INTERFACE INC
Form SC 13G
February 13, 2013

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

SCHEDULE 13G
(Rule 13d-102)

INFORMATION TO BE INCLUDED IN STATEMENTS FILED PURSUANT TO RULES 13D-1(b) AND AMENDMENTS FILED THERETO FILED PURSUANT TO RULE 13D-2(b)

Under the Securities Exchange Act of 1934
(Amendment No. _)*

Interface, Inc.
(Name of Issuer)

Common Stock
(Title of Classes of Securities)

458665304
(CUSIP Number)

December 31, 2012
(Date of Event Which Requires Filing of this Statement)

Check the appropriate box to designate the rule pursuant to which this Schedule is filed:

: X Rule 13d-1(b)
: Rule 13d-1(c)
: Rule 13d-1(d)

*The remainder of this cover page shall be filled out for a reporting person's initial filing on this form with respect to the subject class of securities, and for any subsequent amendment containing information which would alter the disclosures provided in a prior cover page.

The information required in the remainder of this cover page shall not be deemed to be "filed" for the purpose of Section 18 of the Securities Exchange Act of 1934 ("Act") or otherwise subject to the liabilities of that section of the Act but shall be subject to all other provisions of the Act (however, see the Notes).

CUSIP No.:458665304

1	NAME OF REPORTING PERSON I.R.S. IDENTIFICATION NO. OF ABOVE PERSON (ENTITIES ONLY) Invesco Ltd. IRS # 980557567
2	CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP* (a) (b)
3	SEC USE ONLY
4	CITIZENSHIP OR PLACE OF ORGANIZATION Invesco Ltd. – Bermuda

NUMBER OF SHARES BENEFICIALLY OWNED BY EACH REPORTING PERSON WITH	5	SOLE VOTING POWER – 3,804,844
	6	SHARED VOTING POWER – 0
	7	SOLE DISPOSITIVE POWER – 4,083,583
	8	SHARED DISPOSITIVE POWER – 0

9	AGGREGATE AMOUNT BENEFICIALLY OWNED BY EACH REPORTING PERSON 4,083,583
10	CHECK BOX IF THE AGGREGATE AMOUNT IN ROW (9) EXCLUDES CERTAIN SHARES* N/A
11	PERCENT OF CLASS REPRESENTED BY AMOUNT IN ROW 9 6.2%
12	TYPE OF REPORTING PERSON* See Item 3 of this statement

Item 1(a). Name of Issuer:

Interface, Inc.

(b). Address of Issuer's Principal Executive Offices:

2859 Paces Ferry Road; Suite 2000; Atlanta, GA 30339; United States

Item 2(a). Name of Person Filing:

Invesco Ltd.

(b). Address of Principal Business Office or, if none, residence of filing person:

1555 Peachtree Street NE; Atlanta, GA 30309; United States

(c). Citizenship of filing person:

Bermuda

(d). Title of Classes of Securities:

Common Stock

(e). CUSIP Number:

458665304

Item 3. If this statement is filed pursuant to ss240.13d-1(b) or 240.13d-2(b) or (c), check whether the person filing is a:

(e) [x] An investment adviser in accordance with section 240.13d-1(b)(1)(ii)(E)

(g) [x] A parent holding company or control person in accordance with section 240.13d-1(b)(1)(ii)(G)

Item 4. Ownership:

Please see responses to Items 5-8 on the cover of this statement, which are incorporated herein by reference.

Item 5. Ownership of Five Percent or Less of a Class:

If this statement is being filed to report the fact that as of the date hereof the reporting person has ceased to be the beneficial owner of more than five percent of the class of securities, check the following [ ]

Item 6. Ownership of More than Five Percent on Behalf of Another Person:

N/A

Item 7. Identification and Classification of the Subsidiary which Acquired the Security Being Reported on by the Parent Holding Company:

The following subsidiaries of Invesco Ltd. are investment advisers which hold shares of the security being reported:

Invesco Advisers Inc.
Invesco National Trust Company
Invesco PowerShares Capital Management

Item 8. Identification and Classification of Members of the Group:

N/A

Item 9. Notice of Dissolution of a Group:

N/A

Item 10. Certification:

By signing below I certify that, to the best of my knowledge and belief, the securities referred to above were acquired and are held in the ordinary course of business and were not acquired and are not held for the purpose of or with the effect of changing or influencing the control of the issuer of the securities and were not acquired and are not held in connection with or as a participant in any transaction having that purpose or effect.

Signature:

After reasonable inquiry and to the best of my knowledge and belief, I certify that the information set forth in this statement is true, complete and correct.

02/13/2013
Date

Invesco Ltd.

By: /s/ Lisa Brinkley
Lisa Brinkley
Global Assurance Officer

T SIZE=2>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

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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.

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:

State	Developed Acreage Gross	Developed Acreage Net	Undeveloped Acreage Gross	Undeveloped Acreage Net	Total Acreage Gross	Total Acreage 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;
- difficulty associated with coordinating geographically separate organizations;
- the challenge of integrating environmental compliance systems to meet requirements of rapidly changing regulations;
- the challenge of attracting and retaining personnel associated with acquired operations; and

failure to realize the full benefit that we expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition, or to realize these benefits within the expected time frame.

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The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to manage the integration process effectively, or if any significant business activities are interrupted as a result of the integration process, our business could be materially and adversely affected.

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

Our recent growth is due significantly to acquisitions of exploration and production companies, producing properties and undeveloped and unevaluated leaseholds. We expect acquisitions may also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, future oil and natural gas prices, operating and capital costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. We are generally not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. As a result of these factors, we may not be able to acquire oil and natural gas properties that contain economically recoverable reserves or be able to complete such acquisitions on acceptable terms.

We have substantial indebtedness and may incur substantially more debt. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.

We have incurred substantial debt amounting to approximately $2.1 billion as of December 31, 2012 (including current portion). As a result of our indebtedness, we will need to use a portion of our cash flow to pay interest, which will reduce the amount we will have available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Our indebtedness under our Senior Credit Agreement is at a variable interest rate, and so a rise in interest rates will generate greater interest expense to the extent we do not have hedging arrangements that are effective in mitigating interest rate fluctuations. The amount of our debt may also cause us to be more vulnerable to economic downturns and adverse developments in our business.

We may incur substantially more debt in the future. The indentures governing our outstanding senior notes contain restrictions on our incurrence of additional indebtedness. These restrictions, however, are subject to a number of qualifications and exceptions, and under certain circumstances, we could incur substantial additional indebtedness in compliance with these restrictions. Moreover, these restrictions do not prevent us from incurring obligations that do not constitute indebtedness under the indentures. At December 31, 2012, our Senior Credit Agreement was a $1.5 billion facility with a borrowing base of $850.0 million. As of December 31, 2012, we had $298.0 million of debt outstanding, $1.3 million of letters of credit outstanding and $550.7 million of additional borrowing capacity available under this facility.

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

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restrictive covenants relating to our indebtedness could result in a default under that indebtedness, which could adversely affect our business, financial condition and results of operations.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

At December 31, 2012, our corporate credit rating was "B" with a stable outlook by Standard and Poor's (S&P) and "B2" and under review for downgrade by Moody's Investors Service (Moody's). Although we are not aware of any current plans of these or other rating agencies to lower their respective ratings on us or our senior debt, we cannot be assured that our credit ratings will not be downgraded. A downgrade in our credit ratings could negatively impact our cost of capital and our ability to effectively execute aspects of our strategy. If our credit rating were downgraded, it could be difficult for us to raise debt in the public debt markets and the cost of that new debt could be higher than debt we could raise with our current ratings. In addition, a downgrade could impact requirements for us to provide financial assurance of performance under contractual arrangements or derivative agreements.

We may not be able to drill wells on a substantial portion of our acreage.

We may not be able to drill on a substantial portion of our acreage for various reasons. We may not generate or be able to raise sufficient capital to do so. Future deterioration in commodities pricing may also make drilling some acreage uneconomic. Our actual drilling activities and future drilling budget will depend on drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, lease expirations, gathering system and pipeline transportation constraints, regulatory approvals and other factors. In addition, any drilling activities we are able to conduct may not be successful or add additional proved reserves to our overall proved reserves, which could have a material adverse effect on our future business, financial condition and results of operations.

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

The results of our drilling in new or emerging formations, such as the Utica / Point Pleasant formations, Bakken / Three Forks formations and Woodbine / Eagle Ford formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history and consequently we are less able to predict future drilling results in these areas. In addition, the use of horizontal drilling and completion techniques used in all of our shale formations involve certain risks and complexities that do not exist in conventional wells. Our experience, as well as that of the industry as a whole, is significant but still growing. The ultimate success of these drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and production profiles are better established.

If our drilling results are less than anticipated our investment in these areas may not be as attractive as we anticipate and we could incur material write downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

As of December 31, 2012, we owned leasehold interests in approximately 128,000 net acres in areas we believe are prospective for the Bakken / Three Forks formations, approximately 198,000 net acres in areas we believe are prospective for the Woodbine / Eagle Ford formations and 125,000 net acres in areas we believe are prospective for the Utica / Point Pleasant formations. A large portion of our acreage is not currently held by production. Unless production in paying quantities is established

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on units containing these leases during their terms, these leases will expire. If our leases expire, we will lose our right to develop the related properties.

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

Our ability to sell our production and/or receive market prices for our production may be adversely affected by transportation capacity constraints and interruptions.

If the amount of natural gas, condensate or oil being produced by us and others exceeds the capacity of the various transportation pipelines and gathering systems currently available in our operating areas, it will be necessary for new transportation pipelines and gathering systems to be built. Or, in the case of oil and condensate, it will be necessary for us to rely more heavily on trucks to transport our production, which is more expensive and less efficient than transportation via pipeline. Currently, we anticipate that additional pipeline capacity will be required in the Bakken / Three Forks formations to transport oil and condensate production, which increased substantially during 2012 and is expected to continue to increase. The construction of new pipelines and gathering systems is capital intensive and construction may be postponed, interrupted or cancelled in response to changing economic conditions and the availability and cost of capital. In addition, capital constraints could limit our ability to build gathering systems to transport our production to transportation pipelines. In such event, costs to transport our production may increase materially or we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell our production at much lower prices than market or than we currently project, which would adversely affect our results of operations.

A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

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

We have experienced, and expect to continue to experience, substantial capital expenditure and working capital needs, primarily as a result of our drilling program. We intend to continue to selectively increase our acreage position, which would require capital in addition to the capital necessary to drill on our existing acreage. In addition, it is likely that we will acquire acreage in other areas that we believe are prospective for oil and natural gas production and expend capital to develop such acreage. We expect to use borrowings under our Senior Credit Agreement, proceeds from potential asset dispositions and proceeds from potential future capital markets transactions, if necessary, to fund capital expenditures that are in excess of our cash flow and cash on hand.

Our Senior Credit Agreement limits our borrowings to the lesser of the borrowing base and the total commitments. Our borrowing base was $850.0 million as of December 31, 2012 with $298.0 million outstanding. Our borrowing base is determined semi-annually, and may also be redetermined periodically at the discretion of the banks. Lower oil and natural gas prices may result in a reduction in our borrowing base at the next redetermination. A reduction in our borrowing base could require us to repay any indebtedness in excess of the borrowing base. Additionally, the indentures governing our senior unsecured debt contain covenants limiting our ability to incur additional indebtedness, including borrowings under our Senior Credit Agreement, unless we meet one

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of two alternative tests. The first test applies to all indebtedness and requires that after giving effect to the incurrence of additional debt the ratio of our adjusted consolidated EBITDA (as defined in our indentures) to our adjusted consolidated interest expense over the trailing four fiscal quarters will be at least 2.0 to 1.0 under the most restrictive indenture. The second test applies only to borrowings under our Senior Credit Agreement that do not meet the first test and it limits these borrowings to the greater of a fixed sum of $750 million and 30% of our adjusted consolidated net tangible assets (as defined in all of our indentures), which is determined using discounted future net revenues from proved oil and natural gas reserves as of the end of each year. Currently, we are permitted to incur additional indebtedness under these incurrence tests, but may be limited in the future. Lower oil and natural gas prices in the future could reduce our adjusted consolidated EBITDA, as well as our adjusted consolidated net tangible assets, and thus could reduce our ability to incur additional indebtedness.

Additionally, our ability to complete future equity offerings is limited by general market conditions. If we are not able to borrow sufficient amounts under our Senior Credit Agreement and/or are unable to raise sufficient capital to fund our capital expenditures, we may be required to curtail our drilling, development, land acquisition and other activities, which could result in a decrease in our production of oil and natural gas, forfeiture of leasehold interests if we are unable or unwilling to renew them, and could force us to sell some of our assets on an untimely or unfavorable basis, each of which could have a material adverse effect on our results and future operations.

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

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

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

- the domestic and foreign supply of oil and natural gas;
- the ability of members of the Organization of Petroleum Exporting Countries and other producing countries to agree upon and maintain oil prices and production levels;
- social unrest and political instability, particularly in major oil and natural gas producing regions outside the United States, such as the Middle East, and armed conflict or terrorist attacks, whether or not in oil or natural gas producing regions;
- the level of consumer product demand;
- the growth of consumer product demand in emerging markets, such as China;
- labor unrest in oil and natural gas producing regions;
- weather conditions, including hurricanes and other natural occurrences that affect the supply and/or demand of oil and natural gas;
- the price and availability of alternative fuels;
- the price of foreign imports;

worldwide economic conditions; and

the availability of liquid natural gas imports.

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These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of oil and natural gas.

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

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Decline rates are typically greatest early in the productive life of a well. Estimates of the decline rate of an oil or natural gas well are inherently imprecise, and are less precise with respect to new or emerging oil and natural gas formations with limited production histories than for more developed formations with established production histories. Our production levels and the reserves that we currently expect to recover from our wells will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future oil and natural gas reserves and production and, therefore, our cash flow and results of operations are highly dependent upon our success in efficiently developing and exploiting our current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, our cash flows and the value of our reserves may decrease, adversely affecting our business, financial condition and results of operations.

Estimates of proved oil and natural gas reserves involve assumptions and any material inaccuracies in these assumptions will materially affect the quantities and the value of our reserves.

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

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

At December 31, 2012, approximately 53% of our estimated reserves were classified as proved undeveloped. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of these oil and natural gas reserves and the costs associated with development of these reserves in accordance with SEC regulations, actual capital expenditures will likely vary from estimated capital expenditures, development may not occur as scheduled and actual results may not be as estimated.

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

Our success depends upon the continued contributions of our executive officers and key employees, particularly with respect to providing the critical management decisions and contacts necessary to manage and maintain growth within a highly competitive industry. Competition for qualified personnel can be intense, particularly in the oil and natural gas industry, and there are a limited number of people with the requisite knowledge and experience. Under these conditions, we

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could be unable to attract and retain these personnel. The loss of the services of any of our executive officers or other key employees for any reason could have a material adverse effect on our business, operating results, financial condition and cash flows.

Our business is highly competitive.

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

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

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

- human error, accidents, labor force and other factors beyond our control that may cause personal injuries or death to persons and destruction or damage to equipment and facilities;
- blowouts, fires, hurricanes, pollution and equipment failures that may result in damage to or destruction of wells, producing formations, production facilities and equipment;
- unavailability of materials and equipment;
- engineering and construction delays;
- unanticipated transportation costs and delays;
- unfavorable weather conditions;
- hazards resulting from unusual or unexpected geological or environmental conditions;
- environmental regulations and requirements;
- accidental leakage of toxic or hazardous materials, such as petroleum liquids or drilling fluids, into the environment;
- hazards resulting from the presence of hydrogen sulfide (H_2S) or other contaminants in gas we produce;
- changes in laws and regulations, including laws and regulations applicable to oil and natural gas activities or markets for the oil and natural gas produced;

- fluctuations in supply and demand for oil and natural gas causing variations of the prices we receive for our oil and natural gas production; and

- the availability of alternative fuels and the price at which they become available.

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

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

We require significant amounts of undeveloped leasehold acreage to further our development efforts. Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that our leasehold acreage will be profitably developed, that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target results are dependent upon the current and future market prices for oil and natural gas, costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost.

In addition, we may not be successful in controlling our drilling and production costs to improve our overall return. The cost of drilling, completing and operating a well is often uncertain and cost factors can adversely affect the economics of a project. We cannot predict the cost of drilling and completing a well, and we may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including:

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

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

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

- water discharge and disposal permits for drilling operations;
- drilling bonds;
- drilling permits;
- reports concerning operations;
- air quality, noise levels and related permits;

spacing of wells;

rights-of-way and easements;

unitization and pooling of properties;

pipeline construction;

gathering, transportation and marketing of oil and natural gas;

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taxation; and

waste transport and disposal permits and requirements.

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

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

Legislation was proposed in the last Congress to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production. 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. If similar legislation is ultimately adopted, it could establish an additional level of regulation at the federal or state level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business. Certain states have adopted or are considering similar disclosure legislation.

In March 2010, the EPA announced that it would conduct a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. 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. The agency also announced that one of its enforcement initiatives for 2011 to 2013 would be to focus on environmental compliance by the energy extraction sector. This study and enforcement initiative could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

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

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

The EPA has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and required reporting by regulated facilities by March 2011 and annually thereafter. In November 2010, the EPA issued a final rule requiring companies to report certain greenhouse gas emissions from oil and natural gas facilities. On July 19, 2011, the EPA amended the oil and natural gas facility greenhouse gas reporting rule to require reporting beginning in September 2012. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding serves as a first step to issuing regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities. On July 28, 2011, the EPA proposed four new regulations 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.

Operations on the Fort Berthold Indian Reservation of the Three Affiliated Tribes in North Dakota are subject to various federal and tribal regulations and laws, any of which may increase our costs and delay our operations.

Various federal agencies within the U.S. Department of the Interior, particularly the Office of Natural Resources Revenue (formerly the Minerals Management Service) and the Bureau of Indian Affairs, along with the Three Affiliated Tribes, promulgate and enforce regulations pertaining to operations on the Fort Berthold Indian Reservation on which we hold approximately 43,000 net acres. In addition, the Three Affiliated Tribes is a sovereign nation having the right to enforce laws and regulations independent from federal, state and local statutes and regulations. These tribal laws and

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regulations include various taxes, fees and other conditions that apply to lessees, operators and contractors conducting operations on Native American tribal lands. Lessees and operators conducting operations on tribal lands are generally subject to the Native American tribal court system. One or more of these factors may increase our costs of doing business on the Fort Berthold Indian Reservation and may have an adverse impact on our ability to effectively transport products within the Fort Berthold Indian Reservation or to conduct our operations on such lands.

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

Historically, we have entered into a number of commodity derivative contracts in order to hedge a portion of our oil and natural gas production and, periodically, interest expense. On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act which requires the SEC, the Commodity Futures Trading Commission (or CFTC) to promulgate rules and regulations implementing the new legislation. The CFTC has issued regulations setting position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions are exempt from these limits. The CFTC also finalized other regulations implementing the new legislation; however, some regulations remain to be finalized and it is not possible at this time to predict when the CFTC will adopt final rules. The Dodd-Frank Act and regulations may require compliance with margin requirements and with certain clearing and trade-execution requirements in connection with certain derivative activities. The legislation may also require the counterparties to our commodity derivative contracts to spinoff some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

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

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

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

- personal injury;
- bodily injury;
- third party property damage;
- medical expenses;
- legal defense costs;

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- pollution in some cases;
- well blowouts in some cases; and
- workers compensation.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations and cash flows. There can be no assurance that the insurance coverage that we maintain will be sufficient to cover every claim made against us in the future.

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

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

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

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies, water or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. Increasing levels of exploration and production may increase the demand for oilfield services and equipment, and the costs of these services and equipment may increase, while the quality of these services and equipment may suffer. The unavailability or high cost of drilling rigs, pressure pumping equipment, supplies or qualified personnel can materially and adversely affect our operations and profitability. In order to secure drilling rigs and pressure pumping equipment, we have entered into certain contracts that extend over several months and or years. If demand for drilling rigs and pressure pumping equipment subside during the period covered by these contracts, the price we are required to pay may be significantly more than the market rate for similar services.

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

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

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

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

our production is less than expected;

there is a widening of price differentials between delivery points for our production; or

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

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

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

As of December 31, 2012, our net book value of oil and natural gas properties did not exceed our ceiling amount using the WTI unweighted 12-month average price $94.71 per Bbl for oil and natural gas liquids and the Henry Hub unweighted 12-month average of $2.76 per Mmbtu for natural gas. As ceiling test computations depend upon the calculated unweighted arithmetic average prices, it is impossible to predict the likelihood, timing and magnitude of any future impairments. Depending on the magnitude, a ceiling test write down could negatively affect our results of operations.

Costs associated with unevaluated properties, which were approximately $2.3 billion at December 31, 2012, are not initially subject to the ceiling test limitation. Rather, we assess all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value based upon our intentions with respect to drilling on such properties, the remaining lease term, geological and geophysical evaluations, drilling results, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. These factors are significantly influenced by our expectations regarding future commodity prices, development costs, and access to capital at acceptable cost. During any period in which these factors indicate impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization and the ceiling test limitation. Accordingly, a significant change in these factors, many of which are beyond our control, may shift a significant amount of cost from unevaluated properties into the full cost pool that is subject to amortization and the ceiling test limitation.

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

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

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

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

ITEM 3. LEGAL PROCEEDINGS

A description of our legal proceedings is included in Item 8. *Consolidated Financial Statements and Supplementary Data* Note *11, "Commitments and Contingencies,"* and is incorporated herein by reference.

From time to time, we are a party to litigation or other legal proceedings that we consider to be a part of the ordinary course of our business. We are not currently involved in any legal proceedings, nor are we a party to any pending or threatened claims, that could reasonably be expected to have a material adverse effect on our financial condition or results of operations.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

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PART II

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

Our common stock began trading on the New York Stock Exchange (NYSE) under the symbol HK on March 26, 2012. Following the Recapitalization, from February 9, 2012 to March 25, 2012, our common stock traded on the Nasdaq Capital Market under the symbol HK. Effective February 9, 2012, we changed the trading symbol under which our common stock traded on the Nasdaq Capital Market from RAM to HK. Effective May 6, 2011, we changed the trading symbol under which our common stock traded on the Nasdaq Capital Market from RAME to RAM. The following table sets forth the quarterly high and low sales prices per share of our common stock as reported on the NYSE and Nasdaq Capital Market from January 1, 2011 through December 31, 2012. All share prices reflect the one-for-three reverse stock split, which was effective February 10, 2012.

	High	Low
2012		
First Quarter	$ 12.76	$ 8.46
Second Quarter	11.02	8.30
Third Quarter	9.46	6.26
Fourth Quarter	7.34	5.38
2011		
First Quarter	$ 7.35	$ 4.68
Second Quarter	6.36	3.66
Third Quarter	3.75	2.04
Fourth Quarter	9.39	2.01

We intend to retain earnings for use in the operation and expansion of our business and therefore do not anticipate declaring cash dividends on our common stock in the foreseeable future. Any future determination to pay dividends on common stock will be at the discretion of the board of directors and will be dependent upon then existing conditions, including our prospects, and such other factors, as the board of directors deems relevant. We are also restricted from paying cash dividends on common stock under our Senior Credit Agreement and under the terms of the indentures governing our other long-term debt.

Approximately 694 registered stockholders of record as of February 25, 2013 held our common stock. In many instances, a stockholder can hold shares through a broker or other entity holding shares in street name for one or more customers who beneficially own the shares.

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

During the three months ended December 31, 2012, there was no repurchase of shares of our common stock nor were there any shares surrendered by employees in exchange for the payment of tax withholding as no awards were vested during the period. All sales of our unregistered equity securities during the year ended December 31, 2012 were previously reported.

Five-Year Stock Performance Graph

The following common stock performance graph shows the performance of our common stock through December 31, 2012. As required by applicable rules of the SEC, the performance graph shown below was prepared based on the following assumptions:

A $100 investment was made in Halcón common stock and each index on December 31, 2007.

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

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The following graph and table compare the cumulative 5-year total return provided to our stockholders on our common stock beginning December 31, 2007 through December 31, 2012, relative to the cumulative total returns of the Nasdaq Composite Index and the Dow Jones Wilshire MicroCap Exploration & Production Index. The comparison assumes an investment of $100 (with reinvestment of all dividends) was made in our common stock on December 31, 2007, and in each of the indexes and its relative performance is tracked through December 31, 2012. The identity of the companies included in the Dow Jones Wilshire MicroCap Exploration & Production Index will be provided upon request.

Halcón changed its indexes from NASDAQ Composite to NYSE Composite and from the Dow Jones US TSM MicroCap Exploration and Production to the S&P Midcap Oil & Gas Exploration & Production due to the transfer of its stock listing from the NASDAQ to the NYSE in March of 2012 and a change in peer group due increased market capitalization.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among Halcón Resources Corporation, the NASDAQ Composite Index,
the NYSE Composite Index, the S&P Midcap Oil & Gas Exploration & Production Index,
and Dow Jones US TSM MicroCap Exploration & Production Index

Value of Initial $100 Investment (End of Year)

	12/07	12/08	12/09	12/10	12/11	12/12
Halcón Resources Corporation	100.00	17.53	40.84	36.65	62.35	45.95
NASDAQ Composite	100.00	59.03	82.25	97.32	98.63	110.78
NYSE Composite	100.00	60.74	77.92	88.36	84.96	98.55
Dow Jones US TSM MicroCap Exploration & Production	100.00	54.28	66.48	76.44	57.97	43.96
S&P Midcap Oil & Gas Exploration & Production	100.00	41.25	70.14	99.41	85.92	76.02

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ITEM 6. SELECTED FINANCIAL DATA

The following table presents selected historical financial data derived from our consolidated financial statements. The following data is only a summary and should be read with our historical consolidated financial statements and related notes contained in this document. Refer to Item 1. *Business Recent Developments*, for details regarding the recent acquisitions and business combinations that could impact the comparability of the following data.

	Years Ended December 31,				
	2012	2011	2010	2009(6)	2008(7)
	(In thousands, except per share data)				
Income Statement Data:					
Total operating revenues	$ 247,945	$ 103,689	$ 111,141	$ 98,384	$ 183,072
Income (loss) from operations	(29,717)	19,799	24,526	(44,476)	(206,911)
Net income (loss)	(53,885)	(1,403)	2,417	(58,383)	(129,953)
Net income (loss) available to common stockholders	(142,330)	(1,403)	2,417	(58,383)	(129,953)
Net income (loss) per share of common stock*(1)*:					
Basic	$ (0.91)	$ (0.05)	$ 0.09	$ (2.26)	$ (5.40)
Diluted	$ (0.91)	$ (0.05)	$ 0.09	$ (2.26)	$ (5.40)

	As of December 31,				
	2012	2011(8)	2010(8)	2009(8)	2008(8)
	(In thousands)				
Balance sheet data:					
Working capital deficit	$ (390,111)	$ (7,620)	$ (13,878)	$ (15,899)	$ (4,558)
Total assets	5,041,025	267,174	260,733	306,894	399,696
Total long-term debt*(2)(4)*	2,034,498	202,000	196,965	246,041	250,536
Preferred stock*(3)*	695,238				
Stockholders' equity (deficit)*(4)(5)*	1,397,982	1,680	(101)	(4,794)	53,572

(1) No cash dividends were declared or paid for any periods presented.

(2) Excludes current portion of long-term debt for all periods presented.

(3) Preferred Stock outstanding at December 31, 2012 converted into 108.8 million shares of Halcón common stock on January 18, 2013, following stockholder approval.

(4) On December 21, 2011, we entered into a Securities Purchase Agreement with HALRES LLC, formerly Halcón Resources, LLC (HALRES) in which HALRES purchased and we sold 73.3 million shares of our common stock for a purchase price of $275 million and HALRES purchased and we issued a senior convertible promissory note in the principal amount of $275 million, together with five year warrants to purchase 36.7 million shares of our common stock at an exercise price of $4.50 per share, subject to adjustment under certain circumstances. For additional information regarding this recapitalization, see Item 8. Consolidated Financial Statements and Supplementary Data Note 3, "Recapitalization."

(5) 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

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Supplementary Data Note 12, "Preferred Stock and Stockholders' Equity," for additional information regarding the offering and subsequent conversion.

(6) We incurred a $47.6 million impairment on the carrying value of our oil and natural gas properties for the year ended December 31, 2009.

(7) We incurred a $269.9 million impairment on the carrying value of our oil and natural gas properties for the year ended December 31, 2008.

(8) Previously issued consolidated financial statements as of and for the years ended December 31, 2011, 2010, 2009 and 2008 have been restated, see Item 8. Consolidated Financial Statements and Supplementary Data Note 2, "Corrections of Immaterial Errors."

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

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

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

Overview

We are an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich oil and natural 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. We now have an extensive drilling inventory in multiple basins that we believe allow 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 MMBoe, consisting of 87.4 MMBbls of oil, 5.4 MMBbls of natural gas liquids, and 96.1 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. Production for the fourth quarter of 2012 averaged 18,348 Boe/d. Full year 2012 production averaged 9,404 Boe/d compared to 4,121 Boe/d in 2011. Our total operating revenues for 2012 were approximately $247.9 million compared to $103.7 million in 2011.

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 undisclosed locations.

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Our average daily production increased 128% year over year. The increase in production compared to the prior year period 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.

Our financial results depend upon many factors, but are largely driven by the volume of our oil and natural gas production and the price that we receive for that production. Our production volumes will decline as reserves are depleted unless we expend capital in successful development and exploration activities or acquire properties with existing production. The amount we realize for our production depends predominantly upon commodity prices 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 at economical costs is critical to our long-term success.

For the twelve months ended December 31, 2012 we incurred capital expenditures for drilling, completions and leasehold costs of approximately $1.3 billion as compared to a budget of $1.1 billion. Capital spending was more than budgeted primarily because of increased drilling and completion activity in the Bakken / Three forks formations related to the acquisition of the Williston Basin Assets in addition to increased leasing activity in the Utica / Point Pleasant formations.

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.

Recent Acquisitions

Acquisition of Williston Basin Assets

On December 6, 2012, we completed the acquisition of entities owning a total of 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

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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 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, and 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 companies 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.

Acquisition of Unevaluated Acreage and Other

On December 28, 2012, we completed the acquisition of certain oil and natural gas properties, located in Brazos County, Texas, from a group of private sellers for approximately $83.7 million, before customary closing adjustments, consisting of approximately $8.4 million in cash and approximately $75.3 million in promissory notes. The promissory notes have a maturity date of August 30, 2013. The transaction had an effective date of December 1, 2012. Refer to Item 8. *Consolidated Financial*

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Statements and Supplementary Data Note 7,"*Long-term debt,*" for more details regarding the promissory notes.

On September 12, 2012, we completed the acquisition of certain oil and natural gas properties, located in Leon County, Texas from a group of private sellers for approximately $14.0 million, before customary closing adjustments. The transaction had an effective date of September 1, 2012. The acquisition was funded with cash on hand.

On June 28, 2012, we acquired a working interest in approximately 27,000 net acres 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. No oil or natural gas production or proved reserves were attributable to the acquired assets.

In addition to the forgoing acquisitions, during 2012 we incurred approximately $915.6 million in capital expenditures on unevaluated oil and gas leaseholds through numerous leasing and acquisition transactions. No oil or natural gas production or proved reserves were attributable to the acquired unevaluated leasehold assets which were primarily located in Texas, Louisiana, Ohio and Pennsylvania.

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.

Other Recent Developments

Offering of Additional 8.875% Senior Notes

On January 14, 2013, we completed the issuance of an additional $600 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 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.

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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. The Preferred Stock was considered to have a beneficial conversion feature because the proceeds per share, approximately $9.00 per share of common stock, were less than the fair value of our common stock of $10.99 per common share on the commitment date. The estimated fair value allocated to the beneficial conversion feature was $88.4 million and was recorded to additional paid-in capital, creating a discount on the Preferred Stock (the Discount). The Discount resulting from the allocation of value to the beneficial conversion feature was required to be amortized over the 71-month contractual period from issuance to required redemption, or fully amortized upon an accelerated date of redemption or conversion, by increasing Preferred Stock and recording the offsetting amount as a deemed non-cash Preferred Stock dividend. During the three months ended March 31, 2012, we amortized the Discount and recorded a non-cash preferred dividend of $1.1 million. Due to the conversion date occurring on April 17, 2012, the remaining $87.3 million of the Discount amortization was accelerated to the conversion date and reflected as a non-cash preferred dividend in April 2012.

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

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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.

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Capital Resources and Liquidity

The proceeds provided by our recent financing activities have enabled us to increase our focus on expanding our leasehold position in liquids-rich resource areas. We have acquired and/or identified several core resource plays for additional leasing, including the Bakken / Three Forks formations in North Dakota, Utica / Point Pleasant formations in Ohio and Pennsylvania and the Woodbine / Eagle Ford formations in East Texas. In addition to our ongoing lease acquisition efforts in our core resource plays, we have identified several new exploratory areas we believe are prospective for oil and liquids-rich hydrocarbons. In 2012, excluding the Merger and acquisitions of the East Texas Assets and Williston Basin Assets, we invested $1.2 billion on oil and natural gas capital expenditures. The majority of these expenditures were for acreage in the Utica / Point Pleasant and Woodbine / Eagle Ford formations. Additionally, in 2012, we paid approximately $579.5 million, $756.1 million and $296.1 million respectively, in the Merger, the Williston Basin Assets Acquisition and the East Texas Assets Acquisition.

Our near-term capital spending requirements are expected to be partially funded with cash flows from operations, proceeds from potential non-core asset dispositions, proceeds from potential capital market transactions and borrowings under our Senior Credit Agreement, which has a current borrowing base of $850.0 million. Our borrowing base is redetermined on a semi-annual basis (with us and the lenders each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations) and adjusted based on our oil and natural gas properties, reserves, other indebtedness and other relevant factors. Our ability to utilize the full amount of our borrowing capacity is influenced by a variety of factors, including redeterminations of our borrowing base, and covenants under our Senior Credit Agreement and our senior unsecured debt indentures. Our Senior Credit Agreement contains customary financial and other covenants, including minimum working capital levels (the ratio of current assets plus the unused commitment under the Senior Credit Agreement to current liabilities) of not less than 1.0 to 1.0 and minimum coverage of interest expenses (as defined in the Senior Credit Agreement) of not less than 2.5 to 1.0. We are subject to additional covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. Additionally, the indentures governing our senior unsecured debt contain covenants limiting our ability to incur additional indebtedness, including borrowings under our Senior Credit Agreement, unless we meet one of two alternative tests. The first test, the fixed charge coverage ratio test, applies to all indebtedness and requires that after giving effect to the incurrence of additional debt the ratio of our adjusted consolidated EBITDA (as defined in our indentures) to our adjusted consolidated interest expense over the trailing four fiscal quarters will be at least 2.0 to 1.0. The second test allows us to incur additional indebtedness, beyond the limitations of the fixed charge coverage ratio test, as long as this additional debt is incurred under Credit Facilities (as defined in our indentures) and the amount of such additional indebtedness is not more than the greater of a fixed sum of $750 million or 30% of our adjusted consolidated net tangible assets (as defined in all of our indentures), which is determined primarily using discounted future net revenues from proved oil and natural gas reserves as of the end of each year. 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.

We strive to maintain financial flexibility while continuing our aggressive drilling plans and evaluating potential acquisitions, and will therefore likely continue to access capital markets (if on acceptable terms) as necessary to, among other things, 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 while sustaining sufficient operating cash levels. Our ability to complete future debt and equity offerings and maintain or increase our borrowing base is subject to a number of variables, including our level of oil and natural gas production, reserves and commodity prices, as well as various economic and market conditions that

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have historically affected the oil and natural gas industry. If oil and natural gas prices decline for a sustained period of time, our ability to fund our capital expenditures, complete acquisitions, reduce debt, meet our financial obligations and become profitable may be materially impacted.

Our future capital resources and liquidity depend, in part, on our success in developing our leasehold interests, growing reserves and production and finding additional reserves. Cash is required to fund capital expenditures necessary to offset inherent declines in our production and proven reserves, which is typical in the capital-intensive oil and natural gas industry. We therefore continuously monitor our liquidity and the capital markets and evaluate our development plans in light of a variety of factors, including, but not limited to, our cash flows, capital resources, acquisition opportunities and drilling success.

Cash Flow

Our primary source of cash in 2012 was from financing activities. Our primary source of cash in 2011 and 2010 was from operating activities. In 2012, proceeds from the sale of common stock and preferred stock, the issuance of new senior debt and cash received from operations were offset by repayments of borrowings under our Senior Credit Agreement and cash used in investing activities to fund our drilling program and acquisition activities, net of divestiture activities. Operating cash flow fluctuations were substantially driven by changes in commodity prices and changes in our production volumes. Working capital was substantially influenced by these variables. Fluctuation in commodity prices and our overall cash flow may result in an increase or decrease in our future capital expenditures. Prices for oil and natural gas have historically been subject to seasonal fluctuations characterized by peak demand and higher prices in the winter heating season; however, the impact of other risks and uncertainties have influenced prices throughout recent years. See *Results of Operations* below for a review of the impact of prices and volumes on sales.

	Years Ended December 31,		
	2012	2011	2010
	(In thousands)		
Cash flows provided by operating activities	$ 118,174	$ 29,835	$ 37,875
Cash flows provided by (used) investing activities	(2,866,280)	(25,376)	14,970
Cash flows provided by (used) financing activities	2,750,563	(4,447)	(52,937)
Net increase (decrease) in cash	$ 2,457	$ 12	$ (92)

Operating Activities. Net cash flows provided by operating activities were $118.2 million, $29.8 million and $37.9 million for the years ended December 31, 2012, 2011 and 2010, respectively. Key drivers of net operating cash flows are commodity prices, production volumes and operating costs.

Net loss for the year ended December 31, 2012 was $53.9 million. Non-cash items, including $90.3 million of depreciation, depletion and accretion, $9.4 million of non-cash interest and amortization and $6.2 million of amortization and write-off of deferred loan costs served to offset this net loss. The Recapitalization, including change in control and related activities which occurred during February 2012, the Merger and acquisition transaction costs and the impact of additional personnel and facilities in support of the rapidly expanding business base, drove a significant increase in general and administrative expenditures, which adversely affected operating cash flows. The remaining improvement in operating cash flows is largely attributable to a favorable mix in working capital changes.

Net cash flows provided by operating activities decreased in 2011 primarily due to our 30% decrease in our average daily production volumes, which was partially offset by a 34% increase in our average realized Boe price compared to the same period in 2010.

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Investing Activities. The primary driver of cash used in investing activities is capital spending, specifically the acquisition of unevaluated leaseholds in our targeted areas, the Merger and the acquisitions of the East Texas Assets and the Williston Basin Assets. Net cash used in investing activities was $2.9 billion and $25.4 million for the years ended December 31, 2012 and 2011, respectively. Net cash provided by investing activities was $15.0 million for the year ended December 31, 2010.

In 2012, we incurred cash expenditures of $579.5 million, net of cash acquired, on the Merger, $756.1 million on the acquisition of the Williston Basin Assets, and $296.1 million on the acquisition of the East Texas Assets. Additionally, we spent $1.2 billion on oil and natural gas capital expenditures. 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. We spent an additional $38.8 million on other operating property and equipment capital expenditures primarily related to infrastructure for gathering and transportation systems. Proceeds from sales of oil and gas properties were $22.0 million.

In 2011, we spent $25.2 million on capital expenditures of evaluated oil and natural properties. We drilled or participated in the drilling of 54 gross (49.0 net) wells on our oil and natural gas properties, of which, 49 gross (44.8 net) wells were successfully completed as producing wells, 5 gross (4.2 net) wells were abandoned wells and 7 gross (5.9 net) wells were either drilling or waiting to be completed at the end of that period.

In 2010, proceeds from sales of oil and natural gas properties of $49.4 million offset capital expenditures of $34.4 million as a result of property divestitures in conjunction with the execution of our strategic alternative initiative to reduce debt.

Financing Activities. Net cash flows provided by financing activities were $2.8 billion for the year ended December 31, 2012. Net cash flows used in financing activities were $4.4 million and $52.9 million for the years ended December 31, 2011 and 2010, respectively. The primary driver of cash provided by financing activities is proceeds from the issuance of common stock and preferred stock and long-term debt offset by repayments of long-term debt.

On December 6, 2012, in conjunction with the closing of the Williston Basin Assets acquisition, we received net proceeds of approximately $294.0 million from the private placement of 41.9 million shares of our common stock with CPPIB, which acquired the shares for a purchase price of approximately $7.16 per share.

On November 6, 2012, we sold, in a private offering to eligible purchasers, $750.0 million aggregate principal amount of our 8.875% senior notes due 2021. Net proceeds of $725.6 million from the offering were placed into escrow pending the acquisition of the Williston Basin Assets and were subsequently released upon closing and used to fund a portion of the cash consideration paid in the acquisition.

On June 29, 2012, we priced $750.0 million aggregate principal amount of 9.75% senior unsecured notes due 2020 in a private offering. Net proceeds from these notes of approximately $723.1 million were funded into escrow on July 16, 2012 and subsequently released from escrow on August 1, 2012 and utilized to fund portions of the Merger and East Texas Assets Acquisition.

On March 5, 2012, we received $400.0 million, subject to certain adjustments, from the private placement sale of convertible Preferred Stock.

On February 8, 2012, HALRES 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 (February 2012 Warrants). The convertible note provided $231.4 million cash flow

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from borrowings and $43.6 million cash flow from warrants issued. In connection with the closing of the Recapitalization, we entered into the Senior Credit Agreement and terminated our March 2011 Credit Facilities with the payoff of the $210.8 million balance.

Cash flows provided by financing activities include net borrowings from our Senior Credit Agreement of $298.0 million for the year ended December 31, 2012, primarily due to our acquisition activities and our ongoing drilling activities.

Contractual Obligations

We believe we have a significant degree of flexibility to adjust the level of our future capital expenditures as circumstances warrant. Our level of capital expenditures will vary in future periods depending on the success we experience in our acquisition, developmental and exploration activities, oil and natural gas price conditions and other related economic factors. Currently no sources of liquidity or financing are provided by off-balance sheet arrangements or transactions with unconsolidated, limited-purpose entities. The following table summarizes our contractual obligations and commitments by payment periods as of December 31, 2012.

	Payments Due by Period				
Contractual Obligations	**Total**	**2013**	**2014 - 2015**	**2016 - 2017**	**2018 and Beyond**
			(In thousands)		
Promissory notes*(1)*	$ 75,285	$ 75,285	$	$	$
Senior revolving credit facility	298,000			298,000	
8.875% $750 million senior notes*(2)*	750,000				750,000
9.75% $750 million senior notes*(3)*	750,000				750,000
8.0% $275 million senior note*(4)*	289,669			289,669	
Interest expense on long-term debt*(5)*	1,247,178	173,334	346,668	316,667	410,509
Operating leases	53,825	8,074	13,079	12,970	19,702
Drilling rig commitments	79,391	55,257	24,134		
Other commitments	17,809	17,809			
Total contractual obligations	$ 3,561,157	$ 329,759	$ 383,881	$ 917,306	$ 1,930,211

(1) Excludes $0.6 million unamortized discount recorded in conjunction with the issuance of the notes.

(2) Excludes $5.6 million unamortized discount recorded in conjunction with the issuance of the notes. On January 14, 2013, we issued an additional $600 million of these notes which are not reflected in the table. See "8.875% Senior Notes" below and Item 8. Consolidated Financial Statements and Supplementary Data Note 7, "Long-Term Debt" for more details.

(3) Excludes $9.8 million unamortized discount recorded in conjunction with the issuance of the notes. See "9.75% Senior Notes" below and Item 8. Consolidated Financial Statements and Supplementary Data Note 7, "Long-Term Debt" for more details.

(4) Excludes $37.8 million unamortized discount recorded in conjunction with the issuance of the note. See "8.0% Convertible Note" below for more details.

(5) Future interest expense was calculated based on interest rates and amounts outstanding at December 31, 2012 less required annual repayments.

The contractual obligations table does not include obligations to taxing authorities due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations. In addition, amounts related to our asset retirement obligations are not included in the table above given

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the uncertainty regarding the actual timing of such expenditures. The total amount of asset retirement obligations at December 31, 2012 was $75.1 million.

Senior Revolving Credit Facility

In connection with the closing of the Recapitalization, discussed in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 3,*"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. These margins fluctuate based on our utilization of the facility. 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, including minimum working capital levels (the ratio of current assets plus the unused commitment under the Senior Credit Agreement to current liabilities) of not less than 1.0 to 1.0 and minimum coverage of interest expenses (as defined in the Senior Credit Agreement) of not less than 2.5 to 1.0.

On August 1, 2012, in connection with the closing of the Merger and the 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 (the Second Amendment) which amends the Senior Credit Agreement with respect to our ability to enter into certain commodity hedging agreements. The Second Amendment provides, among other things, that we and our subsidiary guarantors 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

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agreement is entered into. The 85% limitations discussed above do not apply to volumes hedged by us 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 and natural gas liquids, for the 66 months following the date such agreement was entered into.

March 2011 Credit Facilities

Our March 2011 credit facilities included a $250.0 million revolving credit facility and a $75.0 million second lien term loan facility (the March 2011 Credit Facilities), replacing the November 2007 facility. SunTrust Bank was the administrative agent for the revolving credit facility, and Guggenheim Corporate Funding, LLC was the administrative agent for the second lien term loan facility. The revolving credit facility allowed for funds advanced to be paid down and re-borrowed during the five-year term of the revolver, and bore interest at LIBOR plus a margin ranging from 2.5% to 3.25% based on a percentage of usage. The second lien term loan facility provided for payments of interest only during its 5.5 year term, and bore interest at LIBOR plus 9.0% with a 2.0% LIBOR floor, or if any period we elected to pay a portion of the interest "in kind", then the interest rate would have been LIBOR plus 10.0% with a 2.0% LIBOR floor, and with 7.0% of the interest amount paid in cash and the remaining 3.0% paid-in-kind by being added to principal. At December 31, 2011, $127.0 million was outstanding under the revolving credit facility and $75.0 million was outstanding under the second lien term loan facility. On February 8, 2012, we paid in full the outstanding balances under the revolving credit facility and the second lien term loan facility and both facilities were terminated, resulting in a $1.5 million charge to interest expense related to an early termination penalty.

8.875% Senior Notes

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

The 2021 Notes bear interest at a rate of 8.875% per annum, payable semi-annually on May 15 and November 15 of each year, beginning on May 15, 2013. The Notes will mature on May 15, 2021. In connection with the issuance of the 2021 Notes, we recorded a discount of approximately $5.65 million to be amortized over the remaining life of the 2021 Notes using the effective interest method. The remaining unamortized discount was $5.58 million at December 31, 2012.

On January 14, 2013, we completed the issuance of an additional $600.0 million aggregate principal amount of our 8.875% senior notes due 2021, issued at 105.000% of par (the additional 2021 Notes). The net proceeds from the sale of the additional 2021 Notes were 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. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 7,*"Long-Term Debt,"* for additional information regarding the 2021 Notes.

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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 issued at 98.646% of par (the 2020 Notes). The net proceeds from the offering were approximately $723.1 million after deducting the initial purchasers' discounts, commissions and offering expenses and were used to fund a portion of the cash consideration paid in the Merger and the East Texas Assets acquisition.

The 2020 Notes bear interest at a rate of 9.75% per annum, payable semi-annually on January 15 and July 15 of each year, which began on January 15, 2013. The 2020 Notes will mature on July 15, 2020. In connection with the issuance of the 2020 Notes, we recorded a discount of approximately $10.2 million to be amortized over the remaining life of the 2020 Notes using the effective interest method. The remaining unamortized discount was $9.8 million at December 31, 2012. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 7, *"Long-Term Debt,"* for additional information regarding the 2020 Notes.

8.0% Convertible Note

On February 8, 2012, we issued the 8.0% senior note in the principal amount of $275.0 million (the 2017 Note) together with the February 2012 Warrants for an aggregate purchase price of $275.0 million. The 2017 Note bears interest at a rate of 8% per annum, payable quarterly on March 31, June 30, September 30 and December 31 of each year and matures on February 8, 2017. Through the March 31, 2014 interest payment date, we may elect to pay-in-kind, by adding to the principal of the 2017 Note, all or any portion of the interest due on the 2017 Note. We elected to pay the interest in-kind on March 31, June 30 and September 30, 2012, and rolled $3.2 million, $5.7 million and $5.8 million of interest incurred during the first, second and third quarters of 2012, respectively, into the 2017 Note, increasing the principal amount to $289.7 million. For the three months ended December 31, 2012, we did not elect to pay-in-kind interest. At any time after February 8, 2014, the noteholder may elect to convert all or any portion of the principal amount and accrued but unpaid interest into common stock. Each $4.50 of principal and accrued but unpaid interest is convertible into one share of our common stock. The 2017 Note is a senior unsecured obligation of ours.

We allocated the proceeds received for the 2017 Note and February 2012 Warrants on a relative fair value basis. Consequently, we recorded a discount of $43.6 million to be amortized over the remaining life of the 2017 Note utilizing the effective interest rate method. The remaining unamortized discount was $37.8 million at December 31, 2012.

Promissory Notes

On December 28, 2012, we completed a transaction consisting of certain oil and natural gas properties in East Texas to expand our existing operations in that area, for approximately $83.7 million, before customary closing adjustments, consisting of approximately $8.4 million in cash and approximately $75.3 million in promissory notes. The promissory notes accrue interest beginning March 29, 2013, to the extent there is a remaining principal balance of the promissory notes at such date. Interest accrues based on the Wall Street Journal Prime Rate effective March 29, 2013. The promissory notes mature on August 30, 2013 and were classified as current as of December 31, 2012.

In conjunction with the issuance of the promissory notes, we recorded a discount of approximately $0.6 million to be amortized over the remaining life of the promissory notes using the effective interest method. The remaining unamortized discount was $0.6 million at December 31, 2012.

Off-Balance Sheet Arrangements

At December 31, 2012, we did not have any material off-balance sheet arrangements.

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Critical Accounting Policies and Estimates

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

Oil and Natural Gas Activities

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

Full Cost Method

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

Proved Oil and Natural Gas Reserves

Estimates of our proved reserves included in this report are prepared in accordance with accounting principles generally accepted in the United States and Securities Exchange Commission

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

Our estimated proved reserves for the years ended December 31, 2012 were prepared by Netherland, Sewell, an independent oil and natural gas reservoir engineering consulting firm. 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. For more information regarding reserve estimation, including historical reserve revisions, refer to Item 8. Consolidated Financial Statements and Supplementary Data "*Supplemental Oil and Gas Information (Unaudited).*"

Depreciation, Depletion and Accretion

Our rate of recording depletion, depreciation and accretion expense (DD&A) is primarily dependent upon our estimate of proved reserves, which is utilized in our unit-of-production method calculation. If the estimates of proved reserves were to be reduced, the rate at which we record DD&A expense would increase, reducing net income. Such a reduction in reserves may result from calculated lower market prices, which may make it non-economic to drill for and produce higher cost reserves. At December 31, 2012 our DD&A rate was $25.05 per Boe and a five percent positive revision to proved reserves would decrease the DD&A rate by approximately $1.53 per Boe and a five percent negative revision to proved reserves would increase the DD&A rate by approximately $1.69 per Boe.

Full Cost Ceiling Test Limitation

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

If the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ended December 31, 2012 had been 10% lower while all other factors remained constant, our ceiling amount related to our net book value of oil and natural gas properties

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would have been reduced by approximately $262 million. This reduction would not have resulted in a full costing ceiling impairment.

Future Development Costs

Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production facilities, gathering systems and related structures and restoration costs. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, well depth, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis. A five percent decrease or increase in future development and abandonment costs would decrease or increase the DD&A rate by approximately $0.64 per Boe.

Asset Retirement Obligations

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

Accounting for Derivative Instruments and Hedging Activities

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

Goodwill

We account for goodwill in accordance with ASC 350, *Intangibles Goodwill and Other* (ASC 350). Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in an acquisition. ASC 350 requires that intangible assets with indefinite lives, including goodwill, be evaluated on an annual basis for impairment or more frequently if an event occurs or circumstances change that could potentially result in impairment. The goodwill impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. Our goodwill relates to the acquisition of GeoResources in 2012.

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Accounting Standards Update (ASU) No. 2011-08, *Testing for Goodwill Impairment* (ASU 2011-08), simplifies testing for goodwill impairments by allowing entities to first assess qualitative factors to determine whether the facts or circumstances lead to the conclusion that it is more likely than not that the fair value of a reporting unit is less than the carrying value. If the entity concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then the entity does not have to perform the two-step impairment test. However, if the same conclusion is not reached, the company is required to perform the first step of the two-step impairment test. In this step, the fair value of the reporting unit is calculated and compared to the carrying value of the reporting unit. If the carrying value exceeds the fair value, then the entity must perform the second step of the impairment test to measure the amount of impairment loss, if any. ASU 2011-08 also allows a company to bypass the qualitative assessment and proceed directly with performing the two-step goodwill impairment test.

Income Taxes

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

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

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Comparison of Results of Operations

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

We reported a net loss available to common stockholders of $142.3 million, including a non-cash preferred dividend of $88.4 million, for the year ended December 31, 2012 compared to a net loss available to common stockholders of $1.4 million for the comparable period in 2011. The following table summarizes key items of comparison and their related change for the periods indicated.

In thousands (except per unit and per Boe amounts)	Years Ended December 31, 2012	2011	Change
Net income (loss) available to common stockholders	$ (142,330)	$ (1,403)	$ (140,927)
Operating revenues:			
Oil	223,048	82,968	140,080
Natural gas	12,458	10,673	1,785
Natural gas liquids	11,088	9,880	1,208
Other	1,351	168	1,183
Operating expenses:			
Production:			
Lease operating	49,941	30,043	19,898
Workover and other	4,429	1,967	2,462
Taxes other than income	19,253	7,214	12,039
Restructuring	2,406	1,071	1,335
General and administrative:			
General and administrative	104,608	17,025	87,583
Share-based compensation	6,741	3,584	3,157
Depletion, depreciation and accretion:			
Depletion Full cost	86,215	20,381	65,834
Depreciation Other	1,763	964	799
Accretion expense	2,306	1,641	665
Other income (expenses):			
Net gain (loss) on derivative contracts	(6,126)	3,479	(9,605)
Interest expense and other	(31,223)	(17,879)	(13,344)
Income tax benefit (provision)	13,181	(6,802)	19,983
Production:			
Crude oil MBbls	2,415	884	1,531
Natural Gas Mmcf	4,554	2,662	1,892
Natural gas liquids MBbls	268	176	92
Total MBoe*(1)*	3,442	1,504	1,938
Average daily production Boe*(1)*	9,404	4,121	5,283
Average price per unit*(2)*:			
Crude oil price Bbl	$ 92.36	$ 93.86	$ (1.50)
Natural gas price Mcf	2.74	4.01	(1.27)
Natural gas liquids price Bbl	41.37	56.14	(14.77)
Total per Boe*(1)*	71.64	68.83	2.81
Average cost per Boe:			
Production:			
Lease operating	14.51	19.98	(5.47)
Workover and other	1.29	1.31	(0.02)
Taxes other than income	5.59	4.80	0.79
Restructuring	0.70	0.71	(0.01)
General and administrative:			
General and administrative	30.39	11.32	19.07
Share-based compensation	1.96	2.38	(0.42)
Depletion	25.05	13.55	11.50

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

For the year ended December 31, 2012, oil, natural gas and natural gas liquids revenues increased $143.1 million from the same period in 2011. The increase was primarily due to an increase in production volumes resulting from the Merger, the East Texas Assets acquisition and the Williston Basin Assets acquisition which collectively accounted for an increase of 1,942 MBoe in production and $145.3 million of incremental revenues. Realized average prices per Boe increased $2.81 per Boe to $71.64 per Boe.

Lease operating expenses increased $19.9 million for the year ended December 31, 2012, primarily due to $16.3 million of costs incurred on our newly acquired assets. The remaining increases are due to surface repair and maintenance costs. Lease operating expenses were $14.51 per Boe in 2012 compared to $19.98 per Boe in 2011. The decrease per Boe is primarily due to a lower rate per Boe on the newly acquired properties.

Workover and other expenses increased $2.5 million for the year ended December 31, 2012 compared to the same period in 2011 primarily due to $2.7 million of expenses incurred on our newly acquired assets.

Taxes other than income increased $12.0 million for the year ended December 31, 2012 as compared to the same period in 2011 primarily due to $9.6 million of production taxes incurred on our newly acquired properties. Most production taxes are based on realized prices at the wellhead. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease directly. On a per unit basis, taxes other than income were $5.59 per Boe and $4.80 per Boe, for the years ended 2012 and 2011, respectively.

In March 2012, we announced our intention to close the Plano, Texas office and began the process of relocating key administrative functions to our corporate headquarters in Houston, Texas (the Restructuring). As part of the Restructuring, we offered certain severance and retention benefits to affected employees. We have incurred $2.4 million in Restructuring costs for the year ended December 31, 2012. In October 2011, we announced a company-wide reorganization of our operating and administrative functions. As part of the reorganization, we recognized restructuring expense of $1.1 million, including $0.7 million of one-time severance benefits, $0.2 million of retention payments, and $0.2 million of share-based compensation related to the acceleration of employee restricted stock awards and payment of share appreciation rights. The reorganization was completed in full during the quarter ended December 31, 2011.

General and administrative expense for the year ended December 31, 2012 increased $87.6 million to $104.6 million as compared to the same period in 2011. The increase was primarily due to transaction costs of $41.0 million in the aggregate for the Merger, the East Texas Assets acquisition and the Williston Basin Assets acquisition. We incurred $8.9 million in connection with the Recapitalization, which included $5.4 million for change in control payments and $2.5 million for engagement termination fees. The remaining increase in general and administrative expenses is attributable to increases in payroll and related employee benefit costs of $18.3 million, office related expenses of $5.2 million and professional fees of $9.7 million, in support of the expanding business base and increased corporate activities subsequent to the Recapitalization.

Share-based compensation expense for the year ended December 31, 2012 was $6.7 million, an increase of $3.2 million compared to the same period in 2011. The increase is primarily due to the accelerated vesting of restricted stock awards and stock appreciation rights resulting from the change in control that occurred due to our Recapitalization, which totaled $4.3 million.

Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs of evaluated properties plus future development costs based on the

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ratio of production volume for the current period to total remaining reserve volume for the evaluated properties. Depletion expense increased $65.8 million to $86.2 million for the year ended December 31, 2012 compared to the same period in 2011 of $20.4 million, primarily due to a higher depletion rate per Boe and increased production. On a per unit basis, depletion expense was $25.05 per Boe for the year ended December 31, 2012 compared to $13.55 per Boe for the year ended December 31, 2011. The increase in depletion and the depletion rate per Boe and production is primarily due to the Merger and acquisitions of the East Texas Assets and the Williston Basin Assets.

Accretion expense is a function of changes in the discounted asset retirement obligation liability from period to period. We recorded $2.3 million for the year ended December 31, 2012, compared to $1.6 million for the year ended December 31, 2011.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. We have also, in the past, entered into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. Consistent with prior years, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the consolidated statements of operations. At December 31, 2012, we had a $7.8 million derivative asset, $7.4 million of which was classified as current, and we had a $12.9 million derivative liability of which $10.4 million was classified as current. We recorded a net derivative loss of $6.1 million ($13.2 million net unrealized loss and $7.1 million net realized gain on settled contracts and premium costs) for the year ended December 31, 2012 compared to a net derivative gain of $3.5 million ($4.8 million net unrealized gain and $1.3 million net realized loss on settled contracts and premium costs) in the prior year.

Interest expense increased $13.3 million for the year ended December 31, 2012. This increase was primarily due to the issuance of new long-term debt partially offset by capitalized interest expense on unevaluated properties. We incurred interest expense of $85.4 million in 2012 compared to $17.4 million in the prior year. Due to significant costs incurred during 2012 on unevaluated properties we began capitalizing interest during 2012, resulting in $53.5 million capitalized for the year ended December 31, 2012. No amounts were capitalized in 2011.

We recorded an income tax benefit of $13.2 million on a loss before income taxes of $67.1 million for the year ended December 31, 2012. The benefit reflects nondeductible interest expense on the Convertible Notes issued as part of the Recapitalization of $3.2 million and nondeductible merger related costs of $3.6 million. For the year ended December 31, 2011, we recorded an income tax provision of $6.8 million on income before income taxes of $5.4 million. The income tax provision for 2011 included a $6.0 million decrease to deferred tax assets, including a Section 382 adjustment related to net operating loss limitations and a decrease in the valuation allowance of $1.9 million.

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

We reported a net loss available to common stockholders of $1.4 million for the year ended December 31, 2011 compared to net income available to common stockholders of $2.4 million for the comparable period in 2010. The following table summarizes key items of comparison and their related change for the periods indicated.

	Years Ended December 31,		
In thousands (except per unit and per Boe amounts)	**2011**	**2010**	**Change**
Net income (loss) available to common stockholders	$ (1,403)	$ 2,417	$ (3,820)
Operating revenues:			
Oil	82,968	76,563	6,405
Natural gas	10,673	20,265	(9,592)
Natural gas liquids	9,880	14,156	(4,276)
Other	168	157	11
Operating expenses:			
Production:			
Lease operating	30,043	30,148	(105)
Workover and other	1,967	1,596	371
Taxes other than income	7,214	8,486	(1,272)
Restructuring	1,071		1,071
General and administrative:			
General and administrative	17,025	14,523	2,502
Share-based compensation	3,584	3,110	474
Depletion, depreciation and accretion:			
Depletion Full cost	20,381	26,166	(5,785)
Depreciation Other	964	1,059	(95)
Accretion expense	1,641	1,527	114
Other income (expenses):			
Net gain on derivative contracts	3,479	1,193	2,286
Interest expense and other	(17,879)	(22,307)	4,428
Income tax (provision) benefit	(6,802)	(995)	(5,807)
Production:			
Crude oil MBbls	884	995	(111)
Natural Gas Mmcf	2,662	4,816	(2,154)
Natural gas liquids MBbls	176	364	(188)
Total MBoe*(1)*	1,504	2,161	(657)
Average daily production Boe*(1)*	4,121	5,921	(1,800)
Average price per unit*(2)*:			
Crude oil price Bbl	$ 93.86	$ 76.95	$ 16.91
Natural gas price Mcf	4.01	4.21	(0.20)
Natural gas liquids price Bbl	56.14	38.89	17.25
Total per Boe*(1)*	68.83	51.36	17.47
Average cost per Boe:			
Production:			
Lease operating	$ 19.98	$ 13.95	$ 6.03
Workover and other	1.31	0.74	0.57
Taxes other than income	4.80	3.93	0.87
Restructuring	0.71		0.71
General and administrative:			
General and administrative	11.32	6.72	4.60
Share-based compensation	2.38	1.44	0.94
Depletion	13.55	12.11	1.44

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

For the year ended December 31, 2011, oil, natural gas and natural gas liquids revenues decreased $7.5 million, or 7%, to $103.5 million when compared to the prior year. The primary reason for the decrease is due to asset divestitures. Excluding asset sales, oil, natural gas and natural gas liquids sales increased $3.5 million for the year ended December 31, 2011, when compared to the year ended December 31, 2010. This increase was primarily driven by commodity price increases, offset by decreased production. Our average realized price increased $17.47 per Boe from $51.36 per Boe in the prior period. Excluding the activities related to the asset divestitures, our production volume decreased 16% as compared to the same period last year primarily due to a shut-in of one well as a result of a major workover in Louisiana and natural production declines.

Lease operating expenses decreased $0.1 million for the year ended December 31, 2011 as compared to the same period in 2010. For the year ended December 31, 2011, lease operating expense was $19.98 per Boe compared to $13.95 per Boe for the year ended December 31, 2010, an increase of 43%.

Taxes other than income decreased $1.3 million for the year ended December 31, 2011 as compared to the same period in 2010 primarily due to asset sales. Excluding asset sales, production taxes increased $0.2 million, primarily due to higher commodity prices during the 2011 period. Production taxes vary by state; most are based on realized prices at the wellhead, while Louisiana production tax is based on volume for natural gas and value for oil. As oil revenues or natural gas volumes increase or decrease, production taxes increase or decrease directly. On a per unit basis, production taxes were $4.80 per Boe and $3.93 per Boe, for the years ended 2011 and 2010, respectively.

Restructuring expenses for the year ended December 31, 2011 were $1.1 million. In 2011, we announced a company-wide reorganization of our operating and administrative functions. As part of the reorganization, we recognized restructuring expense of $1.1 million, including $0.7 million of one-time severance benefits, $0.2 million of retention payments, and $0.2 million of share-based compensation related to the acceleration of employee restricted stock awards and payment of share appreciation rights. There were no restructuring costs incurred for the year ended December 31, 2010.

General and administrative expense for the year ended December 31, 2011 increased $2.5 million to $17.0 million compared to $14.5 million in the same period 2010. This increase is primarily due to divestiture costs recognized in 2011 on a transaction that was terminated.

Historically, our board of directors has granted restricted stock awards and/or stock appreciation rights (SARs). Each of the restricted stock grants vests in equal increments over the vesting period provided for the particular award, typically from one to four years. The share-based compensation on the restricted stock grants was calculated using the closing price per share on each of the grant dates, and the total share-based compensation on all restricted stock grants will be recognized over their respective vesting periods. Share-based compensation expense attributable to SARs is based on the fair value re-measured at each reporting period and recognized over the four-year vesting period. The fair value calculation resulted in $0.8 million of compensation expense recognized for the year ended December 31, 2011. For the year ended December 31, 2011, we recognized a total of $3.4 million share-based compensation related to restricted stock awards compared to $3.1 million for the year ended December 31, 2010. The increase was due to accelerated vesting for retired employees pursuant to our restructuring, and a higher number of shares outstanding in the 2011 period. During the year ended December 31, 2011, $2.8 million of recognized compensation, related to restricted stock awards, was recorded as share-based compensation expense, $0.1 million was recorded as restructuring costs and $0.5 million was recorded as capitalized internal costs. During the year ended December 31, 2010, all recognized compensation was recorded to share-based compensation expense.

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Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs associated with evaluated properties plus future development costs based on the ratio of production volumes for the current period to total remaining reserve volumes for the evaluated properties. Depletion expense decreased $5.8 million for the year ended December 31, 2011 from the same period in 2010 to $20.4 million. On a per unit basis, depletion expense increased $1.44 per Boe to $13.55 per Boe.

Depreciation expense associated with our other operating assets and equipment decreased $0.1 million to $1.0 million for the year ended December 31, 2011.

Accretion expense is a function of changes in the discounted asset retirement obligation liability from period to period. We recorded $1.6 million for the year ended December 31, 2011, compared to $1.5 million for the year ended December 31, 2010.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Consistent with 2010, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the consolidated statement of operations. At December 31, 2011, we had a $3.9 million derivative asset, $1.9 million of which was classified as current and we had a $4.7 million derivative liability, $1.9 million of which was classified as current. We recorded a net derivative gain of $3.5 million ($4.8 million net unrealized gain and $1.3 million net loss for cash received on settled contracts) for the year ended December 31, 2011 compared to a net derivative gain of $1.2 million ($6.4 million net unrealized gain and $5.2 million net loss for cash paid on settled contracts) in the prior year.

Interest expense and other was $17.9 million and $22.3 million for the years ended December 31, 2011 and 2010, respectively, a decrease of $4.4 million. Interest expense decreased due to lower interest rates and lower average outstanding borrowings on our credit facilities throughout the 2011 period. As of December 31, 2011 and 2010, our blended interest rate was 6.2% and 8.0%, respectively.

For the year ended December 31, 2011, we recorded an income tax provision of $6.8 million on income before taxes of $5.4 million. The income tax provision for 2011 included a $6.0 million decrease to deferred tax assets, including a Section 382 adjustment related to net operating loss limitations and a decrease in the valuation allowance of $1.9 million. For the year ended December 31, 2010, we recorded an income tax provision of $1.0 million on income before taxes of $3.4 million. The income tax provision for 2010 included a $5.7 million decrease to deferred tax assets under Section 382 related to net operating loss limitations and a decrease in the valuation allowance of $6.6 million for revisions to future taxable income projections.

Recently Issued Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Derivative Instruments and Hedging Activity

We are exposed to various risks including energy commodity price risk. When oil, natural gas, and natural gas liquids prices decline significantly our ability to finance our capital budget and operations may be adversely impacted. We expect energy prices to remain volatile and unpredictable, therefore we have designed a risk management policy which provides for the use of derivative instruments to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the affect it could have on our operations. The types of derivative instruments that we typically utilize include costless collars, swaps, and put options. The total volumes which we hedge through the

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use of our derivative instruments varies from period to period, however, generally our objective is to hedge approximately 70% to 80% of our current and anticipated production for the next 18 to 24 months. Our hedge policies and objectives may change significantly as our operational profile changes and/or commodities prices change.

We are exposed to market risk on our open derivative contracts related to potential non-performance by our counterparties. 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 of an affiliate of a lender in our Senior Credit Agreement. We did not post collateral under any of these contracts as they are secured under the Senior Credit Agreement. Please refer to Item 8. *Consolidated Financial Statements and Supplementary Data* Note 8,"*Derivatives and Hedging Activities"* for additional information.

We have also been exposed to interest rate risk on our variable interest rate debt. If interest rates increase, our interest expense would increase and our available cash flow would decrease. Historically, we entered into interest rate swaps to reduce the exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. At December 31, 2012, we did not have any open positions that converted our variable interest rate debt to fixed interest rates. We continue to monitor our risk exposure as we incur future indebtedness at variable interest rates and will look to continue our risk management policy as situations present themselves.

We account for our derivative activities under the provisions of ASC 815, *Derivatives and Hedging*, (ASC 815). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 9,"*Derivatives and Hedging Activities"* for more details.

Fair Market Value of Financial Instruments

The estimated fair values for financial instruments under ASC 825, *Financial Instruments*, (ASC 825) are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, cash equivalents, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 8, "*Fair Value Measurements"* for additional information.

Interest Rate Sensitivity

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

At December 31, 2012, total long-term debt was $2.0 billion, excluding the current portion, of which approximately 86% bears interest at a weighted average fixed interest rate of 9.1% per year. The remaining 14% of our total debt balance at December 31, 2012 bears interest at floating or market interest rates that at our option are tied to prime rate or LIBOR. Fluctuations in market interest rates will cause our annual interest costs to fluctuate. At December 31, 2012, the weighted average interest rate on our variable rate debt was 2.7% per year. If the balance of our variable rate debt at December 31, 2012 were to remain constant, a 10% change in market interest rates would impact our cash flow by approximately $0.2 million per quarter.

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ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2012 excluded the acquisition of GeoResources, Inc, completed on August 1, 2012. Such exclusion was in accordance with the U.S. Securities and Exchange Commission guidance that an assessment of recently acquired businesses may be omitted in management's report on internal control over financial reporting, provided the acquisition took place within twelve months of management's evaluation. The acquisition of GeoResources, Inc. represented approximately 26% of our consolidated assets at December 31, 2012 and 37% of our consolidated revenues for the year ended December 31, 2012.

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Halcón Resources Corporation's internal control over financial reporting was effective as of December 31, 2012.

Deloitte & Touche LLP, the Company's independent registered public accounting firm, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2012 which is included herein.

/s/ FLOYD C. WILSON	/s/ MARK J. MIZE
Floyd C. Wilson *Chairman of the Board* *and Chief Executive Officer* Houston, Texas February 28, 2013	Mark J. Mize *Executive Vice President,* *Chief Financial Officer and Treasurer*

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Halcón Resources Corporation
Houston, Texas

We have audited the internal control over financial reporting of Halcón Resources Corporation and subsidiaries (the "Company") as of December 31, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in Management's Report on Internal Control Over Financial Reporting, management excluded from its assessment the internal control over financial reporting at GeoResources Inc., which was acquired on August 1, 2012 and whose financial statements constitute 26% of total assets and 37% of revenues of the consolidated financial statement amounts as of and for the year ended December 31, 2012. Accordingly, our audit did not include the internal control over financial reporting at GeoResources, Inc. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2012 of the Company and our report dated February 28, 2013 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Halcón Resources Corporation
Houston, Texas

We have audited the accompanying consolidated balance sheet of Halcón Resources Corporation and subsidiaries (the "Company") as of December 31, 2012, and the related consolidated statements of operations, stockholders' equity, and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. The consolidated financial statements of the Company for the years ended December 31, 2011 and 2010 were audited by other auditors whose report, dated March 5, 2012 and February 28, 2013 as to Note 2, expressed an unqualified opinion on those statements.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2012, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Halcón Resources Corporation

We have audited the accompanying consolidated balance sheet of Halcón Resources Corporation (formerly RAM Energy Resources, Inc., a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2011, and the related consolidated statements of operations, stockholders' equity (deficit) and cash flows for the two years in the period ended December 31, 2011. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Halcón Resources Corporation and subsidiaries at December 31, 2011, and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2, the accompanying consolidated financial statements have been restated.

/s/ UHY LLP

Houston, Texas
March 5, 2012 (except for effect of the
restatement discussed in Note 2, as to
which the date is February 28, 2013)

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HALCÓN RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	Years Ended December 31, 2012	2011	2010
Operating revenues:			
Oil, natural gas and natural gas liquids sales:			
Oil	$ 223,048	$ 82,968	$ 76,563
Natural gas	12,458	10,673	20,265
Natural gas liquids	11,088	9,880	14,156
Total oil, natural gas and natural gas liquids sales	246,594	103,521	110,984
Other	1,351	168	157
Total operating revenues	247,945	103,689	111,141
Operating expenses:			
Production:			
Lease operating	49,941	30,043	30,148
Workover and other	4,429	1,967	1,596
Taxes other than income	19,253	7,214	8,486
Restructuring	2,406	1,071	
General and administrative	111,349	20,609	17,633
Depletion, depreciation and accretion	90,284	22,986	28,752
Total operating expenses	277,662	83,890	86,615
Income (loss) from operations	(29,717)	19,799	24,526
Other income (expenses):			
Interest expense and other	(31,223)	(17,879)	(22,307)
Net gain (loss) on derivative contracts	(6,126)	3,479	1,193
Total other income (expenses)	(37,349)	(14,400)	(21,114)
Income (loss) before income taxes	(67,066)	5,399	3,412
Income tax benefit (provision)	13,181	(6,802)	(995)
Net income (loss)	(53,885)	(1,403)	2,417
Non-cash preferred dividend	(88,445)		
Net income (loss) available to common stockholders	$ (142,330)	$ (1,403)	$ 2,417
Net income (loss) per share of common stock:			
Basic	$ (0.91)	$ (0.05)	$ 0.09
Diluted	$ (0.91)	$ (0.05)	$ 0.09
Weighted average common shares outstanding:			
Basic	156,494	26,258	26,142

Diluted	156,494	26,258	26,142

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

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HALCÓN RESOURCES CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share amounts)

	December 31,	
	2012	**2011(1)**
Current assets:		
Cash	$ 2,506	$ 49
Accounts receivable	262,809	10,288
Receivables from derivative contracts	7,428	1,850
Current portion of deferred income taxes	5,307	1,080
Inventory	3,116	4,310
Prepaids and other	6,691	2,729
Total current assets	287,857	20,306
Oil and natural gas properties (full cost method):		
Evaluated	2,669,245	715,666
Unevaluated	2,326,598	
Gross oil and natural gas properties	4,995,843	715,666
Less accumulated depletion	(588,207)	(501,993)
Net oil and natural gas properties	4,407,636	213,673
Other operating property and equipment:		
Gas gathering and other operating assets	59,748	9,979
Less accumulated depreciation	(8,119)	(7,133)
Net other operating property and equipment	51,629	2,846
Other noncurrent assets:		
Goodwill	227,762	
Receivables from derivative contracts	371	2,050
Debt issuance costs, net of amortization	51,609	5,966
Deferred income taxes		21,355
Equity in oil and gas partnerships	11,137	
Funds in escrow	2,090	560
Other	934	418
Total assets	$ 5,041,025	$ 267,174
Current liabilities:		
Accounts payable and accrued liabilities	$ 590,551	$ 25,061
Liabilities from derivative contracts	10,429	1,855
Asset retirement obligations	2,319	1,010
Promissory notes	74,669	
Total current liabilities	677,968	27,926
Long-term debt	2,034,498	202,000
Other noncurrent liabilities:		
Liabilities from derivative contracts	2,461	2,855
Asset retirement obligations	72,813	32,703
Deferred income taxes	160,055	
Other	10	10

Commitments and contingencies (Note 11)		
Mezzanine equity:		
Preferred stock: 1,000,000 shares of $0.0001 par value authorized; 10,880 and no shares issued and outstanding as of December 31, 2012 and 2011, respectively	695,238	
Stockholders' equity:		
Common stock: 336,666,666 and 33,333,333 shares of $0.0001 par value authorized; 259,802,377 and 27,694,583 shares issued; 258,152,468 and 26,244,452 outstanding at December 31, 2012 and 2011, respectively	26	3
Additional paid-in capital	1,681,717	229,414
Treasury stock: 1,649,909 and 1,450,131 shares at December 31, 2012 and 2011, respectively, at cost	(9,298)	(7,159)
Accumulated deficit	(274,463)	(220,578)
Total stockholders' equity	1,397,982	1,680
Total liabilities and stockholders' equity	$ 5,041,025	$ 267,174

(1) See further discussion at Note 2, "Corrections of Immaterial Errors."

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

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HALCÓN RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(In thousands)

	Preferred Stock		Common Stock		Additional Paid-In	Treasury Stock		Accumulated	Stockholders' Equity
	Shares	Amount	Shares	Amount	Capital	Shares	Amount	Deficit(1)	(Deficit)(1)
Balances at January 1, 2010		$	26,916	$ 3	$ 222,984	1,266	$ (6,189)	$ (221,592)	$ (4,794)
Long-term incentive plan grants			624						
Long-term incentive plan forfeitures			(7)						
Net income								2,417	2,417
Repurchase of stock						138	(787)		(787)
Share-based compensation					3,063				3,063
Balances at December 31, 2010			27,533	3	226,047	1,404	(6,976)	(219,175)	(101)
Long-term incentive plan grants			280						
Long-term incentive plan forfeitures			(118)						
Net loss								(1,403)	(1,403)
Repurchase of stock						46	(183)		(183)
Share-based compensation					3,367				3,367
Balances at December 31, 2011			27,695	3	229,414	1,450	(7,159)	(220,578)	1,680
Warrants issued					43,590				43,590
Sale of common stock			115,232	11	568,989				569,000
Reverse-stock-split rounding			4						
Sale of preferred stock	4	311,556							311,556
Preferred stock conversion	(4)	(385,476)	44,445	5	385,471				
Offering costs		(14,525)			(5,078)				(19,603)
Common stock issuance			72,114	7	452,032				452,039
Net loss								(53,885)	(53,885)
Preferred beneficial conversion feature					88,445				88,445
Non-cash preferred dividend		88,445			(88,445)				
Long-term incentive plan grants			312						
Repurchase of stock						200	(2,139)		(2,139)
Share-based compensation					7,299				7,299
Balances at December 31, 2012		$	259,802	$ 26	$ 1,681,717	1,650	$ (9,298)	$ (274,463)	$ 1,397,982

(1) See further discussion at Note 2, "Corrections of Immaterial Errors."

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

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HALCÓN RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31,		
	2012	**2011**	**2010**
Cash flows from operating activities:			
Net income (loss)	$ (53,885)	$ (1,403)	$ 2,417
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and accretion	90,284	22,986	28,752
Deferred income tax provision (benefit)	(13,060)	6,549	577
Share-based compensation	4,573	3,584	3,110
Unrealized loss (gain) on derivative contracts	11,727	(2,954)	(1,498)
Amortization and write-off of deferred loan costs	6,212	3,663	2,088
Non-cash interest and amortization of discount	9,387	362	3,086
Other expense (income)	(352)	223	(612)
Change in assets and liabilities, net of acquisitions:			
Accounts receivable	(93,120)	295	3,704
Inventory	1,194	(927)	518
Derivative premium		4,889	(4,468)
Prepaids and other	(749)	403	1,141
Accounts payable and accrued liabilities	155,963	(7,835)	(940)
Net cash provided by (used in) operating activities	118,174	29,835	37,875
Cash flows from investing activities:			
Oil and natural gas capital expenditures	(1,216,835)	(25,214)	(33,535)
Acquisition of GeoResources, Inc., net of cash acquired	(579,497)		
Acquisition of East Texas Assets	(296,139)		
Acquisition of Williston Basin Assets	(756,056)		
Other operating property and equipment capital expenditures	(38,752)	(672)	(865)
Proceeds received from sales of property and equipment	564	48	4
Proceeds received from sale of oil and gas assets	21,964	462	49,366
Funds held in escrow	(1,529)		
Net cash provided by (used in) investing activities	(2,866,280)	(25,376)	14,970
Cash flows from financing activities:			
Proceeds from borrowings	2,466,608	250,167	46,340
Repayments of borrowings	(655,000)	(245,621)	(98,490)
Debt issuance costs	(52,878)	(7,825)	
Offering costs	(18,619)	(985)	
Common stock repurchased	(2,139)	(183)	(787)
Preferred stock issued	311,556		
Preferred beneficial conversion feature	88,445		
Common stock issued	569,000		
Warrants issued	43,590		
Net cash provided by (used in) financing activities	2,750,563	(4,447)	(52,937)
Net increase (decrease) in cash	2,457	12	(92)
Cash at beginning of period	49	37	129
Cash at end of period	$ 2,506	$ 49	$ 37

Supplemental cash flow information:

Cash paid for interest, net of capitalized interest	$ 11,705	$ 554	$ 380
Cash paid for income taxes	89	15,326	17,988
Disclosure of non-cash investing and financing activities:			
Asset retirement obligations	$ 8,587	$ 956	$ 3,006
Preferred dividend	88,445		
Payment-in-kind interest	14,669		
Common stock issued for GeoResources, Inc.	321,416		
Common stock issued for East Texas Assets	130,623		
Preferred stock issued for Williston Basin Assets	695,238		
Current notes payable issued for oil and natural gas properties	74,669		

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

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

Halcón Resources Corporation (Halcón or the Company) is an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich assets in the United States. The consolidated financial statements include the accounts of all majority owned, controlled subsidiaries. The Company operates in one segment which focuses on oil and natural gas acquisition, production, exploration and development. The Company's oil and natural gas properties are managed as a whole rather than through discrete operating areas. Operational information is tracked by operating area; however, financial performance is assessed as a whole. Allocation of capital is made across the Company's entire portfolio without regard to operating area. All intercompany accounts and transactions have been eliminated. The Company has evaluated events or transactions through the date of issuance of this report in conjunction with the preparation of these consolidated financial statements.

On February 10, 2012, the Company completed a three-for-one reverse stock split. As a result, all share and per share information included for all periods presented in these consolidated financial statements reflect the reverse stock split.

Consolidated Financial Statements

The consolidated financial statements include the accounts of Halcón and its majority-owned subsidiaries. The equity method of accounting is used to account for its investments in affiliates in which the Company does not have a majority ownership or control, but has the ability to exert significant influence. The Company's investments in oil and gas limited partnerships for which it serves as general partner and exerts significant influence are accounted for under the equity method of accounting. All intercompany accounts and transactions have been eliminated.

Use of Estimates

The preparation of the Company's consolidated financial statements in conformity with accounting principles generally accepted in the United States requires the Company's management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Estimates and assumptions that, in the opinion of management of the Company, are significant include oil and natural gas revenue accruals, oil and natural gas reserves, capital accruals, amortization relating to oil and natural gas properties, asset retirement obligations, fair value estimates, beneficial conversion feature estimates and income taxes. The Company bases its estimates and judgments on historical experience and on various other assumptions and information that are believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects cannot be perceived with certainty and, accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as the Company's operating environment changes. Actual results may differ from the estimates and assumptions used in the preparation of the Company's consolidated financial statements.

Accounts Receivable and Allowance for Doubtful Accounts

The Company's accounts receivable are primarily receivables from joint interest owners and oil and natural gas purchasers. Accounts receivable are recorded at the amount due, less an allowance for

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

doubtful accounts, when applicable. The Company establishes provisions for losses on accounts receivable if it determines that it will not collect all or part of the outstanding balance. The Company regularly reviews collectability and establishes or adjusts the allowance as necessary using the specific identification method. There are no significant allowances for doubtful accounts as of December 31, 2012 or 2011.

Oil and Natural Gas Properties

The Company uses the full cost method of accounting for its investment in oil and natural gas properties as prescribed by the United States Securities and Exchange Commission (SEC). Accordingly, all costs incurred in the acquisition, exploration and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of proved oil and natural gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%, net of tax considerations.

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

Other Operating Property and Equipment

Gas gathering systems and equipment are recorded at cost. Depreciation is calculated using the straight-line method over a 30-year estimated useful life. Upon disposition, the cost and accumulated depreciation are removed and any gains or losses are reflected in current operations. Maintenance and repair costs are charged to operating expense as incurred. Material expenditures which increase the life of an asset are capitalized and depreciated over the estimated remaining useful life of the asset. The Company capitalized $39.9 million for the year ended December 31, 2012 and no amounts for the year ended December 31, 2011 related to the construction of the Company's gas gathering systems.

Other operating assets are recorded at cost. Depreciation is calculated using the straight-line method over the following estimated useful lives: automobiles and computers, three years; computer software, leasehold improvements, fixtures, furniture and equipment, five years or the lesser of lease term; trailers, seven years; heavy equipment, ten years; and buildings, twenty years. Upon disposition, the cost and accumulated depreciation are removed and any gains or losses are reflected in current operations. Maintenance and repair costs are charged to operating expense as incurred. Material expenditures which increase the life of an asset are capitalized and depreciated over the estimated remaining useful life of the asset.

The Company reviews its gas gathering systems and equipment and other operating assets for impairment in accordance with ASC 360, *Property, Plant, and Equipment* (ASC 360). ASC 360 requires the Company to evaluate gas gathering systems and equipment and other operating assets for impairment as events occur or circumstances change that would more likely than not reduce the fair

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

value below the carrying amount. If the carrying amount is not recoverable from its undiscounted cash flows, then the Company would recognize an impairment loss for the difference between the carrying amount and the current fair value. Further, the Company evaluates the remaining useful lives of its gas gathering systems and equipment and other operating assets at each reporting period to determine whether events and circumstances warrant a revision to the remaining depreciation periods.

Revenue Recognition

Revenues from the sale of crude oil, natural gas, and natural gas liquids are recognized when the product is delivered at a fixed or determinable price, title has transferred, and collectability is reasonably assured and evidenced by a contract. The Company follows the entitlement method of accounting for natural gas sales, recognizing as revenues only its net interest share of all production sold. Any amount attributable to the sale of production in excess of or less than the Company's net interest is recorded as a gas balancing asset or liability. At December 31, 2012 and 2011 the Company's gas imbalances were immaterial.

Concentrations of Credit Risk

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

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

In 2011, STUSCO accounted for $70.4 million, or 68%, of the Company's oil and natural gas revenue for the year. No other purchaser accounted for 10% or more of its oil and natural gas revenue during 2011. In 2011, the Company was subject to a crude purchase contract with STUSCO covering all of its production in its Electra Field in Wichita and Wilbarger Counties, Texas. The contract term covered the period of January 1, 2011 through December 31, 2011. The Company was also subject to a crude purchase contract with STUSCO during 2011 covering all of its oil production in its Fitts and Allen Fields in Oklahoma. Effective December 1, 2011, the Company 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 the Company's oil and natural gas revenue for the year. No other purchaser accounted for 10% or more of its oil and natural gas revenue during 2010. The Company's agreement with STUSCO covered all of the Company's North Texas oil production. The Company was also subject to a crude purchase contract with STUSCO covering all of its oil production in the Fitts and Allen Fields in Oklahoma.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

Risk Management Activities

The Company follows ASC 815, *Derivatives and Hedging* (ASC 815). From time to time, the Company may hedge a portion of its forecasted oil, natural gas, and natural gas liquids production. Derivative contracts entered into by the Company have consisted of transactions in which the Company hedges the variability of cash flow related to a forecasted transaction. The Company recognized all derivative instruments as either assets or liabilities in the consolidated balance sheets at fair value. The Company has elected to not designate any of its positions for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in "*Net gain (loss) on derivative contracts*" on the consolidated statements of operations.

Income Taxes

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

The Company follows ASC 740, *Income Taxes* (ASC 740). ASC 740 creates a single model to address accounting for the uncertainty in income tax positions and prescribes a minimum recognition threshold a tax position must meet before recognition in the consolidated financial statements.

The evaluation of a tax position in accordance with ASC 740 is a two-step process. The first step is a recognition process to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more likely than not recognition threshold, it is presumed that the position will be examined by the appropriate taxing authority with full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more likely than not recognition threshold is calculated to determine the amount of benefit/expense to recognize in the consolidated financial statements. The tax position is measured at the largest amount of benefit/expense that is more likely than not of being realized upon ultimate settlement.

The Company has no liability for unrecognized tax benefits for the years ended December 31, 2012, 2011 or 2010. Accordingly, there is no amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate and there is no amount of interest or penalties currently recognized in the results of operations or statement of financial position as of December 31, 2012. In addition, the Company does not believe that there are any positions for which it is reasonably possible that the total amount of unrecognized tax benefits will significantly increase or decrease within the next twelve months.

The Company includes interest and penalties relating to uncertain tax positions within "*Interest expense and other*" on the Company's consolidated statements of operations. Refer to Note 13, "*Income Taxes*", for more details.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

Generally, the Company's tax years 2009 through 2012 are either currently under audit or remain open and subject to examination by federal tax authorities or the tax authorities in Louisiana, New Mexico, North Dakota, Oklahoma, Texas, Ohio and Pennsylvania which are the jurisdictions in which the Company has had its principal operations. In certain of these jurisdictions, the Company operates through more than one legal entity, each of which may have different open years subject to examination. Additionally, it is important to note that years are technically open for examination until the statute of limitations in each respective jurisdiction expires.

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

Asset Retirement Obligations

ASC 410, *Asset Retirement and Environmental Obligations* (ASC 410) requires that the fair value of an asset retirement cost, and corresponding liability, should be recorded as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The Company records asset retirement obligations to reflect the Company's legal obligations related to future plugging and abandonment of its oil and natural gas wells and gas gathering systems and equipment. The Company estimates the expected cash flows associated with the obligation and discounts the amounts using a credit-adjusted, risk-free interest rate. At least annually, the Company reassesses the obligation to determine whether a change in the estimated obligation is necessary. The Company evaluates whether there are indicators that suggest the estimated cash flows underlying the obligation have materially changed. Should these indicators suggest the estimated obligation may have materially changed on an interim basis (quarterly), the Company will accordingly update its assessment. Additional retirement obligations increase the liability associated with new oil and natural gas wells and gas gathering systems and equipment as these obligations are incurred.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in an acquisition. ASC 350, *Intangibles Goodwill and Other* (ASC 350) requires that intangible assets with indefinite lives, including goodwill, be evaluated on an annual basis for impairment or more frequently if events occur or circumstances change that could potentially result in impairment. The goodwill impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. However, the Company has only one reporting unit. The Company's goodwill relates to its acquisition of GeoResources. Refer to Note 5, *"Acquisitions and Divestitures"* for more details regarding the Merger between the Company and GeoResources.

The Company will perform its goodwill test annually as of July 1, beginning in 2013 or more often if circumstances require. Accounting Standards Update (ASU) No. 2011-08, *Testing for Goodwill Impairment* (ASU 2011-08), simplifies testing for goodwill impairments by allowing entities to first assess qualitative factors to determine whether the facts or circumstances lead to the conclusion that it

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

is more likely than not that the fair value of a reporting unit is less than the carrying value. If the entity concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then the entity does not have to perform the two-step impairment test. However, if the same conclusion is not reached, the company is required to perform the first step of the two-step impairment test. ASU 2011-08 also allows a company to bypass the qualitative assessment and proceed directly with performing the two-step goodwill impairment test. The first step in the two-step impairment test is to determine the fair value of the Company's reporting unit and compare it to the carrying value of the related net assets. Fair value is determined based on the Company's estimates for market values. If this fair value exceeds the carrying value no further analysis or goodwill write down is required. The second step is required if the fair value of the Company's reporting unit is less than the carrying value of the net assets. In this step the implied fair value of the Company's reporting unit is allocated to all the underlying assets and liabilities, including both recognized and unrecognized tangible and intangible assets, based on their fair values. If necessary, goodwill is then written down to its implied fair value. If the fair value of the Company's reporting unit is less than the book value (including goodwill), then goodwill is reduced to its implied fair value and the amount of the write down is charged against earnings. The assumptions used by the Company in calculating its reporting unit fair values at the time of the test include the Company's market capitalization and discounted future cash flows based on estimated reserves and production, future development and operating costs and future oil and natural gas prices. Material adverse changes to any of these factors could lead to an impairment of all or a portion of the Company's goodwill in future periods.

401(k) Plan

The Company sponsors a 401(k) tax deferred savings plan, whereby the Company matches a portion of employees' contributions in cash. Participation in the plan is voluntary and all employees of the Company who are 18 years of age are eligible to participate. The Company provided matching contributions of $1.8 million, $0.7 million, and $0.7 million in 2012, 2011, and 2010, respectively. As of January 1, 2013, the Company matches employee contributions dollar-for-dollar on the first 10% of an employee's pre-tax earnings, subject to individual IRS limitations.

Recently Issued Accounting Pronouncements

In May 2011, FASB issued ASU No. 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in the U.S. Generally Accepted Accounting Principles (GAAP) and International Financial Accounting Reporting Standards (IFRS)* (ASU 2011-04). This pronouncement was issued to provide a consistent definition of fair value and ensure that the fair value measurement and disclosure requirements are similar between GAAP and IFRS. ASU 2011-04 changes certain fair value measurement principles and enhances the disclosure requirements particularly for Level 3 fair value measurements. This update is effective for reporting periods beginning on or after December 15, 2011. The adoption of ASU 2011-04 on January 1, 2012 did not have a material impact on the Company's financial position, results of operations or disclosures.

In July 2011, the FASB issued ASU No. 2011-06, *Fees Paid to the Federal Government by Health Insurers* (ASU 2011-06). This amendment discusses how health insurers should recognize and classify in their income statements the fees mandated by the Health Care and Education Reconciliation Act (the Acts). The Acts impose an annual fee upon health insurers for each calendar year on or after January 1, 2014. The annual fee imposed on the health insurance industry will be allocated to

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES (Continued)

individual entities providing health insurance to employees based on a ratio, as provided for in the Acts. The health insurer's portion of the fee becomes payable to the United States Treasury once an entity provides health insurance for any United States health risk for each calendar year. ASU 2011-06 specifies that the liability for the entity's fee should be estimated and recorded in full once the entity has provided qualifying health insurance in the calendar year in which the fee is payable to the government. A corresponding deferred cost should be recorded and amortized on a straight line basis (unless a better amortization method is available) over the calendar year that the fee is payable. The amendments in this update are effective for calendar years beginning after December 15, 2013, once the fee is instituted. The Company is currently assessing the impact that the adoption of ASU 2011-06 will have on its operating results, financial position, cash flows and disclosures.

In September 2011, the FASB issued ASU No. 2011-08, *Testing for Goodwill Impairment* (ASU 2011-08) to simplify how companies test goodwill for impairment. ASU 2011-08 simplifies testing for goodwill impairments by allowing entities to first assess qualitative factors to determine whether the facts or circumstances lead to the conclusion that it is more likely than not that the fair value of a reporting unit is less than the carrying value. If the entity concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then the entity does not have to perform the two-step impairment test. However, if the same conclusion is not reached, the Company is required to perform the first step of the two-step impairment test. In this step, the fair value of the reporting unit is calculated and compared to the carrying value of the reporting unit. If the carrying value exceeds the fair value, then the entity must perform the second step of the impairment test to measure the amount of impairment loss, if any. ASU 2011-08 also allows a company to bypass the qualitative assessment and proceed directly with performing the two-step goodwill impairment test. ASU 2011-08 is effective for annual and interim goodwill impairment tests for fiscal years beginning after December 15, 2011 and early adoption is permitted. The adoption of ASU 2011-08 did not have a significant impact on the Company's financial position or results of operations.

In December 2011, the FASB issued ASU No. 2011-11, *Disclosures About Offsetting Assets and Liabilities* (ASU 2011-11). ASU 2011- 11 enhances disclosures by requiring an entity to disclose information about netting arrangements, including rights of offset, to enable users of its financial statements to understand the effect of those arrangements on its financial position. This pronouncement was issued to facilitate comparison between financial statements prepared on the basis of GAAP and IFRS. This update is effective for annual and interim reporting periods beginning on or after January 1, 2013 and is to be applied retroactively for all comparative periods presented. The adoption of ASU 2011-11 is not expected to have a significant impact on the Company's disclosures.

2. CORRECTIONS OF IMMATERIAL ERRORS

The consolidated balance sheet as of December 31, 2011 has been restated to reflect the correction of tax basis adjustments to *"Oil and natural gas properties"* and *"Deferred income taxes"* for periods prior to January 1, 2007, and as such, the consolidated statement of stockholders' equity at January 1, 2010 was adjusted by $4.3 million. The Company completed a review of its tax basis in oil and natural gas properties and its deferred tax assets related to oil and natural gas properties and gain on asset dispositions and determined that the adjustments in the table below were needed to correct its December 31, 2011 balance sheet related to prior periods.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. CORRECTIONS OF IMMATERIAL ERRORS (Continued)

The Company noted the following changes to its consolidated balance sheet as of December 31, 2011:

Balance Sheet Location	As Reported	Adjustment	As Restated
		(In thousands)	
Net current deferred income tax assets	$ 2,601	$ (1,521)	$ 1,080
Other noncurrent assets Deferred income taxes	24,102	(2,747)	21,355
Total assets	271,442	(4,268)	267,174
Accumulated deficit	(216,310)	(4,268)	(220,578)
Total liabilities and stockholders' equity	271,442	(4,268)	267,174

The Company noted the following changes to its consolidated statements of stockholders' equity through December 31, 2011:

Adjustments to Statement of Stockholders' Equity	As Reported	Adjustment	As Restated
		(In thousands)	
Accumulated Deficit Balance at January 1, 2010	$ (217,324)	$ (4,268)	$ (221,592)
Stockholders' Equity Balance at January 1, 2010	(526)	(4,268)	(4,794)
Accumulated Deficit Balance at December 31, 2010	(214,907)	(4,268)	(219,175)
Stockholders' Equity Balance at December 31, 2010	4,167	(4,268)	(101)
Accumulated Deficit Balance at December 31, 2011	(216,310)	(4,268)	(220,578)
Stockholders' Equity Balance at December 31, 2011	5,948	(4,268)	1,680

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. CORRECTIONS OF IMMATERIAL ERRORS (Continued)

The Company noted the following changes to its deferred income tax presentation in Note 13, *"Income Taxes"* as of December 31, 2011:

	As Reported	Adjustment (In thousands)	As Restated
Deferred current income tax assets:			
Unrealized hedging transactions	$ 796	$ (2,465)	$ (1,669)
Other	2,372	699	3,071
Gross deferred current income tax assets	3,168	(1,766)	1,402
Valuation allowance	(245)	245	
Deferred current income tax assets	$ 2,923	$ (1,521)	$ 1,402
Deferred current income tax liabilities:			
Other	$ (322)	$	$ (322)
Deferred current income tax liabilities	$ (322)	$	$ (322)
Net current deferred income tax assets	$ 2,601	$ (1,521)	$ 1,080
Deferred noncurrent income tax assets:			
Net operating loss carry-forwards	$ 16,901	$ 8,149	$ 25,050
Depreciable/depletable property, plant and equipment	8,041	(8,945)	(904)
Other	1,382	(1,706)	(324)
Gross deferred noncurrent income tax assets	26,324	(2,502)	23,822
Valuation allowance	(2,040)	(245)	(2,285)
Deferred noncurrent income tax assets	$ 24,284	$ (2,747)	$ 21,537
Deferred noncurrent income tax liabilities:			
Other	$ (182)	$	$ (182)
Deferred noncurrent income tax liabilities	$ (182)	$	$ (182)
Net noncurrent deferred income tax assets	$ 24,102	$ (2,747)	$ 21,355

3. RECAPITALIZATION

On December 21, 2011, the Company entered into a Securities Purchase Agreement (the Purchase Agreement) with HALRES LLC, formerly Halcón Resources, LLC (HALRES). Pursuant to the Purchase Agreement, (i) HALRES purchased and the Company sold 73.3 million shares of the Company's common stock (the Shares) for a purchase price of $275 million and (ii) HALRES purchased and the Company issued a senior convertible promissory note in the principal amount of $275 million (the 2017 Note), together with five year warrants (the February 2012 Warrants) to purchase 36.7 million shares of the Company's common stock at an exercise price of $4.50 per share (the Recapitalization), subject to adjustment under certain circumstances. The 2017 Note is convertible after February 8, 2014 into 61.1 million shares of common stock at a conversion price of $4.50 per share, subject to adjustment under certain circumstances. The Company and HALRES closed the transaction contemplated by the Purchase Agreement on February 8, 2012.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. RECAPITALIZATION (Continued)

In January 2012, shareholders holding a majority of the Company's outstanding shares of common stock approved the issuance of the Shares, the 2017 Note and the February 2012 Warrants pursuant to the terms of the Purchase Agreement. Additionally, the board of directors approved, effective upon the closing (i) the amendment of the Company's certificate of incorporation to (a) increase the Company's authorized shares of common stock from 100 million shares to 1.01 billion shares, both of which were before the one-for-three reverse stock split; (b) a one-for-three reverse stock split of the Company's common stock (which reduced the Company's authorized shares of common stock from 1.01 billion to 336.7 million shares); and (c) a name change from RAM Energy Resources, Inc. to Halcón Resources Corporation; (ii) the amendment of the Company's 2006 Long-Term Incentive Plan (the Plan) to increase the number of shares that may be issued under the Plan from 2.5 million to 3.7 million shares; and (iii) on an advisory (non-binding) basis, the payments made to the Company's named executive officers in connection with the transactions contemplated by the Purchase Agreement.

The closing of the transaction resulted in a change in control of the Company. Material events and items resulting from the transaction include the following:

- completion of transactions contemplated by the Purchase Agreement and shareholder approval as discussed above;
- the resignation and termination of the Company's four executive officers and the resignation of certain other officers;
- change in control payments of $4.6 million to the officers of the Company recorded in general and administrative expense;
- change in control payment of $0.8 million pursuant to a retainer agreement with the Company's then outside law firm recorded in general and administrative expense;
- accelerated vesting of all unvested employee restricted stock shares and accelerated vesting and exercise of all unvested stock appreciation rights resulting in $4.3 million of share-based compensation expense recorded in general and administrative expense;
- payoff and termination of the Company's March 2011 Credit Facilities of $133.0 million plus accrued interest, as well as the expensing of the related unamortized debt issuance costs of $2.9 million;
- payoff and termination of the Company's second lien term facility of $75.0 million plus accrued interest and a prepayment fee of $1.5 million, as well as the expensing of the related unamortized debt issuance costs of $2.9 million; and
- closing costs of $11.2 million related to engagement fees and various professional fees including $2.5 million recorded in general and administrative expense related to a termination fee pursuant to a previous engagement.

In January 2012, the Company approved a one-for-three reverse stock split, which was implemented on February 10, 2012. Retroactive application of the reverse stock split is required and all share and per share information included for all periods presented in these financial statements reflects the reverse stock split.

In February 2012, the transaction with HALRES resulted in an "ownership change" as defined under Section 382 of the Internal Revenue Code of 1986, as amended. As a consequence, the Company

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. RECAPITALIZATION (Continued)

has additional limitations on its ability to use the net operating losses it accrued before the ownership change as a deduction against any taxable income the Company realizes after the ownership change.

4. RESTRUCTURING

In March 2012, the Company announced its intention to close its Plano, Texas office and begin the process of relocating key administrative functions to Houston, Texas (the Restructuring). As part of the Restructuring, the Company offered certain severance and retention benefits, collectively known as, the Severance Program, to the affected employees. The estimated total expense of the Severance Program is approximately $3.2 million and related costs will be recognized as restructuring expense over the requisite service periods through May 2013, as applicable. Below is a reconciliation of the beginning and ending liability balance.

	Severance Program (In thousands)	
Beginning balance, December 31, 2011	$	
Severance and Retention payments		(275)
Increase in accrual		2,406
Ending balance, December 31, 2012	$	2,131

5. ACQUISITIONS AND DIVESTITURES

Acquisitions

Williston Basin Assets

On December 6, 2012, the Company completed the acquisition of two wholly-owned subsidiaries of Petro-Hunt Holdings, LLC and Pillar Holdings, LLC (the Petro-Hunt Parties), which owned acreage prospective for the Bakken / Three Forks formations primarily located in North Dakota, in Williams, Montrail, McKenzie and Dunn counties (the Williston Basin Assets). The Company completed the acquisition of the Williston Basin Assets, thereby acquiring Halcón Williston I, LLC and Halcón Williston II, LLC (the Williston Subs) for a total consideration of approximately $1.5 billion, consisting of approximately $756.1 million in cash and approximately 10,880 shares of the Company's preferred stock that automatically converted into 108.8 million shares of Halcón common stock on January 18, 2013 (equivalent to a conversion price of approximately $7.45 per share of Halcón common stock based on the liquidation preference), following stockholder approval of such conversion and an amendment to Halcón's certificate of incorporation to increase the number of shares of common stock that Halcón is authorized to issue (the Williston Basin Acquisition). No proceeds were received by the Company upon conversion of the preferred stock. No cash dividends were paid on the convertible preferred stock as it converted into common stock before April 6, 2013. The shares of preferred stock were issued to the Petro-Hunt Parties in a private placement pursuant to the exemptions from registration under Section 4(2) of the Securities Act of 1933, as amended. The Williston Basin Acquisition significantly expanded the Company's presence in North Dakota, adding undeveloped acreage, oil and natural gas reserves and production to its existing asset base and operations in this area.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. ACQUISITIONS AND DIVESTITURES (Continued)

Immediately following the completion of the Williston Basin Acquisition (and the related private placement of Halcón common stock described in Note 12, *"Preferred Stock and Stockholders' Equity*"), the Petro-Hunt Parties held preferred stock representing approximately 22% of Halcón's outstanding common stock on an as-converted, fully diluted basis. In addition, Halcón agreed to cause one individual designated by the Petro-Hunt Parties to be elected or appointed to Halcón's board of directors, subject to the reasonable approval of Halcón's Nominating and Corporate Governance Committee, for so long as the Petro-Hunt Parties beneficially own at least 5% of the outstanding shares of Halcón common stock. On December 6, 2012, in connection with the closing of the Williston Basin Transaction and pursuant to the terms of the Reorganization and Interest Purchase Agreement, David S. Hunt was appointed to Halcón's board of directors as a Class B director with a term expiring in 2015.

The transaction had an effective date of June 1, 2012 and was subject to customary closing conditions, including the expiration or early termination of the waiting period mandated under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as well as the execution and delivery of certain other agreements, including a registration rights agreement, a lock-up agreement and a transition services agreement. Under the terms of the registration rights agreement, Halcón has agreed to file with the SEC on or before July 4, 2013, a shelf registration statement covering resales of the 108.8 million shares of Halcón common stock issued as partial consideration in the Williston Basin Acquisition and use commercially reasonable efforts to cause the registration statement to be declared effective as soon as reasonably practicable after the registration statement is filed. The lock-up agreement prohibits the Petro-Hunt Parties from offering for sale, selling, pledging or otherwise disposing of the shares of Halcón common stock received as consideration for the transaction for a period of 180 days following the closing of the transaction.

The Williston Basin Acquisition was accounted for as a business combination in accordance with Accounting Standards Codification (ASC) No. 805, *Business Combinations* (ASC 805) which, among other things, requires assets acquired and liabilities assumed to be measured at their acquisition date fair values. The estimated fair value of the properties approximates the fair value of consideration and as a result no goodwill was recognized.

The purchase price allocation presented below is preliminary with respect to accruals and working capital adjustments, and includes the use of estimates based on information that was available to management at the time these audited consolidated financial statements were prepared. The Company believes the estimates used are reasonable and the significant effects of the Williston Basin Acquisition are properly reflected. However, the estimates are subject to change as additional information becomes available and is assessed by the Company. The following table summarizes the consideration paid to

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. ACQUISITIONS AND DIVESTITURES (Continued)

acquire the Williston Basin Assets, as well as the amounts of assets acquired and liabilities assumed as of the acquisition date (in thousands, except stock prices):

Purchase Price*(1)*:		
Halcón preferred shares issued to Williston Basin Assets Sellers*(2)*	$	695,238
Cash consideration paid to Williston Basin Assets Sellers*(3)*		756,056
Total purchase price	$	1,451,294
Estimated Fair Value of Liabilities Assumed:		
Current liabiltites*(4)*	$	72,850
Asset retirement obligations		5,207
Amount attributable to liabilities assumed		78,057
Total purchase price plus liabilities assumed	$	1,529,351
Estimated Fair Value of Assets Acquired:		
Current assets*(4)*	$	27,139
Evaluated oil and natural gas properties*(5)(6)*		635,216
Unevaluated oil and natural gas properties		866,996
Amount attributable to assets acquired	$	1,529,351
Goodwill		

(1) Based on the terms of the reorganization and interest purchase agreement, consideration paid by Halcón at closing consisted of $756.1 million in cash plus approximately 10,880 shares of convertible preferred stock. The total purchase price is based upon the fair value of the preferred shares which was determined using the lowest price of $6.39 per share of the Company's common stock on December 6, 2012, the number of convertible preferred shares issued and the conversion rate of each convertible preferred share to 10,000 shares of common stock.

(2) Represents the fair value of convertible preferred stock par value $0.0001 per share issued to sellers with each preferred share convertible into 10,000 shares of common stock. The preferred shares are presented on the balance sheet as mezzanine equity due to the fact that the conversion of the preferred shares to common shares was still contingent upon shareholder approval at the December 31, 2012 balance sheet date. See further discussion of the preferred shares at Note 12, "Preferred Stock and Stockholders' Equity".

(3) Represents amount of cash consideration for the purchase of the Williston Basin Assets funded by the issuance of the $750 million 8.875% senior notes with net proceeds of $725.6 million and borrowings under the Senior Credit Agreement revolver. See discussion of 8.875% note and Senior Credit Agreement at Note 7, "Long-term Debt".

(4) In accordance with the purchase agreement, the effective date of the acquisition was June 1, 2012 and therefore revenues, expenses and related capital expenditures from June 1, 2012 through the closing of the Williston Basin Acquisition have been reflected as part

of the purchase accounting and subsequent to closing of the transaction have resulted in working capital adjustments. As a result, the Company recorded a net liability of $45.7 million in post-closing adjustments reducing the working capital at December 31, 2012.

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. ACQUISITIONS AND DIVESTITURES (Continued)

(5) The market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount for future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates used by the Company to estimate the fair value of the oil and natural gas properties represent Level 3 inputs. For additional information on Level 3 inputs, see Note 8, "Fair Value Measurements".

(6) Weighted average commodity prices utilized in the determination of the pro forma fair value of oil and natural gas properties were \$95.17 per barrel of oil and \$10.85 per Mcf of natural gas, after adjustment for transportation fees and regional price differentials. The pricing used in the determination of fair value reflects the differential applied to future prices; differentials for natural gas reflect relatively higher British thermal unit (Btu) gas content.

GeoResources, Inc.

On August 1, 2012, the Company completed an acquisition of GeoResources, Inc. (GeoResources) by means of the merger of GeoResources into a wholly-owned subsidiary of the Company (the Merger). In connection with the Merger, each share of GeoResources common stock issued and outstanding immediately prior to the effective date of the Merger was converted into the right to receive \$20.00 in cash and 1.932 shares of the Company's common stock. All outstanding options to purchase GeoResources common stock were exercised immediately prior to the effective date of the Merger on a net cashless basis. All outstanding GeoResources restricted stock units vested and were settled in shares of GeoResources common stock immediately prior to the effective date of the Merger. All outstanding warrants to purchase GeoResources common stock were assumed by the Company and converted into warrants (the August 2012 Warrants) to acquire equivalent Merger consideration.

In connection with the consummation of the Merger, the Company issued a total of approximately 51.3 million shares of its common stock and paid approximately \$531.5 million in cash to former GeoResources stockholders in exchange for their shares of GeoResources common stock. The acquisition expanded the Company's presence in the Bakken / Three Forks formations of North Dakota and Montana, and the Austin Chalk trend and Eagle Ford Shale in Texas, adding oil and natural gas reserves and production to its existing asset base in these areas.

The acquisition was accounted for as a business combination in accordance with ASC 805 which, among other things, requires assets acquired and liabilities assumed to be measured at their acquisition date fair values. GeoResources results of operations are reflected in the Company's consolidated statements of operations, beginning August 1, 2012.

A preliminary allocation of the purchase price as of August 1, 2012 was prepared in connection with the Company's quarterly financial statements filed on Form 10-Q for the period ended September 30, 2012. In January 2013, the Company received the final year-end reserve report prepared by Netherland, Sewell & Associates, Inc. (Netherland, Sewell) which was compared to the preliminary reserve estimates that were used to prepare the initial purchase price allocation. With the new reserve information, the Company updated the oil and natural gas property amounts acquired, as well as certain other estimates used in the initial purchase price allocation related to asset retirement obligations, deferred tax amounts and other accruals based on more current information. The following allocation is still preliminary with respect to final tax amounts, pending completion of the 2012 GeoResources' tax return and certain accruals and includes the use of estimates based on information

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. ACQUISITIONS AND DIVESTITURES (Continued)

that was available to management at the time these audited consolidated financial statements were prepared. The Company believes the estimates used are reasonable and the significant effects of the Merger are properly reflected. However, the estimates are subject to change as additional information becomes available and is assessed by the Company. Additional changes to the purchase price allocation may result in a corresponding change to the goodwill in the period of change. The following table summarizes the consideration paid to acquire GeoResources and the estimated values of assets

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. ACQUISITIONS AND DIVESTITURES (Continued)

acquired and liabilities assumed in the accompanying audited consolidated balance sheets based on their fair values on August 1, 2012 (in thousands, except stock price):

	August 1, 2012 (As initially reported)	Measurement Period Adjustments(1)	August 1, 2012 (As Adjusted)
Purchase price*(2)*:			
Shares of Halcón common stock issued to GeoResources' stockholders	50,378		50,378
Shares of Halcón common stock issued to GeoResources' stock option holders	966		966
Total Halcón common stock issued	51,344		51,344
Halcón common stock price	$ 6.26	$	$ 6.26
Fair value of common stock issued	$ 321,416	$	$ 321,416
Cash consideration paid to GeoResources' stockholders*(3)*	521,526		521,526
Cash consideration paid to GeoResources' stock option holders*(3)*	9,996		9,996
Fair value of warrants assumed by Halcón*(4)*	1,474		1,474
Total purchase price	$ 854,412	$	$ 854,412
Estimated fair value of liabilities assumed:			
Current liabilities	$ 112,641	$ (417)	$ 112,224
Deferred tax liability*(5)*	238,882	(48,638)	190,244
Asset retirement obligations	9,320	18,744	28,064
Other non-current liabilities	80,024		80,024
Amount attributable to liabilities assumed	$ 440,867	$ (30,311)	$ 410,556
Total purchase price plus liabilities assumed	$ 1,295,279	$ (30,311)	$ 1,264,968
Estimated fair value of assets acquired:			
Current assets	$ 122,528	$ (11,677)	$ 110,851
Evaluated oil and natural gas properties*(6)(7)*	542,820	(84,256)	458,564
Unevaluated oil and natural gas properties	455,000	(1,000)	454,000
Net other operating property and equipment	1,179		1,179
Equity in oil and gas partnerships*(8)*	11,189	(222)	10,967
Other non-current assets	1,645		1,645
Amount attributable to assets acquired	$ 1,134,361	$ (97,155)	$ 1,037,206
Goodwill*(9)*	$ 160,918	$ 66,844	$ 227,762

(1) After the September 30, 2012 condensed consolidated financial statements were issued, the Company updated certain estimates used in the purchase price allocation, primarily with respect to oil and natural gas property amounts, asset retirement obligations, deferred tax amounts and other accruals due to more current information. The adjustments are based on updated assumptions and information related to facts and circumstances that existed as of the acquisition date for oil and

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. ACQUISITIONS AND DIVESTITURES (Continued)

natural gas properties and estimated retirement obligations, as well as confirmatory information related to accruals. Adjustments related to the revised amounts are also reflected in the depletion and accretion expense for the period based on the updated fair values.

(2)

Under the terms of the Merger Agreement, consideration paid by Halcón consisted of $20.00 in cash plus 1.932 shares of Halcón common stock for each share of GeoResources common stock. The total purchase price was based upon the price of Halcón common stock on the closing date of the transaction, August 1, 2012, and approximately 26.6 million shares of GeoResources common stock outstanding at the effective time of the Merger. The Company issued a total of 51.3 million shares of its common stock and paid $531.5 million in cash to former GeoResources stockholders in exchange for their shares of GeoResources common stock.

(3)

Components of cash flow for the Merger (in thousands):

Total cash consideration for Merger and stock options*(i)*	$	531,522
Retirement of GeoResources' long-term debt*(ii)*		80,328
Cash acquired on date of Merger		(32,353)
Total cash outflows, net	$	579,497

(i)

The majority of the cash consideration was funded by the net proceeds from the issuance of the 9.75% senior notes.

(ii)

Includes accrued interest and fees.

(4)

The $1.5 million fair value of the assumed warrants was calculated using a Black-Scholes valuation model with assumptions for the following variables: price of Halcón stock on the closing date of the merger; risk-free interest rates; and expected volatility. The assumed warrants have been classified as liabilities as the warrant holders can receive cash. The assumed warrants are classified as current liabilities as all the warrants will expire within twelve months from December 31, 2012.

(5)

Halcón received carryover tax basis in GeoResources' assets and liabilities because the Merger was not a taxable transaction under the United States Internal Revenue Code of 1986, as amended. Based upon the purchase price allocation, a step-up in financial reporting carrying value related to the property acquired from GeoResources resulted in a Halcón deferred tax liability of approximately $190.2 million, an increase of approximately $128.8 million to GeoResources' existing $61.4 million deferred tax liability.

(6)

Weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties was $6.65 per Mcf of natural gas, $35.66 per barrel of oil equivalent for natural gas liquids and $98.37 per barrel of oil, after adjustment for transportation fees and regional price differentials.

(7)

The market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount for future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates used by the Company to estimate the fair value of the oil and natural gas properties represent Level 3 inputs. For additional information on Level 3 inputs, see Note 8, "Fair Value Measurements".

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. ACQUISITIONS AND DIVESTITURES (Continued)

(8)

As a part of the Merger, the Company acquired investments, in the form of general partnership interests, in two affiliated partnerships, SBE Partners LP (SBE Partners) and OKLA Energy Partners LP (OKLA Energy). These partnerships hold direct working interests in oil and natural gas properties. The Company's investment in an unconsolidated entity in which the Company does not have a majority interest or control, but does have significant influence, is accounted for under the equity method. The Company holds a 2% general partner interest, in OKLA Energy, which reverts to 35.66% interest when the limited partner realizes a contractually specified rate of return. The Company holds a 30% general partner interest in SBE Partners. Under the equity method of accounting the Company records its net share of income and expenses in "Interest expense and other" on the consolidated statements of operations. Contributions to the investment increase the Company's investment while distributions from the investment decrease the Company's carrying value of the investment in "Equity in oil and gas partnerships" on the consolidated balance sheets. The Company reviews its equity method investment for potential impairment whenever events or changes in circumstances indicate that an other-than-temporary decline in the value of the investment has occurred.

(9)

Goodwill was determined as the excess consideration transferred over the fair value of the GeoResources net assets acquired on August 1, 2012. Goodwill recognized will not be deductible for tax purposes.

East Texas Assets

Between August 1, 2012 and August 3, 2012, the Company completed the acquisition of oil and gas leaseholds in East Texas (the East Texas Assets) from CH4 Energy II, LLC, PetroMax Leon, LLC, Petro Texas LLC, King King LLC and several other selling parties for total consideration of $426.8 million comprised of $296.1 million in cash and 20.8 million shares of the Company's common stock (East Texas Acquisition). The East Texas Acquisition expanded the Company's presence in East Texas, adding oil and natural gas reserves and production to its existing asset base in this area. On August 27, 2012 the Company filed a registration statement with the SEC that registered under the Securities Act the resale of the shares of common stock issued as consideration in the East Texas Acquisition.

The East Texas Acquisition was accounted for as a business combination in accordance with ASC 805 which, among other things, requires assets acquired and liabilities assumed to be measured at their acquisition date fair values. The effective date of the East Texas Acquisition was April 1, 2012. The estimated fair value of the properties approximates the fair value of consideration and as a result no goodwill was recognized.

A preliminary allocation of the purchase price as of August 3, 2012 was prepared in connection with the Company's quarterly financial statements filed on Form 10-Q for the period ended September 30, 2012. In January 2013, the Company received the final year-end reserve report prepared by Netherland, Sewell which was compared to the preliminary reserve estimates that were used to prepare the initial purchase price allocation. With the new reserve information, the Company updated the oil and natural gas property amounts acquired, as well as certain other estimates used in the initial purchase price allocation related to accruals. The following allocation is still preliminary with respect to accruals and includes the use of estimates. This preliminary allocation is based on information that was available to management at the time these audited consolidated financial statements were prepared.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. ACQUISITIONS AND DIVESTITURES (Continued)

The Company believes the estimates used are reasonable and the significant effects of the East Texas Acquisition are properly reflected. However, the estimates are subject to change as additional information becomes available and is assessed by the Company. The following table summarizes the consideration paid to acquire the properties and the amounts of the assets acquired and liabilities assumed as of the acquisition date (in thousands, except stock prices):

	August 1 - 3, 2012 (As initially reported)	**Measurement Period Adjustments(1)**	**August 1 - 3, 2012 (As Adjusted)**
Purchase price*(2)*:			
Shares of Halcón common stock issued on August 1, 2012	16,460		16,460
Shares of Halcón common stock issued on August 2, 2012	4,310		4,310
Total Halcón common stock issued	20,770		20,770
Halcón common stock price on August 1, 2012	$ 6.26	$	$ 6.26
Halcón common stock price on August 2, 2012	$ 6.40	$	$ 6.40
Fair value of Halcón common stock issued	$ 130,623	$	$ 130,623
Cash consideration paid to sellers of East Texas Assets*(3)*	301,569	(5,430)	296,139
Total purchase price*(3)*	$ 432,192	$ (5,430)	$ 426,762
Estimated fair value of liabilities assumed:			
Current liabilities	$	$ 192	$ 192
Asset retirement obligations	337		337
Amount attributable to liabilities assumed	$ 337	$ 192	$ 529
Total purchase price plus liabilities assumed	$ 432,529	$ (5,238)	$ 427,291
Estimated fair value of assets acquired:			
Evaluated oil and natural gas properties*(4)(5)*	$ 334,080	$ 3,223	$ 337,303
Unevaluated oil and natural gas properties	98,449	(8,461)	89,988
Amount attributable to assets acquired	$ 432,529	$ (5,238)	$ 427,291
Goodwill	$	$	$

(1) After the September 30, 2012 consolidated financial statements were issued, the Company updated certain estimates used in the purchase price allocation, primarily with respect to oil and natural gas property amounts and other accruals. The adjustments are based on updated assumptions related to facts and circumstances that existed as of the acquisition date for oil and natural gas properties, as well as confirmatory information for customary post-close adjustments. Adjustments related to the revised amounts are also reflected in the depletion expense for the period based on the updated fair values.

(2)

Based on the terms of the purchase and sale agreements relating to the East Texas Assets, consideration paid by Halcón at closing consisted of $301.6 million in cash plus 20.8 million shares of Halcón common stock. The total purchase price is based upon the price on August 1, 2012 of $6.26 per share of Halcón's common stock for CH4 Energy II, LLC, Petromax Leon, LLC and Petro Texas, LLC (Initial Sellers) and price on August 2, 2012 of $6.40 per share of Halcón's

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. ACQUISITIONS AND DIVESTITURES (Continued)

common stock for King King LLC. The East Texas Acquisition was partially financed with the net proceeds from the issuance of $750.0 million of 9.75% senior unsecured notes and cash on hand. See Note 7 "Long-Term Debt" for discussion of the accounting treatment of the 9.75% senior notes.

(3) In accordance with the purchase agreement, the effective date of the acquisition was April 1, 2012 and therefore revenues, expenses and related capital expenditures from April 1, 2012 through the closing of the East Texas Acquisition have been reflected as part of the purchase accounting and subsequent to closing of the transaction have resulted in a reduction of the purchase price. As a result, the Company recorded $5.4 million in post-closing adjustments reducing the total purchase price and cash consideration paid to $426.8 million and $296.1 million, respectively at December 31, 2012.

(4) The market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount for future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates used by the Company to estimate the fair value of the oil and natural gas properties represent Level 3 inputs. For additional information on Level 3 inputs, see Note 8 "Fair Value Measurements".

(5) Weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties were $6.26 per Mcf of natural gas, $49.68 per Boe for natural gas liquids and $98.35 per barrel of oil, after adjustment for transportation fees and regional price differentials.

The following unaudited pro forma combined results of operations are provided for the years ended December 31, 2012 and 2011 as though the Merger, East Texas Acquisition and the Williston Basin Acquisition had been completed as of the beginning of the comparable prior annual reporting period, or January 1, 2011. The pro forma combined results of operations for the years ended December 31, 2012 and 2011 have been prepared by adjusting the historical results of the Company to include the historical results of GeoResources, the East Texas Assets and the Williston Basin Assets. These supplemental pro forma results of operations are provided for illustrative purposes only and do not purport to be indicative of the actual results that would have been achieved by the combined company for the periods presented or that may be achieved by the combined company in the future. The pro forma results of operations do not include any cost savings or other synergies that resulted, or may result, from the Merger, the East Texas Acquisition and the Williston Basin Acquisiton or any estimated costs that will be incurred to integrate GeoResources, the Williston Basin Assets and the

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. ACQUISITIONS AND DIVESTITURES (Continued)

East Texas Assets. Future results may vary significantly from the results reflected in this unaudited pro forma financial information because of future events and transactions, as well as other factors.

	Years ended December 31, 2012 (Unaudited)	2011 (Unaudited)
	(in thousands, except per share amounts)	
Revenue	$ 607,715	$ 329,606
Net income	34,896	14,355
Loss available to Halcón common stockholders	(125,828)	(52,333)
Pro forma net loss per common share:		
Basic	$ (0.63)	$ (0.53)
Diluted	$ (0.63)	$ (0.53)

The Company's historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the Merger and the acquisitions of the East Texas Assets and the Williston Basin Assets and factually supportable. The unaudited pro forma consolidated results include the historical revenues and expenses of assets acquired and liabilities assumed in the Merger and the acquisitions of the East Texas Assets and the Williston Basin Assets with the following adjustments:

Adjustment to recognize incremental depletion expense under the full cost method of accounting based on the fair value of the oil and natural gas properties and incremental accretion expense based on the asset retirement costs of the oil and natural gas properties at acquisition;

Eliminate historical interest expense for GeoResources debt that was extinguished;

Adjustment to recognize interest expense, net of capitalized interest, and preferred dividends for debt and preferred shares issued in connection with the transactions;

Eliminate transaction costs and non-recurring charges directly related to the transactions that were included in the historical results of operations for GeoResources and the Company in the amount of $59.5 million. Transaction costs directly related to the transactions that do not have a continuing impact on the combined Company's operating results have been excluded from the 2012 and 2011 pro forma earnings;

Adjustment to recognize pro forma income tax based on an assumed 38% rate;

Eliminate historical impairment expense for GeoResources that would not have been incurred under the full cost method of accounting;

Adjustment to convert successful efforts method financial statements of GeoResources to full cost method financial statements to adjust exploration expenses which would have been capitalized under the full cost method of accounting for oil and natural gas activities;

Adjustment to GeoResources' historical revenue to reclass net settlements on commodity derivatives that under cash flow hedge accounting were included in GeoResources' revenues from oil and natural gas sales, and adjustment to reflect unrealized gain on commodity derivatives. In accordance with the Company's accounting policy, it does not apply cash flow hedge accounting treatment and the realized and unrealized gain (loss) on commodity derivatives have been reflected as a gain (loss) on derivative contracts;

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5. ACQUISITIONS AND DIVESTITURES (Continued)

Adjustment to recognize the issuance of 51.3 million shares of Halcón common stock as consideration for the GeoResources Merger; and

Adjustment to recognize the issuance of the 20.8 million shares of Halcón common stock as consideration for the acquisition of the East Texas Assets.

For the year ended December 31, 2012, the Company recognized $19.7 million of oil, natural gas and natural gas liquids sales related to properties acquired in the acquisition of the Williston Basin Assets and $6.7 million of net field operating income (oil, natural gas and natural gas liquids revenues less lease operating expense, workover expense, production taxes, depletion expense and income taxes) related to properties acquired in the acquisition of the Williston Basin Assets. Additionally, non-recurring transaction costs of $14.2 million related to the acquisition of the Williston Basin Assets for the year ended December 31, 2012 are included in the consolidated statements of operations in "*General and administrative"* expenses; these non-recurring transaction costs have been excluded from the pro forma results for all periods presented in the above table.

For the year ended December 31, 2012, the Company recognized $90.8 million of oil, natural gas and natural gas liquids sales and $25.7 million of net field operating income (oil, natural gas and natural gas liquids revenues less lease operating expense, workover expense, production taxes, depletion expense and income taxes) related to properties acquired in the Merger. Additionally, non-recurring transaction costs of $21.5 million related to the Merger for the year ended December 31, 2012 are included in the consolidated statements of operations in "*General and administrative"* expenses; these non-recurring transaction costs have been excluded from the pro forma results for all periods presented in the above table.

For the year ended December 31, 2012, the Company recognized $34.8 million of oil, natural gas and natural gas liquids revenues related to properties acquired in the acquisition of the East Texas Assets and $16.5 million of net field operating income (oil, natural gas and natural gas liquids revenues less lease operating expense, workover expense, production taxes, depletion expense and income taxes) related to properties acquired in the acquisition of the East Texas Assets. Additionally, non-recurring transaction costs of $1.1 million related to the acquisition of the East Texas Assets for the year ended December 31, 2012 are included in the consolidated statements of operations in "*General and administrative"* expenses; these non-recurring transaction costs have been excluded from the pro forma results for all periods presented in the above table.

Other Acquisitions

On December 28, 2012, the Company completed the acquisition of certain oil and natural gas properties, located in Brazos County, Texas, from a group of private sellers for approximately $83.7 million, before customary closing adjustments, consisting of approximately $8.4 million in cash and approximately $75.3 million in promissory notes. The promissory notes have a maturity date of August 30, 2013. The transaction had an effective date of December 1, 2012. Refer to Note 7, *"Long-term debt,"* for more details regarding the promissory notes.

On September 12, 2012, the Company completed the acquisition of certain oil and natural gas properties, located in Leon County, Texas from a group of private sellers for approximately $14.0 million, before customary closing adjustments. The transaction had an effective date of September 1, 2012. The acquisition was funded with cash on hand.

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. ACQUISITIONS AND DIVESTITURES (Continued)

Acquisition of Unevaluated Acreage

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

Divestitures

Louisiana Properties

On November 29, 2012, the Company completed the sale of certain oil and natural gas properties located in Eloi Bay/Half Moon Lakes Field, Chandeleur Sound Block 71 Field and Quarantine Bay Field to Cox Oil, LLC for $22.0 million in cash, after customary closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of the Company's full cost pool with no gain or loss recorded. The transaction had an effective date of August 1, 2012.

Electra/Burkburnett Field

During 2011, the Company entered into an agreement in principle to sell a majority interest in the Company's Electra / Burkburnett Field to Argent Energy Trust, a recently formed Canadian energy trust. Argent filed a preliminary prospectus with Canadian regulatory authorities for an initial public offering of its trust units in Canada (Argent IPO). The sale of the Company's Electra / Burkburnett Field was contingent upon several conditions, including completion of the Argent IPO. The Argent IPO was not completed and the agreement between the Company and Argent terminated during December 2011. The Company incurred approximately $2.4 million in related fees. Due to the termination of the agreement these fees are reflected in general and administrative expense in 2011.

North Texas Barnett Shale & Boonsville

On December 8, 2010, the Company closed the sale on all of its oil and natural gas properties and related assets in the Boonsville and Newark East fields of Jack and Wise Counties in Texas to Milagro Producing, LLC for $43.7 million, before customary closing adjustments. The effective date under the agreement was October 1, 2010. In accordance with the full cost method of accounting, the Company did not record a gain or loss on the sale. The full cost pool at December 31, 2010 was reduced by the net proceeds, including closing adjustments, of $41.0 million. Proceeds of $16.0 million were used to reduce the outstanding balance on the Company's revolving credit facility and the remaining net proceeds were used to reduce the outstanding balance on the Company's term loan.

Eastern Oklahoma

On December 30, 2010, the Company completed the sale of certain non-operated natural gas properties located in eastern Oklahoma for $8.0 million, before customary closing adjustments. The effective date under the agreement was December 1, 2010. The full cost pool at December 31, 2010 was reduced by the net proceeds, including closing adjustments, of $7.8 million in accordance with the full cost method of accounting. The proceeds were used to reduce outstanding borrowings under the Company's revolving credit facility.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties as of December 31, 2012 and 2011 consisted of the following:

	December 31,	
	2012	2011
	(In thousands)	
Subject to depletion	$ 2,669,245	$ 715,666
Not subject to depletion:		
Exploration and extension wells in progress	67,992	
Other capital costs:		
Incurred in 2012	2,258,606	
Incurred in 2011		
Incurred in 2010		
Incurred in 2009 and prior		
Total not subject to depletion	2,326,598	
Gross oil and natural gas properties	4,995,843	715,666
Less accumulated depletion	(588,207)	(501,993)
Net oil and natural gas properties	$ 4,407,636	$ 213,673

The Company uses the full cost method of accounting for its investment in oil and natural gas properties. Under this method of accounting, all costs of acquisition, exploration and development of oil and natural gas reserves (including such costs as leasehold acquisition costs, geological expenditures, dry hole costs, tangible and intangible development costs and direct internal costs) are capitalized as the cost of oil and natural gas properties when incurred. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depletion, exceed the discounted future net revenues of proved oil and natural gas reserves, net of deferred taxes, such excess capitalized costs are charged to expense.

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

Investments in unevaluated oil and natural gas properties and exploration and development projects for which depletion expense is not currently recognized, and for which exploration or development activities are in progress, qualify for interest capitalization. The capitalized interest is determined by multiplying the Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred that are excluded from the full cost pool; however, the amount of capitalized interest cannot exceed the amount of gross interest expense incurred in any given period. The capitalized interest amounts are recorded as additions to unevaluated oil and natural gas properties on the consolidated balance sheet. As the costs excluded are transferred to the full cost

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. OIL AND NATURAL GAS PROPERTIES (Continued)

pool, the associated capitalized interest is also transferred to the full cost pool. For the year ended December 31, 2012, the Company capitalized interest costs of $53.5 million. In 2011 and 2010, the Company did not capitalize any interest costs.

The Company has capitalized internal costs of approximately $14.6 million, $4.3 million and $3.1 million for the years ended December 31, 2012, 2011 and 2010, respectively. Such capitalized costs include salaries and related benefits of individuals directly involved in the Company's acquisition, exploration and development activities based on the percentage of their time devoted to such activities.

The ceiling test value of the Company's reserves was calculated based on the following prices:

	West Texas Intermediate (per barrel)(1)(2)	Henry Hub (per MMBtu)(3)
December 31, 2012	$ 94.71	$ 2.76
December 31, 2011	96.19	4.12
December 31, 2010	79.43	4.38

(1) First day average of the 12-months ended December 31, 2012 spot price, adjusted by lease or field for quality, transportation fees and regional price differentials.

(2) First day average of the 12-months ended December 31, 2011 and 2010 posted price, adjusted by lease or field for quality, transportation fees and regional price differentials.

(3) First day average of the 12-months ended price, adjusted by lease or field for quality, transportation fees and regional price differentials.

At December 31, 2012, 2011 and 2010, the Company's net book value of oil and natural gas properties did not exceed the respective ceiling amounts. Changes in production rates, levels of reserves, future development costs, and other factors will determine the Company's actual ceiling test calculation and impairment analyses in future periods.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. LONG-TERM DEBT

Long-term debt as of December 31, 2012 and 2011 consisted of the following:

	December 31,	
	2012(1)	2011
	(In thousands)	
Senior revolving credit facility	$ 298,000	$
8.875% $750 million senior notes*(2)*	744,421	
9.75% $750 million senior notes*(3)*	740,232	
8.0% $275 million senior note*(4)*	251,845	
Revolving credit facility		127,000
Term loan facility		75,000
	$ 2,034,498	$ 202,000

(1) Amount excludes $74.7 million of promissory notes which have been classified as current at December 31, 2012.

(2) Amount is net of a $5.6 million unamortized discount at December 31, 2012. See "8.875% Note" below for more details.

(3) Amount is net of a $9.8 million unamortized discount at December 31, 2012. See "9.75% Notes" below for more details.

(4) Amount is net of a $37.8 million unamortized discount at December 31, 2012. See "8.0% Notes" below for more details.

Senior Revolving Credit Facility

In connection with the closing of the Recapitalization, discussed in Note 3, *"Recapitalization"*, the Company 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 the lenders and the Company each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations. The borrowing base takes into account the Company's 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 the Company 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. These margins fluctuate based on the Company's utilization of the facility. Advances under the Senior Credit Agreement are secured by liens on substantially all of the Company's properties and assets. The Senior Credit Agreement contains representations, warranties and covenants customary in transactions of this nature including restrictions on the payment of

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. LONG-TERM DEBT (Continued)

dividends on the Company's capital stock and financial covenants, including minimum working capital levels (the ratio of current assets plus the unused commitment under the Senior Credit Agreement to current liabilities) of not less than 1.0 to 1.0 and minimum coverage of interest expenses (as defined in the Senior Credit Agreement) of not less than 2.5 to 1.0.

On August 1, 2012, in connection with the closing of the GeoResources and East Texas Assets acquisition, the Company 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, the Company 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. At December 31, 2012 and as of the date of this filing, the Company is in compliance with the financial debt covenants under the Senior Credit Agreement.

On January 25, 2013, the Company entered into the Second Amendment (the Second Amendment) which amends the Senior Credit Agreement with respect to the Company's ability to enter into certain commodity hedging agreements. The Second Amendment provides, among other things, that the Company and its 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 the Company's internally forecasted production (i) from the Company's 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, the Company 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 the Company's 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 volumes hedged by the Company using puts, floors and/or basis differential swap agreements. See Note 16, *"Subsequent Events",* for further discussion.

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 the Company's 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.

March 2011 Credit Facilities

The Company's March 2011 credit facilities included a $250.0 million revolving credit facility and a $75.0 million second lien term loan facility (the March 2011 Credit Facilities), replacing the November 2007 facility. SunTrust Bank was the administrative agent for the revolving credit facility, and Guggenheim Corporate Funding, LLC was the administrative agent for the second lien term loan facility. The revolving credit facility allowed for funds advanced to be paid down and re-borrowed

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. LONG-TERM DEBT (Continued)

during the five-year term of the revolver, and bore interest at LIBOR plus a margin ranging from 2.5% to 3.25% based on a percentage of usage. The second lien term loan facility provided for payments of interest only during its 5.5 year term, and bore interest at LIBOR plus 9.0% with a 2.0% LIBOR floor, or if any period the Company elected to pay a portion of the interest "in kind", then the interest rate would have been LIBOR plus 10.0% with a 2.0% LIBOR floor, and with 7.0% of the interest amount paid in cash and the remaining 3.0% paid in kind by being added to principal. At December 31, 2011, $127.0 million was outstanding under the revolving credit facility and $75.0 million was outstanding under the second lien term loan facility. On February 8, 2012, the Company paid in full the outstanding balances under the revolving credit facility and the second lien term loan facility and both facilities were terminated, resulting in a $1.5 million charge to interest expense related to an early termination penalty.

8.875% Senior Notes

On November 6, 2012, the Company completed a private offering to eligible purchasers of an aggregate principal amount of $750.0 million of its 8.875% senior notes due 2021 (the 2021 Notes), issued at 99.247% of par. The net proceeds from the offering were approximately $725.6 million after deducting the initial purchasers' discounts, commissions and offering expenses and were used to fund a portion of the cash consideration paid in the Williston Basin Assets acquisition.

The 2021 Notes bear interest at a rate of 8.875% per annum, payable semi-annually on May 15 and November 15 of each year, beginning on May 15, 2013. The Notes will mature on May 15, 2021. The 2021 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness. The 2021 Notes are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by the Company's existing wholly-owned subsidiaries. Halcón, the issuer of the 2021 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

In connection with the sale of the 2021 Notes, the Company entered into a Registration Rights Agreement, dated November 6, 2012, between the Company and Wells Fargo Securities, LLC, on behalf of the Initial Purchasers (the Registration Rights Agreement, dated November 6, 2012). Pursuant to the Registration Rights Agreement, dated November 6, 2012, the Company has agreed to conduct a registered exchange offer for the 8.875% Notes or cause to become effective a shelf registration statement providing for the resale of the 2021 Notes. In connection with the exchange offer, the Company is required to (a) file an exchange offer registration statement (the Registration Statement for the 2021 Notes) and use reasonable best efforts to cause such Registration Statement for the 2021 Notes to become effective, (b) promptly following the effectiveness of the Registration Statement for the 2021 Notes, offer to exchange each note of the 2021 Notes for a new note of the Company having terms substantially identical in all material respects to the 2021 Notes, and (c) keep the registered exchange offer open for not less than 20 business days after the date notice of the exchange offer is mailed to the holders of the 2021 Notes. If the exchange offer is not consummated within 365 days after November 6, 2012, or upon the occurrence of certain other contingencies, the Company has agreed to file a shelf registration statement to cover resales of the Notes by holders who satisfy certain conditions relating to the provision of information in connection with the shelf registration statement. If the Company fails to comply with certain obligations under the Registration Rights Agreement, dated November 6, 2012, it will be required to pay liquidated damages in the form of additional cash interest to the holders of the Notes.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. LONG-TERM DEBT (Continued)

On or before November 15, 2015, the Company may redeem up to 35% of the aggregate principal amount of the 2021 Notes with the net cash proceeds of certain equity offerings at a redemption price of 108.875% of the principal amount plus accrued and unpaid interest to the redemption date provided that: at least 65% in aggregate principal amount of the 2021 Notes originally issued remains outstanding immediately after the redemption and the redemption occurs within 180 days of the date of closing of the related equity offering. In addition, at any time prior to November 15, 2016, the Company may redeem some or all of the 2021 Notes for the principal amount thereof, plus accrued and unpaid interest plus a make whole premium equal to the excess , if any of (a) the present value at such time of (i) the redemption price of such note at November 15, 2016, plus (ii) any required interest payments due on the notes through November 15, 2016 (excluding currently accrued and unpaid interest) computed using a discount rate equal to the Treasury Rate plus 50 basis points, discounted to the redemption date on a semi-annual basis, over (b) the principal amount of such note.

On or after November 15, 2016, the Company may redeem some or all of the 2021 Notes at any time or from time to time at the redemption prices (expressed as percentages of the principal amount) set forth in the following table plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the 12-month period beginning November 15 of the years indicated below:

Year	Percentage
2016	104.438%
2017	102.219%
2018 and thereafter	100.000%

In addition, upon a change of control of the Company, holders of the 2021 Notes will have the right to require the Company to repurchase all or any part of their Notes for cash at a price equal to 101% of the aggregate principal amount of the Notes repurchased, plus any accrued and unpaid interest. The 2021 Notes were issued under and governed by an Indenture dated November 6, 2012, between the Company, U.S. Bank National Association, as trustee and the Company's subsidiaries named therein as guarantors (the Indenture). The Indenture contains covenants that, among other things, limit the ability of the Company and its subsidiaries to: incur indebtedness; pay dividends or make other distributions on stock; purchase or redeem stock or subordinated indebtedness; make investments; create liens enter into transactions with affiliates; see assets; refinance certain indebtedness; and merge with or into other companies or transfer substantially all of the Company's assets.

In conjunction with the issuance of the 2021 Notes, the Company recorded a discount of approximately $5.65 million to be amortized over the remaining life of the 2021 Notes using the effective interest method. The remaining unamortized discount was $5.58 million at December 31, 2012.

On January 14, 2013, the Company completed the issuance of an additional $600 million aggregate principal amount of its 8.875% senior notes due 2021 (the additional 2021 Notes), issued at 105.0% of par. The net proceeds from the sale of the additional 2021 Notes were approximately $619.5 million (after deducting offering fees). The net proceeds from this offering will be used to repay all of the outstanding borrowings under the Company's Senior Credit Agreement and for general corporate purposes, including funding a portion of the Company's 2013 capital expenditures program. There was no borrowing base reduction to the Company's Senior Credit Agreement as a result of the issuance of the additional 2021 Notes. For further discussion of this transaction, see Note 16, *"Subsequent Events."*

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. LONG-TERM DEBT (Continued)

9.75% Senior Notes

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

The 2020 Notes bear interest at a rate of 9.75% per annum, payable semi-annually on January 15 and July 15 of each year, beginning on January 15, 2013. The 2020 Notes will mature on July 15, 2020. The 2020 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness. The 2020 Notes are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by the Company's existing wholly-owned subsidiaries. Halcón, the issuer of the 2021 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

In connection with the sale of the 2020 Notes, the Company entered into a Registration Rights Agreement, dated July 16, 2012, between the Company and Barclays Capital Inc., on behalf of the Initial Purchasers (the Registration Rights Agreement, dated July 16, 2012). Pursuant to the Registration Rights Agreement, dated July 16, 2012, the Company agreed to conduct a registered exchange offer for the 2020 Notes or cause to become effective a shelf registration statement providing for the resale of the 2020 Notes. In connection with the exchange offer, the Company is required to (a) file an exchange offer registration statement (the Registration Statement for the 2020 Notes) and use reasonable best efforts to cause such Registration Statement for the 2020 Notes to become effective, (b) promptly following the effectiveness of the Registration Statement for the 2020 Notes, offer to exchange each note of the 2020 Notes for a new note of the Company having terms substantially identical in all material respects to the 2020 Notes, and (c) keep the registered exchange offer open for not less than 20 business days after the date notice of the exchange offer is mailed to the holders of the 2020 Notes. If the exchange offer is not consummated within 365 days after July 16, 2012, or upon the occurrence of certain other contingencies, the Company has agreed to file a shelf registration statement to cover resales of the 2020 Notes by holders who satisfy certain conditions relating to the provision of information in connection with the shelf registration statement. If the Company fails to comply with certain obligations under the Registration Rights Agreement, dated July 16, 2012, it will be required to pay liquidated damages in the form of additional cash interest to the holders of the 2020 Notes.

On or before July 15, 2015, the Company may redeem up to 35% of the aggregate principal amount of the 2020 Notes with the net cash proceeds of certain equity offerings at a redemption price of 109.750% of the principal amount plus accrued and unpaid interest to the redemption date provided that: at least 65% in aggregate principal amount of the 2020 Notes originally issued remains outstanding immediately after the redemption and the redemption occurs within 180 days of the equity offering. In addition, at any time prior to July 15, 2016, the Company may redeem some or all of the 2020 Notes for the principal amount thereof, plus accrued and unpaid interest plus a make whole premium equal to the excess , if any of (a) the present value at such time of (i) the redemption price of such note at July 15, 2016, plus (ii) any required interest payments due on the notes through July 15, 2016 (excluding currently accrued and unpaid interest) computed using a discount rate equal to the

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. LONG-TERM DEBT (Continued)

Treasury Rate plus 50 basis points, discounted to the redemption date on a semi-annual basis, over (b) the principal amount of such note.

On or after July 15, 2016, the Company may redeem some or all of the 2020 Notes at any time or from time to time at the redemption prices (expressed as percentages of the principal amount) set forth in the following table plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the 12-month period beginning July 15 of the years indicated below:

Year	Percentage
2016	104.875%
2017	102.438%
2018 and thereafter	100.000%

In addition, upon a change of control of the Company, holders of the 2020 Notes will have the right to require the Company to repurchase all or any part of their notes for cash at a price equal to 101% of the aggregate principal amount of the notes repurchased, plus any accrued and unpaid interest. The 2020 Notes were issued under and governed by an Indenture dated July 16, 2012, between the Company, U.S. Bank National Association, as trustee and the Company's subsidiaries named therein as guarantors (the Indenture). The Indenture contains covenants that, among other things, limit the ability of the Company and its subsidiaries to: incur indebtedness; pay dividends or make other distributions on stock; purchase or redeem stock or subordinated indebtedness; make investments; create liens enter into transactions with affiliates; see assets; refinance certain indebtedness; and merge with or into other companies or transfer substantially all of the Company's assets.

In conjunction with the issuance of the 2020 Notes, the Company recorded a discount of approximately $10.2 million to be amortized over the remaining life of the 2020 Notes using the effective interest method. The remaining unamortized discount was $9.8 million at December 31, 2012.

8.0% Convertible Note

On February 8, 2012, the Company issued the 2017 Note in the principal amount of $275.0 million together with the February 2012 Warrants for an aggregate purchase price of $275.0 million. The 2017 Note bears interest at a rate of 8% per annum, payable quarterly on March 31, June 30, September 30 and December 31 of each year and matures on February 8, 2017. Through the March 31, 2014 interest payment date, the Company may elect to pay-in-kind, by adding to the principal of the 2017 Note, all or any portion of the interest due on the 2017 Note. The Company elected to pay the interest in kind on March 31, June 30 and September 30, 2012, and rolled $3.2 million, $5.7 million and $5.8 million of interest incurred during the first, second and third quarters of 2012, respectively, into the 2017 Note, increasing the principal amount to $289.7 million. For the three months ended December 31, 2012, the Company did not elect to pay-in-kind interest. At any time after February 8, 2014, the noteholder may elect to convert all or any portion of the principal amount and accrued but unpaid interest into common stock. Each $4.50 of principal and accrued but unpaid interest is convertible into one share of the Company's common stock. The 2017 Note is a senior unsecured obligation of the Company.

The Company allocated the proceeds received for the 2017 Note and February 2012 Warrants on a relative fair value basis. Consequently, the Company recorded a discount of $43.6 million to be

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. LONG-TERM DEBT (Continued)

amortized over the remaining life of the 2017 Note utilizing the effective interest rate method. The remaining unamortized discount was $37.8 million at December 31, 2012.

Promissory Notes

On December 28, 2012, the Company completed acquisition of certain oil and natural gas properties in Brazos County, Texas for approximately $83.7 million, before customary closing adjustments, consisting of approximately $8.4 million in cash and approximately $75.3 million in promissory notes. The promissory notes accrue interest beginning March 29, 2013, to the extent there is a remaining principal balance of the promissory notes at such date. Interest accrues based on the Wall Street Journal Prime Rate effective March 29, 2013. The promissory notes mature on August 30, 2013 and are classified as current as of December 31, 2012.

In conjunction with the issuance of the promissory notes, the Company recorded a discount of approximately $0.6 million to be amortized over the remaining life of the promissory notes using the effective interest method. The remaining unamortized discount was $0.6 million at December 31, 2012.

Debt Maturities

Aggregate maturities required on long-term debt at December 31, 2012 are due in future years as follows (in thousands):

2013*(1)*	$	75,285
2014		
2015		
2016		
2017		587,669
Thereafter		1,500,000
Total	$	2,162,954

(1)
Amount includes $ 75.3 million of promissory notes which have been classified as current at December 31, 2012.

Debt Issuance Costs

The Company capitalizes certain direct costs associated with the issuance of long-term debt and amortizes such costs over the lives of the respective debt. During 2012, the Company capitalized approximately $3.3 million, $13.7 million, $16.8 million and $20.0 million in costs associated with the issuance of the 2017 Note, Senior Credit Agreement, 2020 Notes and 2021 Notes, respectively. During February 2012, the Company expensed $5.8 million of debt issuance costs as a result of the pay off and termination of the March 2011 Credit Facilities. The Company expensed the remaining debt issuance cost associated with the November 2007 facility totaling approximately $2.7 million in the first quarter 2011. At December 31, 2012 and December 31, 2011, the Company had approximately $51.6 million and $6.0 million, respectively, of debt issuance costs remaining that are being amortized over the lives of the respective debt.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. FAIR VALUE MEASUREMENTS

Pursuant to ASC 820, *Fair Value Measurements and Disclosures* (ASC 820), the Company's determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company's consolidated balance sheets, but also the impact of the Company's nonperformance risk on its own liabilities. ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). ASC 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy assigns the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 measurements are inputs that are observable for assets or liabilities, either directly or indirectly, other than quoted prices included within Level 1. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs.

The following tables set forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value as of December 31, 2012 and 2011. As required by ASC 820, a financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	December 31, 2012			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets				
Receivables from derivative contracts	$	$ 7,799	$	$ 7,799
Liabilities				
Liabilities from derivative contracts	$	$ 12,890	$	$ 12,890
Liabilities from warrants*(1)*		1,342		1,342
Total Liabilities	$	$ 14,232	$	$ 14,232

	December 31, 2011			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets				
Receivables from derivative contracts	$	$ 3,900	$	$ 3,900
Liabilities				
Liabilities from derivative contracts	$	$ 4,710	$	$ 4,710

(1) Liabilities from warrants are recorded in "Accounts payable and accrued liabilities" on the consolidated balance sheet.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. FAIR VALUE MEASUREMENTS (Continued)

Derivatives listed above include collars, swaps and put options and interest rate swaps that are carried at fair value. The Company records the net change in the fair value of these positions in *"Net gain (loss) on derivative contracts"* in the Company's consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curves for commodity prices based on quoted markets prices and implied volatility factors related to changes in the forward curves. See Note 9, *"Derivative and Hedging Activities"* for additional discussion of derivatives.

As of December 31, 2012 and 2011, the Company's derivative contracts were with major financial institutions with investment grade credit ratings which are believed to have a minimal credit risk. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above; however, the Company does not anticipate such nonperformance. The counterparties to the Company's current derivative contracts are lenders in the Company's Senior Credit Agreement. The Company did not post collateral under any of these contracts as they are secured under the Senior Credit Agreement.

Warrants listed above are carried at fair value. The Company records the net change in fair value on the August 2012 Warrants in *"Interest expense and other"* in the Company's consolidated statements of operations. During the year ended December 31, 2012 an unrealized gain of $0.1 million was recorded to reflect the change in fair value. The Company valued the August 2012 Warrants based on observable market data, including treasury rates, historical volatility and data for similar instruments which resulted in the Company reporting its warrants as Level 2. See Note 12, *"Preferred Stock and Stockholders' Equity"* for additional discussion on the terms of the warrants.

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of ASC 825, *Financial Instruments*. The estimated fair value amounts have been determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of the Company's Senior Credit Agreement, the March 2011 Credit Facilities and the promissory notes approximates carrying value because the facilities interest rate approximates current market rates. The following table presents the estimated fair values of the Company's fixed interest rate, long-term debt instruments as of December 31, 2012 (excluding discounts):

	December 31, 2012	
Debt	**Carrying Amount**	**Estimated Fair Value**
	(In thousands)	
8.875% $750 million senior notes	$ 750,000	$ 798,750
9.75% $750 million senior notes	750,000	815,160
8.0% $275 million senior note	289,669	625,425
	$ 1,789,669	$ 2,239,335

The fair value of the Company's fixed interest debt instruments was calculated using quoted market prices based on trades of such debt as of December 31, 2012.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. FAIR VALUE MEASUREMENTS (Continued)

Changes in Level 3 Instruments Measured at Fair Value on a Recurring Basis

At December 31, 2012, the Company transferred amounts from Level 3 to Level 2 for its 2020 Notes because inputs became more observable with the passage of time and the larger amount of trading activity which provides the quoted market prices. The following table provides a reconciliation of financial assets measured at fair value on a recurring basis using significant unobservable inputs (Level 3).

	Carrying Amount (In thousands)
December 31, 2011	$
Transfer into Level 3	750,000
Transfer out of Level 3	(750,000)
December 31, 2012	$

The Company now believes it has readily determinable market prices which allow for the long-term debt to be properly measured and the long-term debt was reclassified from Level 3 to Level 2.

9. DERIVATIVE AND HEDGING ACTIVITIES

The Company is exposed to certain risks relating to its ongoing business operations, such as commodity price risk and interest rate risk. Derivative contracts are utilized to economically hedge the Company's exposure to price fluctuations and reduce the variability in the Company's cash flows associated with anticipated sales of future oil and natural gas production. The Company generally hedges a substantial, but varying, portion of anticipated oil and natural gas production for future periods. Derivatives are carried at fair value on the consolidated balance sheets as assets or liabilities, with the changes in the fair value included in the consolidated statements of operations for the period in which the change occurs. Historically, the Company has also entered into interest rate swaps to mitigate exposure to market rate fluctuations.

It is the Company's 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. The counterparties to the Company's current derivative contracts are lenders or affiliates of lenders in its Senior Credit Agreement. The Company did not post collateral under any of these contracts as they are secured under the Company's Senior Credit Agreement.

At December 31, 2012 and 2011, the Company's crude oil and natural gas derivative positions consisted of swaps, costless put/call "collars" and sold put options. Swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for crude oil and natural gas. A costless collar consists of a sold call, which establishes a maximum price the Company will receive for the volumes under contract and a purchased put that establishes a minimum price. A sold put option limits the exposure of the counterparty's risk should the price fall below the strike price. Sold put options limit the effectiveness of purchased put options at the low end of the put/call collars to market prices in excess of the strike price of the put option sold. The Company has elected to not designate any of its derivative contracts for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these derivative contracts, as

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. DERIVATIVE AND HEDGING ACTIVITIES (Continued)

well as all payments and receipts on settled derivative contracts, in *"Net gain (loss) on derivative contracts"* on the consolidated statements of operations.

In February 2012, pursuant to the Senior Credit Agreement, the Company novated its oil and natural gas derivative instruments to counterparties that are lenders within the Senior Credit Agreement resulting in a realized loss of $0.4 million for novation fees and terminated the interest rate derivatives resulting in a $0.6 million realized loss.

In April 2011, pursuant to the Company's March 2011 Credit Facilities, the Company was required to reduce the volume of its existing oil and natural gas derivative contracts so it would not exceed the maximum allowable volumes for future production periods and to novate derivative contracts to counterparties that are lenders within the March 2011 Credit Facilities. During the second quarter of 2011, the Company recognized a $0.9 million realized loss on the unwinding of the excess oil and natural gas derivative contracts and paid $0.5 million in fees to complete the novation, both of which were included in "*Net gain (loss) on derivative contracts"* on the consolidated statements of operations.

At December 31, 2012, the Company had 47 open commodity derivative contracts summarized in the tables below: two natural gas collar arrangements, two natural gas swaps, one natural gas basis swap, 28 oil collar arrangements, 10 oil three-way collars, and four oil swaps.

All derivative contracts are recorded at fair market value in accordance with ASC 815 and ASC 820 and included in the consolidated balance sheets as assets or liabilities. The following table summarizes the location and fair value amounts of all derivative contracts in the consolidated balance sheets as of December 31, 2012 and 2011:

		Asset derivative contracts			Liability derivative contracts	
		December 31,			December 31,	
Derivatives not designated as hedging contracts under ASC 815	**Balance sheet location**	**2012**	**2011**	**Balance sheet location**	**2012**	**2011**
		(In thousands)			(In thousands)	
Commodity contracts	Current assets receivables from derivative contracts	$ 7,428	$ 1,850	Current liabilities liabilities from derivative contracts	$ (10,429)	$ (1,590)
Commodity contracts	Other noncurrent assets receivables from derivative contracts	371	2,050	Noncurrent liabilities liabilities from derivative contracts	(2,461)	(2,602)
Interest rate contracts	Current assets receivables from derivative contracts			Current liabilities liabilities from derivative contracts		(265)
Interest rate contracts	Other noncurrent assets receivables from derivative contracts			Other noncurrent liabilities liabilities from derivative contracts		(253)
Total derivatives not designated as hedging contracts under ASC 815		$ 7,799	$ 3,900		$ (12,890)	$ (4,710)

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. DERIVATIVE AND HEDGING ACTIVITIES (Continued)

The following table summarizes the location and amounts of the Company's realized and unrealized gains and losses on derivative contracts in the Company's consolidated statements of operations:

Derivatives not designated as hedging contracts under ASC 815	Location of gain or (loss) recognized in income on derivative contracts	Amount of gain or (loss) recognized in income on derivative contracts for the year ended December 31, 2012	2011	2010
		(In thousands)		
Commodity contracts:				
Unrealized gain (loss) on commodity contracts	Other income (expenses) net gain (loss) on derivative contracts	$ (13,723)	$ 5,269	$ 6,386
Realized gain (loss) on commodity contracts	Other income (expenses) net gain (loss) on derivative contracts	7,655	(1,078)	(5,193)
Total net gain (loss) on commodity contracts		$ (6,068)	$ 4,191	$ 1,193
Interest rate swaps:				
Unrealized gain (loss) on interest rate swaps	Other income (expenses) net gain (loss) on derivative contracts	$ 518	$ (506)	$
Realized loss on interest rate swaps	Other income (expenses) net gain (loss) on derivative contracts	(576)	(206)	
Total net loss on interest rate swaps		$ (58)	$ (712)	$
Total net gain (loss) on derivative contracts	Other income (expenses) net gain (loss) on derivative contracts	$ (6,126)	$ 3,479	$ 1,193

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. DERIVATIVE AND HEDGING ACTIVITIES (Continued)

At December 31, 2012 and 2011, the Company had the following open oil and natural gas derivative contracts:

				December 31, 2012					
				Floors		Ceilings		Put Options Sold	
Period	Instrument	Commodity	Volume in Mmbtu's/ Bbl's	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
January 2013 - March 2013	3-Way Collars	Crude Oil	130,500	$95.00 - 100.00	$ 95.34	$105.50 - 109.50	$ 101.36	$ 70.00	$ 70.00
January 2013 - March 2013	Basis Swap	Natural Gas	225,000						
January 2013 - March 2013	Collars	Crude Oil	31,500	95.00	95.00	101.50	101.50		
January 2013 - March 2013	Fixed swap	Natural Gas	225,000	4.85	4.85				
April 2013 - June 2013	3-Way Collars	Crude Oil	120,575	95.00	95.00	99.50 - 100.60	99.77	70.00	70.00
April 2013 - June 2013	Collars	Crude Oil	29,575	95.00	95.00	100.60	100.60		
July 2013 - September 2013	Collars	Crude Oil	147,200	95.00	95.00	99.00 - 101.50	99.94		
October 2013 - December 2013	Collars	Crude Oil	142,600	95.00	95.00	99.00 - 101.00	99.71		
January 2013 - December 2013	Collars	Crude Oil	5,201,250	80.00 - 100.00	89.04	91.65 - 107.25	98.06		
January 2013 - December 2013	Collars	Natural Gas	1,825,000	3.75	3.75	4.26	4.26		
January 2013 - December 2013	Fixed swap	Natural Gas	240,000	3.56	3.56				
January 2013 - December 2013	Fixed swap	Crude Oil	360,000	97.60 - 105.55	102.18				
February 2013 - December 2013	Collars	Crude Oil	250,500	100.00	100.00	104.15	104.15		
April 2014 - June 2014	3-Way Collars	Crude Oil	136,500	95.00	95.00	98.20 - 101.00	99.13	70.00	70.00
January 2014 - March 2014	3-Way Collars	Crude Oil	144,000	95.00	95.00	98.60 - 109.50	100.03	70.00	70.00
January 2014 - December 2014	Collars	Crude Oil	2,190,000	85.00	85.00	95.10 - 96.35	95.92		
January 2014 - December 2014	Collars	Natural Gas	1,825,000	3.75	3.75	4.26	4.26		

				December 31, 2011					
				Floors		Ceilings		Put Options Sold	
Period	Instrument	Commodity	Volume in Mmbtu's/ Bbl's	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
January 2012 - December 2012	3-Way Collars	Crude Oil	400,500	$80.00 - 100.00	$ 87.15	$101.70 - 113.25	$ 104.89	$ 70.00	$ 70.00
January 2012 - December 2012	Collars	Crude Oil	299,300	80.00 - 95.00	84.34	102.40 - 107.00	105.43		
January 2012 - March 2012	Put Options	Natural gas	609,700	4.00 - 4.50	4.35				

April 2012 - September 2012	Collars	Natural gas	915,000	4.00	4.00	6.00	6.00		
January 2013 - June 2013	3-Way Collars	Crude Oil	251,075	95.00 - 100.00	95.18	99.50 - 109.50	100.60	70.00	70.00
January 2013 - December 2013	Collars	Crude Oil	350,875	95.00	95.00	99.00 - 101.50	100.04		
January 2014 - December 2014	3-Way Collars	Crude Oil	280,500	95.00	95.00	98.20 - 109.50	99.59	70.00	70.00

The Company's interest rate derivative positions at December 31, 2011, consisting of interest rate swaps, are shown in the following table.

Interest Rate Swaps(1)(3)

Year	Notional Amount (in thousands)	Fixed Rate	Counterparty Floating Rate(2)	Months Covered
2012	$ 50,000	2.51%	3 Month LIBOR	January - December
2013	50,000	2.51%	3 Month LIBOR	January - December
2014	50,000	2.51%	3 Month LIBOR	January - March

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(1) Settlement is paid to the Company if the counterparty floating exceeds the fixed rate and settlement is paid by the Company if the counterparty floating rate is below the fixed rate. Settlement is calculated as the difference in the fixed rate and the counterparty rate.

(2) Subject to minimum rate of 2%

(3) All outstanding interest rate swaps were terminated in conjunction with the recapitalization during February 2012.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. ASSET RETIREMENT OBLIGATIONS

The Company records an asset retirement obligation (ARO) when it can reasonably estimate the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon costs. For gas gathering systems and equipment, the Company records an ARO when the system is placed in service and it can reasonably estimate the fair value of an obligation to perform site reclamation and other necessary work when it is required. The Company records the ARO liability on the consolidated balance sheets and capitalizes a portion of the cost in *"Oil and natural gas properties"* or *"Other operating property and equipment"* during the period in which the obligation is incurred. The Company records the accretion of its ARO liabilities in *"Depletion, depreciation and accretion"* expense in the consolidated statements of operations. The additional capitalized costs are depreciated on a unit-of-production basis or straight-line basis.

The Company recorded the following activity related to the ARO liability for the years ended December 31, 2012 and 2011 (in thousands, inclusive of current portion):

Liability for asset retirement obligation as of December 31, 2010	$ 31,409
Liabilities settled and divested	(514)
Additions	207
Accretion expense	1,641
Revisions in estimated cash flows	970
Liability for asset retirement obligation as of December 31, 2011	$ 33,713
Liabilities settled and divested	(4,213)
Additions	2,627
Acquisitions*(1)*	33,855
Accretion expense	2,306
Revisions in estimated cash flows	6,844
Liability for asset retirement obligation as of December 31, 2012	$ 75,132

(1) See Note 5, *"Acquisitions and Divestitures"* for additional information on acquisitions.

11. COMMITMENTS AND CONTINGENCIES

Commitments

The Company leases corporate office space in Houston and Plano, Texas; Tulsa, Oklahoma; Denver, Colorado; and Williston, North Dakota as well as a number of other field office locations. In addition, the Company has lease commitments for certain equipment under long-term operating lease agreements. The office and equipment operating lease agreements expire on various dates through 2020. Rent expense was approximately $3.7 million, $1.3 million and $1.3 million for the years ended December 31, 2012, 2011and 2010, respectively. Approximate future minimum lease payments for

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. COMMITMENTS AND CONTINGENCIES (Continued)

subsequent annual periods for all non-cancelable operating leases as of December 31, 2012 are as follows (in thousands):

2013	$ 8,074
2014	6,656
2015	6,423
2016	6,383
2017	6,587
Thereafter	19,702
Total	$ 53,825

As of December 31, 2012, the Company has drilling rig commitments totaling $79.4 million as follows (in thousands):

2013	$ 55,257
2014	18,743
2015	5,391
2016	
2017	
Thereafter	
Total	$ 79,391

As of December 31, 2012, early termination of the drilling rigs commitments would require termination penalties of $50.8 million, which would be in lieu of paying the remaining drilling commitments of $79.4 million.

The Company has various other contractual commitments for, among other things, pipeline and well equipment and infrastructure related expenditures.

2013	$ 17,809
2014	
2015	
2016	
2017	
Thereafter	
Total	$ 17,809

The Company has committed to one long-term natural gas sales contract in its Williams County, North Dakota project area in the Bakken trend. Under the terms of this contract the Company has committed substantially all of the natural gas production for the life of its leases to one purchaser. In return for the life of lease commitment, the purchaser has committed to building a gas gathering system across the Company's project area. The sales price under this contract is based on a posted market rate.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. COMMITMENTS AND CONTINGENCIES (Continued)

Contingencies

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

12. PREFERRED STOCK AND STOCKHOLDERS' EQUITY

Preferred Stock and Non-Cash Preferred Stock Dividend

On February 29, 2012 (the Commitment Date), the Company entered into definitive agreements with a group of certain institutional and selected other accredited investors (collectively, the investors) to sell, in a private offering, 4,444.4511 shares of 8% Automatically Convertible Preferred Stock, par value $0.0001 per share (the Preferred Stock), each share of which was convertible into 10,000 shares of common stock. Also on February 29, 2012, the Company received an executed written consent (the Consent) in lieu of a stockholders' meeting authorizing and approving the conversion of the Preferred Stock into common stock. On March 2, 2012, the Company filed a Certificate of Designation, Preferences, Rights and Limitations of the Preferred Stock (the Certificate of Designation) with the Delaware Secretary of State which stated the conversion was to occur on the twentieth day after the mailing of a definitive information statement to stockholders. On March 5, 2012, the Company issued the Preferred Stock to the investors at $90,000 per share. Gross proceeds from the offering were approximately $400.0 million, or $9.00 per share of common stock, before offering expenses. The Company incurred placement agent fees of $14.0 million and associated expenses of approximately $0.5 million in connection with this offering. On March 28, 2012, the Company mailed a definitive information statement to its common stockholders notifying them that Halcón's majority stockholder had consented to the issuance of common stock, par value $0.0001, upon the conversion of the Preferred Stock. The Preferred Stock automatically converted into 44.4 million shares of common stock on April 17, 2012 in accordance with the terms of the Certificate of Designation. No cash dividends were paid on the Preferred Stock since pursuant to the terms of the Certificate of Designation of the Preferred Stock, conversion occurred prior to May 31, 2012.

In accordance with ASC 470 *Debt* (ASC 470), the Company determined that the conversion feature in the Preferred Stock represented a beneficial conversion feature. The fair value of the common stock of $10.99 per share on the Commitment Date was greater than the conversion price of $9.00 per share of common stock, representing a beneficial conversion feature of $1.99 per share of common stock, or $88.4 million in aggregate. Under ASC 470, $88.4 million (the intrinsic value of the beneficial conversion feature) of the proceeds received from the issuance of the Preferred Stock was allocated to additional paid-in capital, creating a discount on the Preferred Stock (the Discount). The Discount resulting from the allocation of value to the beneficial conversion feature was required to be amortized on a non-cash basis over the approximate 71-month period between the issuance date and the required redemption date of February 9, 2018, or fully amortized upon an accelerated date of redemption or conversion, and recorded as a preferred dividend. As a result, approximately $1.1 million of the Discount was amortized and a non-cash preferred dividend was recorded in the first quarter of 2012 and due to the conversion date occurring on April 17, 2012, the remaining $87.3 million of Discount amortization was accelerated to the conversion date and was fully amortized in the second quarter of 2012 as per the guidance of ASC 470. The Discount amortization is reflected as non-cash

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. PREFERRED STOCK AND STOCKHOLDERS' EQUITY (Continued)

preferred dividend in the consolidated statements of operations. In accordance with the guidance in ASC 480, the preferred dividend was charged against additional paid-in capital since no retained earnings were available.

On December 6, 2012, the Company completed the Williston Basin Acquisition 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 Halcón preferred stock that automatically converted into 108.8 million shares of Halcón common stock (equivalent to a conversion price of approximately $7.45 per share of Halcón common stock), following stockholder approval on January 17, 2013 of such conversion and an amendment to Halcón's certificate of incorporation to increase the number of shares of common stock that Halcón is authorized to issue. The shares of preferred stock were issued to the Petro-Hunt Parties in a private placement pursuant to the exemptions from registration under Section 4(2) of the Securities Act of 1933, as amended.

Immediately following the completion of the Williston Basin Acquisition (and the related private placement of Halcon common stock described below), the Petro-Hunt Parties held preferred stock representing approximately 22% of Halcón's outstanding common stock on an as-converted, fully diluted basis. In addition, Halcón has agreed to cause one individual designated by the Petro-Hunt Parties to be elected or appointed to Halcón's board of directors, subject to the reasonable approval of Halcón's Nominating and Corporate Governance Committee, for so long as the Petro-Hunt Parties beneficially own at least 5% of the outstanding shares of Halcón common stock. On December 6, 2012, in connection with the closing of the Williston Basin Transaction and pursuant to the terms of the Purchase Agreement, David S. Hunt was appointed to Halcón's board of directors as a Class B director with a term expiring in 2015.

On January 17, 2013, the Company received the results from the special stockholders' meeting authorizing and approving the issuance of 108.8 million shares of common stock upon the conversion of the convertible preferred stock issued to Petro-Hunt Parties. Following the approval by the stockholders, on January 18, 2013, each outstanding share of the Company's preferred stock converted into 10,000 shares of its common stock at an effective conversion price of approximately $7.45 per share. No proceeds were received by the Company upon conversion of the preferred stock. No cash dividends were paid on the preferred stock since pursuant to the terms of the Certificate of Designation of the Preferred Stock, conversion occurred prior to April 6, 2013.

Common Stock

In January 2012, the Company approved a one-for-three reverse stock split, which was implemented on February 10, 2012. Retroactive application of the reverse stock split is required and all share and per share information included for all periods presented in these financial statements reflects the reverse stock split.

On February 8, 2012 pursuant to the closing of the recapitalization described in Note 3, "*Recapitalization*," the Company issued 73.3 million shares of the Company's common stock for a purchase price of $275.0 million. Costs incurred of $4.0 million were netted against the proceeds of the common stock and recorded accordingly. In addition, the Company amended its certificate of incorporation to increase the Company's authorized shares of common stock from 33.3 million shares to 336.7 million shares.

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. PREFERRED STOCK AND STOCKHOLDERS' EQUITY (Continued)

In early August 2012, in connection with the Merger and the East Texas Acquisition, the Company issued 51.3 million and 20.8 million shares of common stock, respectively. The shares were issued at closing of the transactions as a portion of the consideration of the purchase price. See Note 5, "*Acquisitions and Divestitures*," for additional discussion on the issuance of common stock in connection with these transactions.

On December 6, 2012, the Company completed the private placement of 41.9 million shares of common stock, par value $0.0001 per share, to CPP Investment Board PMI-2 Inc. (CPPIB), for gross proceeds of approximately $300.0 million, or $7.16 per share of common stock (the CPPIB Transaction). The net proceeds to the Company were $294.0 million following the payment of a $6.0 million capital commitment payment to CPPIB upon closing of the transaction. The shares of Halcón common stock were issued to CPPIB in a private placement pursuant to the exemptions from registration provided under Section 4(2) of the Securities Act.

Concurrent with the closing of the CPPIB Transaction, Halcón and CPPIB entered into a Stockholders' Agreement (the Stockholders' Agreement) that provided among other things, that for as long as CPPIB beneficially owns at least 5% of Halcón's common stock, it may designate one individual to serve on Halcón's board of directors and two individuals for so long as it owns 20% or more of Halcón's common stock, such individual(s) to be subject to the reasonable approval of Halcón's Nominating and Corporate Governance Committee. On December 6, 2012, in connection with the closing of the CPPIB Transaction and pursuant to the terms of the Stockholders Agreement, Kevin E. Godwin was appointed to Halcón's board of directors as a Class B director with a term expiring in 2015. At the close of the CPPIB Transaction, CPPIB held approximately 9% of Halcón's outstanding common stock on a fully diluted basis after giving effect to the completion of the Williston Basin Assets acquisition. CPPIB agreed to a one-year lock-up period, ending October 19, 2013, during which time it will not offer for sale, sell, pledge or otherwise dispose of the shares of Halcón common stock it acquired pursuant to the Common Stock Purchase Agreement, subject to certain exceptions. The Stockholders' Agreement also provided CPPIB with certain pre-emptive rights to acquire additional Halcón securities, as well as shelf registration, demand underwriting and piggyback registration rights.

Also, on January 17, 2013 with stockholder approval, the Company filed a Certificate of Amendment of the Amended and Restated Certificate of Incorporation with the Delaware Secretary of State to increase its authorized common stock by approximately 333.3 million shares for a total of 670.0 million authorized shares of common stock.

Warrants

In February 2012, in conjunction with the issuance of the 2017 Notes, the Company issued February 2012 Warrants to purchase 36.7 million shares of the Company's common stock at an exercise price of $4.50 per share of common stock pursuant to the recapitalization described in Note 3, "*Recapitalization.*" The Company allocated $43.6 million to the February 2012 Warrants which is reflected in additional paid-in capital in stockholders' equity, net of $0.6 million in issuance costs. The February 2012 Warrants entitle the holders to exercise the warrants in whole or in part at any time prior to the expiration date of February 8, 2017.

In August 2012, as part of Merger, the Company assumed outstanding GeoResources stock warrants. At the date of the Merger 0.6 million warrants were outstanding and converted to 1.2 million Halcón warrants (the August 2012 Warrants). Each GeoResources warrant was converted into an August 2012 Warrant to acquire one share of Halcón common stock (Share Portion) at an exercise

HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. PREFERRED STOCK AND STOCKHOLDERS' EQUITY (Continued)

price of $8.40 per share of common stock and the right to receive $20 in cash per equivalent assumed share (Cash Portion) at an exercise price of $0.82 per $1.00 received. The August 2012 Warrants will expire on June 9, 2013 and contain substantially the same terms of the original GeoResources warrants with adjustments to the exercise price and addition of the Cash Portion to reflect the impact of the consideration per share from the Merger. These adjustments convert the terms to fundamentally equal what the warrant holders would have received had the warrants been exercised immediately prior to the close of the Merger. Under the terms of the August 2012 Warrants, the warrant holder must exercise the Share Portion and the Cash Portion in tandem. The August 2012 Warrants are reflected as a current liability in the consolidated balance sheets and at December 31, 2012 are recorded at fair value. Changes in fair value are recognized in "*Interest expense and other*" in the consolidated statements of operations.

Incentive Plan

On May 8, 2006, the Company's stockholders first approved its 2006 Long-Term Incentive Plan (the Plan). The Company reserved a maximum of 0.8 million shares of its common stock for issuances under the Plan. On May 8, 2008, the Plan was amended to increase the maximum authorized number of shares to be issued under the Plan from 0.8 million to 2.0 million. On May 3, 2010, the Plan was amended to increase the maximum authorized number of shares to be issued under the Plan from 2.0 million to 2.5 million. On February 8, 2012, as part of the Recapitalization described in Note 3 "*Recapitalization*," the Plan was amended to increase the maximum authorized number of shares to be issued under the Plan from 2.5 million to 3.7 million. On May 17, 2012, shareholders approved an amendment and restatement of the Plan to (i) increase the maximum number of shares to be issued under the Plan from 3.7 million to 11.5 million; (ii) extend the effectiveness of the Plan for ten years from the date of approval; and (iii) amend various other provisions of the Plan. As of December 31, 2012 and December 31, 2011, a maximum of 4.4 million and 491,450 shares of common stock, respectively, remained reserved for issuance under the Plan.

The Company accounts for share-based payment accruals under authoritative guidance on stock compensation, as set forth in ASC Topic 718. The guidance requires all share-based payments to employees and directors, including grants of stock options and restricted stock, to be recognized in the financial statements based on their fair values.

For the years ended December 31, 2012, 2011 and 2010, respectively, the Company recognized $6.7 million, $3.6 million, and $3.1 million, respectively, of share-based compensation expense as a component of "*General and administrative*" on the consolidated statements of operations.

Stock Options

During the year ended December 31, 2012, the Company granted stock options under the Plan covering 4.8 million shares of common stock to employees of the Company. Stock options, when exercised, are settled through the payment of the exercise price in exchange for new shares of stock underlying the option. The stock options have exercise prices ranging from $5.48 per share of common stock to $11.55 per share of common stock with a weighted average exercise price of $7.24 per share of common stock. The weighted average grant date fair value of options granted in 2012 was $16.5 million. These awards typically vest over a three year period at a rate of one-third on the annual anniversary date of the grant and expire ten years from the grant date. At December 31, 2012, the unrecognized compensation expense related to stock options totaled $12.9 million and will be recognized on the graded-vesting method over the requisite service periods. The weighted average remaining vesting period as of December 31, 2012 was 1.7 years.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. PREFERRED STOCK AND STOCKHOLDERS' EQUITY (Continued)

The following table sets forth the stock option transactions for the year ended December 31, 2012:

	Number	Weighted Average Exercise Price Per Share	Aggregate Intrinsic Value(1) (In thousands)	Weighted Average Remaining Contractual Life (Years)
Outstanding at December 31, 2009		$	$	
Granted				
Exercised				
Forfeited				
Outstanding at December 31, 2010		$	$	
Granted				
Exercised				
Forfeited				
Outstanding at December 31, 2011		$	$	
Granted	4,847,333	7.24		
Exercised				
Forfeited	(35,500)	9.35		
Outstanding at December 31, 2012	4,811,833	$ 7.22	$ 2,944	9.7

(1) The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option. No stock options were exercised during the year ended December 31, 2012.

Options outstanding at December 31, 2012 consisted of the following:

	Outstanding			Exercisable(1)			
Range of Grant Prices Per Share	Number	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Live (Years)	Number	Weighted Average Exercise Price per Share	Aggregate Intrinsic Value	Weighted Average Remaining Contractual Live (Years)
$5.48 - $5.96	1,790,000	$ 5.49	9.9		$	$	
5.97 - 6.92	1,357,000	6.64	9.8				
6.93 - 10.00	721,500	8.45	9.5				
10.01 - 11.55	943,333	10.41	9.4				

(1) At December 31, 2012, none of the Company's options were exercisable due to service or performance conditions.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. PREFERRED STOCK AND STOCKHOLDERS' EQUITY (Continued)

The assumptions used in calculating the year ended December 31, 2012 fair value of the Company's share-based compensation are disclosed in the following table:

Weighted average value per option granted during the period	$	3.40
Assumptions:		
Stock price volatility*(1)*		61.84%
Risk free rate of return		0.54%
Expected term		4 years

(1) Due to the Company's limited historical data, expected volatility was estimated using volatilities of similar entities whose share or options prices and assumptions are publicly available.

Restricted Stock

From time-to-time, the Company grants shares of restricted stock to employees and non-employee directors of the Company. Employee shares vests over a three year period at a rate of one-third on the annual anniversary date of the grant, and the non-employee directors' shares vest six-months from the date of grant. At the request of certain of the grantees, the Company repurchased a portion of the vested shares at the closing market price of the Company's common stock as of the vesting date, to satisfy the requesting grantees' federal and state income tax withholding requirements. The repurchased shares are held by the Company as treasury stock.

The number of shares repurchased and their weighted average prices for the three year period ended December 31, 2012 were as follows:

	Shares Repurchased		
Year ended	**Number of Shares**		**Weighted Average Closing Price**
December 31, 2010	138,018	$	5.70
December 31, 2011	46,516		3.93
December 31, 2012	199,778		10.75

The weighted average grant date fair value of the shares granted in 2012, 2011, and 2010 was $2.8 million, $1.5 million and $3.7 million, respectively. At December 31, 2012, 2011 and 2010, the unrecognized compensation expense related to non-vested restricted stock totaled $1.6 million, $2.7 million and $5.1 million, respectively. The weighted average remaining vesting period as of December 31, 2012, 2011, and 2010 was 2.0 years.

In February 2012, the Company realized compensation expense of $2.6 million primarily from the accelerated vesting of all unvested employee restricted stock shares outstanding at the time of the change in control in the Company resulting from the recapitalization as described in Note 3, "*Recapitalization*."

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. PREFERRED STOCK AND STOCKHOLDERS' EQUITY (Continued)

The following table sets forth the restricted stock transactions for the years ended December 31, 2012, 2011 and 2010:

	Number of Shares	Weighted Average Grant Date Fair Value Per Share	Aggregate Intrinsic Value(1) (In thousands)
Unvested outstanding shares at December 31, 2009	787,998	$ 7.92	$ 4,846
Granted	623,885	5.97	
Vested	(519,159)	7.95	
Forfeited	(7,500)	6.81	
Unvested outstanding shares at December 31, 2010	885,224	$ 6.51	$ 4,886
Granted	279,907	5.23	
Vested	(209,710)	7.81	
Forfeited	(117,934)	5.26	
Unvested outstanding shares at December 31, 2011	837,487	$ 5.92	$ 7,864
Granted	312,900	8.91	
Vested	(334,838)	5.44	
Accelerated vesting*(2)*	(547,649)	7.43	
Forfeited			
Unvested outstanding shares at December 31, 2012	267,900	$ 8.72	$ 1,854

(1) The intrinsic value of restricted stock was calculated as the closing market price on December 31, 2012, 2011, 2010 and 2009 of the underlying stock multiplied by the number of restricted shares. The total fair value of shares vested were $9.2 million, $0.8 million and $3.1 million for the years 2012, 2011, and 2010, respectively.

(2) Represents accelerated vesting of all unvested employee restricted stock shares outstanding at the time of the change in control in the Company resulting from the Recapitalization.

Stock Appreciation Rights

In May 2011, the Company granted 0.5 million stock appreciation rights (SARs) under the Plan at an exercise price of $5.19 per share of common stock, which was the weighted average closing price of the Company's common stock on the date of grant. Compensation expense related to the SARs is based on fair value re-measured at each reporting period and recognized over the vesting period (generally four years). As of December 31, 2011, the fair value calculation resulted in $0.8 million unrealized loss recognized as share-based compensation expense, a component of "*General and administrative*" on the consolidated statements of operations, and $0.1 million as restructuring costs on the consolidated statements of operations during the year ended December 31, 2011. The SARs expire ten years from date of grant and upon exercise. The terms of the SARs require settlement in cash, net of applicable taxes. In February 2012, the Company accelerated vesting and exercise of all unvested stock appreciation rights under the Plan, due to the change in control of the Company resulting from the recapitalization described in Note 3, "*Recapitalization*." The Company settled the SARs in cash, resulting in $2.2 million of share-based compensation expense recognized for the year ended

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. PREFERRED STOCK AND STOCKHOLDERS' EQUITY (Continued)

December 31, 2012. The realized compensation expense was partially offset by the reversal of $0.8 million of unrealized losses recorded at December 31, 2011.

A summary of the non-vested SARs as of December 31, 2012, and changes during the year ended December 31, 2012, is presented below:

	Number	Weighted Average Grant Date Fair Value
Non-vested at December 31, 2010		$
Granted	510,167	5.19
Vested	(20,000)	5.19
Forfeited	(71,834)	5.19
Non-vested at December 31, 2011	418,333	5.19
Granted		
Vested	(84,418)	5.19
Accelerated Vesting*(1)*	(333,915)	5.19
Forfeited		
Nonvested at December 31, 2012		

(1) Represents accelerated vesting of all unvested employee SARs outstanding at the time of the change in control in the Company resulting from the Recapitalization.

The Company uses the Black-Scholes option pricing model to compute the fair value of the SARs. The following assumptions were used in calculating fair value:

The risk-free interest rate is based on the zero coupon United States Treasury yield for the expected life of the grant.

The dividend yield on the Company's common stock is assumed to be zero since the Company does not pay dividends and has no current plans to do so in the future.

The volatility of the Company's common stock is based on volatility of the market price of the Company's common stock over a period of time equal to the expected term and ending on the grant date.

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. INCOME TAXES

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

	Years Ended December 31, 2012	2011	2010
	(In thousands)		
Current:			
Federal	$	$ (253)	$ (418)
State	121		
	121	(253)	(418)
Deferred:			
Federal	12,265	(6,549)	(577)
State	795		
	13,060	(6,549)	(577)
Total income tax (provision) benefit	$ 13,181	$ (6,802)	$ (995)

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

	Years Ended December 31, 2012	2011	2010
	(In thousands)		
Expected tax (provision) benefit	$ 23,485	$ (1,836)	$ (1,160)
State income tax expense, net of federal benefit	455	(557)	(124)
Merger costs	(3,580)		
Debt related costs	(3,239)		
Meals and entertainment expense	(29)	(19)	(25)
Non-deductible dues	(28)	(124)	(69)
Reduction in deferred tax asset	(3,218)	(5,957)	(5,731)
Change in valuation allowance and related items		1,883	6,572
Share-based compensation	(638)	(260)	(393)
Other	(27)	68	(65)
Total income tax (provision) benefit	$ 13,181	$ (6,802)	$ (995)

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. INCOME TAXES (Continued)

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

	December 31, 2012	December 31, 2011[1]
	(In thousands)	
Deferred current income tax assets:		
Unrealized hedging transactions	$ 3,588	$ (1,669)
Other	$ 1,719	3,071
Gross deferred current income tax assets	5,307	1,402
Valuation allowance		
Deferred current income tax assets	$ 5,307	$ 1,402
Deferred current income tax liabilities:		
Other	$	$ (322)
Deferred current income tax liabilities	$	$ (322)
Net noncurrent deferred income tax assets	$ 5,307	$ 1,080
Deferred noncurrent income tax assets:		
Net operating loss carry-forwards	$ 157,316	$ 25,050
Depreciable/depletable property, plant and equipment		(904)
Share-based compensation expense	1,063	
Asset retirement obligations	28,488	
Other	2,299	(324)
Gross deferred noncurrent income tax assets	189,166	23,822
Valuation allowance	(2,285)	(2,285)
Deferred noncurrent income tax assets	$ 186,881	$ 21,537
Deferred noncurrent income tax liabilities:		
Book-tax differences in property basis	$ (339,607)	$
Unrealized hedging transactions	(2,620)	
Investment in unconsolidated entities	(4,156)	
Other	(553)	(182)
Deferred noncurrent income tax liabilities	$ (346,936)	$ (182)
Net noncurrent deferred income tax assets	$ (160,055)	$ 21,355

(1) See further discussion at Note 2, *"Corrections of Immaterial Errors."*

ASC 740, *Income Taxes* (ASC 740) prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. The Company has no unrecognized tax benefits for the years ended December 31, 2010, 2011 or 2012.

Generally, the Company's income tax years 2009 through 2012 remain open and subject to examination by Federal tax authorities or the tax authorities in Louisiana, New Mexico, North Dakota,

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. INCOME TAXES (Continued)

Oklahoma, Texas, Ohio, Pennsylvania and certain other small state taxing jurisdictions where the Company has its principal operations. In certain jurisdictions the Company operates through more than one legal entity, each of which may have different open years subject to examination.

The Company recognizes interest and penalties accrued to unrecognized benefits in "*Interest expense and other*" in its statements of operations. For the years ended December 31, 2012, 2011 and 2010 the Company recognized no interest and penalties.

As of December 31, 2012, the Company has available, to reduce future taxable income, a United States net operating loss carryforwards (NOLs) of approximately $423.3 million (net of excess income tax benefits not recognized of $4.2 million) which expires in the years 2020 thru 2030. The majority of these net operating loss carryforwards are subject to the ownership change limitation provisions of Section 382 of the Internal Revenue Code (the "Code"). Despite this limitation, the Company expects that the deferred tax benefits related to the NOLs will be utilized prior to their expiration. The Company also has various state NOL carryforwards of approximately $34.5 million, net of the valuation allowance for losses that the Company anticipates will expire before they can be utilized, as of December 31, 2012 with varying lengths of allowable carryforward periods ranging from five to 20 years that can be used to offset future state taxable income. It is expected that these deferred income tax benefits will be utilized prior to their expiration.

14. EARNINGS PER SHARE

The following represents the calculation of earnings per share:

	Years Ended December 31,		
	2012	**2011**	**2010**
	(In thousands, except per share amounts)		
Basic			
Net income (loss) available to common stockholders	$ (142,330)	$ (1,403)	$ 2,417
Weighted average basic number of common shares outstanding	156,494	26,258	26,142
Basic net income (loss) per common share	$ (0.91)	$ (0.05)	$ 0.09
Diluted			
Net income (loss) available to common stockholders	$ (142,330)	$ (1,403)	$ 2,417
Weighted average basic number of common shares outstanding	156,494	26,258	26,142
Common stock equivalent shares representing shares issuable upon exercise of stock options			
Common stock equivalent shares representing shares issuable upon exercise of warrants			
Common stock equivalent shares representing shares issuable upon conversion of debt or preferred stock			
Weighted average diluted number of common shares outstanding	156,494	26,258	26,142
Diluted net income (loss) per common share	$ (0.91)	$ (0.05)	$ 0.09

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HALCÓN RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

14. EARNINGS PER SHARE (Continued)

Common stock equivalents, including stock options, warrants and convertible debt and convertible preferred stock, totaling 215.8 million shares were not included in the computation of diluted earnings per share of common stock because the effect would have been anti-dilutive for the year ended December 31, 2012. There were no convertible shares for the years ended December 31, 2011 and 2010, respectively.

15. ADDITIONAL FINANCIAL STATEMENT INFORMATION

Certain balance sheet amounts are comprised of the following:

	December 31,	
	2012	2011
	(In thousands)	
Accounts receivable:		
Oil, natural gas and natural gas liquids revenues	$ 143,794	$ 9,519
Joint interest accounts	113,671	597
Affiliated partnerships	475	
Other	4,869	172
	$ 262,809	$ 10,288
Prepaids and other:		
Prepaid	$ 3,690	$ 936
Other	3,001	1,793
	$ 6,691	$ 2,729
Accounts payable and accrued liabilities:		
Trade payables	$ 147,679	$ 11,498
Accrued oil and natural gas capital costs	282,245	1,392
Revenues and royalties payable	91,761	8,564
Accrued interest expense	45,201	464
Accrued income taxes payable	130	406
Accrued employee compensation	12,321	1,600
Drilling advances from partners	8,840	26
Accounts payable to affiliated partnerships	822	
Other	1,552	1,111
	$ 590,551	$ 25,061

16. SUBSEQUENT EVENTS

Issuance of Additional 2021 Notes

On January 14, 2013, the Company completed the issuance of an additional $600 million aggregate principal amount of its 8.875% senior notes due 2021 (the additional 2021 Notes). The additional 2021 Notes are additional notes under an indenture pursuant to which the Company issued its 8.875% Senior Notes due 2021, in an aggregate principal amount of $750.0 million on November 6, 2012 (the Existing Notes). The additional 2021 Notes were issued under the same indenture as the Existing Notes

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16. SUBSEQUENT EVENTS (Continued)

and are part of the same series. Interest on the additional 2021 Notes is payable on May 15 and November 15 of each year, beginning on May 15, 2013. Interest on the additional 2021 Notes will accrue from November 6, 2012, the original issuance date of the series. The additional 2021 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness.

The additional 2021 Notes were sold at 105.0% of the aggregate principal amount of the additional 2021 Notes plus accrued interest. The net proceeds from the sale of the additional 2021 Notes were approximately $619.5 million (after deducting offering fees and expenses). The net proceeds from this offering were used to repay all of the outstanding borrowings under the Company's senior revolving credit facility and for general corporate purposes, including funding a portion of the Company's 2013 capital expenditures program. There was no borrowing base reduction to the Company's Senior Credit Agreement as a result of the issuance of the additional 2021 Notes.

Second Amendment to the Senior Credit Agreement

On January 25, 2013, the Company entered into the Second Amendment to Senior Credit Agreement (the Second Amendment) by and among the Company, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and the other lenders signatory thereto. The Second Amendment amends the Senior Credit Agreement with respect to the Company's ability to enter into certain commodity hedging agreements.

The Second Amendment provides, among other things, that the Company and its subsidiary guarantors 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 the Company's internally forecasted production (i) from the Company's 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, the Company 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 the Company's proved reserves (as forecast based upon the most recently delivered reserve report) 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 (as forecast based upon the most recently delivered reserve report) 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 volumes hedged by the Company 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 the Company's 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.

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SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Natural Gas Reserves

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

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

Estimates of proved reserves at December 31, 2012 were prepared by Netherland, Sewell & Associates, Inc. (Netherland, Sewell), our independent consulting petroleum engineers. Our estimated proved reserves as of 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 Mr. J. Carter Henson, Jr. and Mr. 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 SEC and other industry reserves definitions and guidelines.

Our board of directors has established an independent reserves committee composed of three outside directors, all of whom have experience in energy company reserve evaluations. Our independent engineering firm reports jointly to the reserves committee and to our Manager, Corporate Reserves. The reserves committee is charged with ensuring the integrity of the process of selection and engagement of the independent engineering firm and in making a recommendation to our board of directors as to whether to accept the report prepared by our independent consulting petroleum engineers. The Manager, Corporate Reserves is the technical person primarily responsible for

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overseeing the preparation of the annual reserve report. 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, such as commodity pricing. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent we acquire additional properties containing proved reserves or conduct successful exploration and development activities or both, our proved reserves will decline as reserves are produced.

The following table illustrates the Company's estimated net proved reserves, including changes, and proved developed reserves for the periods indicated. The oil and natural gas liquids prices as of December 31, 2012, 2011 and 2010 are based on the respective 12-month unweighted average of the first of the month prices of the West Texas Intermediate spot price which equates to $94.71 per barrel, $96.19 per barrel and $79.43 per barrel, respectively. The oil and natural gas liquids prices were adjusted by lease or field for quality, transportation fees, and regional price differentials. The natural gas prices as of December 31, 2012, 2011 and 2010 are based on the respective 12-month unweighted average of the first of the month prices of the Henry Hub spot price which equates to $2.76 per Mmbtu, $4.12 per Mmbtu and $4.38 per Mmbtu, respectively. All prices are adjusted by lease or field

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for energy content, transportation fees, and regional price differentials. All prices are held constant in accordance with SEC guidelines. All proved reserves are located in the United States.

	Proved Reserves			
	Oil (MBbls)	Natural Gas (Mmcf)	Natural Gas Liquids (MBbls)	Equivalent (MBoe)
Proved reserves, December 31, 2009	14,067	89,227	4,983	33,921
Extensions and discoveries	347	821	61	545
Purchase of minerals in place				
Production	(995)	(4,816)	(364)	(2,162)
Sale of minerals in place	(174)	(14,591)	(2,004)	(4,610)
Revision of previous estimates	(159)	(17,033)	(301)	(3,299)
Proved reserves, December 31, 2010	13,086	53,608	2,375	24,395
Extensions and discoveries	339	20	1	343
Purchase of minerals in place	5			5
Production	(884)	(2,662)	(176)	(1,504)
Sale of minerals in place				
Revision of previous estimates	(175)	(10,912)	(190)	(2,182)
Proved reserves, December 31, 2011	12,371	40,054	2,010	21,057
Extensions and discoveries	11,691	6,742	352	13,167
Purchase of minerals in place	66,240	71,560	3,433	81,600
Production	(2,415)	(4,554)	(268)	(3,442)
Sale of minerals in place	(1,789)	(2,025)		(2,127)
Revision of previous estimates	1,280	(15,632)	(144)	(1,470)
Proved reserves, December 31, 2012	87,378	96,145	5,383	108,785

	Proved Developed Reserves			
	Oil (MBbls)	Natural Gas (Mmcf)	Natural Gas Liquids (MBbls)	Equivalent (MBoe)
December 31, 2012	38,429	58,785	3,172	51,399
December 31, 2011	8,643	20,997	1,237	13,381
December 31, 2010	8,414	31,776	1,486	15,196

	Proved Undeveloped Reserves			
	Oil (MBbls)	Natural Gas (Mmcf)	Natural Gas Liquids (MBbls)	Equivalent (MBoe)
December 31, 2012	48,949	37,360	2,211	57,386
December 31, 2011	3,728	19,057	773	7,676
December 31, 2010	4,672	21,832	889	9,199

During 2012, through several transactions, the Company acquired 81.6 million barrels of oil equivalent in proved reserves primarily in the Bakken / Three Forks area and Woodbine / Eagle Ford area. As a result of the Company's active development programs in these areas, the Company added 13.2 million barrels of oil equivalent. In 2012, the Company had one divestiture of 2.1 million barrels of oil equivalent in its non-core area. The small negative revision of 1.5 million barrels of oil equivalent comes mostly from the Company's non-core areas and is due to lower gas prices, well performance changes and expiring proved undeveloped locations.

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The Company added 0.3 million Boe in proved reserve extensions and discoveries in 2011 primarily as a result of its development drilling in its Electra/Burkburnett Field in North Texas and in its La Copita Field in South Texas. A significant portion of these reserves is a result of drilling locations in Electra/Burkburnett, Northeast Fitts and Allen Fields that were not booked as proved locations as of December 31, 2010. The revisions of previous reserve estimates in 2011 decreased proved reserves by 2.2 million Boe or approximately 9% of proved reserves at the beginning of the year. The revisions include a positive increase of 0.9 million Boe or 4% of the beginning of the year proved reserves caused by higher crude oil and natural gas prices. This positive revision was offset by the downward revision of 1.4 million barrels of oil equivalent caused by the transfer of proved reserves to unproved categories as a result of updated geological and engineering evaluations and changes to the Company development plans during 2011, and 1.7 million Boe of downward revisions were mostly due to changes in well performance.

The Company added 0.5 million Boe in proved reserve extensions and discoveries in 2010 as a result of development drilling in its Electra/Burkburnett Field in North Texas and in its La Copita Field in South Texas. A significant portion of these reserves is a result of drilling locations in its Electra/Burkburnett Field that were not booked as proved location at year-end 2009. The remainder of the extensions and discoveries in 2010 is primarily from wells drilled in South Texas not previously booked as proved and from a discovery well in Osage County, Oklahoma. Sales of reserves in place during 2010 were primarily due to sales of assets during December 2010 of the Company's North Texas Barnett Shale and Boonsville properties and certain non-operated natural gas properties located in eastern Oklahoma. The revisions of previous reserve estimates decreased proved reserves by 3.3 million Boe or approximately 10% of proved reserves at the beginning of the year. The revisions included a positive increase of 1.8 million Boe caused by higher oil and gas prices. This positive revision was offset by a downward revision of 1.1 million Boe caused by the transfer of proved undeveloped to unproved categories as a result of changes to the Company's development plans during 2010, and 4.0 million Boe of the downward revisions were mostly due to changes in well performance in the Company's gas properties in South Texas.

The Company's reserves have been estimated using deterministic methods. The total proved reserve additions of 87,728 Mboe are comprised of 38,018 MBoe in proved developed and 49,710 MBoe in proved undeveloped reserves, and are primarily from the Bakken / Three Forks area and the Woodbine / Eagle Ford area, driven by the Merger and the acquisitions of the East Texas Assets and the Williston Basin Assets.

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)
Extensions and discoveries	8,656
Ending proved undeveloped reserves at December 31, 2012	57,386

For wells classified as proved developed producing where sufficient production history existed, reserves were based on individual well performance evaluation and production decline curve

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extrapolation techniques. For undeveloped locations and wells that lacked sufficient production history, reserves were based on analogy to producing wells within the same area exhibiting similar geologic and reservoir characteristics, combined with volumetric methods. The volumetric estimates were based on geologic maps and rock and fluid properties derived from well logs, core data, pressure measurements, and fluid samples. Well spacing was determined from drainage patterns derived from a combination of performance-based recoveries and volumetric estimates for each area or field. Proved undeveloped locations were limited to areas of uniformly high quality reservoir properties, between existing commercial producers.

Reliable technologies were used to determine areas where proved undeveloped (PUD) locations are more than one offset away from a producing well. These technologies include seismic data, wire line open hole log data, core data, log cross-sections, performance data, and statistical analysis. In such areas, these data demonstrated consistent, continuous reservoir characteristics in addition to significant quantities of economic estimated ultimate recoveries from individual producing wells. The Company's management team has been a leader in data gathering and evaluation in these areas and was instrumental in developing consortiums that allow various operators to exchange data. The Company relied only on production flow tests and historical production data, along with the reliable geologic data mentioned above to estimate proved reserves. No other alternative methods or technologies were used to estimate proved reserves.

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

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

	December 31,		
	2012	2011	2010
	(In thousands)		
Evaluated oil and natural gas properties*(1)*	$ 2,669,245	$ 715,666	$ 689,472
Unevaluated oil and natural gas properties	2,326,598		
	4,995,843	715,666	689,472
Accumulated depletion, depreciation and amortization*(1)*	(588,207)	(501,993)	(482,886)
	$ 4,407,636	$ 213,673	$ 206,586

(1) Amounts do not include costs for our gas gathering systems and related support equipment.

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

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

	Years Ended December 31,		
	2012	2011	2010
	(In thousands)		
Property acquisition costs, proved*(1)*	$ 1,495,372	$ 724	$ 1,133
Property acquisition costs, unproved*(1)*	2,324,439		
Exploration and extension well costs	232,685	7,135	4,552
Development costs	254,499	17,355	27,850
Total costs	$ 4,306,995	$ 25,214	$ 33,535

(1) Property acquisition costs include preferred stock issued for Williston Basin Assets of $695.2 million, common stock issued for Geo Resources, Inc. of $321.4 million, and common stock issued for East Texas Assets of $130.6 million.

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

The following Standardized Measure of Discounted Future Net Cash Flows has been developed utilizing ASC 932, *Extractive Activities Oil and Gas* (ASC 932) procedures and based on oil and natural gas reserve and production volumes estimated by the Company's engineering staff. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows (Standardized Measure) be viewed as representative of the current value of the Company.

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

- future costs and selling prices will probably differ from those required to be used in these calculations;
- due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations;
- a 10% discount rate may not be reasonable as a measure of the relative risk inherent in realizing future net oil and natural gas revenues; and
- future net revenues may be subject to different rates of income taxation.

At December 31, 2012, 2011 and 2010, as specified by the SEC, the prices for oil and natural gas used in this calculation were the unweighted 12-month average of the first day of the month prices, except for volumes subject to fixed price contracts. Estimates of future income taxes are computed using current statutory income tax rates including consideration for estimated future statutory depletion and tax credits. The resulting net cash flows are reduced to present value amounts by applying a 10% discount factor.

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The Standardized Measure is as follows:

	Years Ended December 31,		
	2012	2011	2010
	(In thousands)		
Future cash inflows	$ 8,714,938	$ 1,440,088	$ 1,355,233
Future production costs	(2,726,382)	(582,662)	(548,638)
Future development costs	(1,416,967)	(102,231)	(117,860)
Future income tax expense	(651,070)	(205,457)	(161,736)
Future net cash flows before 10% discount	3,920,519	549,738	526,999
10% annual discount for estimated timing of cash flows	(1,966,467)	(262,849)	(248,952)
Standardized measure of discounted future net cash flows	$ 1,954,052	$ 286,889	$ 278,047

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

The following is a summary of the changes in the Standardized Measure for the Company's proved oil and natural gas reserves during each of the years in the three year period ended December 31, 2012:

	Years Ended December 31,		
	2012	2011	2010
	(In thousands)		
Beginning of year	$ 286,889	$ 278,047	$ 274,234
Sale of oil and natural gas produced, net of production costs	(172,971)	(64,451)	(71,028)
Purchase of minerals in place	1,898,345	104	
Sales of minerals in place	(53,452)		(25,267)
Extensions and discoveries	290,668	24,659	13,888
Changes in income taxes, net	(195,007)	(18,691)	(24,382)
Changes in prices and costs	(2,985)	93,411	131,366
Previously estimated development costs incurred	36,142	11,209	16,840
Net changes in future development costs	(124,483)	1,940	(1,184)
Revisions of previous quantities	(32,681)	(49,782)	(58,029)
Accretion of discount	87,075	36,425	33,605
Changes in production rates and other	(63,488)	(25,982)	(11,996)
End of year	$ 1,954,052	$ 286,889	$ 278,047

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SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

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

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(In thousands, except per share amounts)			
2012				
Total operating revenues	$ 26,870	$ 23,281	$ 73,140	$ 124,654
Income (loss) from operations	(9,785)	(7,220)	(4,569)	(8,143)
Net income (loss)	(33,322)	7,659	(20,181)	(8,041)
Net income (loss) available to common stockholders	(34,424)	(79,684)	(20,181)	(8,041)
Net income (loss) per share of common stock:				
Basic	$ (0.50)	$ (0.59)	$ (0.11)	$ (0.04)
Diluted	$ (0.50)	$ (0.59)	$ (0.11)	$ (0.04)

	Quarters Ended			
	March 31	June 30	September 30	December 31
2011				
Total operating revenues	$ 25,770	$ 28,152	$ 24,186	$ 25,581
Income (loss) from operations	5,762	8,271	5,730	36
Net income (loss)	(9,911)	8,936	11,776	(12,204)
Net income (loss) available to common stockholders	(9,911)	8,936	11,776	(12,204)
Net income (loss) per share of common stock:				
Basic	$ (0.38)	$ 0.34	$ 0.45	$ (0.46)
Diluted	$ (0.38)	$ 0.34	$ 0.45	$ (0.46)

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

As previously reported on Form 8-K filed with the SEC on April 4, 2012 (the "prior 8-K"), on April 3, 2012, we dismissed our prior independent registered public accounting firm and appointed Deloitte & Touche LLP as our independent registered public accounting firm for the 2012 fiscal year. For more information, please refer to the prior 8-K.

ITEM 9A. CONTROLS AND PROCEDURES

Management's Evaluation of Disclosure Controls and Procedures

In accordance with Rules 13a-15(f) and 15d-15(f), of the Exchange Act, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures based on the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission as of the end of the period covered by this report. In conducting our evaluation of the effectiveness of internal control over financial reporting, we excluded the Merger, which was completed on August 1, 2012. The total assets constitute approximately $1.3 billion, or 26% of our consolidated assets at December 31, 2012, and total revenues for the period from the August 1, 2012 closing date until December 31, 2012 of $90.8 million, or 37% of consolidated revenues for the year ended December 31, 2012. We expect to first include GeoResources in our annual assessment for the year ended December 31, 2013, as permitted for recently acquired businesses. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2012 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Management has assessed, and our independent registered public accounting firm, Deloitte & Touche LLP, has audited, our internal control over financial reporting as of December 31, 2012. The unqualified reports of management and Deloitte & Touche LLP thereon are included in Item 8. *Consolidated Financial Statements and Supplementary Data* of this Annual Report on Form 10-K and are incorporated by reference herein.

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act, during the three months ended December 31, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2013 Annual Meeting of Stockholders.

The Company's Code of Conduct and Code of Ethics for the Chief Executive Officer and Senior Financial Officers can be found on the Company's internet website located at *www.halconresources.com*. Any stockholder may request a printed copy of such materials by submitting a written request to the Company's Corporate Secretary. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company will disclose the information on its internet website. The waiver information will remain on the website for at least twelve months after the initial disclosure of such waiver.

ITEM 11. EXECUTIVE COMPENSATION

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2013 Annual Meeting of Stockholders.

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

Equity Compensation Plan Information

The following table sets forth certain information as of December 31, 2012 with respect to compensation plans (including individual compensation arrangements) under which our equity securities are authorized for issuance.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Optionsand Rights(a)	Weighted-Average Exercise Price of Outstanding Options and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a))
Equity compensation plans approved by security holders*(1)*	5,079,733*(2)*	$ 7.22	4,400,051
Equity compensation plans not approved by security holders			
	5,079,733*(2)*	$ 7.22	4,400,051

(1) Represents information for the 2012 Long-Term Incentive Plan.

(2) Includes 267,900 shares of restricted stock not yet vested.

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2013 Annual Meeting of Stockholders.

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

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2013 Annual Meeting of Stockholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2013 Annual Meeting of Stockholders.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(1) Consolidated Financial Statements:

The consolidated financial statements of the Company and its subsidiaries and reports of independent registered public accounting firms listed in Section 8 of this Annual Report on Form 10-K are filed as a part of this Annual Report on Form 10-K.

(2) Consolidated Financial Statements Schedules:

All schedules are omitted because they are inapplicable or because the required information is contained in the financial statements or included in the notes thereto.

(3) Exhibits:

2.1	Securities Purchase Agreement dated December 21, 2011 by and between RAM Energy Resources, Inc. and Halcón Resources LLC (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed December 22, 2011).
2.1.1	First Amendment to Securities Purchase Agreement dated January 4, 2012 by and between RAM Energy Resources, Inc. and Halcón Resources LLC (Incorporated by reference to Exhibit 2.1.1 of our Current Report on Form 8-K filed January 5, 2012).
2.2	Agreement and Plan of Merger, dated as of April 24, 2012 by and among Halcón Resources Corporation, Leopard Sub I, Inc., Leopard Sub II, LLC and GeoResources, Inc. (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed April 25, 2012).
2.3	Agreement of Sale and Purchase dated May 8, 2012 between NCL Appalachian Partners, L.P., as Seller, and Halcón Energy Properties, Inc., as Buyer (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed July 2, 2012).
2.4	Purchase and Sale Agreement dated as of the 5th day of June, 2012, among CH4 Energy II, LLC, PetroMax Leon, LLC and Petro Texas LLC and Halcón Energy Properties, Inc., and joined by PetroMax Operating Co., Inc. (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed August 7, 2012).
2.5	Reorganization and Interest Purchase Agreement dated October 19, 2012 by and among Halcón Energy Properties, Inc., Petro-Hunt, L.L.C. and Pillar Energy, LLC (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed October 22, 2012).
3.1	Amended and Restated Certificate of Incorporation of RAM Energy Resources, Inc. dated February 8, 2012 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed February 9, 2012).
3.1.1	Certificate of Amendment of the Amended and Restated Certificate of Incorporation of Halcón Resources Corporation, effective as of February 10, 2012 (Incorporated by reference to Exhibit 3.2 of our Current Report on Form 8-K filed February 9, 2012).
3.1.2	Certificate of Designation, Preferences, Rights and Limitations of 8% Automatically Convertible Preferred Stock of Halcón Resources Corporation dated March 2, 2012 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed March 5, 2012).

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3.1.3	Certificate of Elimination of 8% Automatically Convertible Preferred Stock dated November 30, 2012 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed December 4, 2012).
3.1.4	Certificate of Designation, Preferences, Rights and Limitations of 8% Automatically Convertible Preferred Stock of Halcón Resources Corporation dated December 5, 2012 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed December 11, 2012).
3.2	Fourth Amended and Restated Bylaws of Halcón Resources Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed November 6, 2012).
4.1	Convertible Promissory Note dated February 8, 2012, between Halcón Resources Corporation and HALRES LLC (formerly Halcón Resources LLC) (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed February 9, 2012).
4.2	Warrant Certificate dated February 8, 2012, between Halcón Resources Corporation and HALRES LLC (formerly Halcón Resources LLC) (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed February 9, 2012).
4.3	Registration Rights Agreement dated February 8, 2012, between Halcón Resources Corporation and HALRES LLC (formerly Halcón Resources LLC) (Incorporated by reference to Exhibit 4.3 of our Current Report on Form 8-K filed February 9, 2012).
4.4	Indenture dated as of July 16, 2012, among Halcón Resources Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as Trustee, relating to Halcón Resources Corporation's 9.75% Senior Notes due 2020 (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed July 17, 2012).
4.5	Registration Rights Agreement dated July 16, 2012, among Halcón Resources Corporation, the subsidiary guarantors named therein, and the initial purchaser named therein (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed July 17, 2012).
4.6	First Supplemental Indenture dated as of August 1, 2012, by and among Halcón Resources Corporation, the parties named therein as subsidiary guarantors, and U.S. Bank National Association, as Trustee, relating to the 9.75% senior notes due 2020 (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed August 2, 2012).
4.7	Second Supplemental Indenture dated as of August 1, 2012, by and among Halcón Resources Corporation, the parties named therein as subsidiary guarantors, and U.S. Bank National Association, as Trustee, relating to the 9.75% senior notes due 2020 (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed August 2, 2012).
4.8	Registration Rights Agreement dated as of August 1, 2012, among CH4 Energy II, LLC, PetroMax Leon, LLC and Petro Texas LLC and Halcón Resources Corporation (subsequently joined by U.S. King King LLC) (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed August 7, 2012).
4.9	Registration Rights Agreement dated March 5, 2012, between Halcón Resources Corporation and Barclays Capital, Inc. as lead placement agent for the benefit of the initial holders named therein (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed March 5, 2012).

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4.10	Registration Rights Agreement dated as of November 6, 2012, among Halcón Resources Corporation, the subsidiary guarantors named therein, and the initial purchaser named therein (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed November 7, 2012).
4.11	Indenture dated as of November 6, 2012, among Halcón Resources Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as Trustee, relating to Halcón Resources Corporation's 8.875% Senior Notes due 2021 (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed November 7, 2012).
4.12	First Supplemental Indenture dated December 6, 2012, among Halcón Williston I, LLC and Halcón Williston II, LLC, the existing guarantors, Halcón Resources Corporation, the parties named therein as subsidiary guarantors and U.S. Bank National Association, as trustee, relating to the 9.75% senior notes due 2020 (Incorporated by reference to Exhibit 4.3 of our Current Report on Form 8-K filed December 11, 2012).
4.13	Third Supplemental Indenture dated December 6, 2012, among Halcón Resources Corporation and U.S. Bank National Association, as Trustee, relating to the 8.875% senior notes due 2021 (Incorporated by reference to Exhibit 4.4 of our Current Report on Form 8-K filed December 11, 2012).
4.14	First Amendment to Registration Rights Agreement dated December 6, 2012, between Halcón Resources Corporation and HALRES LLC (formerly Halcón Resources LLC) (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed December 11, 2012).
10.1	Employment Agreement between Registrant and Larry E. Lee dated May 8, 2006 (Incorporated by reference to Exhibit 10.15 of our Current Report on Form 8-K filed May 12, 2006).
10.1.1	First Amendment to Employment Agreement between Registrant and Larry E. Lee dated October 18, 2006 (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed June 5, 2006).
10.1.2	Second Amendment to Employment Agreement of Larry E. Lee dated February 25, 2008 (Incorporated by reference to Exhibit 10.6.2 of our Current Report on Form 8-K filed February 26, 2008).
10.1.3	Third Amendment to Employment Agreement of Larry E. Lee dated December 30, 2008 (Incorporated by reference to Exhibit 10.6.3 of our Current Report on Form 8-K filed January 5, 2009).
10.1.4	Fourth Amendment to Employment Agreement of Larry E. Lee dated March 24, 2009 (Incorporated by reference to Exhibit 10.6.4 of our Current Report on Form 8-K filed March 25, 2009).
10.1.5	Fifth Amendment to Employment Agreement of Larry E. Lee dated March 17, 2010 (Incorporated by reference to Exhibit 10.6.5 of our Current Report on Form 8-K filed March 18, 2010).
10.1.6	Sixth Amendment to Employment Agreement of Larry E. Lee dated March 8, 2011 (Incorporated by reference to Exhibit 10.6.6 of our Current Report on Form 8-K filed March 10, 2011).

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10.2	Senior Revolving Credit Agreement dated as of February 8, 2012, among Halcón Resources Corporation, as borrower, each of the lenders from time to time party thereto, and JPMorgan Chase Bank, N.A., as administrative agent for the lenders (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed February 9, 2012).
10.3	Guarantee and Collateral Agreement dated as of February 8, 2012, among Halcón Resources Corporation, as borrower, each of the lenders from time to time party thereto, and JPMorgan Chase Bank, N.A., as administrative agent for the lenders (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed February 9, 2012).
10.4	Compensation Plan for Non-Employee Directors (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed March 8, 2012).
10.5	Stock Ownership Guidelines Policy (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed March 8, 2012).
10.6	Form of Indemnity Agreement (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed March 13, 2012).
10.7	Voting Agreement dated as of April 24, 2012 by and between GeoResources, Inc. and HALRES LLC (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed April 25, 2012).
10.8	Voting Agreement dated as of April 24, 2012 by and among Halcón Resources Corporation, Leopard Sub I, Inc. and each of the stockholders party thereto (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed April 25, 2012).
10.9	Confidential Information, Non-Competition and Non-Solicit Agreement dated as of April 24, 2012 by and between Halcón Resources Corporation and Frank A. Lodzinski (Incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K filed April 25, 2012).
10.10	Halcón Resources Corporation 2012 Long-Term Incentive Plan effective May 17, 2012 (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed May 22, 2012).
10.11	Employment Agreement between Floyd C. Wilson and Halcón Resources Corporation dated June 1, 2012 (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed June 5, 2012).
10.12	Employment Agreement between Stephen W. Herod and Halcón Resources Corporation dated June 1, 2012 (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed June 5, 2012).
10.13	Employment Agreement between Mark J. Mize and Halcón Resources Corporation dated June 1, 2012 (Incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K filed June 5, 2012).
10.14	Employment Agreement between David S. Elkouri and Halcón Resources Corporation dated June 1, 2012 (Incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K filed June 5, 2012).
10.15	Employment Agreement between Joseph S. Rinando, III and Halcón Resources Corporation dated June 1, 2012 (Incorporated by reference to Exhibit 10.5 of our Current Report on Form 8-K filed June 5, 2012).
10.16	Form of Stock Option Award Agreement (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed June 13, 2012).

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10.17	Form of Employee Restricted Stock Agreement (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed June 13, 2012).
10.18	Form of Non-Employee Director Restricted Stock Agreement (Incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K filed June 13, 2012).
10.19*	Purchase Agreement dated June 29, 2012, by and between Halcón Resources Corporation and Wells Fargo Securities, LLC as representative of the initial purchasers named therein relating to Halcón Resources Corporation's 9.75% Senior Notes due 2020.
10.20	Escrow Agreement, dated as of July 16, 2012, by and among Halcón Resources Corporation, U.S. Bank National Association, as trustee under the Indenture, and U.S. Bank National Association, as escrow and paying agent (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed July 17, 2012).
10.21	First Amendment to Senior Revolving Credit Agreement, dated as of August 1, 2012, among Halcón Resources Corporation, as borrower, each of the lenders from time to time party thereto, and JPMorgan Chase Bank, N.A., as administrative agent for the lenders (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed August 2, 2012).
10.22	Employment Agreement between Robert J. Anderson and Halcón Resources Corporation dated August 1, 2012 (Incorporated by reference to Exhibit 10.12 of our Quarterly Report on Form 10-Q filed November 8, 2012).
10.23	Common Stock Purchase Agreement dated October 19, 2012, by and between Halcón Resources Corporation and CPP Investment Board PMI-2 Inc. (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed October 22, 2012).
10.24	Purchase Agreement dated October 23, 2012, by and between Halcón Resources Corporation and Wells Fargo Securities, LLC as representative of the initial purchasers named therein relating to Halcón Resources Corporation's 8.875% Senior Notes due 2021 (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed October 26, 2012).
10.25	Escrow Agreement, dated as of November 6, 2012, by and among Halcón Resources Corporation, U.S. Bank National Association, as trustee under the Indenture, and U.S. Bank National Association, as escrow and paying agent (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed November 7, 2012).
10.26	Stockholders Agreement dated December 6, 2012, between Halcón Resources Corporation and CPP Investment Board PMI-2 Inc. (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed December 11, 2012).
12.1*	Computation of Ratio of Earnings to Combined Fixed Charges and Preference Dividends
21.1*	List of Subsidiaries of Halcón Resources Corporation
23.1*	Consent of Deloitte & Touche LLP
23.2*	Consent of UHY LLP
23.3*	Consent of Netherland, Sewell & Associates, Inc.
23.4*	Consent of Forrest A. Garb & Associates, Inc.
31.1*	Sarbanes-Oxley Section 302 certification of Principal Executive Officer
31.2*	Sarbanes-Oxley Section 302 certification of Principal Financial Officer

32*	Sarbanes-Oxley Section 906 certification of Principal Executive Officer and Principal Financial Officer
99.1*	Report of Netherland, Sewell & Associates, Inc.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

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Attached hereto.

Indicates management contract or compensatory plan or arrangement.

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

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SIGNATURES

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

HALCÓN RESOURCES CORPORATION

Date: February 28, 2013

By: /s/ FLOYD C. WILSON

Floyd C. Wilson
Chairman of the Board and
Chief Executive Officer

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

Signature	Title	Date
/s/ FLOYD C. WILSON **Floyd C. Wilson**	Chairman of the Board, Chief Executive Officer and Director	February 28, 2013
/s/ MARK J. MIZE **Mark J. Mize**	Executive Vice President, Chief Financial Officer and Treasurer	February 28, 2013
/s/ JOSEPH S. RINANDO, III **Joseph S. Rinando, III**	Vice President, Chief Accounting Officer	February 28, 2013
/s/ TUCKER S. BRIDWELL **Tucker S. Bridwell**	Director	February 28, 2013
/s/ JAMES W. CHRISTMAS **James W. Christmas**	Director	February 28, 2013
/s/ THOMAS R. FULLER **Thomas R. Fuller**	Director	February 28, 2013
/s/ KEVIN E. GODWIN **Kevin E. Godwin**	Director	February 28, 2013

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Signature	Title	Date
/s/ DAVID S. HUNT **David S. Hunt**	Director	February 28, 2013
/s/ JAMES L. IRISH III **James L. Irish III**	Director	February 28, 2013
/s/ DAVID B. MILLER **David B. Miller**	Director	February 28, 2013
/s/ DANIEL A. RIOUX **Daniel A. Rioux**	Director	February 28, 2013
/s/ STEPHEN P. SMILEY **Stephen P. Smiley**	Director	February 28, 2013
/s/ MICHAEL A. VLASIC **Michael A. Vlasic**	Director	February 28, 2013
/s/ MARK A. WELSH IV **Mark A. Welsh IV**	Director	February 28, 2013