credit Agreement contains representations, warranties and covenants customary in transactions of this nature including restrictions on the payment of dividends on our capital stock and financial covenants relating to current ratio and minimum interest coverage ratio.

On August 1, 2012, in connection with the closing of the Merger and East Texas Assets acquisition, we entered into the First Amendment to the Senior Credit Agreement (the First Amendment). The First Amendment increased the commitments under the Senior Credit Agreement to an aggregate amount up to $1.5 billion and the borrowing base from $225.0 million to $525.0 million. On December 6, 2012, the borrowing base was increased from $525.0 million to $850.0 million. At December 31, 2012, we had $298.0 million of indebtedness outstanding, $1.3 million of letters of credit outstanding and $550.7 million of borrowing capacity available under the Senior Credit Agreement.

On January 25, 2013, we entered into the Second Amendment which amends the Senior Credit Agreement with respect to our ability to enter into certain commodity hedging agreements (the Second Amendment). The Second Amendment provides, among other things, that we and our subsidiaries may enter into commodity swap, collar and/or call option agreements with approved counterparties so long as the volumes for such agreements do not exceed 85% of our internally forecasted production (i) from our crude oil, natural gas liquids and natural gas, or (ii) in the case of a proposed acquisition of oil and gas properties, from such oil and gas properties that are the subject of such proposed acquisition, in each case for the 24 months following the date such agreement is entered into. Additionally, we may enter into commodity swap, collar and/or call option agreements so long as the volumes for such agreements do not exceed 85% (i) of the reasonably anticipated projected production from our proved reserves for the period of 25 to 66 months following the date such agreement is entered into, or (ii) in the case of a proposed acquisition of oil and gas properties, of the reasonably anticipated projected production from proved reserves from such oil and gas properties that are the subject of such proposed acquisition for the period of 25 to 48 months following the date such agreement is entered into. The 85% limitations discussed above do not apply to our volumes hedged by using puts, floors and/or basis differential swap agreements.

Prior to the Second Amendment, the volumes for commodity swap, collar and/or call option agreements under the Senior Credit Agreement could not exceed 85% of the reasonably anticipated projected production from our proved reserves (as forecast based upon the most recently delivered reserve report), for each month during the period during which the agreement was in effect for each of crude oil, natural gas liquids and natural gas, for the 66 months following the date such agreement was entered into.

2013 Capital Budget

We expect to spend approximately $1.2 billion on drilling and completion capital expenditures during 2013. While this amount represents the vast majority of our expected capital expenditures in 2013, we will also incur additional capital expenditures associated with ongoing leasing efforts, transportation, infrastructure, and seismic and other expenditures. Of the $1.2 billion budget for drilling and completions, approximately $475 million is planned for the Bakken / Three Forks formations in North Dakota, approximately $490 million is budgeted for Woodbine / Eagle Ford formations in East Texas, approximately $200 million is planned for the Utica / Point Pleasant formations in Ohio and Pennsylvania with the remaining amount planned for various other project areas. Our 2013 drilling and completion budget contemplates six to eight operated rigs running in the Bakken / Three Forks, five to seven operated rigs running in the Woodbine / Eagle Ford and two to three operated rigs running in the Utica / Point Pleasant. Our drilling and completion budget for 2013 is based on our current view of market conditions and current business plans, and is subject to change.

We expect to fund our budgeted 2013 capital expenditures with cash flows from operations, proceeds from potential non-core asset divestitures 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.

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 predominately upon commodity prices and our related commodity price hedging activities, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Accordingly, finding and developing oil and natural gas reserves in an economical manner is critical to our long-term success.

Business Strategy

Our primary objective is to increase stockholder value by growing reserves, production and cash flow. To accomplish this objective, we intend to execute the following business strategies:

Develop and Grow Our Liquids Rich Resource-Style Acreage Positions Using Our Proven Development Expertise. We plan to leverage our management team's expertise and the latest available technologies to economically develop our existing property portfolio with a focus on our core liquids-rich resource style plays. We expect to be the operator for the majority of our acreage,

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which gives us more control over timing, execution and costs. It also allows us to adjust our capital expenditure plans based on drilling results and the economic environment. Our leasing strategy is to pursue long-term contracts that allow us to maintain flexible development plans and avoid short-term obligations to drill wells. As operator, we will also be able to evaluate industry drilling results to implement improved operating practices which may enhance our initial production rates, ultimate recovery factors and rate of return on invested capital. We currently have 17 operated rigs running in our core resource plays, and another three operated rigs running in our non-core areas.

Manage Our Property Portfolio Actively. We continually evaluate our property base to identify and divest non-core areas, higher cost or lower volume producing properties with limited development potential. This strategy allows us to focus on a portfolio of core resource plays with significant potential to increase our proved reserves and production. We expect that divestitures of non-core area assets will provide us with cash to reinvest in our business and repay our current debt and/or future debt we may incur, reducing our reliance on the capital markets for financing.

Maintain Strong Balance Sheet. We believe our cash, internally generated cash flows, borrowing capacity, asset sales and access to the capital markets will provide us with sufficient liquidity to execute our current capital program and strategy. We have no near term debt maturities. Our management team has a successful track record of issuing equity and debt, and selling non-core assets to maintain a strong balance sheet. Since February 2012, Halcón has issued in aggregate approximately $3.4 billion of equity and debt securities. We also employ a hedging program to reduce the variability of our cash flows used to support our capital spending.

Our Competitive Strengths

We have a number of competitive strengths that we believe will allow us to successfully execute our business strategies:

Proven Management Team with Significant Ownership Stake. Our management team and technical professionals, including geologists and engineers, have decades of combined experience in the industry. Our management team has successfully founded, grown, operated and sold companies in this industry sector. Floyd C. Wilson was Chairman and Chief Executive Officer of Petrohawk Energy Corporation, which was acquired by BHP Billiton in August 2011, Chairman and Chief Executive Officer of 3TEC Energy Corporation, which was acquired by Plains Exploration & Production Company in 2003, and Chairman and Chief Executive Officer of Hugoton Energy Corporation, which was acquired by Chesapeake Energy Corporation in 1998.

Geographically and Geologically Diverse Asset Base. Our proved reserves, production and acreage are located in concentrated positions within multiple onshore U.S. basins. These various basins provide exposure to a variety of reservoir formations, each of which has its own characteristics that impact the costs to drill, complete and operate as well as the composition (and therefore value) of the hydrocarbon stream. We believe that this geographic diversity provides us with broad flexibility to direct our capital resources to project with the greatest potential returns and access to multiple key end markets which mitigates our exposure to temporary price dislocations in any one market.

Extensive Experience in Resource Plays. Our team has significant experience in all aspects of the development of resource plays. In addition to their core strength in exploration and production, our personnel have experience in building midstream infrastructure and have managed oilfield service activities.

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Strong Technical Team. We believe that there are certain competitive advantages to be gained by employing a highly skilled technical staff. The technical staff (including field personnel) currently represents a majority of Halcón's employee base. This team has significant experience and expertise in applying the most sophisticated technologies used in conventional and unconventional resource style plays, including 3-D seismic interpretation capabilities, horizontal drilling, deep onshore drilling, comprehensive multi-stage hydraulic fracture stimulation programs, and other exploration, production, and processing technologies. We believe this technical expertise is partly responsible for our management team's strong track record of successful exploration and development, including new discoveries and defining core producing areas in emerging plays.

Oil and Natural Gas Reserves

Estimates of proved reserves at December 31, 2012 were prepared by Netherland, Sewell, our independent consulting petroleum engineers. Our estimated proved reserves for the years ended December 31, 2011 and 2010 were prepared by Forrest A. Garb & Associates, an independent oil and natural gas reservoir engineering consulting firm. Netherland, Sewell is a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. Netherland, Sewell was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within Netherland Sewell, the technical persons primarily responsible for preparing the estimates set forth in the Netherland, Sewell reserves report incorporated herein are J. Carter Henson, Jr. and Mike K. Norton. Mr. Henson has been practicing consulting petroleum engineering at Netherland, Sewell since 1989. Mr. Henson is a Licensed Professional Engineer in the State of Texas (No. 73964) and has over 30 years of practical experience in petroleum engineering, with over 27 years of experience in the estimation and evaluation of reserves. He graduated from Rice University in 1981 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Norton has been practicing consulting petroleum geology at Netherland, Sewell since 1989. Mr. Norton is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 441) and has over 30 years of practical experience in petroleum geosciences, with over 23 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1978 with a Bachelor of Science Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying Securities and Exchange Commission (SEC) and other industry reserves definitions and guidelines.

Our board of directors has established a reserves committee composed of three independent directors, all of whom have experience in energy company reserve evaluations. Our independent engineering firm reports jointly to the reserves committee and to our Manager, Corporate Reserves for 2012. 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. In 2012, the Manager, Corporate Reserves was the technical person primarily responsible for overseeing the preparation of the annual reserve report by Netherland, Sewell. He holds a Bachelor of Science degree in Mechanical Engineering from The University of Missouri-Rolla and has over 35 years of experience in reservoir engineering, economic modeling and reserve evaluation.

The reserves information in this Annual Report on Form 10-K represents only estimates. There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control. Reserve evaluation 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

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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 significantly. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent we acquire additional properties containing proved reserves or conduct successful exploration and development activities or both, our proved reserves will decline as reserves are produced. For additional information regarding estimates of proved reserves, the preparation of such estimates by Netherland, Sewell and other information about our oil and natural gas reserves, see Item 8. *Consolidated Financial Statements and Supplementary Data "Supplemental Oil and Gas Information (Unaudited).*"

Proved reserve estimates are based on the unweighted arithmetic average prices on the first day of each month for the 12-month period ended December 31, 2012. Average prices for the 12-month period were as follows: West Texas Intermediate (WTI) spot price of $94.71 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 price of $2.76 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 SEC guidelines. The following table presents certain information as of December 31, 2012.

	Total
Proved Reserves at Year End (MBoe)*(1)*	
Developed	51,399
Undeveloped	57,386
Total	108,785

(1) Natural gas reserves are converted to oil reserves using a 1:6 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, 2012 and 2011. Shut-in wells currently not capable of production are excluded from producing well information.

	Years Ended December 31,			
	2012		**2011**	
	Gross	**Net(1)**	**Gross**	**Net(1)**
Oil	2,428	1,396.0	1,424	1,116.5
Natural Gas	893	425.6	396	186.1
Total	3,321	1,821.6	1,820	1,302.6

(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.

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Oil and Natural Gas Production

Core Resource Plays

At December 31, 2012, we have estimated proved reserves in our core resource plays of approximately 75.6 MMBoe, of which 92% are oil and natural gas liquids and 38% are proved developed. In general, our core resource plays are characterized by high oil and liquids-rich natural gas content in thick, continuous sections of source rock that can provide repeatable drilling opportunities and significant initial production rates. Our core resource plays are as follows:

Bakken / Three Forks Formations

We have working interests in approximately 128,000 net acres as of December 31, 2012 prospective for the Bakken / Three Forks formations in North Dakota and Montana. Multiple initiatives are underway to lower costs and improve recoveries in our operated project areas. We expect to spud 65 to 75 gross horizontal wells on our operated acreage in 2013 with an average working interest of 63%. We expect to operate an average of six to eight rigs throughout 2013 in the Williston Basin. As of December 31, 2012, we had approximately 105 operated wells producing in this area in addition to minor working interest in hundreds of non-operated wells. Our average daily net production from this area for the three months ended December 31, 2012 was 5,753 Boe/d. As of December 31, 2012, proved reserves for the Bakken / Three Forks formations were approximately 48.6 MMBoe, of which approximately 45% were classified as proved developed and approximately 55% as proved undeveloped.

Woodbine / Eagle Ford Formations

Our Woodbine / Eagle Ford acreage is prospective for the Woodbine, Eagle Ford and other formations, with targeted depths ranging anywhere from 7,000 feet to 10,400 feet. Our hydrocarbon stream is largely comprised of oil and natural gas liquids, which receive premium pricing given their proximity to key United States markets for these products. As of December 31, 2012, we had approximately 198,000 net acres leased or under contract primarily in Leon, Madison, Grimes, Brazos, and Polk Counties, Texas. Leasing efforts will continue in key areas as we develop the field. We finished 2012 with a six rig drilling program and approximately 25 producing wells. In 2013, we plan to run an average of five to seven rigs and spud 75 to 85 gross horizontal wells with an average working interest of approximately 90%. Our average daily net production from this area for the three months ended December 31, 2012 was 2,807 Boe/d. As of December 31, 2012, proved reserves for the Woodbine / Eagle Ford formations were approximately 27 MMBoe, of which approximately 24% were classified as proved developed and approximately 76% as proved undeveloped.

Utica / Point Pleasant Formations

We believe the Utica / Point Pleasant formations in Ohio and Pennsylvania are in some areas geologically analogous to the Eagle Ford Shale based on reservoir thickness, porosity, water saturation and permeability. We are focused on what we believe to be the volatile oil and liquids-rich gas window in the play, and as of December 31, 2012, we had approximately 125,000 net acres leased or under contract in Trumbull and Mahoning Counties, Ohio, and Mercer, Venango and Crawford Counties, Pennsylvania. Substantially all of our acreage in these areas is either held by shallow production or provides for five years to drill a well plus a renewal option for an additional five years. We expect to spud 20 to 25 gross horizontal wells in 2013 with an average working interest of approximately 91%. We are currently operating two rigs in the Utica / Point Pleasant formations and expect to operate an average of two to three rigs throughout 2013. We expect to gain drilling efficiencies while lowering well costs through the use of pad drilling once a sufficient backlog of approved drilling permits has been established. Due to infrastructure requirements, combined with the practice of shutting in wells for up to 60 days after completion in an effort to maximize recoveries, we estimate a spud-to-production time of 120 days per well. As of the date of this report, two wells are resting after being completed, two wells are being completed or waiting on completion and two wells are being drilled. First production is anticipated early in the second quarter of 2013. As of December 31, 2012, we did not have any proved reserves for the Utica / Point Pleasant formations. We can provide no assurance that this exploratory area, or any wells we subsequently drill in these formations we have targeted for exploration and development, will be successful.

Non-Core Areas

Electra-Burkburnett Field

We are the operator and have a 100% working interest in more than 12,000 net acres in Wichita and Wilbarger Counties, Texas that we are actively water flooding in shallow Cisco aged Pennsylvania sandstone and limestone reservoirs. In 2012, we produced 484 MBoe, or 1,322 Boe/d, from approximately 700 active producing wells and approximately 230 active water injection wells. We are currently running one company owned drilling rig and nine company owned work over rigs to improve injection and production well patterns, maximize injection profiles, and increase production performance. Management believes that significant reserve upside can be achieved through the modification and expansion of the existing water flood. During 2012, we drilled a total of 38 gross (38.0 net) wells, 31 gross (31.0 net) producers and 7 gross (7.0 net) injectors in our Electra-Burkburnett Field. The positive production response from our 640 acre water flood modification pilot on the west side of the field focused our efforts to set up a field wide water flood modification program. It is believed that the modified water flood will improve areal and vertical sweep efficiency and thereby accelerate production withdrawal rates, reduce production decline rates, and increase reserve recovery. We are also improving upon the reservoir geological correlation and are targeting injection into areas that were not previously produced.

During the second quarter of 2012, we began working on the first lease of the modified water flood expansion project by investing $9 million on operations across the 1,100 acre lease. We drilled a total of 20 gross (20.0 net) wells in 2012, 13 gross (13.0 net) producers and 7 gross (7.0 net) injectors in addition to multiple well conversions and workovers to re-activate both injectors and producers. The project is currently ahead of schedule (approximately 70% complete) and is producing oil at rates above the projected response rates. Additional leases will be added as scheduled and as the project is expanded to optimize production and recoverable reserve potential across our leasehold. As of December 31, 2012, the estimated proved reserves for our Electra-Burkburnett Field were approximately 7.1 MMBoe, or 7% of our total proved reserves, of which approximately 54% were classified as proved developed and 46% as proved undeveloped. The natural gas liquids are processed from the casing head gas through a company owned gas plant. We believe that additional reserves will be added to adjacent leases above the reserves currently booked as we expand our project boundaries and the modified leases respond to the more favorable water flood configuration. In addition to the water flood modification, management also believes that additional upside potential exists with the recompletion of previously bypassed zones and from inefficiently connected reservoirs not previously swept.

La Copita Field

Our position in the La Copita Field covers 3,720 gross acres and 2,829 net acres in Starr County, Texas. For the year ended December 31, 2012, our average net daily production was 623 Boe/d. We operate 100% of this production and our working interest ranges from 75% to 100%. The production is primarily natural gas with a high concentration of natural gas liquids producing from Vicksburg Sands at depths ranging from approximately 7,200 feet to 10,500 feet. We did not drill any new wells during 2012. Estimated proved reserves for the Field totaled 3.0 MMBoe as of December 31, 2012.

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Other Areas

We have various other oil and natural gas properties with varying working interests located across the United States, including the Austin Chalk Trend and Eagle Ford Shale in Texas, the Fitts-Allen Fields in Central Oklahoma, and various other areas across South Louisiana, Montana, North Dakota, New Mexico, and West Virginia. Production from these areas totaled 1,607 MBoe, or 4,391 Boe/d, in 2012. As of December 31, 2012, proved reserves for these other properties were approximately 23.1 MMBoe in aggregate, of which approximately 78% were classified as proved developed and approximately 22% as proved undeveloped. We are currently pursuing certain activities to enhance these assets, including redesigning existing waterflood programs. We will consider divesting certain of these assets that we determine are non-core and reinvesting the proceeds in our core resource plays.

Liquids-Rich Exploratory Plays

In addition to the disclosed areas, we anticipate we will continue to acquire acreage in undisclosed unconventional exploratory plays as opportunities arise. We would expect to utilize multi-stage hydraulic fracturing to complete wells drilled in these areas. Our strategy for our exploratory projects is to use our in-house geologic expertise to identify underdeveloped areas that we believe are prospective for oil or liquids-rich production. We can provide no assurance that any of these exploratory areas, or any wells we subsequently drill in the formations we have targeted for exploration and development, will be successful. Due to competitive concerns, we intend to keep the details of such plays confidential until such time we deem it appropriate to disclose specifics.

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 declines and interest rate increases. Derivative contracts are utilized to economically hedge our exposure to price fluctuations and reduce the variability in our cash flows associated with anticipated sales on future oil and natural gas production. We hedge a substantial, but varying, portion of anticipated oil and natural gas production for the next 18 to 24 months. Historically, we entered into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates (such as those on our Senior Credit Agreement) to fixed interest rates.

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 costless collar agreements, swap agreements and put options to attempt to manage price risk more effectively. The costless 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. All costless 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 swap agreements call for payments to, or receipts from, counterparties depending 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 agreement is put in place. Under put option agreements, 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 the difference between the index price and the floor price (netted against the fixed premium payable to the counterparty). 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 or an affiliate of a lender in our Senior Credit Agreement. We will continue to evaluate the benefit of

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employing derivatives in the future. See Item 7A. *Quantitative and Qualitative Disclosures about Market Risk* and Item 8. *Consolidated Financial Statements and Supplementary Data* Note 9*, "Derivative and Hedging Activities"* for additional information.

Oil and Natural Gas Operations

Our principal properties consist of leasehold interests in developed and undeveloped oil and natural gas properties and the reserves associated with these properties. Generally, oil and natural gas leases remain in force as long as production is maintained. Leases on undeveloped oil and natural gas properties 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 leases on our undeveloped properties can be extended by option payments; the amount of any payments and time extended vary by lease.

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

	Years Ended December 31,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive*(1)*	1	0.9	6	6.0	3	3.0
Dry	2	2.0	4	4.0	1	0.2
Total Exploratory	3	2.9	10	10.0	4	3.2
Extension Wells*(2)*:						
Productive*(1)*	101	30.1				
Dry	1	0.9				
Total Extension	102	31.0				
Development Wells:						
Productive*(1)*	87	54.3	43	38.8	59	51.0
Dry			1	0.2		
Total Development	87	54.3	44	39.0	59	51.0
Total Wells:						
Productive*(1)*	189	85.3	49	44.8	62	54.0
Dry	3	2.9	5	4.2	1	0.2
Total	192	88.2	54	49.0	63	54.2

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

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

We own interests in developed and undeveloped oil and natural gas acreage in the locations set forth in the table below. These ownership interests generally take the form of working interests in oil

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and natural gas leases that have varying terms. The following table presents a summary of our acreage interests as of December 31, 2012:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
State	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alabama	42,480	21,240			42,480	21,240
Colorado	3,724	2,403	25,858	12,959	29,582	15,362
Louisiana	17,773	10,311	177,664	161,123	195,437	171,434
Montana	15,478	7,403	13,924	5,942	29,402	13,345
New Mexico	12,657	8,393	280	40	12,937	8,433
North Dakota	278,792	95,564	136,235	46,218	415,027	141,782
Ohio			47,871	45,367	47,871	45,367
Oklahoma	116,593	35,348	24,700	16,311	141,293	51,659
Pennsylvania			83,407	79,705	83,407	79,705
Texas	126,611	74,082	495,567	262,323	622,178	336,405
West Virginia	7,835	7,726	27,804	22,349	35,639	30,075
All others	6,580	2,969	101,238	63,177	107,818	66,146
Total Acreage	628,523	265,439	1,134,548	715,514	1,763,071	980,953

The table below reflects the percentage of our total net undeveloped and mineral acreage as of December 31, 2012 that will expire each year if we do not establish production in paying quantities on the units in which such acreage is included or do not pay (to the extent we have the contractual right to pay) delay rentals or obtain other extensions to maintain the lease.

Year	**Percentage Expiration**
2013	10%
2014	6%
2015	13%
2016	8%
2017	32%
2018 & beyond	31%
	100%

At December 31, 2012, we had estimated proved reserves of approximately 108.8 MMBoe comprised of 87.4 MMBbls of oil, 5.4 MMBbls of natural gas liquids, and 96.1 Mmcf of natural gas. The following table sets forth, at December 31, 2012, these reserves:

	Proved Developed	**Proved Undeveloped**	**Total Proved**
Oil (MBbls)	38,429	48,949	87,378
Natural Gas Liquids (MBbls)	3,172	2,211	5,383
Natural Gas (Mmcf)	58,785	37,360	96,145
Equivalent (MBoe)*(1)*	51,399	57,386	108,785

(1) Natural gas reserves are converted to oil reserves using a 1:6 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.

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At December 31, 2012, our estimated proved undeveloped (PUD) reserves were approximately 57.4 MMBoe, a 49.7 MMBoe net increase over the previous year's estimate of 7.7 MMBoe. The increase is largely due to acquisitions totaling 42.9 MMBoe of undeveloped reserves primarily in the Bakken / Three Forks and Woodbine / Eagle Ford areas. As of December 31, 2012, more than 97% of our PUD reserves are less than five years old. The following details the changes in proved undeveloped reserves for 2012 (MBoe):

Beginning proved undeveloped reserves at December 31, 2011	7,676
Undeveloped reserves transferred to developed	(4,285)
Revisions	2,879
Purchases	42,926
Divestitures	(466)
Extension and discoveries	8,656
Ending proved undeveloped reserves at December 31, 2012	57,386

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

We account for our oil and natural gas producing activities using the full cost method of accounting in accordance with SEC regulations. Accordingly, all costs incurred in the acquisition, exploration, and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs, direct internal costs and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of evaluated oil and natural gas properties are subject to a quarterly full cost ceiling test. At December 31, 2012 the ceiling test value of our reserves was calculated based on the first day average of the 12-months ended December 31, 2012 of the WTI spot price of $94.71 per barrel, adjusted by lease or field for quality, transportation fees, and regional price differentials, and the first day average of the 12-months ended December 31, 2012 of the Henry Hub price of $2.76 per Mmbtu, adjusted by lease or field for energy content, transportation fees, and regional price differentials. Using these prices, our net book value of oil and natural gas properties at December 31, 2012, did not exceed the ceiling amount. See further discussion in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 6*, "Oil and Natural Gas Properties."*

Capitalized costs of our evaluated and unevaluated properties at December 31, 2012, 2011 and 2010 are summarized as follows:

	December 31,		
	2012	**2011**	**2010**
		(In thousands)	
Oil and natural gas properties (full cost method):			
Evaluated	$ 2,669,245	$ 715,666	$ 689,472
Unevaluated	2,326,598		
Gross oil and natural gas properties	4,995,843	715,666	689,472
Less accumulated depletion	(588,207)	(501,993)	(482,886)
Net oil and natural gas properties	$ 4,407,636	$ 213,673	$ 206,586

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

	Years Ended December 31,		
	2012	**2011**	**2010**
Production:			
Crude oil MBbl			
Bakken / Three Forks	650		
Woodbine / Eagle Ford	372		
Electra/Burkburnett	437	441	471
La Copita	16	24	41
Other	940	419	483
Total	2,415	884	995
Natural gas Mmcf			
Bakken / Three Forks	224		
Woodbine / Eagle Ford	129		
Electra/Burkburnett			
La Copita	914	1,079	1,682
Other	3,287	1,583	3,134
Total	4,554	2,662	4,816
Natural gas liquids MBbl			
Bakken / Three Forks	13		
Woodbine / Eagle Ford	26		
Electra/Burkburnett	47	44	41
La Copita	60	83	126
Other	122	49	197
Total	268	176	364
Production:			
Total MBoe*(1)*	3,442	1,504	2,161
Average daily production Boe*(1)*	9,404	4,121	5,921
Average price per unit:*(2)*			
Crude oil price Bbl	$ 92.36	$ 93.86	$ 76.95
Natural gas price Mcf	2.74	4.01	4.21
Natural gas liquids price Bbl	41.37	56.14	38.89
Barrel of oil equivalent price Boe*(1)*	71.64	68.83	51.36
Average cost per Boe:			
Production:			
Lease operating	$ 14.51	$ 19.98	$ 13.95
Workover and other	1.29	1.31	0.74
Taxes other than income	5.59	4.80	3.93

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

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

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The 2012, 2011 and 2010 average crude 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 "*Net gain (loss) on derivative contracts*" in the consolidated statements of operations, consistent with our decision not to elect hedge accounting. Including this impact 2012, 2011 and 2010 average crude oil sales prices were $93.25, $91.84 and $74.88 per Bbl and average natural gas sales prices were $3.56, $4.95 and $4.58 per Mcf.

Competitive Conditions in the Business

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

Other Business Matters

Markets and Major Customers

The purchasers of our oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. Historically, we have not experienced any significant losses from uncollectible accounts. In 2012, two individual purchasers of our production, Shell Trading US Co. (STUSCO) and Sunoco Partners Marketing & Terminals L.P., (Sunoco), each accounted for approximately 20% and 19%, respectively, of our total sales.

In 2011, STUSCO accounted for $70.4 million, or 68%, of our oil and natural gas revenue for the year. In 2011, we were subject to a crude purchase contract with STUSCO covering all of our production in our Electra Field in Wichita and Wilbarger Counties, Texas. The contract term covered the period of January 1, 2011 through December 31, 2011. We were also subject to a crude purchase contract with STUSCO, in 2011, covering all of our oil production in our Fitts and Allen Fields in Oklahoma. Effective December 1, 2011, we cancelled the crude purchase contract with STUSCO and entered into a new crude oil purchase agreement with Sunoco for a term of December 1, 2011 through May 31, 2012.

In 2010, STUSCO, accounted for $68.1 million, or 61%, of our oil and natural gas revenue for the year. No other purchaser accounted for 10% or more of our oil and natural gas revenue during 2010. Our agreement with STUSCO covered all of our North Texas oil production. We were also subject to a crude purchase contract with STUSCO covering all of our oil production in our Fitts and Allen Fields in Oklahoma.

Seasonality of Business

Weather conditions affect the demand for, and prices of, natural gas and can also delay drilling activities, disrupting our overall business plans. Demand for natural gas is typically higher during the winter, resulting in higher natural gas prices for our natural gas production during our first and fourth

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fiscal quarters. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of the results that we may realize on an annual basis.

Operational Risks

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

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

Regulations

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

Our operations are also subject to various conservation laws and regulations. These laws and regulations govern the size of drilling and spacing units, the density of wells that may be drilled in oil and natural gas properties and the unitization or pooling of oil and natural gas properties. In this regard, some states allow the forced pooling or integration of land and leases to facilitate exploration which other states rely primarily or exclusively on voluntary pooling of land and leases. In areas where pooling is primarily or exclusively voluntary, it may be difficult to form units and therefore difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose specified requirements regarding the ratability of production. On some occasions, tribal and local authorities have imposed moratoria or other restrictions on exploration and production activities that must be addressed before those activities can proceed.

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Environmental Regulations

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

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

Comprehensive Environmental Response, Compensation and Liability Act and Hazardous Substances

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

The Solid Waste Disposal Act and Waste Management

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

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have not been made aware, it is not possible to estimate the potential costs that may arise from unknown, latent liability risks.

The Clean Water Act, wastewater and storm water discharges

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

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

The federal Safe Drinking Water Act (SDWA) and the Underground Injection Control (UIC) program promulgated under the SDWA and state programs regulate the drilling and operation of salt water disposal wells. EPA directly administers the UIC program in some states and in others it is delegated to the state for administering. Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking salt water to groundwater. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with many of the wells for which we are the operator. Certain states have adopted and are considering laws that require the disclosure of the chemical constituents in hydraulic fracturing fluids. In addition, in 2010, the EPA announced that it would be conducting a study on the environmental effects of hydraulic fracturing. In December 2012, the EPA issued a progress report describing its ongoing study, and announcing its expectation that a final draft report will be released for public comment and peer review in 2014.

Additional disclosure requirements could result in increased regulation, operational delays, and increased operating costs that could make it more difficult to perform hydraulic fracturing.

The Clean Air Act

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

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Climate change legislation and greenhouse gas regulation

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, governments have begun adopting domestic and international climate change regulations that require reporting and reductions of the emission of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, and the Kyoto Protocol address greenhouse gas emissions, and several countries including those comprising the European Union have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs or have begun considering adopting greenhouse gas regulatory programs.

The EPA has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and required reporting by regulated facilities by March 2011 and annually thereafter. In November 2010, the EPA issued a final rule requiring companies to report certain greenhouse gas emissions from oil and natural gas facilities. On July 19, 2011, the EPA amended the oil and natural gas facility greenhouse gas reporting rule to require reporting which went into effect September 2012. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding serves as a first step to issuing regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities. On July 28, 2011, the EPA proposed four new regulations for the oil and natural gas industry, with the potential to affect our business. On August 16, 2012, the EPA issued its final rule, which includes: a new source performance standard for volatile organic compounds (VOCs); a new source performance standard for sulfur dioxide; an air toxics standard for oil and natural gas production; and an air toxics standard for natural gas transmission and storage. The final rule includes the first federal air standards for natural gas wells that are hydraulically fractured, or refractured, as well as requirements for several sources, such as storage tanks and other equipment, and limits methane emissions from these sources. Compliance with these regulations will impose additional requirements and costs on our operations.

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

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

The National Environmental Policy Act

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

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that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

Threatened and endangered species, migratory birds, and natural resources

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

Hazard communications and community right to know

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

Occupational Safety and Health Act

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

Employees and Principal Office

As of December 31, 2012, we had 435 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.

As of December 31, 2012, we lease corporate office space in Houston, Texas at 1000 Louisiana Street, where our principal offices are located. We also lease corporate offices in Plano, Texas; Tulsa, Oklahoma; Denver, Colorado; and Williston, North Dakota as well as a number of other field office locations.

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.halconresources.com* as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. In addition, our insider trading policy, regulation FD policy, equity-based incentive grant policy, corporate governance guidelines, code of conduct, code of ethics, audit committee charter, compensation committee charter, nominating and corporate governance committee charter and reserves committee charter are available on our website under the heading

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"Investor Relations Corporate Governance". Within the time period required by the SEC and the New York Stock Exchange (NYSE), as applicable, we will post on our website any modifications to the code of conduct and the code of ethics for our Chief Executive Officer and senior financial officers and any waivers applicable to senior officers as defined in the applicable code, as required by the Sarbanes-Oxley Act of 2002. You may also read and copy any document we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, our reports, proxy and information statements, and our other filings are also available to the public over the internet at the SEC's website at *www.sec.gov*. Unless specifically incorporated by reference in this Annual Report on Form 10-K, information that you may find on our website is not part of this report.

ITEM 1A. RISK FACTORS

We will be subject to risks in connection with acquisitions, and the integration of significant acquisitions may be difficult.

Our business plan contemplates significant acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy, which may include the acquisition of asset packages of producing properties or existing companies or businesses operating in our industry, such as the Merger and our acquisitions of the East Texas Assets and the Williston Basin Assets. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil, natural gas and natural gas liquids prices and their appropriate differentials;
- development and operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis.

Significant acquisitions of existing companies or businesses and other strategic transactions may involve additional risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with our own while carrying on our ongoing business;