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;

- 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.

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

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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.

