**UNITED STATES SECURITIES AND EXCHANGE COMMISSION**

**Washington, D.C. 20549**

# FORM 10-K

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

**For the fiscal year ended December 31, 2012**

**or**

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

**For the transition period from ____________________ to ____________________**

**Commission file number: 1-33615**

**Concho Resources Inc.**

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Delaware** | **76-0818600** |
| State or other jurisdiction of incorporation or organization | (I.R.S. Employer Identification No.) |
| **One Concho Center 600 West Illinois Avenue Midland, Texas** | **79701** |

| (Address of principal executive offices) | (Zip code) |
|---|---|

**(432) 683-7443**
Registrant's telephone number, including area code
Securities Registered Pursuant to Section 12(b) of the Act:

| Title of each class | Name of each exchange on which registered |
|---|---|
| **Common Stock, $0.001 par value** | **New York Stock Exchange** |

Securities Registered Pursuant to Section 12(g) of the Act: **None**

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

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

| | |
|---|---|
| Large accelerated filer þ | Accelerated filer o |
| Non-accelerated filer o (Do not check if a smaller reporting company) | Smaller reporting company o |

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

| | |
|---|---|
| Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant’s most recently completed second fiscal quarter: | $8,671,278,502 |
| Number of shares of registrant’s common stock outstanding as of February 20, 2013: | 104,666,903 |

**Documents Incorporated by Reference:**

Portions of the registrant's definitive proxy statement for its 2012 Annual Meeting of Stockholders, which will be filed with the United States Securities and Exchange Commission within 120 days of December 31, 2012, are incorporated by reference into Part III of this report for the year ended December 31, 2012.

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**CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS**

Various statements contained in or incorporated by reference into this report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). These forward-looking statements include statements, projections and estimates concerning our operations, performance, business strategy, oil and natural gas reserves, drilling program, capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "foresee," "plan," words that convey the uncertainty of future events or outcomes. Forward-looking statements are not guarantees of performance. We have based these forward-looking statements on our current expectations and assumptions about future events. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Actual results may differ materially from those implied or expressed by the forward-looking statements. These forward-looking statements speak only as of the date of this report, or if earlier, as of the date they were made. We disclaim any obligation to update or revise these statements unless required by law, and we caution you not to rely on them unduly. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks discussed in "Item 1A. Risk Factors," as well as those factors summarized below:

- sustained or further declines in the prices we receive for our oil and natural gas;
- uncertainties about the estimated quantities of oil and natural gas reserves;
- drilling and operating risks, including risks related to properties where we do not serve as the operator and risks related to hydraulic fracturing activities;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our credit facility;
- the effects of government regulation, permitting and other legal requirements, including new legislation or regulation of hydraulic fracturing;
- difficult and adverse conditions in the domestic and global capital and credit markets;
- risks related to the concentration of our operations in the Permian Basin of Southeast New Mexico and West Texas;
- shortages of oilfield equipment, supplies, services and qualified personnel and increased costs for such equipment, supplies, services and personnel;
- potential financial losses or earnings reductions from our commodity price management program;
- risks and liabilities associated with acquired properties or businesses;

- uncertainties about our ability to successfully execute our business and financial plans and strategies;
- uncertainties about our ability to replace reserves and economically develop our current reserves;
- general economic and business conditions, either internationally or domestically or in the jurisdictions in which we operate;
- competition in the oil and natural gas industry; and
- uncertainty concerning our assumed or possible future results of operations.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by our reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ from the quantities of oil and natural gas that are ultimately recovered.

# PART I

***Item 1. Business***

## *General*

Concho Resources Inc., a Delaware corporation (“Concho,” the “Company,” “we,” “us” and “our”) formed in February 2006, i an independent oil and natural gas company engaged in the acquisition, development and exploration of oil and natural gas properties. Our core operating areas are located in the Permian Basin region of Southeast New Mexico and West Texas, a large onshore oil and natural gas basin in the United States. The Permian Basin is one of the most prolific oil and natural gas producing regions in the United States and is characterized by an extensive production history, long reserve life, multiple producing horizons and enhanced recovery potential. We refer to our three core operating areas as the (i) New Mexico Shelf, where we primarily target the Yeso formation, (ii) Delaware Basin, where we primarily target the Bone Spring formation (including the Avalon shale and the Bone Spring sands) and the Wolfcamp shale, and (iii) Texas Permian, where we primarily target the Wolfberry, a term applied to the combined Wolfcamp and Spraberry horizons. We intend to grow our reserves and production through development drilling and exploration activities on our multi-year project inventory and through acquisitions that meet our strategic and financial objectives.

***Acquisitions***

***Three Rivers Acquisition***

In July 2012, we completed an acquisition of producing and non-producing assets from Three Rivers Operating Company LLC and certain affiliated entities (the “Three Rivers Acquisition”) for cash consideration of approximately $1.0 billion. We estimated that the Three Rivers Acquisition had approximately 45.5 MMBoe of proved reserves at closing. The Three Rivers Acquisition was primarily funded with borrowings under our credit facility.

***PDC Acquisition***

In February 2012, we completed an acquisition of producing and non-producing assets in the Wolfberry trend in the Permian Basin from Petroleum Development Corporation (the “PDC Acquisition”) for approximately $189.2 million in cash. We estimated that the PDC Acquisition had approximately 9.8 MMBoe of proved reserves at closing. The PDC Acquisition was primarily funded with borrowings under our credit facility.

***Delaware Basin Acquisitions***

*OGX Acquisition.* In November 2011, we acquired three entities affiliated with OGX Holdings II, LLC (collectively the “OGX Acquisition”) for cash consideration of approximately $252.0 million. The OGX Acquisition consisted of producing and non-producing acreage in the Delaware Basin of Southeast New Mexico and West Texas. We estimate that the OGX Acquisition contained approximately 5.7 MMBoe of proved reserves at closing. The OGX Acquisition was primarily funded with borrowings under our credit facility.

*Other Delaware Basin Acquisitions.* In the third and fourth quarters of 2011, in four acquisitions, we acquired for approximately $79.0 million in cash additional non-producing acreage in the Delaware Basin. These acquisitions were primarily funded with borrowings under our credit facility. We collectively refer to these acquisitions and the OGX Acquisition as the “Delaware Basin Acquisitions.”

***Marbob and Settlement Acquisitions***

In July 2010, we entered into an asset purchase agreement to acquire certain of the oil and natural gas leases, interests, properties and related assets owned by Marbob Energy Corporation and its affiliates (collectively, “Marbob”) for aggregate consideration of (i) cash in the amount of $1.45 billion, (ii) the issuance to Marbob of a $150 million 8.0% senior note due 2018, which was repaid in May of 2011 with borrowings under our credit facility, and (iii) the issuance to Marbob of approximately 1.1 million shares of our common stock, subject to purchase price adjustments, which included downward purchase price adjustments based on the exercise by third parties of contractual preferential purchase rights in properties to be acquired from Marbob (the “Marbob Acquisition”).

On October 7, 2010, we closed the Marbob Acquisition. At closing, we paid approximately $1.1 billion in cash plus the senior note and common stock described above for a total purchase price of approximately $1.4 billion. The total purchase price as originally announced was reduced due to third party contractual preferential purchase rights in the Marbob properties. Certain of the third parties’ contractual preferential purchase rights became subject to litigation.

We funded the cash consideration in the Marbob Acquisition with (a) borrowings under our credit facility and (b) net proceeds of $292.7 million from a private placement of approximately 6.6 million shares of our common stock at a price of $45.30 per share that closed on October 7, 2010.

On October 15, 2010, we resolved the litigation related to the disputed contractual preferential purchase rights. As a result of the settlement, we acquired a non-operated interest in substantially all of the oil and natural gas assets subject to the litigation for approximately $286 million in cash (the “Settlement Acquisition”). We funded the Settlement Acquisition with borrowings under our credit facility.

The properties acquired in the Marbob and Settlement Acquisitions are primarily located in the Permian Basin of Southeast New Mexico, including a large acreage position contiguous to our core Yeso play on the southeast New Mexico Shelf and a significant acreage position in the Delaware Basin. We estimate that the assets acquired in the Marbob and Settlement Acquisitions contained approximately 72.4 MMBoe of proved reserves at closing.

***Divestitures***

In December 2012, we sold certain of our non-core assets, some of which were acquired in the Three Rivers Acquisition, for cash consideration of approximately $488.1 million, subject to customary post-closing adjustments, and recognized a pre-tax loss on the disposition of assets (included in discontinued operations) of approximately $18.7 million. For the year ended December 31, 2012, these assets produced an average of 4,937 Boe per day, which was approximately 63 percent oil. We estimate that the proved reserves of these assets at closing were approximately 35.3 MMBoe.

In March 2011, we sold our Bakken assets for cash consideration of approximately $195.9 million and recognized a pre-tax gain on the disposition of assets (included in discontinued operations) of approximately $135.9 million. For the first quarter of 2011, these assets produced an average of 1,369 Boe per day. We estimate that the proved reserves of the Bakken assets at closing were approximately 8.4 MMBoe.

In December 2010, we sold certain of our non-core Permian Basin assets for cash consideration of approximately $103.3 million and recognized a pre-tax gain on the disposition of assets (included in discontinued operations) of approximately $29.1 million. For 2010, these assets produced an average of 1,393 Boe per day. We estimate that the proved reserves of these assets at closing were approximately 6.0 MMBoe.

***Business and Properties***

Our core operations are focused in the Permian Basin of Southeast New Mexico and West Texas. It underlies an area of Southeast New Mexico and West Texas approximately 250 miles wide and 300 miles long. Commercial accumulations of hydrocarbons occur in multiple stratigraphic horizons, at depths ranging from approximately 1,000 feet to over 25,000 feet. At December 31, 2012, substantially all of our 447.2 MMBoe total estimated proved reserves were located in our core operating areas and consisted of approximately 61.2 percent oil and 38.8 percent natural gas. We have assembled a multi-year inventory of development drilling and exploration projects, including projects to further evaluate (i) the areal extent of the Yeso formation and the Wolfberry play and (ii) the Bone Spring and Wolfcamp formations in the Delaware Basin, which we believe will allow us to grow our proved reserves and production.

We continually evaluate opportunities that could develop into an emerging play. We view an emerging play as an area where we can acquire large undeveloped acreage positions and apply horizontal drilling and/or advanced fracture stimulation technologies to achieve economic and repeatable production results. We have assembled an exploration team to target such emerging plays.

The following table sets forth information with respect to drilling of wells commenced during the periods indicated:

| | |
|---|---|
| Gross wells | |
| Net wells | |
| | |
| Percent of gross wells drilled horizontally | |
| | |
| Percent of gross wells: | |
| | Producers |
| | Unsuccessful |
| | Awaiting completion at year-end |

In 2012, we drilled approximately 27% of our wells horizontally. We will continue to evaluate converting our identified vertical locations to horizontal opportunities, where possible. We believe horizontal drilling is more capital efficient than vertical drilling, in many situations. In 2013, we plan to spend approximately $900 million of our $1.4 billion drilling and completion costs budget on horizontal drilling opportunities.

We produced approximately 29.8 MMBoe, 23.6 MMBoe and 15.6 MMBoe of oil and natural gas during 2012, 2011 and 2010, respectively. Included in those production amounts are 1,807 MBoe, 1,679 MBoe and 2,345 MBoe of production related to our discontinued operations during 2012, 2011 and 2010, respectively. In addition, we increased our average daily production from 66.2 MBoe during the fourth quarter of 2011 to 84.7 MBoe during the fourth quarter of 2012. During 2012, we increased our total estimated proved reserves by approximately 60.7 MMBoe, after giving effect to (i) acquisitions of 56.5 MMBoe and (ii) sales of minerals-in-place of 35.3 MMBoe.

***Summary of Core Operating Areas and Other Plays***

The following is a summary of information regarding our core operating areas and other plays that are further described below:

| | Areas |
|---|---|
| **Core Operating Areas:** | |
| New Mexico Shelf ............ | |
| Delaware Basin ............ | |
| Texas Permian ............ | |
| **Other ............** | |
| Total ............ | |

(a) Our Standardized Measure at December 31, 2012 was $5.8 billion. The present value of estimated future net revenues discounted at an annual rate of 10 percent ("PV-10") is not a GAAP financial measure and is derived from the Standardized Measure, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas assets. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas assets. PV-10, however, is not a substitute for the

Standardized Measure. Our PV-10 measure and the Standardized Measure do not purport to present the fair value of our oil and natural gas reserves. See “Item 1. Business —Non-GAAP Financial Measures and Reconciliations.”

(b) Of the 12,269 gross identified drilling locations, 2,326 locations were associated with proved reserves.

(c) Includes production of 1,807 MBoe (an average of 4,937 Boe per day for the year) for the non-core assets divested in December 2012.

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**Core operating areas**

***New Mexico Shelf.*** This area represents our most significant concentration of assets and, at December 31, 2012, we had estimated proved reserves in this area of 224.4 MMBoe, representing 50.2 percent of our total proved reserves and 55.7 percent of our PV-10.

Within this area our primary objectives are the Yeso, San Andres and Grayburg formations, with producing depths ranging from approximately 900 feet to 7,500 feet. We have drilled and plan to continue to evaluate drilling horizontally in the Yeso. During 2012, we continued our development of the Yeso formation on 10 acre spacing.

During the year ended December 31, 2012, we commenced drilling or participated in the drilling of 360 (257 net) wells in this area, of which 298 (223 net) wells were completed as producers, 2 (1 net) wells were unsuccessful and 60 (33 net) wells were in various stages of drilling and completion at December 31, 2012. During 2012, approximately 18 percent of the wells we commenced or participated in drilling were drilled horizontally.

At December 31, 2012, we had 228,936 gross (103,814 net) acres in this area. At December 31, 2012, on our assets in this area, we had identified 2,083 (1,401 net) drilling locations, with proved reserves attributed to 616 (457 net) of such locations. Of these 2,083 drilling locations, 1,044 locations target the Yeso formation vertically and 676 locations target the Yeso formation horizontally.

In 2013, we plan to spend approximately $285 million, or 21 percent, of our 2013 capital budget on drilling and completion costs on the New Mexico Shelf assets, with which we expect to drill 190 (116 net) wells. In 2013, we expect that approximately 31 percent of these wells will be drilled horizontally.

***Delaware Basin.*** At December 31, 2012, we had estimated proved reserves in the Delaware Basin of 81.7 MMBoe, representing 18.3 percent of our total proved reserves and 16.8 percent of our PV-10.

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Within this area, we utilize horizontal drilling and fracturing technologies to target the oil-prone Bone Spring formation that includes three Bone Spring sandstone members, the Avalon shale member and the Wolfcamp shale. These formations produce from 4,700 feet to 13,500 feet for our currently targeted activity. Within the Delaware Basin, we have drilled and are also actively evaluating the Delaware sands and Penn shale opportunities on our acreage.

During the year ended December 31, 2012, we commenced drilling or participated in the drilling of 154 (76 net) wells in this area, of which 107 (51 net) wells were completed as producers, 2 (2 net) wells were unsuccessful and 45 (23 net) wells were in various stages of drilling and completion at December 31, 2012. During 2012, we continued (i) our development and step-out activity on the Avalon shale, Bone Spring sands and Wolfcamp shale and (ii) evaluation of our fracture stimulation procedures in the completion of certain horizontal wells. During 2012, approximately 99% of the wells we commenced or participated in drilling were drilled horizontally.

At December 31, 2012, we had 476,223 gross (315,742 net) acres in this area.  At December 31, 2012, we had identified 4,212 (1,949 net) drilling locations, with proved reserves attributed to 246 (128 net) of such locations. These locations include 2,462 targeting the Bone Spring sands, 1,016 targeting the Avalon shale and 734 targeting other formations.

In 2013, we plan to spend approximately $725 million, or 54 percent, of our 2013 capital budget on drilling and completion costs on the Delaware Basin assets, with which we expect to drill 175 (99 net) wells. In 2013, we expect that approximately 95 percent of these wells will be drilled horizontally.

***Texas Permian.***  At December 31, 2012, our estimated proved reserves of 141.0 MMBoe in this area accounted for 31.5 percent of our total proved reserves and 27.5 percent of our PV-10 value.

Our primary objective in the Texas Permian area is the Wolfberry in the Midland Basin. “Wolfberry” is the term applied to the combined production from the Spraberry and Wolfcamp horizons out of vertical wellbores, which are typically encountered at depths of 7,500 feet to 10,500 feet. These formations are comprised of a sequence of basinal, interbedded sands, shales and carbonates.  On our Texas Permian assets we are continuing to evaluate (i) our 20-acre downspacing on the Wolfberry assets, (ii) the potential of horizontal Wolfcamp drilling and (iii) the other potential zones on our acreage, such as the Cline shale (a Pennsylvanian age formation).

At December 31, 2012, we had 426,601 gross (155,490 net) acres in this area. In addition, at December 31, 2012, we had identified 5,974 (3,638 net) drilling locations, with proved reserves attributed to 1,464 (749 net) of such drilling locations. Of these 5,974 drilling locations, 1,955 target the Wolfberry play through 40-acre spacing, 2,486 target the Wolfberry play on 20-acre spacing, 1,410 target the shallow Wolfcamp vertically and the remaining drilling locations target other objectives.

During 2012, we commenced drilling or participated in the drilling of 326 (186 net) wells in this area, of which 270 (153 net) wells were completed as producers, 1 (1 net) well was unsuccessful and 55 (32 net) wells were in various stages of drilling and completion at December 31, 2012. During 2012, approximately 2 percent of the wells we commenced or participated in drilling were drilled horizontally.

In 2013, we plan to spend approximately $342 million, or 25 percent, of our 2013 capital budget on drilling and completion costs on the Texas Permian assets, with which we expect to drill 266 (165 net) wells. In 2013, we expect that approximately 3 percent of these wells will be drilled horizontally.

*Drilling Activities*

The following table sets forth information with respect to (i) wells drilled and completed during the periods indicated and (ii) wells drilled in a prior period but completed in the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value.

| | |
|---|---|
| **Development wells:** | |
| Productive ........................................ | |
| Dry ........................................ | |
| **Exploratory wells:** | |
| Productive ........................................ | |
| Dry ........................................ | |
| **Total wells:** | |
| Productive ........................................ | |
| Dry ........................................ | |
| **Total** ........................................ | |

The following table sets forth information about our wells for which drilling was in-progress or are pending completion at December 31, 2012, which are not included in the above table:

| | |
|---|---|
| Development wells | |
| Exploratory wells | |
| Total | |

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***Our Production, Prices and Expenses***

The following table sets forth summary information concerning our production and operating data from continuing operations for the years ended December 31, 2012, 2011 and 2010. The table below excludes production and operating data that we have classified as discontinued operations, which is more fully described in Note N of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data." The actual historical data in this table excludes results from the (i) Three Rivers Acquisition for periods prior to July 2012, (ii) PDC Acquisition for periods prior to March 2012, (iii) OGX Acquisition for periods prior to December 2011 and (iv) Marbob and Settlement Acquisitions for periods prior to their respective close dates in October 2010. Because of normal production declines, increased or decreased drilling activities and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

| | |
|---|---|
| ***Production and operating data:*** | |
| **Net production volumes:** | |
| Oil (MBbl) | |
| Natural gas (MMcf) | |
| Total (MBoe) | |
| **Average daily production volumes:** | |
| Oil (Bbl) | |
| Natural gas (Mcf) | |
| Total (Boe) | |
| **Average prices:** | |
| Oil, without derivatives (Bbl) | |
| Oil, with derivatives (Bbl) (a) | |
| Natural gas, without derivatives (Mcf) | |
| Natural gas, with derivatives (Mcf) (a) | |

Total, without derivatives (Boe) ..........

Total, with derivatives (Boe) (a) ..........

**Operating costs and expenses per Boe:**

Lease operating expenses and workover costs ..........

Oil and natural gas taxes ..........

Depreciation, depletion and amortization ..........

General and administrative ..........

(a) Includes the effect of cash settlements received from (paid on) commodity derivatives not designated as hedges and report
following table reflects the amounts of cash settlements received from (paid on) commodity derivatives not designated as h
average prices with derivatives and reconciles to the amount in (gain) loss on derivatives not designated as hedges as repor

**(in thousands)**

**Gain (loss) on derivatives not designated as hedges:**

Cash receipts from (payments on) oil derivatives ..........

Cash receipts from natural gas derivatives ..........

Cash payments on interest rate derivatives ..........

Unrealized mark-to-market gain (loss) on commodity and interest rate derivatives ..........

Gain (loss) on derivatives not designated as hedges ..........

The presentation of average prices with derivatives is a non-GAAP measure as a result of including the cash receipts from
that are presented in gain (loss) on derivatives not designated as hedges in the statements of operations. This presentation o
means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and present
derivatives in a manner consistent with the presentation generally used by the investment community.

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***Productive Wells***

The following table sets forth the number of productive oil and natural gas wells on our properties at December 31, 2012, 2011 and 2010. This table does not include wells in which we own a royalty interest only.

| |
|---|
| ***December 31, 2012*** |
| **Core Operating Areas:** |
| New Mexico Shelf |
| Delaware Basin |
| Texas Permian |
| Total |
| ***December 31, 2011*** |
| **Core Operating Areas:** |
| New Mexico Shelf |
| Delaware Basin |
| Texas Permian |
| Total |
| ***December 31, 2010*** |
| **Core Operating Areas:** |
| New Mexico Shelf |
| Delaware Basin |

Texas Permian

**Other**

Total

***Marketing Arrangements***

***General***. We market our oil and natural gas in accordance with standard energy practices. The marketing effort is coordinated with our operations group as it relates to the planning and preparation of future drilling programs so that available markets can be assessed and secured. This planning also involves the coordination of access to the physical facilities necessary to connect new producing wells as efficiently as possible upon their completion.

***Oil***. We do not transport, refine or process the oil we produce. A significant portion of our oil in Southeast New Mexico, primarily on the New Mexico Shelf, is connected directly to oil gathering pipelines. Most of our gathered oil in this area is utilized in a two-refinery complex in Southeast New Mexico. A significant portion of our West Texas production is on pipeline. Most of this production is sweet crude and is transported by third parties to the Cushing, Oklahoma hub. The balance of our oil in these areas that is not directly connected to pipeline is (i) trucked to unloading stations on those same pipelines or (ii) railed to the Gulf Coast in lieu of transporting by pipeline. We sell the majority of the oil we produce under contracts using market-based pricing. This price is then adjusted for differentials based upon delivery location and oil quality.

***Natural Gas***. We consider all natural gas gathering and delivery infrastructure in the areas of our production and evaluate market options to obtain the best price reasonably available under the circumstances. We sell the majority of our natural gas under individually negotiated natural gas purchase contracts using market-based pricing. The majority of our natural gas is subject to term agreements that extend at least three years from the date of the subject contract.

The majority of the natural gas we sell is casinghead gas sold at the lease under a percentage of proceeds processing contract. The purchaser gathers our casinghead natural gas in the field where it is produced and transports it via pipeline to a natural gas processing plant where the natural gas liquid products are extracted and sold by the processor. The remaining natural gas product is residue gas, or dry gas, which is placed on residue pipeline systems available in the area. Under our percentage of proceeds contracts, we receive a percentage of the value for the extracted liquids and the residue gas. In a limited number of cases (typically dry gas production), the natural gas gathering and transportation is performed by a third party gathering company which transports the production from the production location to the purchaser’s mainline.

***Our Principal Customers***

We sell our oil and natural gas production principally to marketers and other purchasers that have access to pipeline facilities. In areas where there is no practical access to pipelines, oil is transported to storage facilities by trucks and rail owned or otherwise arranged by the marketers or purchasers. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted.

For 2012, revenues from oil and natural gas sales to Holly Frontier Refining and Marketing, LLC and Phillips 66 (formerly the ConocoPhillips Company) accounted for approximately 26 percent and 14 percent, respectively, of our total operating revenues. While the loss of either of these purchasers may result in a temporary interruption in sales of, or a lower price for, our production, we believe that the loss of any of these purchasers would not have a material adverse effect on our operations, as there are alternative purchasers in our producing regions.

***Competition***

The oil and natural gas industry in the regions in which we operate is highly competitive. We encounter strong competition from numerous parties, ranging generally from small independent producers to major integrated companies. We primarily encounter significant competition in acquiring properties, contracting for drilling, pressure pumping and workover equipment and securing trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger than ours. As a result, our competitors may be able to pay more for desirable properties, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit.

In addition to competition for drilling, pressure pumping and workover equipment, we are also affected by the availability of related equipment and materials. The oil and natural gas industry periodically experiences shortages of drilling and workover rigs, equipment, pipe, materials and personnel, which can delay drilling, workover and exploration activities and cause significant price increases. The shortages of personnel make it difficult to attract and retain personnel with experience in the oil and natural gas industry and caused us to increase our general and administrative budget. We are unable to predict the timing or duration of any such shortages.

Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases and drilling rights. Although we regularly evaluate acquisition opportunities and submit bids as part of our growth strategy, we do not have any current agreements, understandings or arrangements with respect to any material acquisition.

***Applicable Laws and Regulations***

*Regulation of the Oil and Natural Gas Industry*

***Regulation of transportation and sale of oil****.* Sales of oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our sales of oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission (the “FERC”) regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system that permits an oil pipeline, subject to limited challenges, to annually increase or decrease its transportation rates due to inflationary changes in costs using a FERC approved index, without making a cost of service filing. Every five years, the FERC reviews the appropriateness of the index in relation to industry costs. On December 16, 2010, the FERC established a new Producer Price Index for Finished Goods (the “PPI-FG”) of PPI-FG plus 2.65 percent for the five-year period beginning July 1, 2011. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis at posted tariff rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Effective November 4, 2009, pursuant to the Energy Independence and Security Act of 2007, the Federal Trade Commission ("FTC") issued a rule prohibiting market manipulation in the petroleum industry. The FTC rule prohibits any person, directly or indirectly, in connection with the purchase or sale of oil, gasoline or petroleum distillates at wholesale from knowingly engaging in any act, practice or course of business, including the making of any untrue statement of material fact, that operates or would operate as a fraud or deceit upon any person, or intentionally failing to state a material fact that under the circumstances renders a statement made by such person misleading, provided that such omission distorts or is likely to distort market conditions for any such product. A violation of this rule may result in civil penalties of up to $1 million per day per violation, in addition to any applicable penalty under the Federal Trade Commission Act.

***Regulation of transportation and sale of natural gas***. Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938 (the "Natural Gas Act"), the Natural Gas Policy Act of 1978 (the "Natural Gas Policy Act") and regulations issued under those acts by the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future, and market participants are prohibited from engaging in market manipulation. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act which removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

The FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued Order No. 636 and a series of related orders to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly altered. The interstate pipelines' traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although these orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting.

In August 2005, Congress enacted the Energy Policy Act of 2005 (the "EPAct 2005"). Among other matters, EPAct 2005 amends the Natural Gas Act to make it unlawful for "any entity," including otherwise non-jurisdictional producers such as us, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. The FERC's rules implementing this provision make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the Natural Gas Act or Natural Gas Policy Act up to $1 million per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales, gathering or production, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" natural gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order No. 704, described below. EPAct 2005 therefore reflects a significant expansion of the FERC's enforcement authority. We do not anticipate we will be affected any differently than other producers of natural gas.

In December 2007, the FERC issued a rule ("Order No. 704"), as clarified in orders on rehearing, requiring that any market participant, including a producer such as us, that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million MMBtus during a calendar year to annually report, starting May 1, 2009, such sales and purchases to the FERC. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and in detecting market manipulation. We do not anticipate that we will be affected by these rules any differently than other producers of natural gas.

We cannot accurately predict whether the FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before the FERC and the courts. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, the FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting natural gas to point of sale locations.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. During the 2007 legislative session, the Texas State Legislature passed H.B. 3273 (the "Competition Bill") and H.B. 1920 (the "LUG Bill"). The Competition Bill gives the Railroad Commission of Texas the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering and intrastate transportation pipelines in formal rate proceedings. It also gives the Railroad Commission specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in an informal complaint process and to punish purchasers, transporters, and gatherers for taking discriminatory actions against shippers and sellers. The Competition Bill also provides producers with the unilateral option to determine whether or not confidentiality provisions are included in a contract to which a producer is a party for the sale, transportation or gathering of natural gas. The LUG Bill modifies the informal complaint process at the Railroad Commission with procedures unique to lost and unaccounted for natural gas issues. It extends the types of information that can be requested, provides producers with an annual audit right, and provides the Railroad Commission with the authority to make determinations and issue orders in specific situations. Both the Competition Bill and the LUG Bill became effective September 1, 2007, and the Railroad Commission rules implementing the Railroad Commission's authority pursuant to the bills became effective on April 28, 2008.

Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

***Regulation of production***. The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and the plugging and abandonment of 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. 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. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

*Environmental, Health and Safety Matters*

***General***. Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling and production and saltwater disposal activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, environmental laws and regulations are revised frequently, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The following is a summary of some of the existing laws, rules and regulations to which our business is subject.

***Waste handling***. The Resource Conservation and Recovery Act (the “RCRA”) and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Pursuant to regulatory guidance issued by the federal Environmental Protection Agency (the “EPA”), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil or natural gas are currently regulated under RCRA’s non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

***Comprehensive Environmental Response, Compensation and Liability Act***. The Comprehensive Environmental Response, Compensation and Liability Act (the “CERCLA”), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial operations to prevent future contamination.

***Water discharges***. The federal Water Pollution Control Act (the “Clean Water Act”) and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

***Air emissions***. The federal Clean Air Act (“CAA”), 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 CAA and associated state laws and regulations.

For example, in August 2012, the EPA adopted new rules that make all oil and gas operations (production, processing, transmission, storage and distribution) subject to regulation under the New Source Performance Standards (“NSPS”) and National Emission Standards for Hazardous Air Pollutants (“NESHAPS”) programs. These new EPA rules also impose NSPS standards for completions of hydraulically fractured gas wells. These standards include requirements for operators to use the reduced emission completion (“REC”) techniques developed in EPA’s Natural Gas STAR program along with pit flaring of gas not sent to the gathering line. The standards are applicable to newly drilled and fractured wells as well as existing wells that are refractured. The requirement for flaring of gas not sent to a gathering line became effective on October 15, 2012, and all operators are required to use REC techniques beginning January 1, 2015. Further, the new NESHAPS regulations impose maximum achievable control technology ("MACT") standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. We are currently evaluating the effect these rules could have on our business.

***Climate change***. In December 2009, the EPA determined that emissions of carbon dioxide, methane and other "greenhouse gases", or GHGs, present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. The EPA recently adopted two sets of rules regulating GHG emissions under the CAA, one of which requires a reduction in emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources, effective January 2, 2011. The EPA's rules relating to emissions of GHGs are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing, or requiring state environmental agencies to implement, the rules. In 2011, the EPA adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including certain onshore oil and natural gas facilities, on an annual basis beginning in 2012 for emissions occurring in 2011. We fulfilled our 2011 emissions reporting in 2012 as required by EPA's rules.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of GHGs and almost one-half of the states have already taken legal measures to reduce emissions of GHGs gases primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

***Hydraulic fracturing.*** Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We commonly use hydraulic fracturing as part of our operations. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example, Texas adopted rules requiring public disclosure of non-confidential information regarding fluids used in hydraulic fracturing activities that became effective on February 1, 2012, and New Mexico adopted similar rules that became effective on February 15, 2012. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and the EPA is performing a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater resources. The EPA's study includes 18 separate research projects addressing topics such as water acquisition, chemical mixing, well injection, flowback and produced water, and wastewater treatment and waste disposal. The EPA has indicated that it expects to issue its study report in late 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the United States Department of Energy and the United States Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

To our knowledge, there have been no citations, suits, or contamination of potable drinking water arising from our fracturing operations. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our general liability and excess liability insurance policies may cover third-party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies. If new laws or regulations significantly restrict hydraulic fracturing activities or impose burdens on new permitting or operating requirements, our ability to utilize hydraulic fracturing may be curtailed and this may in turn reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

***Endangered species.*** The federal Endangered Species Act and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. Some of our drilling operations are conducted in areas where protected species are known to exist. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting drilling operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to drilling activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where we perform drilling activities could impair our ability to timely complete drilling and developmental operations and could adversely affect our future production from those areas.

***National Environmental Policy Act.*** Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act (the "NEPA"). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having 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 that are subject to the requirements of NEPA. This process has the potential to delay or even halt development of some of our oil and natural gas projects.

***OSHA and other laws and regulation***. We are subject to the requirements of the federal Occupational Safety and Health Act (“OSHA”), and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. Also, pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards relating to workplace exposure to hazardous substances and employee health and safety. We believe that we are in substantial compliance with the applicable requirements of OSHA and comparable laws.

We believe that we are in substantial compliance with existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. For instance, we did not incur any material capital expenditures for remediation or pollution control activities during 2012. Additionally, as of the date of this report, we are not aware of any environmental issues or claims that will require material capital expenditures during 2012. However, we cannot assure you that the passage or application of more stringent laws or regulations in the future will not have a negative impact on our financial position or results of operation.

***Our Employees***

Our corporate headquarters are located at One Concho Center, 600 West Illinois Avenue Midland, Texas 79701. We also maintain various field offices in Texas and New Mexico. At December 31, 2012, we had 745 employees, 290 of whom were employed in field operations. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be good. We also utilize the services of independent contractors to perform various field and other services.

***Available Information***

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the United States Securities and Exchange Commission (the “SEC”) under the Exchange Act. The public may read and copy any materials that we file or furnish with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file or furnish electronically with the SEC. The public can obtain any documents that we file with the SEC at *www.sec.gov*.

We also make available free of charge through our website, *www.concho.com*, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

***Non-GAAP Financial Measures and Reconciliations***

***PV-10***

PV-10 is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas assets. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas assets. PV-10, however, is not a substitute for the standardized measure of discounted future net cash flows. Our PV-10 measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV-10 to the standardized measure of discounted future net cash flows at December 31, 2012, 2011 and 2010:

| | December 31, | | |
|---|---|---|---|
| **(in millions)** | **2012** | **2011** | **2010** |
| PV-10 | $ 8,327.0 | $ 8,399.8 | $ 6,061 |
| Present value of future income taxes discounted at 10% | (2,538.9) | (2,698.7) | (1,885. |
| Standardized measure of discounted future net cash flows | $ 5,788.1 | $ 5,701.1 | $ 4,176 |

***EBITDAX***

We define EBITDAX as net income (loss), plus (1) exploration and abandonments expense, (2) depreciation, depletion and amortization expense, (3) accretion expense, (4) impairments of long-lived assets, (5) non-cash stock-based compensation expense, (6) bad debt expense, (7) ineffective portion of cash flow hedges, (8) unrealized (gain) loss on derivatives not designated as hedges, (9) (gain) loss on sale of assets, net, (10) interest expense, (11) federal and state income taxes on continuing operations and (12) similar items listed above that are presented in discontinued operations. EBITDAX is not a measure of net income or cash flow as determined by GAAP.

Our EBITDAX measure provides additional information which may be used to better understand our operations, and it is also a material component of one of the financial covenants under our credit facility. EBITDAX is one of several metrics that we use as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to, or more meaningful than, net income, as an indicator of our operating performance. Certain items excluded from EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. EBITDAX, as used by us, may not be comparable to similarly titled measures reported by other companies. We believe that EBITDAX is a widely followed measure of operating performance and is one of many metrics used by our management team and by other users of our consolidated financial statements, including by lenders pursuant to a covenant in our credit facility. For example, EBITDAX can be used to assess our operating performance and return on capital in comparison to other independent exploration and production companies without regard to financial or capital structure, and to assess the financial performance of our assets and our company without regard to capital structure or historical cost basis. Further, under our credit facility, an event of default could arise if we were not able to satisfy and remain in compliance with specified financial ratios, including the maintenance of a quarterly ratio of total debt to consolidated last twelve months EBITDAX of no greater than 4.0 to 1.0. Non-compliance with this ratio could trigger an event of default under our credit facility, which then could trigger an event of default under our indentures.

The following table provides a reconciliation of net income (loss) to EBITDAX:

**(in thousands)**

**Net income (loss)** ...............................................................................................................................................................

| | |
|---|---|
| Exploration and abandonments | |
| Depreciation, depletion and amortization | |
| Accretion of discount on asset retirement obligations | |
| Impairments of long-lived assets | |
| Non-cash stock-based compensation | |
| Bad debt expense | |
| Ineffective portion of cash flow hedges | |
| Unrealized (gain) loss on derivatives not designated as hedges | |
| (Gain) loss on sale of assets, net | |
| Interest expense | |
| Income tax expense (benefit) on continuing operations | |
| Discontinued operations | |
| **EBITDAX** | |

# Item 1A. Risk Factors

*You should consider carefully the following risk factors together with all of the other information included in this report and other reports filed with the SEC, before investing in our shares. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our shares could decline and you could lose all or part of your investment.*

***Risks Related to Our Business***

***Oil, natural gas and NGL prices are volatile. A decline in oil, natural gas and NGL prices could adversely affect our financial position, financial results, cash flow, access to capital and ability to grow.***

Our future financial condition, revenues, results of operations, rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prices we receive for our oil and natural gas production and the prices prevailing from time to time for oil and natural gas. Oil, natural gas, and NGL prices historically have been volatile, and are likely to continue to be volatile in the future, especially given current geopolitical conditions. This price volatility also affects the amount of cash flow we have available for capital expenditures and our ability to borrow money or raise additional capital. The prices for oil, natural gas and NGLs are subject to a variety of factors beyond our control, including:

- the level of consumer demand for oil, natural gas and NGLs;
- the domestic and foreign supply of oil, natural gas, and NGLs;
- inventory levels of Cushing, Oklahoma, the benchmark for WTI oil prices;
- liquefied natural gas deliveries to and from the United States;

- commodity processing, gathering and transportation availability and the availability of refining capacity;
- the price and level of imports of foreign oil and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries and other exporting nations to agree to and maintain oil price and production controls;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuel sources;
- weather conditions;
- political conditions or hostilities in oil and natural gas producing regions, including the Middle East, Africa and South America;
- technological advances affecting energy consumption;
- effect of energy conservation efforts;
- variations between product prices at sales points and applicable index prices; and
- worldwide economic conditions.

Furthermore, oil and natural gas prices continued to be volatile in 2012. For example, the NYMEX oil prices in 2012 ranged from a high of $109.77 to a low of $77.69 per Bbl and the NYMEX natural gas prices in 2012 ranged from a high of $3.90 to a low of $1.91 per MMBtu. Further, the NYMEX oil prices and NYMEX natural gas prices reached lows of $91.82 per Bbl and $3.11 per MMBtu, respectively, during the period from January 1, 2013 to February 20, 2013.

Declines in oil, natural gas and NGL prices would not only reduce our revenue, but could also reduce the amount of oil and natural gas that we can produce economically. This in turn would lower the amount of oil and natural gas reserves we could recognize and, as a result, could have a material adverse effect on our financial condition and results of operations. If the oil and natural gas industry experiences significant price declines, we may, among other things, be unable to maintain or increase our borrowing capacity, repay current or future indebtedness or obtain additional capital on attractive terms, all of which can adversely affect the value of our securities.

***Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could cause our expenses to increase or our cash flows and production volumes to decrease.***

Our future financial condition and results of operations will depend on the success of our exploration and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economical than forecasted. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory and contractual requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;

- equipment failures or accidents;
- adverse weather conditions;
- reductions in oil, natural gas and NGL prices;
- surface access restrictions;
- loss of title or other title related issues;
- oil, natural gas liquids or natural gas gathering, transportation and processing availability restrictions or limitations; and
- limitations in the market for oil, natural gas and NGLs.

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. We routinely utilize hydraulic fracturing techniques in many of our drilling and completion programs. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act's Underground Injection Control Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA's recent decision.

At the same time, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic-fracturing practices, and the EPA is performing a study of the potential environmental impacts of hydraulic fracturing activities on drinking water and groundwater resources. The EPA's study includes 18 separate research projects addressing topics such as water acquisition, chemical mixing, well injection, flowback and produced water, and wastewater treatment and waste disposal. The EPA has indicated that it expects to issue its study report in late 2014. In addition, the United States Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Additionally, certain members of the Congress have called upon the United States Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the United States Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. Legislation also has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanism.

In addition, some states have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations. For example, Colorado, Pennsylvania, and Wyoming have each adopted a variety of well construction, set back, and disclosure regulations limiting how fracturing can be performed and requiring various degrees of chemical disclosure. In addition, Texas adopted rules requiring public disclosure of non-confidential information regarding fluids used in hydraulic fracturing activities that became effective on February 1, 2012, and New Mexico adopted similar rules that became effective on February 15, 2012. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

Further, in August 2012, the EPA adopted new rules that make all oil and natural gas operations (production, processing, transmission, storage and distribution) subject to regulation under the NSPS and NESHAPS programs. These new EPA rules also impose NSPS standards for completions of hydraulically fractured natural gas wells. These standards include requirements for operators to use the REC techniques developed in the EPA's Natural Gas STAR program along with pit flaring of natural gas not sent to the gathering line. The standards are applicable to newly drilled and fractured wells as well as existing wells that are refractured. The requirement for flaring of gas not sent to a gathering line became effective on October 15, 2012, and all operators are required to use REC techniques beginning January 1, 2015. Further, the new NESHAPS regulations impose MACT standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. We are currently evaluating the effect these rules could have on our business.

If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements, and also result in permitting delays and potential cost increases. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

***Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.***

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners and other sources for use in our operations. During 2012, West Texas and Southeast New Mexico experienced the lowest inflows of water in recent history. As a result of this severe drought, some local water districts may begin restricting the use of water subject to their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash flows.

***Estimates of proved reserves and future net cash flows are not precise. The actual quantities of our proved reserves and our future net cash flows may prove to be lower than estimated.***

Numerous uncertainties exist in estimating quantities of proved reserves and future net cash flows therefrom. Our estimates of proved reserves and related future net cash flows are based on various assumptions, which may ultimately prove to be inaccurate.

Petroleum engineering is a subjective process of estimating accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas;
- the assumed effects of regulations by governmental agencies;
- the quality, quantity and interpretation of available relevant data;
- assumptions concerning future commodity prices; and
- assumptions concerning future operating costs; severance, ad valorem and excise taxes; development costs; and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items, or other items not identified below, may differ materially from those assumed in estimating reserves:

- the quantities of oil and natural gas that are ultimately recovered;

- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future commodity prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

***Our business requires substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a decline in our oil and natural gas reserves.***

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the acquisition, exploration and development of oil and natural gas reserves. At December 31, 2012, total debt outstanding under our credit facility was $304.0 million (and total debt at December 31, 2012 was $3.1 billion), and approximately $2.2 billion was available to be borrowed under our credit facility. Expenditures for acquisition, exploration and development of oil and natural gas properties are the primary use of our capital resources. We incurred approximately $2.8 billion in acquisition, exploration and development activities (excluding asset retirement obligations) during the year ended December 31, 2012 ($1.3 billion of which was related to acquisitions). Under our 2013 capital budget, we currently intend to invest approximately $1.6 billion for exploration and development activities and customary acquisition of leasehold acreage.

We intend to finance our future capital expenditures, other than significant acquisitions, primarily through cash flow from operations and, if needed, through borrowings under our credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. Additional borrowings under our credit facility or the issuance of additional debt securities will require that a greater portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. In addition, our credit facility imposes certain limitations on our ability to incur additional indebtedness other than indebtedness under our credit facility. If we desire to issue additional debt securities other than as expressly permitted under our credit facility, we will be required to seek the consent of the lenders in accordance with the requirements of the credit facility, which consent may be withheld by the lenders at their discretion. If we incur certain additional indebtedness, our borrowing base under our credit facility may be

reduced. Additional financing also may not be available on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which our commodities are sold;
- global credit and securities markets;
- the ability and willingness of lenders and investors to provide capital and the cost of the capital; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our credit facility decrease as a result of lower commodity prices, operating difficulties, declines in reserves, lending requirements or regulations, or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. As a result, we may require additional capital to fund our operations, and we may not be able to obtain debt or equity financing to satisfy our capital requirements. If cash generated from operations or borrowings available under our credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to the development of our prospects, which in turn could lead to a decline in our oil and natural gas reserves, and could adversely affect our production, revenues and results of operations.

***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 had approximately $3.1 billion of outstanding debt at December 31, 2012. At December 31, 2012, the borrowing base under our credit facility was $3.0 billion and commitments from our bank group totaled $2.5 billion, of which approximately $2.2 billion was available to be borrowed.

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 fund 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 credit facility is at a variable interest rate, and so a rise in interest rates will generate greater interest expense to the extent we do not have applicable interest rate fluctuation hedges. The 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 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.

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 equity on terms that we may not find attractive if it may be done at all. Further, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under that indebtedness, which could adversely affect our business, financial condition and results of operations.

***Our lenders can limit our borrowing capabilities, which may materially impact our operations.***

At December 31, 2012, we had approximately $304.0 million of outstanding debt under our credit facility, and our borrowing base was $3.0 billion and commitments from our bank group totaled $2.5 billion. The borrowing base under our credit facility is semi-annually redetermined based upon a number of factors, including commodity prices and reserve levels. In addition, between redeterminations we and, if requested by 66 2/3 percent of our lenders, our lenders, may each request one special redetermination.

Upon a redetermination, our borrowing base could be substantially reduced, and in the event the amount outstanding under our credit facility at any time exceeds the borrowing base at such time, we may be required to repay a portion of our outstanding borrowings. If we incur certain additional indebtedness, our borrowing base under our credit facility may be reduced. We expect to utilize cash flow from operations, bank borrowings, debt and equity financings and asset sales to fund our acquisition, exploration and development activities. A reduction in our borrowing base could limit our activities. In addition, we may significantly alter our capitalization in order to make future acquisitions or develop our properties. These changes in capitalization may significantly increase our level of debt. If we incur additional debt for these or other purposes, the related risks that we now face could intensify. A higher level of debt also increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of debt depends on our future performance which is affected by general economic conditions and financial, business and other factors, many of which are beyond our control.

***Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.***

We may incur significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our oil and natural gas exploration, development and production, and related saltwater disposal activities. These delays, costs and liabilities could arise under a wide range of federal, state and local laws and regulations relating to protection of the environment, health and safety, including regulations and enforcement policies that have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations.

Strict as well as joint and several liability for a variety of environmental costs may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our production, revenues and results of operations could be adversely affected.

***Our producing properties are concentrated in the Permian Basin of Southeast New Mexico and West Texas, making us vulnerable to risks associated with operating in one major geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing horizons within this area.***

Our producing properties are geographically concentrated in the Permian Basin of Southeast New Mexico and West Texas. At December 31, 2012, substantially all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or natural gas liquids.

In addition to the geographic concentration of our producing properties described above, at December 31, 2012, approximately (i) 40.6 percent of our proved reserves were attributable to the Yeso formation, which includes both the Paddock and Blinebry intervals, underlying our oil and natural gas properties located in Southeast New Mexico; and (ii) 27.6 percent of our proved reserves were attributable to the Wolfberry play in West Texas. This concentration of assets within a small number of producing horizons exposes us to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within a field.

***Future price declines could result in a reduction in the carrying value of our proved oil and natural gas properties, which could adversely affect our results of operations.***

Declines in commodity prices may result in having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of production or economic factors change, accounting rules may require us to write-down, as a noncash charge to earnings, the carrying value of our proved oil and natural gas properties for impairments. We are required to perform impairment tests on proved assets whenever events or changes in circumstances warrant a review of our proved oil and natural gas properties. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our oil and natural gas properties, the carrying value may not be recoverable and therefore require a write-down. We may incur impairment charges in the future, which could materially adversely affect our results of operations in the period incurred.

***We periodically evaluate our unproved oil and natural gas properties for impairment, and could be required to recognize noncash charges to earnings of future periods.***

At December 31, 2012, we carried unproved property costs of $ 1.1 billion. GAAP requires periodic evaluation of these costs on a project-by-project basis in comparison to their estimated fair value. These evaluations will be affected by the results of exploration activities, commodity price circumstances, planned future sales or expiration of all or a portion of the leases, contracts and permits appurtenant to such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, we will recognize noncash charges to earnings of future periods.

***Part of our strategy involves exploratory drilling, including drilling in new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.***

The results of our exploratory drilling in new or emerging plays are more uncertain than drilling results in areas that are developed and have established production. Since new or emerging plays and new formations have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

***Our commodity price risk management program may cause us to forego additional future profits or result in our making cash payments to our counterparties.***

To reduce our exposure to changes in the prices of commodities, we have entered into and may in the future enter into additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Commodity price risk management arrangements expose us to the risk of financial loss and may limit our ability to benefit from increases in commodity prices in some circumstances, including the following:

- the counterparty to a commodity price risk management contract may default on its contractual obligations to us;

- there may be a change in the expected differential between the underlying price in a commodity price risk management agreement and actual prices received; or

- market prices may exceed the prices which we are contracted to receive, resulting in our need to make significant cash payments to our counterparties.

Our commodity price risk management activities could have the effect of reducing our revenues, net income and the value of our securities. At December 31, 2012, the net unrealized gain on our commodity price risk management contracts was approximately $25.1 million. An average increase in the commodity price of $10.00 per barrel of oil from the commodity price at December 31, 2012 would have resulted in a $245.9 million net unrealized loss on our commodity price risk management contracts, as reflected on our balance sheet at December 31, 2012. We may continue to incur significant unrealized gains or losses in the future from our commodity price risk management activities to the extent market prices increase or decrease and our derivatives contracts remain in place.

***Our identified inventory of drilling locations and recompletion opportunities are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.***

We have identified and scheduled the drilling of certain of our drilling locations as an estimation of our future multi-year development activities on our existing acreage. At December 31, 2012, we had identified 12,269 gross drilling locations, with proved reserves attributable to 2,326 of such locations. These identified locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including (i) our ability to timely drill wells on lands subject to complex development terms and circumstances; (ii) the availability of capital, equipment, services and personnel; (iii) seasonal conditions; (iv) regulatory and third party approvals; (v) commodity prices; and (vi) drilling and recompletion costs and results. Because of these and other potential uncertainties, we may never drill the numerous potential locations we have identified or produce oil or natural gas from these or any other potential locations. As such, our actual development activities may materially differ from those presently identified, which could adversely affect our production, revenues and results of operations.

***Approximately 39 percent of our total estimated proved reserves at December 31, 2012 were undeveloped, and those reserves may not ultimately be developed.***

At December 31, 2012, approximately 39 percent of our total estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling. Our reserve data assumes that we can and will make these expenditures and conduct these operations successfully. These assumptions, however, may not prove correct. Our reserve report at December 31, 2012 includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $2.9 billion. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves, we will be required to write-off these reserves. In addition, under the SEC's reserve rules, because proved undeveloped reserves may be booked only if they relate to wells scheduled to be drilled within five years of the date of booking, we may be required to write-off any proved undeveloped reserves that are not developed within this five year timeframe. Any such write-offs of our reserves could reduce our ability to borrow money and could reduce the value of our securities.

***Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flow, our ability to raise capital and the value of our securities.***

Unless we conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. The value of our securities and our ability to raise capital will be adversely impacted if we are not able to replace our reserves that are depleted by production. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production.

***The Standardized Measure and PV-10 of our estimated reserves are not accurate estimates of the current fair value of our estimated proved oil and natural gas reserves.***

Standardized Measure is a reporting convention that provides a common basis for comparing oil and natural gas companies subject to the rules and regulations of the SEC. Our non-GAAP financial measure, PV-10, is a similar reporting convention that we have disclosed in this report. Both measures require the use of operating and development costs prevailing as of the date of computation. Consequently, they will not reflect the prices ordinarily received or that will be received for oil and natural gas production because of varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and natural gas properties. Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. In addition, the 10 percent discount factor, which is required by the rules and regulations of the SEC to be used in calculating discounted future net cash flows for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our company or the oil and natural gas industry in general. Therefore, Standardized Measure or PV-10 included in this report should not be construed as accurate estimates of the current fair value of our proved reserves.

If average oil prices were $10.00 per barrel lower than the average price we used, our PV-10 at December 31, 2012 would have decreased from $8.3 billion to $7.2 billion. If average natural gas prices were $1.00 per MMBtu lower than the average price we used, our PV-10 at December 31, 2012, would have decreased from $8.3 billion to $7.4 billion. Any adjustments to the estimates of proved reserves or decreases in the price of our commodities may decrease the value of our securities.

***We may be unable to make attractive acquisitions or successfully integrate acquired companies or assets, and any inability to do so may disrupt our business and hinder our ability to grow.***

One aspect of our business strategy calls for acquisitions of businesses or assets that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive candidates, we may not be able to complete the acquisition of them or do so on commercially acceptable terms.

In addition, our credit facility and the indentures governing our senior notes impose certain limitations on our ability to enter into mergers or combination transactions. Our credit facility and the indentures governing our senior notes also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses or assets. If we desire to engage in an acquisition that is otherwise prohibited by our credit facility or the indentures governing our senior notes, we will be required to seek the consent of our lenders or the holders of the senior notes in accordance with the requirements of the credit facility or the indentures, which consent may be withheld by the lenders under our credit facility or such holders of senior notes at their sole discretion.

If we acquire another business or assets, we could have difficulty integrating its operations, systems, management and other personnel and technology with our own. These difficulties could disrupt our ongoing business, distract our management and employees, increase our expenses and adversely affect our results of operations. In addition, we may incur additional debt or issue additional equity to pay for any future acquisitions, subject to the limitations described above.

***Our acquisitions may prove to be worth less than what we paid because of uncertainties in evaluating recoverable reserves and could expose us to potentially significant liabilities.***

We obtained the majority of our current reserve base through acquisitions of producing properties and undeveloped acreage. We expect that acquisitions will continue to contribute to our future growth. In connection with these and potential future acquisitions, we are often only able to perform limited due diligence.

Successful acquisitions of oil and natural gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing of recovering reserves, exploration potential, future commodity prices, operating costs and potential environmental, regulatory and other liabilities. Such assessments are inexact, and we cannot make these assessments with a high degree of accuracy. In connection with our assessments, we perform a review of the acquired properties. 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.

There may be threatened, contemplated, asserted or other claims against the acquired assets related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We are sometimes able to obtain contractual indemnification for preclosing liabilities, including environmental liabilities, but we generally acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties. In addition, even when we are able to obtain such indemnification from the sellers, these indemnification obligations usually expire over time and expose us to potential unindemnified liabilities, which could materially adversely affect our production, revenues and results of operations.

***Shortages of oilfield equipment, services and qualified personnel could delay our drilling program and increase the prices we pay to obtain such equipment, services and personnel.***

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with commodity prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher commodity prices generally stimulate demand and result in increased prices for drilling and workover rigs, crews and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be. These types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results, or restrict our ability to drill the wells and conduct the operations which we currently have planned and budgeted or which we may plan in the future.

***Our exploration and development drilling may not result in commercially productive reserves.***

Drilling activities are subject to many risks, including the risk that commercially productive reservoirs will not be encountered. New wells that we drill may not be productive, or we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or may be produced economically. Drilling for oil and natural gas often involves unprofitable results, not only from dry holes but also from wells that are productive but do not produce sufficient net reserves to return a profit at then realized prices after deducting drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or lost circulation in formations;

- equipment failures or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increases in the cost of, or shortages or delays in the availability of, electricity, water, supplies, materials, drilling or workover rigs, equipment and services.

***We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. In addition, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.***

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities, including well stimulation and completion activities such as hydraulic fracturing, are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- abnormally pressured or structured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;

- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property and equipment;
- damage to natural resources due to underground migration of hydraulic fracturing fluids;
- pollution and other environmental damage, including spillage or mishandling of recovered hydraulic fracturing fluids;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not covered or not fully covered by insurance could have a material adverse effect on our production, revenues and results of operations.

***Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.***

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, those companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past few years due to competition and may increase substantially in the future. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital. Our failure to acquire properties, market oil and natural gas and secure trained personnel and adequately compensate personnel could have a material adverse effect on our production, revenues and results of operations.

***Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.***

Market conditions or the unavailability of satisfactory oil and natural gas processing or transportation arrangements may hinder our access to oil, natural gas and NGL markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil, natural gas and NGLs, the proximity of reserves to pipelines and terminal facilities, competition for such facilities and the inability of such facilities to gather, transport or process our production due to shutdowns or curtailments arising from mechanical, operational or weather related matters, including hurricanes and other severe weather conditions. Our ability to market our production depends in substantial part on the availability and capacity of gathering and transportation systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could have a material adverse effect on our business, financial condition and results of operations. We may be required to shut in or otherwise curtail production from wells due to lack of a market or inadequacy or unavailability of oil, NGL or natural gas pipeline or gathering, transportation or processing capacity. If that were to occur, then we would be unable to realize revenue from those wells until suitable arrangements were made to market our production.

***We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, timing, manner or feasibility of conducting our operations.***

Our oil and natural gas exploration, development and production, and related saltwater disposal operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, local and governmental authorities. We may incur substantial costs and experience delays in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase or our operations may be otherwise adversely affected if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. These and other costs could have a material adverse effect on our production, revenues and results of operations.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our production, revenues and results of operations.

***Certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated as a result of future legislation.***

President Obama's budget proposal for the fiscal year 2013 recommended the elimination of certain key United States federal income tax preferences currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs and (iii) the increase in the amortization period from two years to seven years for geophysical costs paid or incurred in connection with the exploration for, or development of, oil or natural gas within the United States.

It is unclear whether any such changes will actually be enacted or, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of the budget proposal or any other similar change in United States federal income tax law could affect certain tax deductions that are currently available to us with respect to our oil and natural gas exploration and production activities.



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***Climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the crude oil and natural gas that we produce.***

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA's rules relating to emissions of greenhouse gases, including emissions, from large stationary sources are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing, or requiring state environmental agencies to implement, the rules. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs.  Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produced. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

***The recent adoption of derivatives legislation by Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our***

***business.***

Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including us, which participate in that market. The new legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), became law on July 21, 2010 and requires the Commodities Futures Trading Commission (the "CFTC") and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In its rulemaking under the Dodd-Frank Act, the CFTC has proposed regulations to set 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 or positions would be exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize these regulations. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off 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 derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the 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. Finally, the legislation was intended, in part, to reduce the volatility of commodity prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

***The loss of our chief executive officer or other key personnel could negatively impact our ability to execute our business strategy.***

We depend, and will continue to depend in the foreseeable future, on the services of our chief executive officer, Timothy A. Leach, and other officers and key employees who have extensive experience and expertise in evaluating and analyzing producing oil and natural gas properties and drilling prospects, maximizing production from oil and natural gas properties, marketing oil and natural gas production, and developing and executing acquisition, financing and hedging strategies. Our ability to hire and retain our officers and key employees is important to our continued success and growth. The unexpected loss of the services of one or more of these individuals could negatively impact our ability to execute our business strategy.

***Because we do not operate and therefore control the development of certain of the properties in which we own interests, we may not be able to produce economic quantities of oil and natural gas in a timely manner.***

At December 31, 2012, approximately 8.4 percent of our proved reserves were attributable to properties for which we were not the operator. As a result, the success and timing of drilling and development activities on such nonoperated properties depend upon a number of factors, including:

- the nature and timing of drilling and operational activities;
- the timing and amount of capital expenditures;
- the operators’ expertise and financial resources;
- the approval of other participants in such properties; and
- the selection and application of suitable technology.

If drilling and development activities are not conducted on these properties or are not conducted on a timely basis, we may be unable to increase our production or offset normal production declines or we will be required to write-off the reserves attributable thereto, which may adversely affect our production, revenues and results of operations. Any such write-offs of our reserves could reduce our ability to borrow money and could reduce the value of our securities

***Uncertainties associated with enhanced recovery methods may result in us not realizing an acceptable return on our investments in such projects.***

We inject water into formations on some of our properties to increase the production of oil and natural gas. We may in the future expand these efforts to more of our properties or employ other enhanced recovery methods in our operations. The additional production and reserves, if any, attributable to the use of enhanced recovery methods are inherently difficult to predict. If our enhanced recovery methods do not allow for the extraction of oil and natural gas in a manner or to the extent that we anticipate, we may not realize an acceptable return on our investments in such projects. In addition, if proposed legislation and regulatory initiatives relating to hydraulic fracturing become law, the cost of some of these enhanced recovery methods could increase substantially.

***A terrorist attack or armed conflict could harm our business by decreasing our revenues and increasing our costs.***

Terrorist activities, anti-terrorist efforts and other armed conflict involving the United States may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur or escalate, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our production and causing a reduction in our revenue. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if significant infrastructure or facilities used for the production, transportation, processing or marketing of oil and natural gas production are destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.



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***Risks Relating to Our Common Stock***

***Our restated certificate of incorporation, our bylaws and Delaware law contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.***

Our restated certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation, our bylaws and Delaware law could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- the organization of our board of directors as a classified board, which allows no more than approximately one-third of our directors to be elected each year;

- stockholders cannot remove directors from our board of directors except for cause and then only by the holders of not less than 66 2/3 percent of the voting power of all outstanding voting stock;

- the prohibition of stockholder action by written consent; and

- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

***Because we have no plans to pay dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in us.***

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Covenants contained in our credit facility and the indentures governing our senior notes restrict the payment of dividends. Investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Investors seeking cash dividends should not purchase our common stock.

***The availability of shares for sale in the future could reduce the market price of our common stock.***

In the future, we may issue securities to raise cash for acquisitions. We may also acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities convertible into, or exchangeable for, or that represent the right to receive, our common stock. Any of these events may dilute your ownership interest in our company, reduce our earnings per share and have an adverse impact on the price of our common stock.

In addition, sales of a substantial amount of our common stock in the public market, or the perception that these sales may occur, could reduce the market price of our common stock. This could also impair our ability to raise additional capital through the sale of our securities.

**Item 1B. Unresolved Staff Comments**

There are no unresolved staff comments.

## Item 2. Properties

### *Our Oil and Natural Gas Reserves*

The estimates of our proved reserves at December 31, 2012, all of which were located in the United States, were based on evaluations prepared by the independent petroleum engineering firms of Cawley, Gillespie & Associates, Inc. ("CGA") and Netherland, Sewell & Associates, Inc. ("NSAI") (or collectively, our "external engineers"). Reserves were estimated in accordance with guidelines established by the SEC and the Financial Accounting Standards Board (the "FASB").

***Internal controls.*** Our proved reserves are estimated at the property level and compiled for reporting purposes by our corporate reservoir engineering staff, all of whom are independent of our operating teams. We maintain our internal evaluations of our reserves in a secure reserve engineering database. The corporate reservoir engineering staff interact with our internal staff of petroleum engineers and geoscience professionals in each of our operating areas and with accounting and marketing employees to obtain the necessary data for the reserves estimation process. Reserves are reviewed and approved internally by members of our senior management and the reserves committee.

Our internal professional staff works closely with our external engineers to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. All of the reserve information maintained in our secure reserve engineering database is provided to the external engineers. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their evaluation of our reserves.

***Qualifications of responsible technical persons.***

*E. Joseph Wright* has been our Senior Vice President and Chief Operating Officer since November 2010. Mr. Wright previously served as the Vice President — Engineering and Operations from our formation in February 2004 to October 2010. Previously, Mr. Wright served as Vice President — Operations/Engineering of Concho Oil & Gas Corp. from its formation in January 2001 until its sale in January 2004, and as Vice President – Operations for Concho Resources Inc. (which was a different company from the current company). He has also worked in several operations, engineering and capital markets positions at Mewbourne Oil Company. Mr. Wright is a graduate of Texas A&M University with a Bachelor of Science degree in Petroleum Engineering.

*Rick Morton* joined the Company in 2011 as Corporate Engineering Manager. Prior to joining the Company, Mr. Morton served as Division Acquisition Coordinator for EOG Resources, Inc. Mr. Morton was also previously employed by Southwest Royalties, Inc. as Vice President and Exploitation Manager, and by Merit Energy Company in various engineering positions. Mr. Morton began his career in 1983 with Arco Oil and Gas Company as an Operations/Analytical Engineer before moving to a Production Supervisor position. He is a graduate of Texas A&M University with a Bachelor of Science degree in Petroleum Engineering.

*CGA.* Approximately 68 percent of the proved reserves estimates shown herein at December 31, 2012 have been independently prepared by CGA, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. CGA was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-693. Within CGA, the technical person primarily responsible for preparing the estimates set forth in the CGA letter dated January 23, 2013, filed as an exhibit to this Annual Report on Form 10-K, was Mr. Zane Meekins. Mr. Meekins has been a practicing consulting petroleum engineer at CGA since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas (License No. 71055) and has over 23 years of practical experience in petroleum engineering, with over 20 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a Bachelor of Science degree in Petroleum Engineering. Mr. Meekins meets or exceeds 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; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

*NSAI.* Approximately 32 percent of the proved reserve estimates shown herein at December 31, 2012 have been independently prepared by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical person primarily responsible for preparing the estimates set forth in the NSAI letter dated January 28, 2013, filed as an exhibit to this Annual Report on Form 10-K, was Mr. G. Lance Binder. Mr. Binder has been a practicing consulting petroleum engineer at NSAI since 1983. Mr. Binder is a Registered Professional Engineer in the State of Texas (License No. 61794) and has over 30 years of practical experience in petroleum engineering, with over 30 years of experience in the estimation and evaluation of reserves. He graduated from Purdue University in 1978 with a Bachelor of Science degree in Chemical Engineering. Mr. Binder meets or exceeds 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; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

***Our oil and natural gas reserves.*** The following table sets forth our estimated proved oil and natural gas reserves, PV-10 and Standardized Measure at December 31, 2012. PV-10 and Standardized Measure include the present value of our estimated future abandonment and site restoration costs for proved properties net of the present value of estimated salvage proceeds from each of these properties. Our reserve estimates and our computation of future net cash flows are based on SEC pricing of (i) $91.21 per Bbl West Texas Intermediate posted oil price and (ii) $2.76 per MMBtu Henry Hub spot natural gas price, adjusted for location and quality by property.

| | **Oil (MBbl)** | **Natural Gas (MMcf)** | **Total (MBoe)** | **PV-10** (a) |
|---|---|---|---|---|
| **Core Operating Areas:** | | | | |
| New Mexico Shelf | 145,415 | 473,717 | 224,368 | $ 4,642.2 |
| Delaware Basin | 39,414 | 253,979 | 81,744 | 1,396.8 |
| Texas Permian | 88,673 | 313,714 | 140,959 | 2,287.0 |
| **Other** | 6 | 669 | 117 | 1.0 |
| Total | 273,508 | 1,042,079 | 447,188 | 8,327.0 |
| Present value of future income taxes discounted at 10% | | | | (2,538.9) |
| Standardized Measure | | | | $ 5,788.1 |

The following table sets forth our estimated proved reserves by category at December 31, 2012:

| | **Oil** (MBbl) | **Natural Gas** (MMcf) | **Total** (MBoe) | **Percent of Total** | **PV-10** (a) |
|---|---|---|---|---|---|
| Proved developed producing | 143,250 | 616,958 | 246,076 | 55.0% | $ 5,797.4 |
| Proved developed non-producing | 17,686 | 48,461 | 25,763 | 5.8% | 599.0 |
| Proved undeveloped | 112,572 | 376,660 | 175,349 | 39.2% | 1,930.6 |
| Total proved | 273,508 | 1,042,079 | 447,188 | 100.0% | $ 8,327.0 |
| Total proved developed | 160,936 | 665,419 | 271,839 | 60.8% | $ 6,396.4 |

(a) Our Standardized Measure at December 31, 2012 was $5.8 billion. PV-10 is a Non-GAAP financial measure and is derived from the Standardized Measure which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas assets. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas assets. PV-10, however, is not a substitute for the Standardized Measure. Our PV-10 measure and the Standardized Measure do not purport to present the fair value of our oil and natural gas reserves. See "Item 1. Business —Non-GAAP Financial Measures and Reconciliations."

***Changes to proved reserves.*** The following table sets forth the changes in our proved reserve volumes by area during the year ended December 31, 2012 (in MBoe):

| | Production | Extensions and Discoveries | Purchases of Minerals-in-Place | Sales of Minerals-in-Place | Revisions of Previous Estimates |
|---|---|---|---|---|---|
| **Core Operating Areas:** | | | | | |
| New Mexico Shelf | (14,247) | 45,624 | 7,942 | (11,087) | (14,133) |
| Delaware Basin | (7,702) | 34,562 | 9,593 | (2,474) | (1,984) |
| Texas Permian | (7,807) | 11,734 | 37,957 | (20,748) | (6,670) |
| | (12) | - | 988 | (962) | 93 |
| Total | (29,768) | 91,920 | 56,480 | (35,271) | (22,694) |

*Production.* Production volumes of 29.8 MMBoe include production of 1.8 MMBoe for the non-core assets divested in December 2012.

*Extensions and discoveries.* Extensions and discoveries are primarily the result of our continued success from our extension and infill drilling in the Yeso of Southeast New Mexico and the Wolfberry in West Texas and our exploratory drilling success in the Delaware Basin.

*Purchases of minerals-in-place.* Purchases of minerals-in-place are composed of approximately 45.5 MMBoe from the Three Rivers Acquisition, which closed in July 2012, 9.8 MMBoe from the PDC Acquisition and various other acquisitions throughout the year.

*Sales of minerals-in-place.* In December 2012, we closed the divestiture of certain of our non-core assets, a portion of which were acquired in the Three Rivers Acquisition, for approximately $488.1 million, subject to customary post-closing adjustments.

*Revisions of previous estimates.* Revisions of previous estimates are comprised of (i) 5.1 MMBoe of negative price revisions primarily resulting from a decrease in natural gas prices, (ii) 10.8 MMBoe of proved reserves reclassified to unproved reserves, in part as a result of the SEC's 5-year proved undeveloped reserves rules and (iii) 6.6 MMBoe of negative revisions primarily resulting from technical and performance evaluations. The Company's proved reserves at December 31, 2012 were determined using the SEC prices of $91.21 per Bbl of oil for West Texas Intermediate and $2.76 per MMBtu of natural gas for Henry Hub spot, compared to corresponding prices of $92.71 per Bbl of oil and $4.12 per MMBtu of natural gas at December 31, 2011.

***Proved undeveloped reserves.*** At December 31, 2012, we had approximately 175.3 MMBoe of proved undeveloped reserves as compared to 150.6 MMBoe at December 31, 2011.

The following table summarizes the changes in our proved undeveloped reserves during 2012 (in MBoe):

| | |
|---|---|
| **At December 31, 2011** | 150,592 |
| Extensions and discoveries | 54,349 |
| Purchases of minerals-in-place | 24,281 |
| Sales of minerals-in-place | (8,314) |
| Revisions of previous estimates | (16,363) |
| Conversion to proved developed reserves | (29,196) |
| **At December 31, 2012** | 175,349 |

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Our purchases of minerals-in-place are primarily attributable to the PDC Acquisition, which closed in the first quarter of 2012, and the Three Rivers Acquisition, which closed in the third quarter of 2012. Our extensions and discoveries are primarily the result of our continued success from our extension and infill drilling in the Yeso of Southeast New Mexico and the Wolfberry in West Texas and our exploratory drilling success in the Delaware Basin.

The following table sets forth, since 2008, proved undeveloped reserves converted to proved developed reserves during the respective year and the investment required to convert proved undeveloped reserves to proved developed reserves:

| Years Ended December 31, |
| --- |
| 2008 ........................................................................................................................................................ |
| 2009 ........................................................................................................................................................ |
| 2010 ........................................................................................................................................................ |
| 2011 ........................................................................................................................................................ |
| 2012 ........................................................................................................................................................ |
| Total ........................................................................................................................................................ |

The following table sets forth the estimated timing and cash flows of developing our proved undeveloped reserves at December 31, 2012 (dollars in thousands):

| | Years Ended December 31, (a) |
|---|---|
| 2013 | |
| 2014 | |
| 2015 | |
| 2016 | |
| 2017 | |
| Thereafter | |
| Total | |

(a) Beginning in 2014 and thereafter, the production and cash flows represent the drilling results from the respective year plus t incremental effects from the results of proved undeveloped drilling from previous years.

Historically, our drilling programs were substantially funded from our cash flow and were weighted towards drilling unproven locations. Our expectation in the future is to continue to fund our drilling programs primarily from our cash flows. Based on our current expectations over the next 5 years of our cash flows and drilling programs, which includes drilling of proved undeveloped and unproven locations, we believe that we can continue to substantially fund our drilling activities from our cash flow and, if needed, with borrowings from our credit facility.

***Developed and Undeveloped Acreage***

The following table presents our total gross and net developed and undeveloped acreage by area at December 31, 2012:

| |
|---|
| **Core Operating Areas:** |
| New Mexico Shelf |
| Delaware Basin |
| Texas Permian |
| **Other** |
| Total |

The following table sets forth the future expiration amounts of our gross and net undeveloped acreage at December 31, 2012 by area. Expirations may be less if production is established or continuous development activities are undertaken beyond the primary term of the lease.

| |
|---|
| **Core Operating Areas:** |
| New Mexico Shelf |
| Delaware Basin |
| Texas Permian |
| **Other** |
| Total |

(a) Our 2013 capital budget contemplates avoiding a significant portion of these lease expirations.

***Title to Our Properties***

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a more thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect defects affecting those properties, we are typically responsible for curing any such defects at our expense. We generally will not commence drilling operations on a property until we have cured known material title defects on such property. We have reviewed the title to substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Prior to completing an acquisition of producing oil and natural gas properties, we perform title reviews on the most significant properties and, depending on the materiality of properties, we may obtain a title opinion or review or update previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens to secure borrowings under our credit facility, liens for current taxes and other burdens which we believe do not materially interfere with the use or affect our carrying value of the properties.

## Item 3. Legal Proceedings

We are a party to proceedings and claims incidental to our business. While many of these other matters involve inherent uncertainty, we believe that the liability, if any, ultimately incurred with respect to such other proceedings and claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future results of operations. We will continue to evaluate proceedings and claims involving us on a regular basis and will establish and adjust any reserves as appropriate to reflect our assessment of the then current status of the matters.

## Item 4. Mine Safety Disclosures

Not applicable.

# PART II

## Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

### *Market Information*

Our common stock trades on the NYSE under the symbol "CXO." The following table shows, for the periods indicated, the high and low sales prices for our common stock, as reported on the NYSE.

| | Price Per Share High | Price Per Share Low |
|---|---|---|
| **2011:** | | |
| First Quarter | $ 110.89 | $ 84.13 |
| Second Quarter | $ 109.95 | $ 83.51 |
| Third Quarter | $ 99.47 | $ 71.05 |
| Fourth Quarter | $ 105.66 | $ 63.20 |
| **2012:** | | |
| First Quarter | $ 116.82 | $ 95.56 |
| Second Quarter | $ 109.25 | $ 76.17 |
| Third Quarter | $ 102.26 | $ 80.57 |
| Fourth Quarter | $ 98.22 | $ 76.81 |

On February 20, 2013 the last sales price of our common stock as reported on the New York Stock Exchange was $94.67 per share.

As of February 20, 2013, there were 701 holders of record of our common stock.

***Dividend Policy***

We have not paid, and do not intend to pay in the foreseeable future, cash dividends on our common stock. Covenants contained in our credit facility and the indentures governing our senior notes restrict the payment of dividends on our common stock. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant.

***Repurchase of Equity Securities***

| Period | Total number of shares withheld (a) | Average price per share | Total number of shares purchased as part of publicly announced plans | Maximum number of shares that may yet be purchased under the plan |
|---|---|---|---|---|
| October 1, 2012 - October 31, 2012 | 119 | $ 95.06 | - | |
| November 1, 2012 - November 30, 2012 | 2,894 | $ 87.34 | - | |
| December 1, 2012 - December 31, 2012 | 2,455 | $ 83.29 | - | |

(a) Represents shares that were withheld by us to satisfy tax withholding obligations of certain of our officers and key employees that arose upon the lapse of restrictions on restricted stock.

**Item 6. Selected Financial Data**

This section presents our selected historical consolidated financial data. The selected historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements. You should read the following data along with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and related notes, each of which is included in this report.

***Selected Historical Financial Information***

Our results of operations for the periods presented below may not be comparable either from period to period or going forward for the following reasons:

- in July 2008, we closed our acquisition of Henry Petroleum LP and certain entities affiliated with Henry Petroleum LP (which we refer to collectively as the "Henry Entities"), together with certain additional non-operated interests in oil and natural gas properties from persons affiliated with the Henry Entities. In August 2008 and September 2008, we acquired additional non-operated interests in oil and natural gas properties from persons affiliated with the Henry Entities (known as "along-side interests"). The assets acquired in the acquisition of the Henry Entities and the along-side interests (which we refer to as the "Henry Properties") contained approximately 30.1 MMBoe of proved reserves at closing. We paid approximately $583.7 million in net cash for the Henry Properties, which was funded with borrowings under our credit facility and net proceeds of approximately $242.4 million from our private placement of 8.3 million shares of our common stock. The results of operations prior to August 2008 do not include results from the Henry Properties acquisition;

- in September 2009, we issued $300 million of 8.625% senior notes at a discount, resulting in a yield-to-maturity of 8.875 percent. The net proceeds from this offering was used to repay a portion of the borrowings under our credit facility;

- in December 2009, together with the acquisition of related additional interests that closed in 2010, we closed two acquisitions of interests in producing and non-producing assets in the Wolfberry play in Texas for approximately $270.7 million in cash (the "Wolfberry Acquisitions"). The results of operations prior to 2010 do not include results from the Wolfberry Acquisitions;

- in February 2010, we issued approximately 5.3 million shares of our common stock at $42.75 per share in a secondary public offering resulting in net proceeds of approximately $219.3 million. The net proceeds from this offering were used to repay a portion of the borrowings under our credit facility;

- in October 2010, we closed the Marbob and Settlement Acquisitions for aggregate consideration of approximately $1.6 billion. The Marbob Acquisition consideration was comprised of (i) approximately $1.1 billion in cash which was funded with borrowings under our credit facility and with net proceeds of a $292.7 million private placement of 6.6 million shares of our common stock, (ii) issuance of 1.1 million shares of our common stock to the sellers and (iii) issuance of a $150 million 8.0% senior note due 2018 to the sellers, which was repaid in May of 2011 with borrowings under our credit facility. The Settlement Acquisition cash consideration of $286 million was primarily funded with borrowings under our credit facility. The results of operations prior to October 2010 do not include results from the Marbob and Settlement Acquisitions;

- in December 2010, we issued in a secondary public offering 2.9 million shares of our common stock at $82.50 per share and we received net proceeds of approximately $227.4 million. We used the net proceeds from this offering to repay a portion of the borrowings under our credit facility;

- in December 2010, we issued $600 million in principal amount of 7.0% senior notes due 2021 at par and we received net proceeds of approximately $587.4 million. We used the net proceeds from this offering to repay a portion of the borrowings under our credit facility;

- in December 2010, we sold certain of our non-core Permian Basin assets for cash consideration of approximately $103.3 million and recognized a pre-tax gain on the disposition of assets (included in discontinued operations) of approximately $29.1 million. We used the net proceeds from this divestiture to repay a portion of the borrowings under our credit facility. For 2010, these assets produced an average of 1,393 Boe per day, of which approximately 46 percent was oil;

- in March 2011, we sold our Bakken assets for cash consideration of approximately $195.9 million and recognized a pre-tax gain on the disposition of assets (included in discontinued operations) of approximately $135.9 million. We used the net proceeds from this divestiture to repay a portion of the borrowings under our credit facility. For the first quarter of 2011, these assets produced an average of 1,369 Boe per day;

- in May 2011, we issued $600 million in principal amount of 6.5% senior notes due 2022 at par and we received net proceeds of approximately $587.1 million. We used the net proceeds to repay a portion of the borrowings under our credit facility;

- in November 2011, we closed the OGX Acquisition for cash consideration of approximately $252.0 million. The results of operations prior to December 2011 do not include results from the OGX Acquisition;

- in February 2012, we completed the PDC Acquisition for cash consideration of approximately $189.2 million. The PDC Acquisition was primarily funded with borrowings under our credit facility. The results of operations prior to March 2012 do not include results from the PDC Acquisition;

- in March 2012, we issued $600 million aggregate principal amount of 5.5% senior notes due 2022 at par, for which we received net proceeds of approximately $590.0 million. We used the net proceeds to repay a portion of the borrowings under our credit facility;

- in July 2012, we completed the Three Rivers Acquisition for cash consideration of approximately $1.0 billion. The Three Rivers Acquisition was primarily funded with borrowings under our credit facility. The results of operations prior to July 2012 do not include results from the Three Rivers Acquisition;

- in August 2012, we issued $700 million aggregate principal amount of 5.5% senior notes due 2023 at par, for which we received net proceeds of approximately $688.6 million. We used the net proceeds to repay a portion of the borrowings under our credit facility; and

- in December 2012, we sold certain of our non-core assets, a portion of which were acquired in the Three Rivers Acquisition, for approximately $488.1 million, subject to customary post-closing adjustments. We used the net proceeds from this divestiture to repay a portion of the borrowings under our credit facility. For the year ended December 31, 2012 these assets produced an average of 4,937 Boe per day.

Our financial data below is derived from (i) our audited consolidated financial statements included in this report and (ii) other audited consolidated financial statements of ours not included in this report, after taking into account the necessary reclassifications to present discontinued operations.

**(in thousands, except per share amounts)**

**Statement of operations data:**

Total operating revenues ....................................................
Total operating costs and expenses ....................................

**Income (loss) from operations** ..............................................................................................................................

**Income (loss) from continuing operations, net of tax** ..........................................................................................

**Income from discontinued operations, net of tax** ..................................................................................................

**Net income (loss) attributable to common shareholders** ........................................................................................

**Basic earnings per share:**

Income (loss) from continuing operations ..........................
Income from discontinued operations, net of tax ................

**Diluted earnings per share:**

Income (loss) from continuing operations ..........................
Income from discontinued operations, net of tax ................

**Other financial data:**

Net cash provided by operations ........................................
Net cash used in investing activities ...................................
Net cash provided by financing activities ...........................
EBITDAX (e) ....................................................................

**(in thousands)**

**Balance sheet data:**

| |
|---|
| Cash and cash equivalents ........................................... |
| Property and equipment, net ........................................... |
| Total assets ........................................... |
| Long-term debt, including current maturities ........................ |
| Stockholders' equity ........................................... |

(a) The Three Rivers Acquisition closed in July 2012. See Note D of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.”

(b) The Marbob and Settlement Acquisitions closed in October 2010. See Note D of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.”

(c) The Wolfberry Acquisitions closed in December 2009.

(d) The Henry Entities acquisition closed in July 2008.

(e) EBITDAX is defined as net income (loss), plus (1) exploration and abandonments expense, (2) depreciation, depletion and amortization expense, (3) accretion expense, (4) impairments of long-lived assets, (5) non-cash stock-based compensation expense, (6) bad debt expense, (7) ineffective portion of cash flow hedges, (8) unrealized (gain) loss on derivatives not designated as hedges, (9) (gain) loss on sale of assets, net, (10) interest expense, (11) federal and state income taxes on continuing operations and (12) similar items listed above that are presented in discontinued operations. See “Item 1. Business —Non-GAAP Financial Measures and Reconciliations.”

**Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations**

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our historical consolidated financial statements and notes, as well as the selected historical consolidated financial data included elsewhere in this report. As a result of the acquisitions and divestures discussed below, many comparisons between periods will be difficult or impossible.

In December 2012, we sold certain of our non-core assets, a portion of which were acquired in the Three Rivers Acquisition, for cash consideration of approximately $488.1 million, subject to customary post-closing adjustments, and recognized a pre-tax loss on this sale of approximately $18.7 million (included in discontinued operations). For the year ended December 31, 2012, these assets produced an average of 4,937 Boe per day.

In July 2012, we acquired producing and non-producing assets from Three Rivers Operating Company (the "Three Rivers Acquisition") for cash consideration of approximately $1.0 billion. The Three Rivers Acquisition was primarily funded with borrowings under our credit facility. The results of operations prior to July 2012 do not include results from the Three Rivers Acquisition.

In February 2012, we acquired producing and non-producing assets from Petroleum Development Corporation (the "PDC Acquisition") for cash consideration of approximately $189.2 million. The PDC Acquisition was primarily funded with borrowings under our credit facility. The results of operations prior to March 2012 do not include results from the PDC Acquisition.

In November 2011, we acquired three entities affiliated with OGX Holdings II, LLC (collectively the "OGX Acquisition") for cash consideration of approximately $252.0 million. The results of operations prior to December 2011 do not include results from the OGX Acquisition.

In March 2011, we closed our divestiture of our Bakken assets for cash consideration of approximately $195.9 million and recognized a pre-tax gain on this sale of approximately $135.9 million (included in discontinued operations). For the first quarter of 2011, these assets produced an average of 1,369 Boe per day.

In December 2010, we sold certain of our non-core Permian Basin assets for cash consideration of approximately $103.3 million and recognized a pre-tax gain on this sale of approximately $29.1 million (included in discontinued operations). For the year ended December 31, 2010, these assets produced an average of 1,393 Boe per day.

In October 2010, we closed the Marbob and Settlement Acquisitions for consideration of approximately $1.6 billion. The results of these acquisitions are included in our results of operations for periods after their respective closing dates in October 2010.

Certain statements in our discussion below are forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause actual results to differ materially from these implied or expressed by the forward-looking statements. Please see "Cautionary Statement Regarding Forward-Looking Statements."

***Overview***

We are an independent oil and natural gas company engaged in the acquisition, development and exploration of producing oil and natural gas properties. Our core operations are primarily focused in the Permian Basin of Southeast New Mexico and West Texas. We refer to our three core operating areas as the (i) New Mexico Shelf, where we primarily target the Yeso formation, (ii) Delaware Basin, where we primarily target the Bone Spring formation (which includes the Avalon Shale and the Bone Spring sands) and the Wolfcamp shale, and (iii) Texas Permian, where we primarily target the Wolfberry, a term applied to the combined Wolfcamp and Spraberry horizons. Oil comprised 61.2 percent of our 447.2 MMBoe of estimated proved reserves at December 31, 2012 and 60.5 percent of our 29.8 MMBoe of production for 2012. We seek to operate the wells in which we own an interest, and we operated wells that accounted for 91.3 percent of our proved developed producing PV-10 and 81.6 percent of our approximately 5,800 gross wells at December 31, 2012. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and stimulation methods used.

***Financial and Operating Performance***

Our financial and operating performance for 2012 included the following highlights:

- Net income was $431.7 million ($4.15 per diluted share), as compared to net income of $548.1 million ($5.28 per diluted share) in 2011. The decrease in earnings was primarily due to:

§ $105.1 million decrease in income from discontinued operations in 2012, primarily related to the (i) $135.9 million pre-tax gain related to the sale of the Bakken assets in 2011 and (ii) the $18.7 million pre-tax loss related to the sale of non-core assets in 2012;

§ $175.1 million increase in depreciation, depletion and amortization (“DD&A”) expense from continuing operations, primarily due to (i) capitalized costs associated with new wells that were successfully drilled and completed in 2011 and 2012 and (ii) the acquisitions in 2011 and 2012;

§ $65.8 million increase in oil and natural gas production costs from continuing operations due in part to increased (i) production, partially related to acquisitions in 2011 and 2012 and (ii) oil and natural gas revenues that directly increased our oil and natural gas production taxes; and

§ $64.3 million increase in interest expense due to (i) a 62 percent increase in the weighted average debt balance outstanding between the periods primarily related to acquisitions and (ii) our senior note issuances in 2011 and 2012 which bear higher interest costs than borrowings under our credit facility;

partially offset by:

§ $202.0 million increase in oil and natural gas revenues from continuing operations as a result of a 27 percent increase in production partially offset by a 12 percent decrease in commodity price realizations per Boe (excluding the effects of derivative activities) which were primarily related to a decrease in natural gas price realizations; and

§ a $127.4 million gain on derivatives not designated as hedges in 2012, as compared to a $23.4 million loss on derivatives not designated as hedges in 2011.

- Average daily sales volumes from continuing operations increased by 27 percent from 60,180 Boe per day during 2011 to 76,397 Boe per day during 2012. The increase is primarily attributable to our successful drilling efforts during 2011 and 2012 and our acquisitions in 2011 and 2012.

- Net cash provided by operating activities increased by approximately $38.0 million to $1,237.5 million for 2012, as compared to $1,199.5 million in 2011, primarily due to increased oil and natural gas revenues offset by increases in related oil and natural gas production costs, interest expense and other cash related costs.

- Long-term debt was increased by approximately $1.0 billion during 2012, primarily as a result of the PDC Acquisition and Three Rivers Acquisition in February 2012 and July 2012, respectively, partially offset by our non-core asset divestiture in December 2012.

- At December 31, 2012, availability under our credit facility was approximately $2.2 billion.

***Commodity Prices***

Our results of operations are heavily influenced by commodity prices. Commodity prices may fluctuate widely in response to relatively minor changes in the supply of and demand for oil, natural gas and NGLs market uncertainty and a variety of additional factors that are beyond our control. Factors that may impact future commodity prices, including the price of oil, natural gas and NGLs include:

- economic stimulus initiatives in the United States;

- worldwide and continuing economic struggles in Eurozone nations' economies;

- political and economic developments in the Middle East;

- demand from Asian and European markets;

- the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations are able to continue to manage oil supply through export quotas;

- technological advances affecting energy consumption and energy supply;

- the effect of energy conservation efforts;

- the price and availability of alternative fuels;

- domestic and foreign governmental regulations and taxation;

- the proximity, capacity, cost and availability of pipelines and other transportation facilities;

- the overall global demand for oil; and

- overall North American natural gas supply and demand fundamentals, including:

§ the United States economy impact,

§ weather conditions, and

§ liquefied natural gas deliveries to the United States.

Although we cannot predict the occurrence of events that may affect future commodity prices or the degree to which these prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production. From time to time, we expect that we may economically hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See Note H of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our commodity derivative positions at December 31, 2012.

Oil and natural gas prices have been subject to significant fluctuations during the past several years. In general, oil prices were consistent during 2012 measured against 2011, while natural gas prices decreased. The following table sets forth the average NYMEX oil and natural gas prices for the years ended December 31, 2012, 2011 and 2010, as well as the high and low NYMEX price for the same periods:

| | |
|---|---|
| **Average NYMEX prices:** | |
| Oil (Bbl) ........................................ | |
| Natural gas (MMBtu) ........................................ | |
| **High and Low NYMEX prices:** | |
| ***Oil (Bbl):*** | |
| High ........................................ | |
| Low ........................................ | |
| ***Natural gas (MMBtu):*** | |
| High ........................................ | |
| Low ........................................ | |

Further, the NYMEX oil price and NYMEX natural gas price reached highs and lows of $97.94 and $91.82 per Bbl and $3.57 and $3.11 per MMBtu, respectively, during the period from January 1, 2013 to February 20, 2013. At February 20, 2013, the NYMEX oil price and NYMEX natural gas price were $94.46 per Bbl and $3.28 per MMBtu, respectively.

***Recent Events***

***Divestiture.*** In December 2012, we sold certain of our non-core assets for cash consideration of approximately $488.1 million, subject to customary post-closing adjustments, and recognized a pre-tax loss on the disposition of assets (included in discontinued operations) of approximately $18.7 million. We used the net proceeds from this divestiture to repay a portion of the borrowings under our credit facility. For the year ended December 31, 2012, these assets produced an average of 4,937 Boe per day. We estimate that he proved reserves of these assets at closing were approximately 35.3 MMBoe.

***2013 capital budget.*** In November 2012, we announced our 2013 capital budget of approximately $1.6 billion, which we expect will be substantially funded within our cash flow, based on current commodity prices and capital costs. We take a longer-term view on spending within our cash flow, and our spending during any specific period may exceed our cash flow for that period. However, our capital budget is largely discretionary, and if we experience sustained commodity prices significantly below the current levels or substantial increases in our costs, we may reduce our capital spending program to be substantially within our cash flow.

| **(in millions)** |
| --- |
| Drilling and completion costs: |
| New Mexico Shelf |
| Delaware Basin |
| Texas Permian |
| Acquisition of leasehold acreage and geological and geophysical data |
| Facilities and other capital in our core operating areas |
| Total |

***Credit facility amendment.*** In October 2012, we amended our credit facility, increasing our borrowing base to $3.0 billion, but maintaining the aggregate lender commitments at $2.5 billion. At December 31, 2012, we had borrowings outstanding under our credit facility of approximately $0.3 billion, and our availability under our credit facility was approximately $2.2 billion.

***Senior notes issuances.*** In August 2012, we issued $700 million aggregate principal amount of 5.5% senior notes due 2023 at par, for which we received net proceeds of approximately $688.6 million. In March 2012, we issued $600 million aggregate principal amount of 5.5% senior notes due 2022 at par, for which we received net proceeds of approximately $590.0 million. We used the net proceeds to repay a portion of the borrowings under our credit facility.

***Three Rivers Acquisition.*** In July 2012, we completed the Three Rivers Acquisition for cash consideration of approximately $1.0 billion. The Three Rivers Acquisition was primarily funded with borrowings under our credit facility.

***PDC Acquisition.*** In February 2012, we completed the PDC Acquisition for cash consideration of approximately $189.2 million. The PDC Acquisition was primarily funded with borrowings under our credit facility.

### *Derivative Financial Instruments*

***Derivative financial instrument exposure.*** At December 31, 2012, the fair value of our financial derivatives was a net asset of $25.1 million. All of our counterparties to these financial derivatives are parties to our credit facility and have their outstanding debt commitments and derivative exposures collateralized pursuant to our credit facility. Under the terms of our financial derivative instruments and their collateralization under our credit facility, we do not have exposure to potential "margin calls" on our financial derivative instruments. We currently have no reason to believe that our counterparties to these commodity derivative contracts are not financially viable. Our credit facility does not allow us to offset amounts we may owe a lender against amounts we may be owed related to our financial instruments with such party.

After December 31, 2012, we entered into the following additional oil related price swaps to hedge additional amounts of our estimated future production:

| | |
|---|---|
| **Oil Swaps: (a)** | |
| ***2013:*** | |
| Volume (Bbl) | |
| Price per Bbl | |
| ***2014:*** | |
| Volume (Bbl) | |
| Price per Bbl | |
| | |
| **Oil Basis Swaps: (b)** | |
| ***2013:*** | |
| Volume (Bbl) | |
| Price per Bbl | |

(a) The index prices for the oil price swaps are based on the NYMEX – WTI monthly average futures price.
(b) The basis differential price is between Midland – WTI and Cushing – WTI.

**Results of Operations**

The following table sets forth summary information concerning our production and operating data from continuing operations for the years ended December 31, 2012, 2011 and 2010. The table below excludes production and operating data that we have classified as discontinued operations, which is more fully described in Note N of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.” The actual historical data in this table excludes results from (i) the Three Rivers Acquisition for periods prior to July 2012, (ii) the PDC Acquisition for periods prior to March 2012, (iii) the OGX Acquisition for periods prior to December 2011and (iv) the Marbob and Settlement Acquisitions for periods prior to their respective close dates in October 2010. Because of normal production declines, increased or decreased drilling activities and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

***Production and operating data:***

**Net production volumes:**

| |
|---|
| Oil (MBbl) |
| Natural gas (MMcf) |
| Total (MBoe) |

**Average daily production volumes:**

| |
|---|
| Oil (Bbl) |
| Natural gas (Mcf) |
| Total (Boe) |

**Average prices:**

| |
|---|
| Oil, without derivatives (Bbl) |
| Oil, with derivatives (Bbl) (a) |
| Natural gas, without derivatives (Mcf) |
| Natural gas, with derivatives (Mcf) (a) |

| | |
|---|---|
| Total, without derivatives (Boe) | |
| Total, with derivatives (Boe) (a) | |
| **Operating costs and expenses per Boe:** | |
| Lease operating expenses and workover costs | |
| Oil and natural gas taxes | |
| Depreciation, depletion and amortization | |
| General and administrative | |

(a) Includes the effect of cash settlements received from (paid on) commodity derivatives not designated as hedges and report
following table reflects the amounts of cash settlements received from (paid on) commodity derivatives not designated as h
average prices with derivatives and reconciles to the amount in (gain) loss on derivatives not designated as hedges as repor

| **(in thousands)** | |
|---|---|
| **Gain (loss) on derivatives not designated as hedges:** | |
| Cash receipts from (payments on) oil derivatives | |
| Cash receipts from natural gas derivatives | |
| Cash payments on interest rate derivatives | |
| Unrealized mark-to-market gain (loss) on commodity and interest rate derivatives | |
| Gain (loss) on derivatives not designated as hedges | |

The presentation of average prices with derivatives is a non-GAAP measure as a result of including the cash receipts from
that are presented in gain (loss) on derivatives not designated as hedges in the statements of operations. This presentation c
means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and present
derivatives in a manner consistent with the presentation generally used by the investment community.

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The following table sets forth summary information from our discontinued operations concerning our production and operating data for the years ended December 31, 2012, 2011 and 2010. The discontinued operations presentation is the result of reclassifying the results of operations from the divestitures of our (i) non-core Permian Basin assets in December 2010, (ii) Bakken assets in March 2011 and (iii) non-core assets in December 2012 which are more fully described in Note N of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| ***Production and operating data:*** | | | |
| **Net production volumes:** | | | |
| Oil (MBbl) | 1,144 | 1,246 | 1,669 |
| Natural Gas (Mcf) | 3,978 | 2,596 | 4,058 |
| Total (MBoe) | 1,807 | 1,678 | 2,345 |
| **Average daily production volumes:** | | | |
| Oil (Bbl) | 3,126 | 3,415 | 4,572 |
| Natural gas (Mcf) | 10,869 | 7,112 | 11,118 |
| Total (Boe) | 4,937 | 4,600 | 6,426 |
| **Average prices:** | | | |
| Oil, without derivatives (Bbl) | $ 88.60 | $ 89.80 | $ 73.83 |
| Oil, with derivatives (Bbl) (a) | $ 88.60 | $ 89.80 | $ 73.83 |
| Natural gas, without derivatives (Mcf) | $ 4.67 | $ 7.64 | $ 5.78 |
| Natural gas, with derivatives (Mcf) (a) | $ 4.67 | $ 7.64 | $ 5.78 |
| Total, without derivatives (Boe) | $ 66.37 | $ 78.50 | $ 62.56 |
| Total, with derivatives (Boe) (a) | $ 66.37 | $ 78.50 | $ 62.56 |

| | | | |
|---|---|---|---|
| **Operating costs and expenses per Boe:** | | | |
| Lease operating expenses and workover costs | $ 12.95 | $ 12.01 | $ 10.40 |
| Oil and natural gas taxes | $ 6.01 | $ 6.89 | $ 5.65 |
| Depreciation, depletion and amortization | $ 16.68 | $ 18.15 | $ 19.54 |
| General and administrative (a) | $ (1.38) | $ (1.35) | $ (1.33) |

(a) Represents the fees received from third-parties for operating oil and natural gas properties that were sold. We reflect these fees as a reduction of general and administrative expenses.

The following tables present selected production and operating data for the fields which represent greater than 15 percent of our total proved reserves at December 31, 2012, 2011 and 2010:

***Production and operating data:***

**Net production volumes:**

.................................................................................................................................................................................................................

**Average prices:**

.................................................................................................................................................................................................................

**Production costs per Boe:**

***Production and operating data:***

**Net production volumes:**

Oil (MBbl) ....................
Natural gas (MMcf) ....
Total (MBoe) ...............

**Average prices:**

Oil, without derivatives
Natural gas, without de
Total, without derivativ

**Production costs per Boe:**

Lease operating expens

Oil and natural gas taxe

***Production and operating data:***

**Net production volumes:**

**Average prices:**

**Production costs per Boe:**

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

***Oil and natural gas revenues.*** Revenue from oil and natural gas operations was $1,819.8 million for the year ended December 31, 2012, an increase of $202.0 million (12 percent) from $1,617.8 million for the year ended December 31, 2011. This increase was primarily due to an increase in the realized oil price and increased production due to (i) successful drilling efforts during 2011 and 2012, (ii) production from the OGX Acquisition which closed in November 2011, (iii) production from the PDC Acquisition which closed in February 2012 and (iv) production from the Three Rivers Acquisition which closed in July 2012. Specific factors affecting oil and natural gas revenues include the following:

- total oil production was 16,859 MBbl for the year ended December 31, 2012, an increase of 3,413 MBbl (25 percent) from 13,446 MBbl for the year ended December 31, 2011;

- average realized oil price (excluding the effects of derivative activities) was $87.96 per Bbl during the year ended December 31, 2012, a decrease of 4 percent from $91.34 per Bbl during the year ended December 31, 2011;

- total natural gas production was 66,613 MMcf for the year ended December 31, 2012, an increase of 15,495 MMcf (30 percent) from 51,118 MMcf for the year ended December 31, 2011; and

- average realized natural gas price (excluding the effects of derivative activities) was $5.06 per Mcf during the year ended December 31, 2012, a decrease of 34 percent from $7.62 per Mcf during the year ended December 31, 2011. Our natural gas prices have been significantly higher than the related NYMEX prices primarily due to the value of the natural gas liquids in our liquids-rich natural gas stream.

***Production expenses.*** The following table provides the components of our total oil and natural gas production costs for the years ended December 31, 2012 and 2011:

| | Years Ended Dec |
|---|---|
| | 2012 |
| | Per |

| (in thousands, except per unit amounts) | Amount | Boe | A |
|---|---|---|---|
| Lease operating expenses | $ 182,716 | $ 6.53 | $ 1 |
| Taxes: | | | |
| Ad valorem | 13,695 | 0.49 | |
| Production | 137,106 | 4.90 | 1 |
| Workover costs | 10,226 | 0.37 | |
| Total oil and natural gas production expenses | $ 343,743 | $ 12.29 | $ 2 |

Among the cost components of production expenses, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are directly related to commodity price changes.

Lease operating expenses for the year ended December 31, 2011 included a $3.1 million ($0.13 per Boe) underestimate of costs related to periods prior to 2011.

Lease operating expenses were $182.7 million ($6.53 per Boe) for the year ended December 31, 2012, which was an increase of $37.7 million (26 percent) from $145.0 million ($6.60 per Boe) for the year ended December 31, 2011. The increase in lease operating expenses was primarily due to (i) our wells successfully drilled and completed in 2011 and 2012, (ii) the acquisitions in 2011 and 2012 and (iii) an increase in cost of services, primarily labor related, due to the increased demand for services and related labor in the Permian Basin offset by an underestimate of costs in periods prior to 2011 as mentioned above. The decrease in lease operating expenses per Boe was primarily due to (i) the $0.13 per Boe included in the year December 31, 2011 related to the underestimate of costs in periods prior to 2011 mentioned above and (ii) additional production from our wells successfully drilled which were completed in 2011 and 2012 where we are receiving benefits from economies of scale, offset in part by cost increases in services, primarily labor related.

Ad valorem taxes have increased primarily as a result of increased valuations of our Texas properties and the increase in the number of wells primarily associated with our 2011 and 2012 drilling activity in our Texas Permian area and the Texas properties acquired in the PDC Acquisition and the Three Rivers Acquisition.

Production taxes per unit of production were $4.90 per Boe during the year ended December 31, 2012, a decrease of 12 percent from $5.56 per Boe during the year ended December 31, 2011. The decrease was directly related to the decrease in natural gas prices offset by our increase in oil and natural gas revenues related to increased volumes. Over the same period, our per Boe prices (excluding the effects of derivatives) decreased 12 percent.

Workover expenses were approximately $10.2 million and $1.9 million for the years ended December 31, 2012 and 2011, respectively. The 2012 amounts related primarily to workovers in the New Mexico Shelf and Texas Permian areas, while the 2011 amounts related primarily to activity in the Texas Permian area performed to increase or restore production.

***Exploration and abandonments expense.*** The following table provides a breakdown of our exploration and abandonments expense for the years ended December 31, 2012 and 2011:

| (in thousands) | Years Ended December 31, 2012 | Years Ended December 31, 2011 |
|---|---|---|
| Geological and geophysical | $ 19,927 | $ 4,977 |
| Exploratory dry hole costs | 7,518 | 1,067 |
| Leasehold abandonments and other | 12,395 | 5,350 |
| Total exploration and abandonments | $ 39,840 | $ 11,394 |

Our geological and geophysical expense, which primarily consists of the costs of acquiring and processing seismic data, geophysical data and core analysis, primarily relating to our Delaware Basin and Texas Permian areas, was approximately $19.9 million and $5.0 million for the years ended December 31, 2012 and 2011, respectively.

Our exploratory dry hole costs during the year ended December 31, 2012 was primarily related to (i) expensing an unsuccessful lateral on a horizontal well due to mechanical issues in the Delaware Basin area, (ii) expensing a dry hole that logged no pay in the Lower Abo formation in the New Mexico Shelf area and (iii) expensing the costs of drilling a well that experienced mechanical issues in the Texas Permian area.

For the year ended December 31, 2012, we recorded approximately $12.4 million of leasehold abandonments, which related to non-core prospects in our New Mexico Shelf area. For the year ended December 31, 2011, we recorded approximately $5.4 million of leasehold abandonments, which related to non-core prospects in our New Mexico Shelf area.

***Depreciation, depletion and amortization expense.*** The following table provides components of our depreciation, depletion and amortization expense for the years ended December 31, 2012 and 2011:

| | Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2012 | | 2011 | |
| **(in thousands, except per unit amounts)** | **Amount** | **Per Boe** | **Amount** | **Per Boe** |
| Depletion of proved oil and natural gas properties ........................................................................................ | $ 561,291 | $ 20.07 | $ 392,859 | $ 17.88 |
| Depreciation of other property and equipment ........................................................................................ | 12,376 | 0.44 | 5,702 | 0.26 |
| Amortization of intangible asset - operating rights ........................................................................................ | 1,461 | 0.05 | 1,461 | 0.07 |
| Total depletion, depreciation and amortization ........................................................................................ | $ 575,128 | $ 20.56 | $ 400,022 | $ 18.21 |
| Oil price used to estimate proved oil reserves at period end ........................................................................... | $ 91.21 | | $ 92.71 | |
| Natural gas price used to estimate proved natural gas reserves at period end ........................................... | $ 2.76 | | $ 4.12 | |

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Depletion of proved oil and natural gas properties was $561.3 million ($20.07 per Boe) for the year ended December 31, 2012, an increase of $168.4 million (43 percent) from $392.9 million ($17.88 per Boe) for the year ended December 31, 2011. The increase in depletion expense was primarily due to (i) capitalized costs associated with new wells that were successfully drilled and completed in 2011 and 2012 and (ii) costs associated with our acquisitions in 2011 and 2012. The increase in depletion expense per Boe was primarily due to (i) the properties acquired in the Three Rivers Acquisition having a higher rate per Boe than our legacy wells, (ii) drilling deeper, higher-cost wells and (iii) the decrease in the natural gas price between periods utilized to determine proved reserves.

The amortization of the intangible asset is a result of the value assigned to the operating rights that we acquired in an acquisition. The intangible asset is currently being amortized over an estimated life of 25 years.

***Impairment of long-lived assets.*** We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting. Due primarily to downward adjustments to the economically recoverable proved reserves associated with well performance on certain natural gas assets in our New Mexico Shelf area, we recognized a non-cash charge against earnings of $0.4 million during the year ended December 31, 2011. We did not recognize any impairment charges for the year ended December 31, 2012.

***General and administrative expenses.*** The following table provides components of our general and administrative expenses for the years ended December 31, 2012 and 2011:

| | Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2012 | | 2011 | |
| **(in thousands, except per unit amounts)** | **Amount** | **Per Boe** | **Amount** | **Per Boe** |
| General and administrative expenses | $ 118,256 | $ 4.23 | $ 90,376 | $ 4.11 |
| Non-cash stock-based compensation | 29,872 | 1.07 | 19,271 | 0.88 |
| Less: Third-party operating fee reimbursements | (14,332) | (0.51) | (11,122) | (0.51) |
| Total general and administrative expenses | $ 133,796 | $ 4.79 | $ 98,525 | $ 4.48 |

General and administrative expenses were approximately $133.8 million ($4.79 per Boe) for the year ended December 31, 2012, an increase of $35.3 million (36 percent) from $98.5 million ($4.48 per Boe) for the year ended December 31, 2011. The increase in general and administrative expenses and non-cash stock-based compensation was primarily due to an increase in the number of employees and related personnel expenses to handle our increased activities, both from (i) increased drilling and exploration activities and (ii) our acquisitions in 2011 and 2012. The increase in general and administrative expenses per Boe was primarily due to (i) an increase in the number of employees and related personnel expenses to handle our increased activities and (ii) an increase in non-cash stock-based compensation expense, offset in part by (i) increased production from our wells successfully drilled and completed in 2011 and 2012, (ii) additional production associated with our acquisitions in 2011 and 2012 and (iii) increased third-party operating fee reimbursements.

As the operator of certain oil and natural gas properties in which we own an interest, we earn overhead reimbursements during the drilling and production phases of the property. We earned reimbursements of $14.3 million and $11.1 million during the years ended December 31, 2012 and 2011, respectively. This reimbursement is reflected as a reduction of general and administrative expenses in the consolidated statements of operations. The increase in third-party operating fee reimbursements is primarily due to drilling and completing wells in which we own a lower working interest resulting in increased third-party income.

***(Gain) loss on derivatives not designated as hedges.*** The following table sets forth the cash settlements and the non-cash mark-to-market adjustments for the derivative contracts not designated as hedges for the years ended December 31, 2012 and 2011:

| | Years Ended December 31, | |
|---|---|---|
| **(in thousands)** | **2012** | **2011** |
| ***Cash payments (receipts):*** | | |
| Commodity derivatives - oil | $ (22,411) | $ 103,969 |
| Commodity derivatives - natural gas | (1,125) | (25,739) |
| Financial derivatives - interest | - | 6,624 |
| ***Mark-to-market (gain) loss:*** | | |
| Commodity derivatives - oil | (104,882) | (75,380) |
| Commodity derivatives - natural gas | 975 | 19,630 |
| Financial derivatives - interest | - | (5,754) |
| (Gain) loss on derivatives not designated as hedges | $ (127,443) | $ 23,350 |

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash settlements of those derivatives, which can be volatile. To the extent the future commodity price outlook declines between measurement periods, we will have mark-to-market gains, and to the extent future commodity price outlook increases between measurement periods, we will have mark-to-market losses.

***Interest expense.*** The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the years ended December 31, 2012 and 2011:

**(dollars in thousands)**

Interest expense ......................................................................................................................................................................

Weighted average interest rate - credit facility ..................................................................................................................................

Weighted average interest rate - senior notes ...................................................................................................................................

Total weighted average interest rate ................................................................................................................................................

Weighted average credit facility balance ..........................................................................................................................................

Weighted average senior notes balance ...........................................................................................................................................

Total weighted average debt balance ............................................................................................................................................ ....................................

The increase in weighted average debt balance during the year ended December 31, 2012 as compared to the corresponding period in 2011 was due primarily to (i) borrowings associated with our acquisitions in 2011 and 2012 and (ii) timing of our capital expenditures. The increase in interest expense was due to an overall increase in the weighted average debt balance, offset in part by a lower weighted average interest rate due to (i) the weighted average debt balance of credit facility borrowings bearing a lower interest rate than our senior notes and (ii) our recent senior note issuances having lower interest rates than historical issuances.

***Income tax provisions.*** We recorded an income tax expense of $251.0 million and $261.8 million for the years ended December 31, 2012 and 2011, respectively. The effective income tax rate for the years ended December 31, 2012 and 2011 was 38.1 percent and 38.4 percent, respectively.

***Income from discontinued operations, net of tax.*** In December 2012, we closed the sale of certain of our non-core assets for cash consideration of $488.1 million, subject to customary post-closing adjustments. In March 2011, we closed our divestiture of our Bakken assets for cash consideration of approximately $195.9 million.

The results of operations of these assets and the related gain (loss) on disposition are reported as discontinued operations in the accompanying consolidated statements of operations, described in more detail in Note N of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data." We recognized income from discontinued operations of $23.5 million and $128.6 million for the years ended December 31, 2012 and 2011, respectively. For the years ended December 31, 2012 and 2011, income from discontinued operations included a pre-tax loss of $18.7 million on the sale of our non-core assets and a pre-tax gain of $135.9 million on the sale of our Bakken assets.

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

***Oil and natural gas revenues.*** Revenue from oil and natural gas operations was $1,617.8 million for the year ended December 31, 2011, an increase of $766.4 million (90 percent) from $851.4 million for the year ended December 31, 2010. This increase was primarily due to (i) 2011 having a full year effect of the Marbob and Settlement Acquisitions which closed in October 2010 and (ii) successful drilling efforts during 2010 and 2011, coupled with increases in realized oil and natural gas prices. Specific factors affecting oil and natural gas revenues include the following:

- total oil production was 13,446 MBbl for the year ended December 31, 2011, an increase of 4,785 MBbl (55 percent) from 8,661 MBbl for the year ended December 31, 2010;

- average realized oil price (excluding the effects of derivative activities) was $91.34 per Bbl during the year ended December 31, 2011, an increase of 19 percent from $76.48 per Bbl during the year ended December 31, 2010;

- total natural gas production was 51,118 MMcf for the year ended December 31, 2011, an increase of 23,771 MMcf (87 percent) from 27,347 MMcf for the year ended December 31, 2010; and

- average realized natural gas price (excluding the effects of derivative activities) was $7.62 per Mcf during the year ended December 31, 2011, an increase of 10 percent from $6.91 per Mcf during the year ended December 31, 2010. Our natural gas prices have been significantly higher than the related NYMEX prices primarily due to the value of the natural gas liquids in our liquids-rich natural gas stream.

***Production expenses.*** The following table provides the components of our total oil and natural gas production costs for the years ended December 31, 2011 and 2010:

| | **Years Ended Dec** | | |
|---|---|---|---|
| | **2011** | | |
| **(in thousands, except per unit amounts)** | **Amount** | **Per Boe** | **A** |

| | | | |
|---|---|---|---|
| Lease operating expenses | $ 145,020 | $ 6.60 | $ |
| Taxes: | | | |
| Ad valorem | 8,854 | 0.40 | |
| Production | 122,187 | 5.56 | |
| Workover costs | 1,868 | 0.09 | |
| Total oil and natural gas production expenses | $ 277,929 | $ 12.65 | $ 1 |

Among the cost components of production expenses, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are directly related to commodity price changes.

Lease operating expense for the year ended December 31, 2011 included a $3.1 million ($0.13 per Boe) underestimate of costs in periods prior to 2011.

Lease operating expenses were $145.0 million ($6.60 per Boe) for the year ended December 31, 2011, which was an increase of $76.0 million (110 percent) from $69.0 million ($5.22 per Boe) for the year ended December 31, 2010. The increase in lease operating expenses was primarily due to (i) 2011 having a full year effect from the Marbob and Settlement Acquisitions which closed in October 2010, (ii) our wells successfully drilled and completed in 2010 and 2011, (iii) an increase in cost of services, primarily labor related, due to the increased demand for services and related labor in the Permian Basin, (iv) incurring of higher than normal routine environmental related costs, and (v) an underestimate of costs in periods prior to 2011 mentioned above. The increase in lease operating expenses per Boe was primarily due to (i) cost increases in services, primarily labor related, (ii) incurrence of higher than normal routine environmental related costs and (iii) and underestimate of costs in periods prior to 2011 mentioned above, offset in part by additional production from our wells successfully drilled and completed in 2010 and 2011 where we are receiving benefits from economies of scale.

Ad valorem taxes have increased primarily as a result of increased valuations of our Texas properties and the increase in the number of wells primarily associated with our 2010 and 2011 drilling activity in our Texas Permian area.

Production taxes per unit of production were $5.56 per Boe during the year ended December 31, 2011, an increase of 13 percent from $4.92 per Boe during the year ended December 31, 2010. The increase was directly related to the increase in commodity prices and our increase in oil and natural gas revenues related to increased volumes. Over the same period, our per Boe prices (excluding the effects of derivatives) increased 14 percent.

Workover expenses were approximately $1.9 million for each of the years ended December 31, 2011 and 2010. The 2011 amounts related primarily to workovers in the Texas Permian area, while the 2010 amounts related primarily to workovers in both the Texas Permian and New Mexico Shelf areas performed primarily to restore production.

***Exploration and abandonments expense.*** The following table provides a breakdown of our exploration and abandonments expense for the years ended December 31, 2011 and 2010:

| **(in thousands)** | **Years Ended December 31, 2011** | **2010** |
|---|---|---|
| Geological and geophysical | $ 4,977 | $ 2,712 |
| Exploratory dry hole costs | 1,067 | 37 |
| Leasehold abandonments and other | 5,350 | 7,381 |
| Total exploration and abandonments | $ 11,394 | $ 10,130 |

Our geological and geophysical expense, which primarily consists of the costs of acquiring and processing seismic data, geophysical data and core analysis, was approximately $5.0 million and $2.7 million, primarily relating to our Delaware Basin and Texas Permian areas, for the years ended December 31, 2011 and 2010, respectively.

Our exploratory dry hole costs during the year ended December 31, 2011 were primarily attributable to partially expensing an exploratory well located in our Delaware Basin area. The lower portion of this well was deemed not commercial; however, the upper portion of this well was completed successfully.

For the year ended December 31, 2011, we recorded approximately $5.4 million of leasehold abandonments, which related to non-core prospects in our New Mexico Shelf area. For the year ended December 31, 2010, we recorded approximately $7.4 million of leasehold abandonments, which related to non-core prospects in our Delaware Basin and Texas Permian areas.

***Depreciation, depletion and amortization expense.*** The following table provides components of our depreciation, depletion and amortization expense for the years ended December 31, 2011 and 2010:

| | Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2011 | | 2010 | |
| **(in thousands, except per unit amounts)** | **Amount** | **Per Boe** | **Amount** | **Per Boe** |
| Depletion of proved oil and natural gas properties ........................................................................................ | $ 392,859 | $ 17.88 | $ 206,922 | $ 15.65 |
| Depreciation of other property and equipment ............................................................................................ | 5,702 | 0.26 | 3,104 | 0.23 |
| Amortization of intangible asset - operating rights ........................................................................................ | 1,461 | 0.07 | 1,461 | 0.11 |
| Total depletion, depreciation and amortization ........................................................................................... | $ 400,022 | $ 18.21 | $ 211,487 | $ 15.99 |
| Oil price used to estimate proved oil reserves at period end ......................................................................... | $ 92.71 | | $ 75.96 | |
| Natural gas price used to estimate proved natural gas reserves at period end .......................................... | $ 4.12 | | $ 4.38 | |

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Depletion of proved oil and natural gas properties was $392.9 million ($17.88 per Boe) for the year ended December 31, 2011, an increase of $186.0 million (90 percent) from $206.9 million ($15.65 per Boe) for the year ended December 31, 2010. The increase in depletion expense was primarily due to (i) capitalized costs associated with new wells that were successfully drilled and completed in 2011 and 2010 and (ii) 2011 having a full year effect from the Marbob and Settlement Acquisitions, offset in part by the increase in the oil prices between the periods utilized to determine proved reserves.

The amortization of the intangible asset is a result of the value assigned to the operating rights that we acquired in an acquisition. The intangible asset is currently being amortized over an estimated life of 25 years.

***Impairment of long-lived assets.*** We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting. Due primarily to downward adjustments to the economically recoverable proved reserves associated with well performance on certain natural gas assets in our New Mexico Shelf area, we recognized a non-cash charge against earnings of $0.4 million during the year ended December 31, 2011. For the year ended December 31, 2010, we recognized a non-cash charge against earnings of $11.6 million, which was comprised primarily of natural gas properties in our New Mexico Shelf area and to a lesser extent impairment in value of certain of our inventoried tubular goods.

***General and administrative expenses.*** The following table provides components of our general and administrative expenses for the years ended December 31, 2011 and 2010:

| | **Years Ended December 31,** | | | |
|---|---|---|---|---|
| | **2011** | | **2010** | |
| **(in thousands, except per unit amounts)** | **Amount** | **Per Boe** | **Amount** | **Per Boe** |
| General and administrative expenses | $ 90,376 | $ 4.11 | $ 59,704 | $ 4.52 |
| Non-recurring bonus paid to Henry Entities' employees | - | - | 5,059 | 0.38 |
| Non-cash stock-based compensation | 19,271 | 0.88 | 12,931 | 0.98 |
| Less: Third-party operating fee reimbursements | (11,122) | (0.51) | (11,294) | (0.85) |
| Total general and administrative expenses | $ 98,525 | $ 4.48 | $ 66,400 | $ 5.03 |

General and administrative expenses were $98.5 million ($4.48 per Boe) for the year ended December 31, 2011, an increase of $32.1 million (48 percent) from $66.4 million ($5.03 per Boe) for the year ended December 31, 2010. The increase in general and administrative expenses was primarily due to (i) additional personnel and related costs associated with the Marbob Acquisition, (ii) an increase in the number of employees and related personnel expenses to handle our increased activities, partially offset by a decrease in the non-recurring bonus due to the Henry Entities' employees (discussed in the next paragraph) and (iii) an increase in non-cash stock-based compensation for stock-based compensation awards. The decrease in total general and administrative expenses per Boe was primarily due to (i) increased production from our wells successfully drilled and completed in 2010 and 2011 and (ii) 2011 having a full year effect of the production from our Marbob and Settlement Acquisitions.

In connection with the Henry Entities acquisition in July 2008, we agreed to pay certain of the Henry Entities' former employees a predetermined bonus amount, in addition to the normal recurring compensation we pay these employees, at each of the first and second anniversaries of the closing of the acquisition. Since these employees earned this bonus over the two years following the acquisition and it is outside of our control, we are reflecting the cost in our general and administrative costs as non-recurring. The final payment of the Henry Entities bonuses occurred in July 2010.

As the operator of certain oil and natural gas properties in which we own an interest, we earn overhead reimbursements during the drilling and production phases of the property. We earned reimbursements of $11.1 million and $11.3 million during the years ended December 31, 2011 and 2010, respectively. This reimbursement is reflected as a reduction of general and administrative expenses in the consolidated statements of operations. The per Boe rate decreased primarily due to increased production.

***Loss on derivatives not designated as hedges.*** The following table sets forth the cash settlements and the non-cash mark-to-market adjustments for the derivative contracts not designated as hedges for the years ended December 31, 2011 and 2010:

| **(in thousands)** | **Years Ended December 31, 2011** | **2010** |
|---|---|---|
| ***Cash payments (receipts):*** | | |
| Commodity derivatives - oil | $ 103,969 | $ 26,281 |
| Commodity derivatives - natural gas | (25,739) | (17,414) |
| Financial derivatives - interest | 6,624 | 4,957 |
| ***Mark-to-market (gain) loss:*** | | |
| Commodity derivatives - oil | (75,380) | 93,595 |
| Commodity derivatives - natural gas | 19,630 | (23,347) |
| Financial derivatives - interest | (5,754) | 3,253 |
| Loss on derivatives not designated as hedges | $ 23,350 | $ 87,325 |

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash settlements of those derivatives, which can be volatile. To the extent the future commodity price outlook declines between measurement periods, we will have mark-to-market gains, and to the extent future commodity price outlook increases between measurement periods, we will have mark-to-market losses.

***Interest expense.*** The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the years ended December 31, 2011 and 2010:

| **(dollars in thousands)** |
| --- |
| Interest expense |
| Weighted average interest rate - credit facility |
| Weighted average interest rate - senior notes |
| Total weighted average interest rate |
| Weighted average credit facility balance |
| Weighted average senior notes balance |
| Total weighted average debt balance |

The increase in weighted average debt balance during the year ended December 31, 2011 was due primarily to borrowings in October 2010 for the Marbob and Settlement Acquisitions. The increase in interest expense was due to (i) the October 2010 borrowings related to the Marbob and Settlement Acquisitions and the issuance of the 8.0% Marbob note, which was repaid in May 2011, (ii) the December 2010 issuance of 7.0% senior notes due 2021, (iii) the May 2011 issuance of 6.5% senior notes due 2022 and (iv) the amortization of capitalized loan costs associated with debt financing and the Marbob note premium. The proceeds from the senior notes were used to pay down our credit facility. The increase in the weighted average cash interest rate is primarily due to the issuance of our senior notes, which bear a higher fixed interest rate than was available under our credit facility.

***Income tax provisions.*** We recorded an income tax expense of $261.8 million and $101.6 million for the years ended December 31, 2011 and 2010, respectively. The effective income tax rate for the years ended December 31, 2011 and 2010 was 38.4 percent and 40.8 percent, respectively.

We recorded an $8.3 million charge to income tax expense in the fourth quarter of 2010 to increase our estimated overall state tax rate utilized to record our net deferred tax liability. This increase in the tax rate is due to an increase in our overall blended state income tax rate, a result of the assets acquired in the Marbob and Settlement Acquisitions being located in New Mexico where the state income tax rate is higher than in Texas. Also, in 2010, we recorded a benefit of approximately $1.5 million associated with revisions to our 2009 income tax provision.

Excluding the effect of these items, our effective income tax rate would have been 38.0 percent in 2010, which would approximate a more “normalized” effective income tax rate.

***Income from discontinued operations, net of tax.*** In December 2012 we closed on the sale of certain non-core assets for cash considerations of approximately $488.1 million, subject to customary post-closing adjustments. In March 2011, we closed our divestiture of our Bakken assets for cash consideration of approximately $195.9 million. In December 2010, we closed the sale of certain of our non-core Permian Basin assets for cash consideration of $103.3 million.

The results of operations of these assets and the related gain (loss) on disposition are reported as discontinued operations in the accompanying consolidated statements of operations, described in more detail in Note N of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.” We recognized income from discontinued operations of $128.6 million and $56.9 million for the years ended December 31, 2011 and 2010, respectively. For the years ended December 31, 2011 and 2010, income from discontinued operations included a pre-tax gain of $135.9 million on the sale of our Bakken assets and a pre-tax gain of $29.1 million on the sale of our non-core Permian Basin assets.

***Capital Commitments, Capital Resources and Liquidity***

***Capital commitments.*** Our primary needs for cash are development, exploration and acquisition of oil and natural gas assets, payment of contractual obligations and working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow, financing under our credit facility or proceeds from the disposition of assets or alternative financing sources, as discussed in "— Capital resources" below.

***Oil and natural gas properties.*** Our costs incurred on oil and natural gas properties, excluding acquisitions and asset retirement obligations, during the years ended December 31, 2012, 2011 and 2010 totaled $1.5 billion, $1.3 billion and $679.0 million respectively. The primary reason for the differences in the costs incurred and cash flow expenditures is the timing of payments. The 2012 expenditures were funded in part from borrowings under our credit facility.

In November 2012, we announced our 2013 capital budget of approximately $1.6 billion, which we expect can be substantially funded within our cash flow, based on current commodity prices and capital costs. We take a longer-term view on spending within our cash flow, and our spending during any specific period may exceed our cash flow for that period. However, our capital budget is largely discretionary, and if we experience sustained commodity prices significantly below the current levels or substantial increases in our costs, we may reduce our capital spending program to be substantially within our cash flow.

Although we cannot provide any assurance, we generally attempt to fund our non-acquisition expenditures with our available cash and cash flow as adjusted from time to time; however, we may also use our credit facility, or other alternative financing sources, to fund such expenditures. The actual amount and timing of our expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the timing of expenditures by third parties on projects that we do not operate, the availability of drilling rigs and other services and equipment, regulatory, technological and competitive developments and market conditions. In addition, under certain circumstances we would consider increasing or reallocating our capital spending plans.

Other than the customary purchase of leasehold acreage, our capital budgets are exclusive of acquisitions. We do not have a specific acquisition budget, since the timing and size of acquisitions are difficult to forecast. We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek to acquire oil and natural gas properties that provide opportunities for the addition of reserves and production through a combination of development, high-potential exploration and control of operations that will allow us to apply our operating expertise.

***Acquisitions.*** Our expenditures for acquisitions of proved and unproved properties totaled approximately $1.3 billion, $0.5 billion and $1.7 billion during the years ended December 31, 2012, 2011 and 2010, respectively. The significant expenditures for acquisitions during the year ended December 31, 2012 primarily related to the PDC Acquisition and the Three Rivers Acquisition. Expenditures for leasehold acreage acquisitions (which are expenditures we generally provide for in our planned capital expenditures) included in the total above was approximately $36.1 million for the year ended December 31, 2012.

***Divestitures.*** In December 2012, we sold certain of our non-core assets for cash consideration of approximately $488.1 million, subject to customary post-closing adjustment, and recognized a pre-tax loss on the disposition of assets (included in discontinued operations) of approximately $18.7 million. For the year ended December 31, 2012 these assets produced an average of 4,937 Boe per day. We estimate that the proved reserves of these assets at closing were approximately 35.3 MMBoe. We used the net proceeds from this divestiture to repay a portion of the outstanding borrowings under our credit facility.

In March 2011, we sold our Bakken assets for cash consideration of approximately $195.9 million and recognized a pre-tax gain on the sale of assets (included in discontinued operations) of approximately $135.9 million. For the first quarter of 2011, these assets produced an average of 1,369 Boe per day. We used the net proceeds from this divestiture to repay a portion of the outstanding borrowings under our credit facility.

In December 2010, we sold certain of our non-core Permian Basin assets for cash consideration of approximately $103.3 million and recognized a pre-tax gain on the sale of assets (included in discontinued operations) of approximately $29.1 million. For 2010, these assets produced an average of 1,393 Boe per day. We used the net proceeds from this divestiture to repay a portion of the outstanding borrowings under our credit facility.

***Contractual obligations.*** Our contractual obligations include long-term debt, cash interest expense on debt, operating lease obligations, drilling commitments, employment agreements with executive officers, derivative liabilities and other obligations.

We had the following contractual obligations at December 31, 2012:

| | Payments Due by Period | | | | |
|---|---|---|---|---|---|
| (in thousands) | Total | Less than 1 year | 1 - 3 years | 3 - 5 years | More than 5 years |
| Long-term debt (a) | $ 3,104,000 | $ - | $ - | $ 604,000 | $ 2,500,000 |
| Cash interest expense on debt (b) | 1,615,162 | 248,958 | 369,308 | 352,278 | 644,618 |
| Operating lease obligations (c) | 16,824 | 4,445 | 7,485 | 3,205 | 1,689 |
| Drilling commitments (d) | 11,951 | 11,083 | 868 | - | - |
| Employment agreements with officers (e) | 4,610 | 4,610 | - | - | - |
| Derivative liabilities (f) | 13,633 | 1,584 | 12,049 | - | - |
| Asset retirement obligations (g) | 86,261 | 3,308 | 19,044 | 3,426 | 60,483 |
| Total contractual obligations | $ 4,852,441 | $ 273,988 | $ 408,754 | $ 962,909 | $ 3,206,790 |

(a) See Note I of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for information regarding future interest payment obligations on our senior notes. The amounts included in the table above represent principal maturities only.

(b) Cash interest expense on our senior notes is estimated assuming no principal repayment until their maturity dates. Cash interest expense on our credit facility is estimated assuming (i) a principal balance outstanding equal to the balance at December 31, 2012 of $304.0 million with no principal repayment until the instrument due date of April 25, 2016 and (ii) a fixed interest rate of 2.1 percent, which was our interest rate at December 31, 2012. Also included in the “Less than 1 year” column is accrued interest at December 31, 2012 for our senior notes and the credit facility of approximately $64.3 million.

(c) See Note J of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.”

(d) Consists of daywork drilling contracts related to drilling rigs contracted at December 31, 2012. See Note J of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.”

(e) Represents amounts of cash compensation we are obligated to pay to our officers under employment agreements assuming such employees continue to serve the entire term of their employment agreement and their cash compensation is not adjusted.

(f) Derivative obligations represent commodity derivatives that were valued at December 31, 2012. The ultimate settlement amounts of our derivative obligations are unknown because they are subject to continuing market risk. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” and Note H of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding our derivative obligations.

(g) Amounts represent costs related to expected oil and natural gas property abandonments related to proved reserves by period, net of any future accretion. See Note E of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.”

***Off-balance sheet arrangements.*** Currently, we do not have any material off-balance sheet arrangements.

***Capital resources.*** Our primary sources of liquidity have been cash flows generated from operating activities (including the cash settlements received from (paid on) derivatives not designated as hedges presented in our investing activities) and financing provided by our credit facility. Based on current commodity prices and capital costs, we believe our 2013 capital expenditures budget excluding acquisitions will be substantially funded within our cash flow. We believe that we have adequate availability under our credit facility to fund any cash flow deficits, though we could reduce our capital spending program to remain substantially within our cash flow.

The following table summarizes our net increase (decrease) in cash and cash equivalents for the years ended December 31, 2012, 2011 and 2010:

| | Years Ended December 31, | | |
|---|---|---|---|
| **(in thousands)** | **2012** | **2011** | **2010** |
| Net cash provided by operating activities | $ 1,237,478 | $ 1,199,458 | $ 651,582 |
| Net cash used in investing activities | (2,240,444) | (1,651,418) | (2,043,457) |
| Net cash provided by financing activities | 1,005,504 | 451,918 | 1,389,025 |
| Net increase (decrease) in cash and cash equivalents | $ 2,538 | $ (42) | $ (2,850) |

***Cash flow from operating activities.*** The increase in operating cash flows during the year ended December 31, 2012 over 2011 was principally due to increases in our oil and natural gas production as a result of (i) our PDC Acquisition and Three Rivers Acquisition and (ii) our exploration and development program; offset in part by (i) the divestitures in 2011 and 2012, (ii) decreases in average realized oil and natural gas prices and (iii) increases in oil and natural gas production costs, general and administration expense, and interest expense. The increase in operating cash flows during the year ended December 31, 2011 over 2010 was principally due to increases in our oil and natural gas production as a result of our (i) exploration and development program and (ii) 2011 having a full year effect from the Marbob and Settlement Acquisitions and increases in average realized oil and natural gas prices, offset in part by increases in oil and natural gas production costs, general and administrative expense, and interest expense.

Our net cash provided by operating activities also includes a reduction of $0.5 million, $19.6 million and $29.2 million for the years ended December 31, 2012, 2011 and 2010, respectively, associated with changes in working capital items. Changes in working capital items adjust for the timing of receipts and payments of actual cash.

***Cash flow used in investing activities.*** During the years ended December 31, 2012, 2011 and 2010, we invested $2.7 billion, $1.7 billion and $2.1 billion, respectively, for capital expenditures on oil and natural gas properties. Cash flows used in investing activities were substantially higher during the year ended December 31, 2012 as compared to 2011, due to (i) our PDC Acquisition and Three Rivers Acquisition in 2012 and (ii) an increase in our exploration and development expenditures in 2012. Cash flows used in investing activities were higher during the year ended December 31, 2010 over 2011, primarily due to the size of the Marbob and Settlement Acquisitions in 2010 compared to acquisitions in 2011, offset in part by the significant increase in drilling activity in 2011.

***Cash flow from financing activities.*** Below is a description of our financing activities. During 2012, 2011 and 2010 we completed the following significant capital markets activities:

- in August 2012, we issued $700 million in aggregate principal amount of 5.5% senior notes due 2023 at par, for which we received net proceeds of approximately $688.6 million. We used the net proceeds to repay a portion of the borrowings under our credit facility.

- in March 2012, we issued $600 million in aggregate principal amount of 5.5% senior notes due 2022 at par, for which we received net proceeds of approximately $590.0 million. We used the net proceeds to repay a portion of the borrowings under our credit facility.

- in May 2011, we issued $600 million in aggregate principal amount of 6.5% senior notes due 2022 at par, for which we received net proceeds of approximately $587.1 million. We used the net proceeds to repay a portion of the borrowings under our credit facility.

- in December 2010, we issued, in a secondary public offering, 2.9 million shares of our common stock at $82.50 per share, and we received net proceeds of approximately $227.4 million. We used the net proceeds from this offering to repay a portion of the borrowings under our credit facility;

- in December 2010, we issued $600 million in principal amount of 7.0% senior notes due 2021 at par, and we received net proceeds of approximately $587.4 million. We used the net proceeds from this offering to repay a portion of the borrowings under our credit facility;

- in October 2010, we closed the private placement of our common stock, simultaneously with the closing of the Marbob Acquisition, on 6.6 million shares of our common stock at a price of $45.30 per share for net proceeds of approximately $292.7 million; and

- in February 2010, we issued approximately 5.3 million shares of our common stock at $42.75 per share in a secondary public offering, and we received net proceeds of approximately $219.3 million. The net proceeds from this offering were used to repay a portion of the borrowings under our credit facility.

Our credit facility has a maturity date of April 25, 2016. Our borrowing base is $3.0 billion until the next scheduled borrowing base redetermination in April 2013, and commitments from our bank group total $2.5 billion. Between scheduled borrowing base redeterminations, the Company and the lenders (requiring a 66 2/3 percent vote), may each request one special redetermination. At December 31, 2012 our availability to borrow additional funds was approximately $2.2 billion based on bank commitments of $2.5 billion.

Advances on our credit facility bear interest, at our option, based on (i) the prime rate of JPMorgan Chase Bank ("JPM Prime Rate") (3.25 percent at December 31, 2012) or (ii) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). The credit facility's interest rates of Eurodollar rate advances and JPM Prime Rate advances varied, with interest margins ranging from 150 to 250 basis points and 50 to 150 basis points, respectively, per annum depending on the debt balance outstanding. We pay commitment fees on the unused portion of the available commitment ranging from 37.5 to 50 basis points per annum, depending on utilization of the commitments.

In conducting our business, we may utilize various financing sources, including the issuance of (i) fixed and floating rate debt, (ii) convertible securities, (iii) preferred stock, (iv) common stock and (v) other securities. Over the last three years, we have demonstrated our use of the capital markets by issuing common stock in public offerings and private placements and issuing senior unsecured debt. However, there are no assurances that we can access the capital markets to obtain additional funding, if needed, and at what cost and terms. We may also sell assets and issue securities in exchange for oil and natural gas assets or interests in oil and natural gas companies. Additional securities may be of a class senior to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined from time to time by our board of directors. Utilization of some of these financing sources may require approval from the lenders under our credit facility.

***Liquidity.*** Our principal sources of short-term liquidity are cash on hand and available borrowing capacity under our credit facility. At December 31, 2012, we had $2.9 million of cash on hand.

At December 31, 2012, the commitments under our credit facility were $2.5 billion, which provided us with approximately $2.2 billion of available borrowing capacity. Upon a redetermination, our $3.0 billion borrowing base could be substantially reduced. There is no assurance that our borrowing base will not be reduced, which could affect our liquidity.

***Debt ratings.*** We receive debt credit ratings from Standard & Poor's Ratings Group, Inc. ("S&P") and Moody's Investors Service, Inc. ("Moody's"), which are subject to regular reviews. S&P's corporate rating for us is "BB+" with a stable outlook. Moody's corporate rating for us is "Ba3" with a stable outlook. S&P and Moody's consider many factors in determining our ratings including: production growth opportunities, liquidity, debt levels and asset and reserve mix. A reduction in our debt ratings could negatively affect our ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing.

***Book capitalization and current ratio.*** Our book capitalization at December 31, 2012 was $6.6 billion, consisting of debt of $3.1 billion and stockholders' equity of $3.5 billion. Our debt to book capitalization was 47 percent and 41 percent at December 31, 2012 and December 31, 2011, respectively. Our ratio of current assets to current liabilities was 0.62 to 1.0 at December 31, 2012 as compared to 0.59 to 1.0 at December 31, 2011.

***Inflation and changes in prices.*** Our revenues, the value of our assets, and our ability to obtain bank financing or additional capital on attractive terms have been and will continue to be affected by changes in commodity prices and the costs to produce our reserves. Commodity prices are subject to significant fluctuations that we are unable to control or predict. During the year ended December 31, 2012, we received, from continuing operations, an average of $87.96 per barrel of oil and $5.06 per Mcf of natural gas before consideration of commodity derivative contracts compared to $91.34 per barrel of oil and $7.62 per Mcf of natural gas in the year ended December 31, 2011. Although certain of our costs are affected by general inflation, inflation does not normally have a significant effect on our business. In a trend that began in 2004, and that has continued until recently, oil prices have increased significantly. The higher oil price led to increased activity in the industry and, consequently, rising costs. These cost trends have put pressure not only on our operating costs, but also on capital costs. Although we have seen a decrease in commodity prices, the cost trends have not followed proportionally.

***Critical Accounting Policies and Practices***

Our historical consolidated financial statements and related notes to consolidated financial statements contain information that is pertinent to our management’s discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to us.

In management’s opinion, the more significant reporting areas impacted by management’s judgments and estimates are revenue recognition, the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations, impairment of long-lived assets, valuation of stock-based compensation, valuation of business combinations and valuation of financial derivative instruments. Management’s judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates, as additional information becomes known.

***Successful Efforts Method of Accounting***

We utilize the successful efforts method of accounting for our oil and natural gas exploration and development activities. Under this method, exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment, undeveloped leases and developmental dry holes are capitalized. Exploratory drilling costs are initially capitalized, but are charged to expense if and when the well is determined not to have found proved reserves. Generally, a gain or loss is recognized when producing properties are sold. This accounting method may yield significantly different results than the full cost method of accounting.

The application of the successful efforts method of accounting requires management’s judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that proved reserves have been discovered may take considerable time, and requires both judgment and application of industry experience. The evaluation of oil and natural gas leasehold acquisition costs included in unproved properties requires management’s judgment to estimate the fair value of such properties. Drilling activities in an area by other companies may also effectively condemn our leasehold positions.

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually significant non-producing properties or projects are periodically assessed for impairment of value by considering future drilling plans, the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects.

Depletion of capitalized drilling and development costs of oil and natural gas properties is computed using the unit-of-production method on a field basis based on total estimated proved developed oil and natural gas reserves. Depletion of producing leaseholds is based on the unit-of-production method using our total estimated proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. Service properties, equipment and other assets are depreciated using the straight-line method over estimated useful lives of 2 to 31 years. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated depreciation and depletion are eliminated from the accounts and the resulting gain or loss is recognized.

*Oil and Natural Gas Reserves and Standardized Measure of Discounted Net Future Cash Flows*

This report presents estimates of our proved reserves as of December 31, 2012, which have been prepared and presented in accordance with SEC guidelines. The pricing that was used for estimates of our reserves as of December 31, 2012 was based on an unweighted average twelve month West Texas Intermediate posted price of $91.21 per Bbl for oil and a Henry Hub spot natural gas price of $2.76 per MMBtu for natural gas.

Our independent engineers and technical staff prepare the estimates of our oil and natural gas reserves and associated future net cash flows. Even though our independent engineers and technical staff are knowledgeable and follow authoritative guidelines for estimating reserves, they must make a number of subjective assumptions based on professional judgments in developing the reserve estimates. Reserve estimates are updated at least annually and consider recent production levels and other technical information about each field. Periodic revisions to the estimated reserves and future net cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly alter future depletion and result in impairment of long-lived assets that may be material.

It should not be assumed that the Standardized Measure included in this Report as of December 31, 2012 is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based the 2012 Standardized Measure on a 12-month average of commodity prices on the first day of the month and prevailing costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs utilized in the estimate. See “Item 1A. Risk Factors” and “Item 2. Properties” for additional information regarding estimates of proved reserves.

Our estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, the rate at which we record depletion expense will increase, reducing future earnings. Such a decline may result from lower commodity prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of our assessment of our proved properties for impairment.

*Asset Retirement Obligations*

There are legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and the normal operation of a long-lived asset. The primary impact of this relates to oil and natural gas wells on which we have a legal obligation to plug and abandon. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and, generally, a corresponding increase in the carrying amount of the related long-lived asset. The determination of the fair value of the liability requires us to make numerous judgments and estimates, including judgments and estimates related to future costs to plug and abandon wells, future inflation rates and estimated lives of the related assets.

*Impairment of Long-Lived Assets*

All of our long-lived assets are monitored for potential impairment when circumstances indicate that the carrying value of an asset may be greater than its future net cash flows, including cash flows from risk adjusted proved reserves. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test an asset for impairment may result from significant declines in sales prices or downward revisions in estimated quantities of oil and natural gas reserves. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded.

*Valuation of Stock-Based Compensation*

In accordance with GAAP, we are required to expense options and other stock-based compensation based on the fair value of the award on the grant date. The calculation of the fair value of stock-based compensation requires the use of estimates to derive the inputs necessary for using the various valuation methods utilized by us. We utilize the average of the high and low stock price on the date of grant for the fair value of restricted stock awards.

*Valuation of Business Combinations*

In connection with a purchase business combination, the acquiring company must record assets acquired and liabilities assumed based on fair values as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed, we make various assumptions. The most significant assumptions related to the estimated fair values assigned to proved and unproved oil and natural gas properties. To estimate the fair values of these properties, we utilize estimates of oil and natural gas reserves. We make future price assumption to apply to the estimated reserves quantities acquired and estimate future operating and development costs to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows were discounted using a market-based weighted average cost of capital rates determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rates are subject to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net cash flows of the unproved reserves were reduced by additional risk-weighting factors.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in a higher depletion expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value, or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

*Valuation of Financial Derivative Instruments*

In order to reduce commodity price uncertainty and increase cash flow predictability relating to the marketing of our oil and natural gas, we enter into commodity price hedging arrangements with respect to a portion of our expected production. In addition, we have used derivative instruments in connection with acquisitions and certain price-sensitive projects. Management exercises significant judgment in determining the types of instruments to be used, production volumes to be hedged, prices at which to hedge and the counterparties' creditworthiness. All derivative instruments are reflected at fair value in our consolidated balance sheets.

Our open commodity derivative instruments were in a net asset position with a fair value of $25.1 million at December 31, 2012. In order to determine the fair value at the end of each reporting period, we compute discounted cash flows for the duration of each commodity derivative instrument using the terms of the related contract. Inputs consist of published forward commodity price curves as of the date of the estimate. We compare these prices to the price parameters contained in our hedge contracts to determine estimated future cash inflows or outflows. We then discount the cash inflows or outflows using a combination of published LIBOR rates, Eurodollar futures rates and interest swap rates. The fair values of our commodity derivative assets and liabilities include a measure of credit risk based on current published credit default swap rates. In addition, for collars, we estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract parameters.

Changes in the fair values of our commodity derivative instruments have a significant impact on our net income because we follow mark-to-market accounting and recognize all gains and losses on such instruments in earnings in the period in which they occur. For the year ended December 31, 2012, we reported a $103.9 million non-cash mark-to-market gain on commodity derivative instruments.

We compare our estimates of the fair values of our commodity and interest rate derivative instruments with those provided by our counterparties. There have been no significant differences.

***Recent Accounting Pronouncements***

In December 2011, the FASB issued amendments to enhance disclosures required by U.S. GAAP by requiring improved information about financial instruments and derivative instruments that are either (i) offset in accordance with the current definition of "right of setoff" or the current balance sheet netting for derivative instruments allowed under current U.S. GAAP or (ii) subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset in accordance with either the definition of "right of setoff" or the current balance sheet netting for derivative instruments. This information will enable users of an entity's financial statements to evaluate the effect or potential effect of netting arrangements on an entity's financial position, including the effect or potential effect of rights of setoff associated with certain financial instruments and derivative instruments in the scope of the update.

An entity is required to apply the amendments for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. We adopted this update on January 1, 2013 and it did not have a significant impact on the consolidated financial statements.

**Item 7A. Quantitative and Qualitative Disclosure About Market Risk**

We are exposed to a variety of market risks including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which includes the use of derivative instruments. The following quantitative and qualitative information is provided about financial instruments to which we are a party at December 31, 2012, and from which we may incur future gains or losses from changes in market interest rates or commodity prices and losses from extension of credit. We do not enter into derivative or other financial instruments for speculative or trading purposes.

Hypothetical changes in interest rates and commodity prices chosen for the following estimated sensitivity analysis are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. However, since it is not possible to accurately predict future changes in interest rates and commodity prices, these hypothetical changes may not necessarily be an indicator of probable future fluctuations.

***Credit risk***. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which we market to energy marketing companies and refineries and to a lesser extent our derivative counterparties. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty's creditworthiness. Although we have not generally required our counterparties to provide collateral to support their obligation to us, we may, if circumstances dictate, require collateral in the future. In this manner, we reduce credit risk.

We have entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of our derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of set off upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note H of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our derivative activities.

***Commodity price risk***. We are exposed to market risk as the prices of our commodities are subject to fluctuations resulting from changes in supply and demand. To reduce our exposure to changes in the prices of our commodities we have entered into, and may in the future enter into, additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our commodity price risk management activities could have the effect of reducing net income and the value of our securities. An average increase in the commodity price of $10.00 per barrel of oil from the commodity price at

December 31, 2012, would have resulted in a net unrealized loss on our commodity price risk management contracts of approximately $245.9 million.

At December 31, 2012, we had oil price swaps that settle on a monthly basis covering future oil production from January 1, 2013 through June 30, 2017. See Note H of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information on the commodity derivative instruments. The average NYMEX oil price for the year ended December 31, 2012, was $94.19 per Bbl. At February 20, 2013, the NYMEX oil price was $94.46 per Bbl.

A decrease in the average NYMEX oil price below those at December 31, 2012, would increase the fair value asset of our commodity derivative contracts from their recorded balance at December 31, 2012. Changes in the recorded fair value of the undesignated commodity derivative contracts are marked to market through earnings as unrealized gains or losses. The potential increase in our fair value asset would be recorded in earnings as an unrealized gain. However, an increase in the average NYMEX oil price above those at December 31, 2012, would decrease the fair value asset of our commodity derivative contracts from their recorded balance at December 31, 2012. The potential decrease in our fair value asset would be recorded in earnings as an unrealized loss. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our commodity derivative contracts.

The fair value of our derivative instruments is determined based on our valuation models. We did not change our valuation method during the year ended December 31, 2012. During the year ended December 31, 2012, we were party to commodity derivative instruments. See Note H of the Condensed Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our derivative instruments. The following table reconciles the changes that occurred in the fair values of our derivative instruments during the year ended December 31, 2012:

| **(in thousands)** | **Commodity Derivative Instruments Net Assets (Liabilities) (a)** |
|---|---|
| Fair value of contracts outstanding at December 31, 2011 | $ (78,830) |
| Changes in fair values (b) | 127,444 |
| Contract maturities | (23,536) |
| Fair value of contracts outstanding at December 31, 2012 | $ 25,078 |

(a) Represents the fair values of open derivative contracts subject to market risk.
(b) At inception, new derivative contracts entered into by us have no intrinsic value.

***Interest rate risk***. Our exposure to changes in interest rates relates primarily to debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. To reduce our exposure to changes in interest rates we have entered into, and may in the future enter into additional interest rate risk management arrangements for a portion of our outstanding debt. The agreements that we have entered into generally have the effect of providing us with a fixed interest rate for a portion of our variable rate debt. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our credit facility, and the terms of our credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available commitments.

We had total indebtedness of $304.0 million outstanding under our credit facility at December 31, 2012. The impact of a one percent increase in interest rates on this amount of debt would result in increased annual interest expense of approximately $3.0 million.

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**Item 8. Financial Statements and Supplementary Data**

Our consolidated financial statements and supplementary financial data are included in this report beginning on page F-1.

**Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure**

We had no changes in, and no disagreements with, our accountants on accounting and financial disclosure.

**Item 9A. Controls and Procedures**

***Evaluation of Disclosure Controls and Procedures.*** As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective at December 31, 2012 at the reasonable assurance level.

***Changes in Internal Control over Financial Reporting.*** There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

**MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING**

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2012, management assessed the effectiveness of the Company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in “Internal Control - Integrated Framework,” issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting at December 31, 2012.

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.

Grant Thornton LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this annual report on Form 10-K, has issued their report on the effectiveness of the Company's internal control over financial reporting at December 31, 2012. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting at December 31, 2012, is included in this Item under the heading “Report of Independent Registered Public Accounting Firm.”

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

Board of Directors and Stockholders

Concho Resources Inc.

We have audited the internal control over financial reporting of Concho Resources Inc. (a Delaware 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 (COSO). 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 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 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.

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2012, and our report dated February 22, 2013 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 22, 2013

**Item 9B. Other Information**

None.

## PART III

### Item 10. Directors, Executive Officers and Corporate Governance

Item 10 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2012.

### Item 11. Executive Compensation

Item 11 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2012.

### Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

***Equity Compensation Plans***

At December 31, 2012, a total of 7,500,000 shares of common stock were authorized for issuance under our equity compensation plan. In the table below, we describe certain information about these shares and the equity compensation plan which provides for their authorization and issuance. You can find descriptions of our stock incentive plan under Note F of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

| | (1) Number of | (2) Weighted average | (3) Number of securities remaining available for future issuance under |
|---|---|---|---|

| Plan category | securities to be issued upon exercise of outstanding options | exercise price of outstanding options | equity compensation plans (excluding securities reflected in column (1)) |
|---|---|---|---|
| Equity compensation plan approved by the security holders (a) | 429,879 | $ 20.28 | 2,140,979 |
| Equity compensation plan not approved by the security holders (b) | - | $ - | - |
| Total | 429,879 | | 2,140,979 |

(a) 2006 Stock Incentive Plan, as amended and restated. See Note F of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

(b) None.

The remaining information required by Item 12 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2012.

**Item 13. Certain Relationships and Related Transactions, and Director Independence**

Item 13 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the ye