

CONCHO RESOURCES INC
Form 10-K
February 22, 2013

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
State or other jurisdiction
of incorporation or organization

76-0818600
(I.R.S. Employer
Identification No.)

**One Concho Center
600 West Illinois Avenue
Midland, Texas**

79701

Edgar Filing: CONCHO RESOURCES INC - Form 10-K

(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 No

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 No

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 No

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 No

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.

Edgar Filing: CONCHO RESOURCES INC - Form 10-K

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

Accelerated filer

Non-accelerated filer (Do not check if a smaller reporting company)

Smaller reporting company

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

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.

TABLE OF CONTENTS

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS
..... 1

PART I

.....
2

Item 1. Business

..... 2

General

.....
2

Acquisitions

..... 2

Divestitures

..... 3

Business and Properties

..... 3

Summary of Core Operating Areas and Other Plays

..... 5

Drilling Activities

..... 7

Our Production, Prices and Expenses

..... 8

Productive Wells

.....
9

Marketing Arrangements

..... 10

Our Principal Customers	10
.....	
Competition	10
.....	
Applicable Laws and Regulations	11
.....	
Our Employees	
.....	
17	
Available Information	17
.....	
Non-GAAP Financial Measures and Reconciliations	18
.....	
Item 1A. Risk Factors	20
.....	
Risks Related to Our Business	20
.....	
Risks Related to Our Common Stock	33
.....	
Item 1B. Unresolved Staff Comments	33
.....	
Item 2. Properties	34
.....	
Our Oil and Natural Gas Reserves	34
.....	
Developed and Undeveloped Acreage	38
.....	
Title to Our Properties	38
.....	
Item 3. Legal Proceeding	38
.....	
Item 4. Mine Safety	
Disclosure	38

PART II

.....
39

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

Equity Securities

..... 39

Market Information

..... 39

Dividend Policy

..... 39

Repurchase of Equity Securities

..... 39

Item 6. Selected Financial Data

..... 40

Selected Historical Financial Information

..... 40

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

..... 43

Overview

..... 43

Financial and Operating Performance

..... 44

Commodity Prices

..... 44

Recent Events

..... 46

Derivative Financial Instruments

..... 47

Results of Operations

..... 48

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

51

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010
56

Capital Commitments, Capital Resources and Liquidity
..... 61

Critical Accounting Policies and Practices
..... 66

Recent Accounting Pronouncements
..... 69

Item 7A. Quantitative and Qualitative Disclosure About Market Risk
..... 70

Credit risk
..... 70

Commodity price risk
..... 70

Interest rate risk
..... 71

Item 8. Financial Statements and Supplementary Data
..... 72

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure
..... 72

Item 9A. Quantitative and Qualitative Disclosure About Market Risk
..... 72

Evaluation of Disclosure Controls and Procedures
..... 72

Changes in Internal Control over Financial Reporting
..... 72

Item 9B. Other Information
..... 75

PART III
.....

76

Item 10. Directors, Executive Officers and Corporate Governance

..... 76

Item 11. Executive Compensation

..... 76

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

Matters

..... 76

Equity Compensation Plans

..... 76

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

..... 76

Item 14. Principal Accounting Fees and Services

..... 76

PART IV

.....
77

Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

..... 77

GLOSSARY OF TERMS

..... 83

SIGNATURES

.....
87

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

..... F-1

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, is 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.

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.

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.....

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 reported in the following table reflects the amounts of cash settlements received from (paid on) commodity derivatives not designated as hedges at average prices with derivatives and reconciles to the amount in (gain) loss on derivatives not designated as hedges as reported in the following table.

(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 derivatives that are presented in gain (loss) on derivatives not designated as hedges in the statements of operations. This presentation of derivatives 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.

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

.....
8

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:

(in millions)	December 31,		
	2012	2011	2010
PV-10	\$ 8,327.0	\$ 8,399.8	\$ 6,061.1
Present value of future income taxes discounted at 10%	(2,538.9)	(2,698.7)	(1,885.1)
Standardized measure of discounted future net cash flows	\$ 5,788.1	\$ 5,701.1	\$ 4,176.0

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.

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.

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	Natural Gas	Total	PV-10
	(MBbl)	(MMcf)	(MBoe)	(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
-------	---------

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 the 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	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 divestitures 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 the 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 2011 and (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 reported in the following table reflects the amounts of cash settlements received from (paid on) commodity derivatives not designated as hedges at average prices with derivatives and reconciles to the amount in (gain) loss on derivatives not designated as hedges as reported in the following table.

(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 commodity derivatives that are presented in gain (loss) on derivatives not designated as hedges in the statements of operations. This presentation of commodity derivatives means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and present commodity derivatives in a manner consistent with the presentation generally used by the investment community.

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

Production and operating data:

Net production volumes:

Average prices:

Production costs per Boe:

50

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
Item 1A. Risk Factors		115

(in thousands, except per unit amounts)	Amount	Boe	A
Lease operating expenses	\$ 182,716	\$ 6.53	\$ 1
Taxes:			
Ad valorem	13,695	0.49	1
Production	137,106	4.90	1
Workover costs	10,226	0.37	1
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	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:

(in thousands, except per unit amounts)	Years Ended December 31, 2012		2011	
	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	

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:

(in thousands, except per unit amounts)	Years Ended December 31, 2012		2011	
	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:

(in thousands)	Years Ended December 31,	
	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:

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

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:

(in thousands, except per unit amounts)	Years Ended December 31,			
	2011		2010	
	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	

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:

(in thousands, except per unit amounts)	Years Ended December 31,			
	2011	Per Boe	2010	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:

(in thousands)	Total	Payments Due by Period			
		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:

(in thousands)	Years Ended December 31,		
	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 risk 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.

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.

76

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

Plan category	securities to be issued upon	exercise price of	equity compensation plans (excluding securities reflected in column (1))
	exercise of outstanding options	outstanding options	
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 year ended December 31, 2012.

Item 14. Principal Accounting Fees and Services

Item 14 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.

PART IV

Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a) Listing of Financial Statements

Financial Statements

The following consolidated financial statements of ours are included in “Financial Statements and Supplementary Data:”

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets at December 31, 2012 and 2011

Consolidated Statements of Operations for the Years Ended December 31, 2012, 2011 and 2010

Consolidated Statements of Stockholders’ Equity for the Years Ended December 31, 2012, 2011 and 2010

Consolidated Statements of Cash Flows for the Years Ended December 31, 2012, 2011 and 2010

Notes to Consolidated Financial Statements

Successful Efforts Method of Accounting

Unaudited Supplementary Information

(b) Exhibits

The exhibits to this report required to be filed pursuant to Item 15(b) are listed below and in the “Index to Exhibits” attached hereto.

(c) Financial Statement Schedules

No financial statement schedules are required to be filed as part of this report or they are inapplicable.

Exhibits

Exhibit
Number

- 2.1 Purchase Agreement, dated May 11, 2012, by and among COG Operating LLC, as purchaser, and Three Rivers May 11, 2012, and incorporated herein by reference).
- 3.1 Restated Certificate of Incorporation (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on Aug
- 3.2 Second Amended and Restated Bylaws of Concho Resources Inc., as amended November 7, 2012 (filed as Exhi
- 4.1 (a) Specimen Common Stock Certificate.
- 4.2 Indenture, dated September 18, 2009, between Concho Resources Inc., the subsidiary guarantors named therein, 2009, and incorporated herein by reference).
- 4.3 First Supplemental Indenture, dated September 18, 2009, between Concho Resources Inc., the subsidiary guaran September 22, 2009, and incorporated herein by reference).
- 4.4 Second Supplemental Indenture, dated November 3, 2010, between Concho Resources Inc., the subsidiary guaran Company's Registration Statement on Form S-3 on December 7, 2010, and incorporated herein by reference).
- 4.5 Third Supplemental Indenture, dated December 14, 2010, between Concho Resources Inc., the subsidiary guaran December 14, 2010, and incorporated herein by reference).
- 4.6 Fourth Supplemental Indenture, dated May 23, 2011, between Concho Resources Inc., the subsidiary guarantors May 23, 2011, and incorporated herein by reference).
- 4.7 Fifth Supplemental Indenture, dated December 12, 2011, between Concho Resources Inc., the subsidiary guaran February 24, 2012, and incorporated herein by reference).
- 4.8 Sixth Supplemental Indenture, dated March 12, 2012, between Concho Resources Inc., the subsidiary guarantor March 12, 2012, and incorporated herein by reference).

Edgar Filing: CONCHO RESOURCES INC - Form 10-K

- 4.9 Seventh Supplemental Indenture, dated August 17, 2012, between Concho Resources Inc., the subsidiary guarantor of the Company's 8.625% Senior Notes due 2017 (included in Exhibit 4.2 to the Company's Current Report on Form 8-K on August 17, 2012, and incorporated herein by reference).
- 4.10 Form of 8.625% Senior Notes due 2017 (included in Exhibit 4.2 to the Company's Current Report on Form 8-K on August 17, 2012, and incorporated herein by reference).
- 4.11 Form of 7.0% Senior Notes due 2021 (included in Exhibit 4.1 to the Company's Current Report on Form 8-K on August 17, 2012, and incorporated herein by reference).
- 4.12 Form of 6.5% Senior Notes due 2022 (included in Exhibit 4.1 to the Company's Current Report on Form 8-K on August 17, 2012, and incorporated herein by reference).
- 4.13 Form of 5.5% Senior Notes due 2022 (included in Exhibit 4.2 to the Company's Current Report on Form 8-K on August 17, 2012, and incorporated herein by reference).
- 4.14 Form of 5.5% Senior Notes due 2023 (included in Exhibit 4.1 to the Company's Current Report on Form 8-K on August 17, 2012, and incorporated herein by reference).
- 10.1 (a)** Form of Restricted Stock Agreement (for officers).
- 10.2 (a)** Separation and Release Agreement dated January 2, 2013, between Concho Resources Inc. and Jack F. Harper (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 2, 2013, and incorporated herein by reference).
- 10.3 ** Form of Performance Unit Award Agreement (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 2, 2013, and incorporated herein by reference).
- 10.4 ** Amended and Restated Concho Resources Inc. 2006 Stock Incentive Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 2, 2013, and incorporated herein by reference).
- 10.5 ** Form of Nonstatutory Stock Option Agreement (filed as Exhibit 10.16 to the Company's Annual Report on Form 10-K for the year ended December 31, 2011, and incorporated herein by reference).
- 10.6 ** Form of Restricted Stock Agreement (for employees) (filed as Exhibit 10.16 to the Company's Registration Statement on Form S-1, filed with the SEC on January 2, 2013, and incorporated herein by reference).
- 10.7 ** Form of Restricted Stock Agreement (for non-officer employees) (filed as Exhibit 10.36 to the Company's Annual Report on Form 10-K for the year ended December 31, 2011, and incorporated herein by reference).
- 10.8 ** Form of Restricted Stock Agreement (for non-employee directors) (filed as Exhibit 10.18 to the Company's Annual Report on Form 10-K for the year ended December 31, 2011, and incorporated herein by reference).
- 10.9 ** Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Timothy A. Leach (filed as Exhibit 10.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference).
- 10.10 ** Employment Agreement dated December 19, 2008, between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.2 to the Company's Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference).
- 10.11 ** Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Darin G. Holderness (filed as Exhibit 10.3 to the Company's Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference).
- 10.12 ** Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Matthew G. Hyde (filed as Exhibit 10.4 to the Company's Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference).
- 10.13 ** Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Jack F. Harper (filed as Exhibit 10.5 to the Company's Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference).
- 10.14 ** Employment Agreement dated November 5, 2009, between Concho Resources Inc. and C. William Giraud (filed as Exhibit 10.6 to the Company's Annual Report on Form 10-K for the year ended December 31, 2009, and incorporated herein by reference).
- 10.15 ** Form of First Amendment to Employment Agreement between Concho Resources Inc. and each of Messrs. Leach, Wright, Holderness, Hyde, Harper, and Giraud (filed as Exhibit 10.7 to the Company's Annual Report on Form 10-K for the year ended December 31, 2009, and incorporated herein by reference).
- 10.16 ** Form of Indemnification Agreement between Concho Resources Inc. and each of the officers and directors thereof (filed as Exhibit 10.8 to the Company's Annual Report on Form 10-K for the year ended December 31, 2009, and incorporated herein by reference).
- 10.17 ** Indemnification Agreement, dated February 27, 2008, by and between Concho Resources, Inc. and William H. Merriman (filed as Exhibit 10.9 to the Company's Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference).
- 10.18 ** Indemnification Agreement, dated May 21, 2008, by and between Concho Resources, Inc. and Matthew G. Hyde (filed as Exhibit 10.10 to the Company's Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference).
- 10.19 ** Indemnification Agreement, dated August 25, 2008, by and between Concho Resources, Inc. and Darin G. Holderness (filed as Exhibit 10.11 to the Company's Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference).
- 10.20 ** Indemnification Agreement, dated November 5, 2009, by and between Concho Resources, Inc. and Mark B. Pugh (filed as Exhibit 10.12 to the Company's Annual Report on Form 10-K for the year ended December 31, 2009, and incorporated herein by reference).
- 10.21 ** Indemnification Agreement, dated November 5, 2009, by and between Concho Resources, Inc. and C. William Giraud (filed as Exhibit 10.13 to the Company's Annual Report on Form 10-K for the year ended December 31, 2009, and incorporated herein by reference).
- 10.22 ** Indemnification Agreement, dated January 10, 2012, between Concho Resources Inc. and Gary A. Merriman (filed as Exhibit 10.14 to the Company's Current Report on Form 8-K on January 10, 2012, and incorporated herein by reference).
- 10.23 ** Consulting Agreement dated June 9, 2009, by and between Concho Resources Inc. and Steven L. Beal (filed as Exhibit 10.15 to the Company's Annual Report on Form 10-K for the year ended December 31, 2009, and incorporated herein by reference).
- 10.24 Amended and Restated Credit Agreement, dated July 31, 2008, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on August 6, 2008, and incorporated herein by reference).
- 10.25 First Amendment to Amended and Restated Credit Agreement dated as of April 7, 2009, to the Amended and Restated Credit Agreement dated July 31, 2008, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K on April 7, 2009, and incorporated herein by reference).
- 10.26 Limited Consent and Waiver, dated September 4, 2009, to the Amended and Restated Credit Agreement dated July 31, 2008, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on September 4, 2009, and incorporated herein by reference).
- 10.26 Second Amendment to Amended and Restated Credit Agreement, dated April 26, 2010, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on April 26, 2010, and incorporated herein by reference).
- 10.27 Third Amendment to Amended and Restated Credit Agreement and Limited Waiver, dated June 16, 2010, among Concho Resources Inc., JP Morgan Chase Bank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K on June 16, 2010, and incorporated herein by reference).
- 10.28 Fourth Amendment to Amended and Restated Credit Agreement, dated October 7, 2010, among Concho Resources Inc., JP Morgan Chase Bank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K on October 13, 2010, and incorporated herein by reference).
- 10.29 Fifth Amendment to Amended and Restated Credit Agreement and Limited Waiver, dated as of December 7, 2010, among Concho Resources Inc., JP Morgan Chase Bank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.5 to the Company's Current Report on Form 8-K on December 10, 2010, and incorporated herein by reference).
- 10.30 Sixth Amendment to Amended and Restated Credit Agreement, dated as of April 25, 2011, among Concho Resources Inc., JP Morgan Chase Bank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.6 to the Company's Current Report on Form 8-K on April 27, 2011, and incorporated herein by reference).
- 10.31 Seventh Amendment to Amended and Restated Credit Agreement, dated as of October 12, 2011, among Concho Resources Inc., JP Morgan Chase Bank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.7 to the Company's Current Report on Form 8-K on October 14, 2011, and incorporated herein by reference).
- 10.32 Eighth Amendment to Amended and Restated Credit Agreement, dated as of April 12, 2012, among Concho Resources Inc., JP Morgan Chase Bank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.8 to the Company's Current Report on Form 8-K on April 16, 2012, and incorporated herein by reference).

Edgar Filing: CONCHO RESOURCES INC - Form 10-K

- 10.33 Ninth Amendment to Amended and Restated Credit Agreement, dated as of May 31, 2012, among Concho Resources Inc. and the other signatories (Report on Form 8-K on June 5, 2012, and incorporated herein by reference).
- 10.34 Tenth Amendment to Amended and Restated Credit Agreement, dated as of October 26, 2012, among Concho Resources Inc. and the other signatories (Report on Form 8-K on October 29, 2012, and incorporated herein by reference).
- 10.35 Registration Rights Agreement dated February 27, 2006, among Concho Resources Inc. and the other signatories.
- 12.1 (a) Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preferred Stock Dividends.
- 21.1 (a) Subsidiaries of Concho Resources Inc.
- 23.1 (a) Consent of Grant Thornton LLP.
- 23.2 (a) Consent of Netherland, Sewell & Associates, Inc.
- 23.3 (a) Consent of Cawley, Gillespie & Associates, Inc.
- 31.1 (a) Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- 31.2 (a) Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- 32.1 (b) Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- 32.2 (b) Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- 99.1 (a) Netherland, Sewell & Associates, Inc. Reserve Report.
- 99.2 (a) Cawley, Gillespie & Associates, Inc. Reserve Report.
- 101.INS (a) XBRL Instance Document.
- 101.SCH (a) XBRL Schema Document.
- 101.CAL (a) XBRL Calculation Linkbase Document.
- 101.DEF (a) XBRL Definition Linkbase Document.
- 101.LAB (a) XBRL Labels Linkbase Document.
- 101.PRE (a) XBRL Presentation Linkbase Document.

(a) Filed herewith.

(b) Furnished herewith.

** Management contract or compensatory plan or arrangement.

GLOSSARY OF TERMS

The following terms are used throughout this report:

Bbl One stock tank barrel, of 42 United States gallons liquid volume, used herein in reference to oil, condensate or natural gas liquids.

Boe One barrel of oil equivalent, a standard convention used to express oil and natural gas volumes on a comparable oil equivalent basis. Natural gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of oil or condensate.

Basin A large natural depression on the earth's surface in which sediments accumulate.

Development wells Wells drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

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

Exploratory wells Wells drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known reservoir.

Field An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

GAAP	Generally accepted accounting principles in the United States of America.
Gross wells	The number of wells in which a working interest is owned.
Horizontal drilling	A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a high angle to vertical (which can be greater than 90 degrees) in order to stay within a specified interval.
Infill drilling	Drilling into the same pool as known producing wells so that oil or natural gas does not have to travel as far through the formation.
LIBOR	London Interbank Offered Rate, which is a market rate of interest.
MBbl	One thousand barrels of oil, condensate or natural gas liquids.
MBoe	One thousand Boe.
Mcf	One thousand cubic feet of natural gas.
MMBoe	One million Boe.
MMBtu	One million British thermal units.

MMcf	One million cubic feet of natural gas.
NGL	Natural gas liquid.
NYMEX	The New York Mercantile Exchange.
NYSE	The New York Stock Exchange.
Net acres	The percentage of total acres an owner owns out of a particular number of acres within a specified tract. For example, an owner who has a 50 percent interest in 100 acres owns 50 net acres.
Net wells	The total of fractional working interests owned in gross wells.
PV-10	When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses except for specific general and administrative expenses incurred to operate the properties, discounted to a present value using an annual discount rate of 10 percent. PV-10 is a non-GAAP financial measure.
Productive wells	Wells that produce commercial quantities of hydrocarbons, exclusive of their capacity to produce at a reasonable rate of return.
Proved developed reserves	Proved developed reserves are reserves of any category that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) through installed extraction equipment and infrastructure operational at the time of the reserve estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Proved Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Proved Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Proved reserves Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to

operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) the area identified by drilling and limited by fluid contacts, if any, and

(B) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (“LKH”) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (“HKO”) elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) the project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves Proved undeveloped oil and natural gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

Recompletion The addition of production from another interval or formation in an existing wellbore.

Reservoir A formation beneath the surface of the earth from which hydrocarbons may be present. Its make-up is sufficiently homogenous to differentiate it from other formations.

Spacing The distance between wells producing from the same reservoir. Spacing is expressed in terms of acres, e.g., 40-acre spacing, and is established by regulatory agencies.

Standardized measure The present value (discounted at an annual rate of 10 percent) of estimated future net revenues to be generated from the production of proved reserves net of estimated income taxes associated with such net revenues, as determined in accordance with FASB guidelines, without giving effect to non-property related expenses such as indirect general and administrative expenses, and debt service or to depreciation, depletion and amortization. Standardized measure does not give effect to derivative transactions.

Undeveloped acreage Acreage owned or leased on which wells can be drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Wellbore The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called a well or borehole.

Working interest The right granted to the lessee of a property to explore for and to produce and own oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Workover

Operations on a producing well to restore or increase production.

WTI

western Texas.

West Texas Intermediate - light, sweet blend of oil produced from fields in

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONCHO RESOURCES INC.

Date: February 22, 2013 By /s/ Timothy A. Leach
 Timothy A. Leach
 Director, Chairman of the Board of Directors,
 Chief Executive
 Officer and President (Principal Executive
 Officer)

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

Signature	Title	Date
/s/ TIMOTHY A. LEACH Timothy A. Leach	Director, Chairman of the Board of Directors, Chief Executive Officer and President (Principal Executive Officer)	February 22, 2013
/s/ DARIN G. HOLDERNESS Darin G. Holderness	Senior Vice President, Chief Financial Officer (Principal Financial and Accounting Officer)	February 22, 2013
/s/ STEVEN L. BEAL Steven L. Beal	Director	February 22, 2013
/s/ TUCKER S. BRIDWELL Tucker S. Bridwell	Director	February 22, 2013

/s/ WILLIAM H. EASTER III William H. Easter III	Director	February 22, 2013
/s/ W. HOWARD KEENAN, JR. W. Howard Keenan, Jr.	Director	February 22, 2013
/s/ GARY A. MERRIMAN Gary A. Merriman	Director	February 22, 2013
/s/ RAY M. POAGE Ray M. Poage	Director	February 22, 2013
/s/ MARK B. PUCKETT Mark B. Puckett	Director	February 22, 2013
/s/ A. WELLFORD TABOR A. Wellford Tabor	Director	February 22, 2013

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Financial Statements of Concho Resources Inc.:

Report of Independent Registered Public Accounting Firm	F-2.....
Consolidated Balance Sheets at December 31, 2012 and 2011	F-3.....
Consolidated Statements of Operations for the Years Ended December 31, 2012, 2011 and 2010	F-4.....
Consolidated Statement of Stockholders' Equity for the Years Ended December 31, 2012, 2011 and 2010	F-5.....
Consolidated Statements of Cash Flows for the Years Ended December 31, 2012, 2011 and 2010.....	F-6.....
Notes to Consolidated Financial Statements	F-7.....
Unaudited Supplementary Information	F-47.....

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Concho Resources Inc.

We have audited the accompanying consolidated balance sheets of Concho Resources Inc. (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2012 and 2011, and the related consolidated statements of operations, stockholders’ equity and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Concho Resources Inc. and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company’s internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated February 22, 2013, expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 22, 2013

**Concho Resources Inc.
Consolidated Balance Sheets**

(in thousands, except share and per share amounts)

Assets

Current assets:

Cash and cash equivalents

Accounts receivable, net of allowance for doubtful accounts:

Oil and natural gas

Joint operations and other

Derivative instruments

Deferred income taxes

Prepaid costs and other

Total current
assets

Property and equipment:

Oil and natural gas properties, successful efforts method

Accumulated depletion and depreciation

Total oil and natural gas properties, net

Other property and equipment, net

Total property and equipment,
net

Funds held in escrow

Deferred loan costs, net

Intangible asset - operating rights, net

Inventory

Noncurrent derivative instruments

Other assets

Total assets

Liabilities and Stockholders' Equity

Current liabilities:

Accounts payable:

Trade

Related

parties.....

Bank overdrafts

Revenue payable

Accrued and prepaid drilling costs

Derivative

instruments.....

Deferred income taxes

Other current liabilities

Total current liabilities

Long-term debt

Deferred income

taxes.....

Noncurrent derivative instruments

Asset retirement obligations and other long-term liabilities

Commitments and contingencies (Note J)

Stockholders' equity:

Common stock, \$0.001 par value; 300,000,000 authorized; 104,668,427 and 103,756,222 shares issued at December 31, 2012 and 2011, respectively

Additional paid-in capital

Retained earnings

Treasury stock, at cost; 86,861 and 55,990 shares at December 31, 2012 and 2011, respectively

Total stockholders' equity.....

Total liabilities and stockholders' equity

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

(in thousands, except per share amounts)

Operating revenues:

Oil sales
 Natural gas sales

Operating costs and expenses:

Oil and natural gas production
 Exploration and abandonments
 Depreciation, depletion and amortization
 Accretion of discount on asset retirement obligations
 Impairments of long-lived assets
 General and administrative (including non-cash stock-based compensation of \$29,872, \$19,271

Bad debt expense
 (Gain) loss on derivatives not designated as hedges

Income from operations

Other income (expense):

Interest expense
 Other, net

Income from continuing operations before income taxes

Income tax expense

Income from continuing operations

Income from discontinued operations, net of tax

Net income

Basic earnings per share:

Income from continuing operations
 Income from discontinued operations, net of tax

Weighted average shares used in basic earnings per share.....

Diluted earnings per share:

Income from continuing operations
 Income from discontinued operations, net of tax

Weighted average shares used in diluted earnings per share

(a) Retrospectively adjusted for presentation of discontinued operations as described in Note B.

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

**Concho Resources
Consolidated Statements of Sto**

(in thousands)

BALANCE AT JANUARY 1, 2010.....
Net income.....
Issuance of common stock
Common stock issued in acquisition
Stock options exercised
Grants of restricted stock
Stock-based compensation
Cancellation of restricted stock
Excess tax benefits related to stock-based compensation.....
Purchase of treasury stock
BALANCE AT DECEMBER 31, 2010.....
Net income.....
Stock options exercised
Grants of restricted stock
Stock-based compensation
Cancellation of restricted stock
Excess tax benefits related to stock-based compensation.....
Purchase of treasury stock
BALANCE AT DECEMBER 31, 2011.....
Net income.....
Stock options exercised
Grants of restricted stock
Stock-based compensation
Cancellation of restricted stock
Excess tax benefits related to stock-based compensation.....
Purchase of treasury stock
BALANCE AT DECEMBER 31, 2012

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

Concho Resources Inc.
Consolidated Statements of Cash Flows

(in thousands)

CASH FLOWS FROM OPERATING ACTIVITIES:

Net income.....	\$.
Adjustments to reconcile net income to net cash provided by operating activities:	
Depreciation, depletion and amortization	
Impairments of long-lived assets	
Accretion of discount on asset retirement obligations	
Exploration and abandonments, including dry holes	
Non-cash compensation expense	
Bad debt expense	
Deferred income taxes	
Loss on sale of assets, net.....	
(Gain) loss on derivatives not designated as hedges	
Discontinued operations	
Other non-cash items	
Changes in operating assets and liabilities, net of acquisitions:	
Accounts receivable	
Prepaid costs and other	
Inventory	
Accounts payable	
Revenue payable	
Other current liabilities	
Net cash provided by operating activities	

CASH FLOWS FROM INVESTING ACTIVITIES:

Capital expenditures on oil and natural gas properties

.....
 Additions to other property and equipment

.....
 Proceeds from the sale of assets

.....
 Funds held in escrow

.....
 Settlements received from (paid on) derivatives not designated as hedges

.....
 Net cash used in investing activities

CASH FLOWS FROM FINANCING ACTIVITIES:

Proceeds from issuance of debt

.....
 Payments of debt

.....
 Exercise of stock options

.....
 Excess tax benefit from stock-based compensation

.....
 Net proceeds from issuance of common stock

.....
 Payments for loan costs

.....
 Purchase of treasury stock

.....
 Bank overdrafts

.....
 Net cash provided by financing activities

.....
 Net increase (decrease) in cash and cash equivalents

.....
 Cash and cash equivalents at beginning of period

.....
 Cash and cash equivalents at end of period

SUPPLEMENTAL CASH FLOWS:

Cash paid for interest and fees, net of \$73 and \$184 capitalized interest in 2011 and 2010

.....
 Cash paid for income taxes

NON-CASH INVESTING AND FINANCING ACTIVITIES:

Issuance of common stock for a business combination

.....
 Issuance of debt for a business combination

(a) Retrospectively adjusted for presentation of discontinued operations as described in Note B.

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

F-53

Note A. Organization and nature of operations

Concho Resources Inc. (the “Company”) is a Delaware corporation formed on February 22, 2006. The Company’s principal business is the acquisition, development and exploration of oil and natural gas properties primarily located in the Permian Basin region of Southeast New Mexico and West Texas.

Note B. Summary of significant accounting policies

Principles of consolidation. The consolidated financial statements of the Company include the accounts of the Company and its wholly-owned subsidiaries. In addition, a third-party has formed entities to effectuate a tax-free exchange of assets for the Company. The Company has 100 percent control over the decisions of the entities, but has no direct ownership. The third-party conveys ownership to the Company upon completion of the tax-free exchange process. The Company consolidates the financial statements of these entities. All material intercompany balances and transactions have been eliminated.

Discontinued operations. The Company made the following divestitures of assets during the periods covered by these consolidated financial statements:

(dollars in millions)	Asset Group		
	Non-Core Assets	Bakken Assets	Permian Basin Assets
Date divested	December 2012	March 2011	December 2010
Net proceeds	\$ 488.1	\$ 195.9	\$ 103.3
Gain (loss) on sale of assets	\$ (18.7)	\$ 135.9	\$ 29.1

As a result, the Company has reflected the results of operations of these divested assets as discontinued operations, rather than as a component of continuing operations. See Note N for additional information regarding these divestitures and their discontinued operations.

Use of estimates in the preparation of financial statements. Preparation of financial statements in conformity with generally accepted accounting principles in the United States of America (“U.S. GAAP”) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates. Depletion of oil and natural gas properties are determined using estimates of proved oil and natural gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and natural gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves and commodity price outlooks. Other significant estimates include, but are not limited to, the asset retirement obligations, fair value of derivative financial instruments, purchase price allocations for business combinations and fair value of stock-based compensation.

Cash equivalents. The Company considers all cash on hand, depository accounts held by banks, money market accounts and investments with an original maturity of three months or less to be cash equivalents. The Company’s cash and cash equivalents are held in a few financial institutions in amounts that exceed the insurance limits of the Federal Deposit Insurance Corporation. However, management believes that the Company’s counterparty risks are minimal based on the reputation and history of the institutions selected.

Accounts receivable. The Company sells oil and natural gas to various customers and participates with other parties in the drilling, completion and operation of oil and natural gas wells. Joint interest and oil and natural gas sales receivables related to these

operations are generally unsecured. The Company determines joint interest operations accounts receivable allowances based on management's assessment of the creditworthiness of the joint interest owners and the Company's ability to realize the receivables through netting of anticipated future production revenues. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. The Company had an allowance for doubtful accounts of approximately \$0.7 million at both December 31, 2012 and 2011.

Inventory. Inventory consists primarily of tubular goods and other oilfield goods that the Company plans to utilize in its ongoing exploration and development activities and is carried at the lower of cost or market value, on a weighted average cost basis.

Deferred loan costs. Deferred loan costs are stated at cost, net of amortization, which is computed using the effective interest and straight-line methods. The Company had deferred loan costs of \$77.6 million and \$65.6 million, net of accumulated amortization of \$38.8 million and \$26.8 million, at December 31, 2012 and December 31, 2011, respectively.

Future amortization expense of deferred loan costs at December 31, 2012 is as follows:

(in thousands)

2013.....	
2014.....	
2015.....	
2016.....	
2017.....	
Thereafter	
.....	
Total	
.....	

Oil and natural gas properties. The Company utilizes the successful efforts method of accounting for its oil and natural gas properties. Under this method all costs associated with productive wells and nonproductive development wells are capitalized, while nonproductive exploration costs are expensed. Capitalized acquisition costs relating to proved properties are depleted using the unit-of-production method based on proved reserves. The depletion of

capitalized exploratory drilling and development costs is based on the unit-of-production method using proved developed reserves. During the years ended December 31, 2012, 2011 and 2010, the Company recognized depletion expense from continuing and discontinued operations of \$591.3 million, \$423.2 million and \$252.7 million, respectively.

The Company generally does not carry the costs of drilling an exploratory well as an asset in its consolidated balance sheets for more than one year following the completion of drilling unless the exploratory well finds oil and natural gas reserves in an area requiring a major capital expenditure and both of the following conditions are met:

- (i) the well has found a sufficient quantity of reserves to justify its completion as a producing well; and
- (ii) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Due to the capital intensive nature and the geographical location of certain projects, it may take the Company longer than one year to evaluate the future potential of the exploration well and economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and being pursued constantly. Consequently, the Company's assessment of suspended exploratory well costs is continuous until a decision can be made that the well has found proved reserves or is

noncommercial and is charged to exploration and abandonments expense. See Note C for additional information regarding the Company's suspended exploratory well costs.

Proceeds from the sales of individual properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depletion. Generally, no gain or loss is recognized until the entire amortization base is sold. However, gain or loss is recognized from the sale of less than an entire amortization base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base. Ordinary maintenance and repair costs are expensed as incurred.

Costs of significant nonproducing properties, wells in the process of being drilled and completed and development projects are excluded from depletion until such time as the related project is developed and proved reserves are established or impairment is determined. The Company capitalizes interest, if debt is outstanding, on expenditures for significant development projects until such projects are ready for their intended use. At December 31, 2012 and 2011, the Company had excluded \$222.7 million and \$168.1 million, respectively, of capitalized costs from depletion, and the Company had capitalized interest of \$0.1 million and \$0.2 million, during 2011 and 2010, respectively. The Company had no capitalized interest during 2012.

The Company reviews its long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset. The Company reviews its oil and natural gas properties by amortization base or by individual well for those wells not constituting part of an amortization base. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value (discounted future cash flows) of the properties would be recognized at that time. Estimating future cash flows involves the use of judgments, including estimation of the proved and unproved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs. The Company recognized impairment expense from continuing and discontinued operations of \$0.4 million and \$15.2 million during the years ended December 31, 2011 and 2010, respectively, primarily related to its proved oil and natural gas properties. The Company did not recognize impairment expense related to its long-lived assets for the year ended December 31, 2012.

Unproved oil and natural gas properties are each periodically assessed for impairment 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. During the years ended December 31, 2012, 2011 and 2010, the Company recognized expense from continuing and discontinued operations of \$12.4 million, \$5.7 million and \$7.6 million, respectively, related to abandoned prospects, which is included in exploration and abandonments expense in the accompanying consolidated statements of operations.

Other property and equipment. Other capital assets include buildings, transportation equipment, computer equipment and software, telecommunications equipment, leasehold improvements and furniture and fixtures. These items are recorded at cost, or fair value if acquired, and are depreciated using the straight-line method based on expected lives of the individual assets or group of assets ranging from two to 31 years. During the years ended December 31, 2012, 2011 and 2010, the Company recognized depreciation expense of \$12.4 million, \$5.7 million and \$3.1 million, respectively.

F-6

Intangible assets. The Company has capitalized certain operating rights acquired in an acquisition. The gross operating rights, which have no residual value, are amortized over the estimated economic life of 25 years. Impairment will be assessed if indicators of potential impairment exist or when there is a material change in the remaining useful economic life. The following table reflects the gross and net intangible assets at December 31, 2012 and 2011, respectively:

(in thousands)	December 31,	
	2012	2011
Gross intangible - operating rights	\$ 36,557	\$ 38,717
Accumulated amortization	(6,481)	(5,292)
Net intangible - operating rights	\$ 30,076	\$ 33,425

The following table reflects amortization expense from continuing and discontinued operations for the years ended December 31, 2012, 2011 and 2010:

(in thousands)	Years Ended December 31,		
	2012	2011	2010
Amortization expense	\$ 1,549	\$ 1,549	\$ 1,549

The following table reflects the estimated aggregate amortization expense for each of the periods presented below at December 31, 2012:

(in thousands)

2013.....

2014.....
2015.....
2016.....
2017.....
Thereafter
.....
Total
.....

Environmental. The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. At December 31, 2012 and 2011, the Company has accrued approximately \$2.5 million and \$3.5 million, respectively, related to environmental liabilities. During the years ended December 31, 2012, 2011 and 2010, the Company recognized environmental charges of \$4.4 million, \$9.6 million and \$3.0 million, respectively.

F-7

Derivative instruments. The Company recognizes all derivative instruments as either assets or liabilities measured at fair value. The Company netted the fair value of derivative instruments by counterparty in the accompanying consolidated balance sheets where the right of offset exists. The Company did not have any derivatives designated as fair value or cash flow hedges during the years ended December 31, 2012, 2011, or 2010.

Asset retirement obligations. The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related asset is allocated to expense through depletion of the asset. Changes in the liability due to passage of time are generally recognized as an increase in the carrying amount of the liability and as corresponding accretion expense.

Treasury stock. Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares held is reduced by the average purchase price per share of the aggregate treasury shares held.

General and administrative expense. The Company receives fees for the operation of jointly owned oil and natural gas properties and records such reimbursements as reductions of general and administrative expense. Such fees from continuing and discontinued operations totaled approximately \$16.8 million, \$13.4 million and \$14.4 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Stock-based compensation. From time to time, the Company exchanges its equity instruments for services provided by employees and directors that are based on the fair value of the Company's equity instruments or that may be settled by the issuance of those equity instruments in exchange for the services. The cost of the services received in exchange for equity instruments, including stock options, is measured based on the grant-date fair value of those instruments. That cost is recognized as compensation expense over the requisite service period (generally the vesting period). Generally, no compensation cost is recognized for equity instruments that do not vest.

Income taxes. The Company recognizes deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company evaluates uncertain tax positions for recognition and measurement in the consolidated financial statements. To recognize a tax position, the Company determines whether it is more likely than not that the tax positions will be sustained upon examination, including resolution of any related appeals or litigation, based on the technical merits of the position. A tax position that meets the more likely than not threshold is measured to determine

the amount of benefit to be recognized in the consolidated financial statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. The Company had no uncertain tax positions that required recognition in the consolidated financial statements at December 31, 2012 and 2011. Any interest or penalties would be recognized as a component of income tax expense.

Reclassifications. Certain prior period amounts have been reclassified to conform to the 2012 presentation. These reclassifications had no impact on net income (loss), total stockholders' equity or cash flows.

Recent accounting pronouncements. In December 2011, the Financial Accounting Standards Board (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

Concho Resources Inc.**Notes to Consolidated Financial Statements****December 31, 2012, 2011 and 2010**

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. The Company adopted this update on January 1, 2013, and it did not have a significant impact on the consolidated financial statements.

Note C. Exploratory well costs

The Company capitalizes exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. The capitalized exploratory well costs are carried in unproved oil and natural gas properties. See Unaudited Supplementary Data for the proved and unproved components of oil and natural gas properties. If the exploratory well is determined to be impaired, the well costs are charged to expense.

The following table reflects the Company's capitalized exploratory well activity during each of the years ended December 31, 2012, 2011 and 2010:

(in thousands)	Years Ended December 31,		
	2012	2011	2010
Beginning capitalized exploratory well costs	\$ 107,767	\$ 46,826	\$ 8,668
.....			
Additions to exploratory well costs pending the determination of proved reserves	693,138	515,916	175,343
Reclassifications due to determination of proved reserves	(680,123)	(454,975)	(137,185)
.....			
Exploratory well costs charged to expense	(1,976)	-	-
.....			

Ending capitalized exploratory well costs						
.....	\$	118,806	\$	107,767	\$	46,826

F-9

Concho Resources Inc.**Notes to Consolidated Financial Statements****December 31, 2012, 2011 and 2010**

The following table provides an aging at December 31, 2012 and 2011 of capitalized exploratory well costs based on the date drilling was completed:

(in thousands)	December 31,	
	2012	2011
Exploratory wells in progress	\$ 22,837	\$ 24,963
Capitalized exploratory well costs that have been capitalized for a period of one year or less	95,969	82,804
Capitalized exploratory well costs that have been capitalized for a period greater than one year	-	-
Total capitalized exploratory well costs	\$ 118,806	\$ 107,767

At December 31, 2012, the Company had 69 gross exploratory wells either drilling or waiting on results from completion and testing, of which 33 wells were in the Delaware Basin area, 24 wells were in the New Mexico Shelf area and 12 wells were in the Texas Permian area.

Note D. Business combinations

Three Rivers Acquisition. In July 2012, the Company acquired certain producing and non-producing assets from Three Rivers Operating Company LLC and certain affiliated entities (collectively, the “Three Rivers Acquisition”) for cash consideration of approximately \$1.0 billion. The Three Rivers Acquisition was primarily funded with borrowings under the Company’s credit facility. The Company’s results of operations prior to July 2012 do not include results from the Three Rivers Acquisition.

The following table reflects the fair value of the acquired assets and liabilities associated with the Three Rivers Acquisition:

(in thousands)

Fair value of net assets:

Proved oil and natural gas
properties.....

Unproved oil and natural gas
properties.....

Total assets
acquired.....

Current liabilities, including current portion of asset retirement obligations
.....

Asset retirement obligations
assumed.....

Fair value of net assets
acquired.....

Fair value of consideration paid for net assets:

Cash
consideration.....

F-10

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

PDC Acquisition. In February 2012, the Company acquired certain 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 the Company’s credit facility. The Company’s results of operations prior to March 2012 do not include results from the PDC Acquisition.

The following table reflects the fair value of the acquired assets and liabilities associated with the PDC Acquisition:

(in thousands)

Fair value of net assets:

Current assets

.....
 Proved oil and natural gas properties

.....
 Unproved oil and natural gas properties

.....
 Total assets acquired

.....
 Current liabilities

.....
 Asset retirement obligations assumed

.....
 Fair value of net assets acquired

Fair value of consideration paid for net assets:

.....
 Cash consideration

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

OGX Acquisition. In November 2011, the Company acquired three entities affiliated with OGX Holdings II, LLC (collectively, the “OGX Acquisition”) for cash consideration of approximately \$252.0 million. The OGX Acquisition was primarily funded with borrowings under the Company’s credit facility. The Company’s results of operations prior to December 2011 do not include results from the OGX Acquisition.

The following table reflects the fair value of the acquired assets and liabilities associated with the OGX Acquisition:

(in thousands)

Fair value of net assets:

Current assets, net of cash acquired of \$205.....	\$ 5,579
Proved oil and natural gas properties	98,383
Unproved oil and natural gas properties	164,798
Total assets acquired	268,760.....
Current liabilities	(16,438).....
Asset retirement obligations	(321).....
Fair value of net assets acquired	\$ 252,001

Fair value of consideration paid for net assets:

Cash consideration, net of cash acquired of \$205	\$ 252,001
---	------------

Marbob and Settlement Acquisitions. In July 2010, the Company 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 \$150 million 8.0% senior note due 2018 and (iii) the issuance to Marbob of approximately 1.1 million shares of the Company's common stock, subject to purchase price adjustments, which included downward purchase price adjustments based on the exercise of third parties of contractual preferential purchase rights in properties to be acquired from Marbob ("Marbob Acquisition").

On October 7, 2010, the Company closed the Marbob Acquisition. At closing, the Company 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, as discussed below.

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

Certain of the Marbob interests in properties contained contractual preferential purchase rights by third parties if Marbob were to sell them. Marbob informed the Company of its receipt of a notice from BP America Production Company ("BP") electing to exercise its contractual preferential purchase rights in certain of Marbob's properties as a result of the Marbob Acquisition.

On July 20, 2010, BP announced it was selling all its assets in the Permian Basin to a subsidiary of Apache Corporation ("Apache"). Marbob and BP owned common interests in certain properties subject to contractual preferential purchase rights. BP and Apache contested Marbob's ability to exercise its contractual preferential purchase rights in this situation. As a result, Marbob and the Company filed suit against BP and Apache seeking declaratory judgment and injunctive relief to protect Marbob's contractual right to have the option to purchase these interests in these common properties.

On October 15, 2010, the Company and Marbob resolved the litigation with BP and Apache related to the disputed contractual preferential purchase rights. As a result of the settlement, the Company acquired a non-operated interest in substantially all of the oil

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

and natural gas assets subject to the litigation for approximately \$286 million in cash (the "Settlement Acquisition"). The Company funded the Settlement Acquisition with borrowings under its credit facility.

The results of operations of the Marbob and Settlement Acquisitions are included in the Company's results of operations since their respective closing dates in October 2010.

The following table reflects the estimated fair value of the acquired assets and liabilities associated with the Marbob and Settlement Acquisitions:

(in thousands)	Marbob Acquisition	Se Ac
Fair value of net assets:		
Proved oil and natural gas properties	\$ 1,014,734	\$
Unproved oil and natural gas properties	334,866	
Other long-term assets	20,771	
Total assets acquired	1,370,371	
Asset retirement obligations and other liabilities assumed	(7,851)	
Fair value of net assets acquired	\$ 1,362,520	\$
Fair value of consideration paid for net assets:		
Cash consideration	\$ 1,127,747	\$
Marbob \$150 million senior unsecured 8% note, due 2018	159,000 (a)	
Common stock, \$0.01 par value; 1,103,752 shares used	75,773 (b)	
Total purchase price	\$ 1,362,520	\$

- (a) The fair value of the \$150 million 8.0% senior unsecured note due 2018 issued to Marbob, was calculated by reference to the traded market yield of Concho's 8.625% senior unsecured notes due 2017, at September 30, 2010.
- (b) The fair value of the Concho common stock issued to Marbob was valued at the average of the high and low price on the closing date (October 7, 2010), of \$68.65 per share.

F-13

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Pro forma data. The following unaudited pro forma combined condensed financial data for the years ended December 31, 2012 and 2011, were derived from the historical financial statements of the Company giving effect to the Three Rivers Acquisition, as if it had occurred on January 1, 2011. The results of operations for the Three Rivers Acquisition since the closing in July 2012 are included in the Company's results of operations for the year ended 2012. The pro forma financial data does not include the results of operations for the OGX Acquisition or PDC Acquisition, as their results of operations were not deemed material. The unaudited pro forma combined condensed financial data has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Three Rivers Acquisition taken place as of the date indicated and is not intended to be a projection of future results.

(in thousands, except per share amounts)	Years Ended December 31,	
	2012	2011
	(unaudited)	
Operating revenues	\$ 1,885,821	\$ 1,767,806
Net income	\$ 374,569	\$ 423,320
Earnings per common share:		
Basic	\$ 3.63	\$ 4.13
Diluted	\$ 3.60	\$ 4.08

F-14

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Note E. Asset retirement obligations

The Company's asset retirement obligations represent the estimated present value of the estimated cash flows the Company will incur to plug, abandon and remediate its producing properties at the end of their productive lives, in accordance with applicable state laws. The Company does not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined. The Company has no assets that are legally restricted for purposes of settling asset retirement obligations.

The Company's asset retirement obligation transactions during the years ended December 31, 2012, 2011 and 2010 are summarized in the table below:

(in thousands)

Asset retirement obligations, beginning of period	\$
.....	
Liabilities incurred from new wells	
.....	
Liabilities assumed in acquisitions	
.....	
Accretion expense for continuing operations	
.....	
Accretion expense for discontinued operations	
.....	
Disposition of wells	
.....	
Liabilities settled upon plugging and abandoning wells	
.....	
Revision of estimates	
.....	
Asset retirement obligations, end of period	\$
.....	

Note F. Incentive plans

Defined contribution plan. The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all employees. Currently, the Company matches 100 percent of employee contributions, not to exceed 10 percent of the employee's annual salary. The Company's contributions to the plan for the years ended December 31, 2012, 2011 and 2010 were approximately \$4.0 million, \$1.8 million and \$0.7 million, respectively.

F-15

Concho Resources Inc.**Notes to Consolidated Financial Statements****December 31, 2012, 2011 and 2010**

Stock incentive plan. The Company's 2006 Stock Incentive Plan, as amended and restated (the "Plan"), provides for granting stock options, restricted stock awards and performance awards to employees and individuals associated with the Company. The following table shows the number of existing awards and awards available under the Plan at December 31, 2012:

	Number of Common Shares
Approved and authorized awards	7,500,000
Stock option grants, net of forfeitures	(1,982,162)
Restricted stock grants, net of forfeitures	(3,463,720)
Treasury shares	86,861
Awards available for future grant	2,140,979

Restricted stock awards. All restricted shares are treated as issued and outstanding in the accompanying consolidated balance sheets. If an employee terminates employment prior to the restriction lapse date, the awarded shares are forfeited and cancelled and are no longer considered issued and outstanding. A summary of the Company's restricted stock award activity for the years ended December 31, 2012, 2011 and 2010 is presented below:

Restricted stock:

Outstanding at January 1,
2010.....
Shares granted
.....
Shares cancelled / forfeited
.....
Lapse of restrictions
.....
Outstanding at December 31,
2010.....
Shares granted
.....
Shares cancelled / forfeited
.....
Lapse of restrictions
.....
Outstanding at December 31,
2011.....
Shares granted
.....
Shares cancelled / forfeited
.....
Lapse of restrictions
.....
Outstanding at December 31,
2012.....

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

The following table summarizes information about stock-based compensation for the Company's restricted stock awards activity under the Plan for years ended December 31, 2012, 2011 and 2010:

(in thousands)

Grant date fair value for awards during the period: (a)

Employee grants

.....
Officer and director grants.....

Total

Stock-based compensation expense from restricted stock:

Employee grants

.....
Officer and director grants

.....
Total

Income taxes and other information:

Income tax benefit related to restricted stock

Deductions in current taxable income related to restricted stock

(a) The year ended December 31, 2010 includes effects of modifications to certain stock-based awards, see discussion below.

Stock option awards. A summary of the Company's stock option award activity under the Plan for the years ended December 31, 2012, 2011 and 2010 is presented below:

Stock options:

Outstanding at beginning of
period.....

Options exercised
.....

Outstanding at end of
period.....

Vested at end of period
.....

Exercisable at end of period
.....

F-17

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

The following table summarizes information about the Company's vested and exercisable stock options outstanding at December 31, 2012, 2011 and 2010:

Range of Exercise Prices	Number Vested	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Intrinsic Value (in thousands)
December 31, 2012				
<i>Vested and exercisable options:</i>				
\$8.00.....	15,244	1.62 years	\$ 8.00	\$ 1,105
\$12.00.....	40,911	2.82 years	\$ 12.00	2,805
\$12.50 - \$15.50.....	77,500	3.86 years	\$ 14.91	5,088
\$20.00 - \$23.00.....	209,687	5.42 years	\$ 21.57	12,369
\$28.00 - \$37.27.....	59,735	5.42 years	\$ 31.25	2,946
	403,077	4.67 years	\$ 20.24	\$ 24,313
December 31, 2011				
<i>Vested and exercisable options:</i>				
\$8.00.....	125,781	2.62 years	\$ 8.00	\$ 10,786
\$12.00.....	52,911	3.80 years	\$ 12.00	4,325
\$12.50 - \$15.50.....	240,000	5.02 years	\$ 14.18	19,097
\$20.00 - \$23.00.....	280,087	6.31 years	\$ 21.67	20,188
\$28.00 - \$37.27.....	72,295	6.45 years	\$ 31.55	4,497
	771,074	5.15 years	\$ 17.37	\$ 58,893
December 31, 2010				
<i>Vested options:</i>				

Edgar Filing: CONCHO RESOURCES INC - Form 10-K

\$8.00.....	519,381.....	1.61.years..\$.....	8.00 \$.....	41,379.....
\$12.00.....	91,124.....	4.05.years..\$.....	12.00.....	6,895.....
\$12.50 -				
\$15.50.....	311,250.....	5.87.years..\$.....	14.49.....	22,778.....
\$20.00 -				
\$23.00.....	258,121.....	7.31.years..\$.....	21.65.....	17,041.....
\$28.00 -				
\$37.27.....	41,789.....	7.43.years..\$.....	31.24.....	2,358.....
	1,221,665	4.28 years \$	13.63 \$	90,451

Exercisable options:

\$8.00.....	132,369.....	3.49.years..\$.....	8.00 \$.....	10,546.....
\$12.00.....	73,296.....	4.79.years..\$.....	12.00.....	5,546.....
\$12.50 -				
\$15.50.....	311,250.....	5.87.years..\$.....	14.49.....	22,778.....
\$20.00 -				
\$23.00.....	258,121.....	7.31.years..\$.....	21.65.....	17,041.....
\$28.00 -				
\$37.27.....	41,789.....	7.43.years..\$.....	31.24.....	2,358.....
	816,825	5.92 years \$	16.33 \$	58,269

F-18

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

The following table summarizes information about stock-based compensation for stock options for the years ended December 31, 2012, 2011 and 2010:

(in thousands)

Stock-based compensation expense from stock options:

Employee grants

.....
Officer and director grants

.....
Total

Income taxes and other information:

Income tax benefit related to stock options

Deductions in current taxable income related to stock options exercised

Modification of stock-based awards. David W. Copeland, the Company's former Vice President, General Counsel and Corporate Secretary, retired December 31, 2010. Mr. Copeland stepped down from such positions on November 5, 2009, but remained with the Company as Senior Counsel until his retirement. As part of Mr. Copeland's retirement agreement, all of Mr. Copeland's stock-based awards were modified to permit full vesting on his retirement date. As a result of this modification, the Company recognized (i) a reduction in stock-based compensation of approximately \$30,000 for the year ended December 31, 2012, (ii) approximately \$0.1 million reduction of stock-based compensation during the year ended December 31 2011 and (iii) approximately \$0.5 million of stock-based compensation during the year ended December 31, 2010.

Steven L. Beal, the Company's former President and Chief Operating Officer, retired from such positions on June 30, 2009. Mr. Beal began serving as a consultant on July 1, 2009; see Note M. As part of the consulting agreement, certain of Mr. Beal's stock-based awards were modified to permit vesting and exercise under the original terms of the stock-based awards as if Mr. Beal was still an employee of the Company while he performs consulting services for the Company. As a result of this modification, the Company recognized approximately \$30,000, \$0.2 million and \$0.7 million of stock-based compensation during the years ended December 31, 2012, 2011 and 2010, respectively.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Future stock-based compensation expense. The following table reflects the future stock-based compensation expense to be recorded for all the stock-based compensation awards that are outstanding at December 31, 2012:

(in thousands)

2013

.....
2014

.....
2015

.....
2016.....

Total
.....

Note G. *Disclosures about fair value of financial instruments*

The Company uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following fair value input hierarchy:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. The Company considers active markets to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that the Company values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Level 2 instruments primarily include non-exchange traded derivatives such as over-the-counter commodity price swaps, basis swaps, investments and interest rate swaps. The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The Company utilizes its counterparties' valuations to assess the reasonableness of its prices and valuation techniques.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (*i.e.*, supported by little or no market activity). Level 3 instruments primarily include derivative instruments, such as commodity price collars and floors, as well as investments. The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) volatility factors and (iv) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Although the Company utilizes its counterparties' valuations to assess the reasonableness of its prices and valuation techniques, the Company does not have sufficient corroborating market evidence to support classifying these assets and liabilities as Level 2.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

The fair value input hierarchy level to which an asset or liability measurement in its entirety falls is determined based on the lowest level input that is significant to the measurement in its entirety. The following tables present the Company's assets and liabilities that are measured at fair value on a recurring basis at December 31, 2012 and 2011, for each of the fair value hierarchy levels:

(in thousands)	Fair Value Measurements at Reporting Date Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value at December 31, 2012
Assets:				
Commodity derivative price swap contracts	\$ -	\$ 68,579	\$ -	\$ 68,579
	-	68,579	-	68,579
Liabilities:				
Commodity derivative price swap contracts	-	(43,501)	-	(43,501)
	-	(43,501)	-	(43,501)
Net financial assets	\$ -	\$ 25,078	\$ -	\$ 25,078

	Fair Value Measurements at Reporting Date Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value Observable at December 31, 2011
(in thousands)				
Assets:				
Commodity derivative price swap contracts	\$ -	\$ 47,607	\$ -	\$ 47,607
.....	-	47,607	-	47,607
Liabilities:				
Commodity derivative price swap contracts	-	(126,437)	-	(126,437)
.....	-	(126,437)	-	(126,437)
Net financial liabilities	\$ -	\$ (78,830)	\$ -	\$ (78,830)
.....	\$ -	\$ (78,830)	\$ -	\$ (78,830)

F-21

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The following table presents the carrying amounts and fair values of the Company's financial instruments at December 31, 2012 and 2011:

(in thousands)

Assets:

Derivative instruments
.....

Liabilities:

Derivative
instruments.....

Credit facility
.....

8.625% senior notes due 2017
.....

7.0% senior notes due 2021
.....

6.5% senior notes due 2022
.....

5.5% senior notes due 2022
.....

5.5% senior notes due 2023
.....

Cash and cash equivalents, accounts receivable, other current assets, accounts payable, interest payable and other current liabilities. The carrying amounts approximate fair value due to the short maturity of these instruments.

Credit facility. The fair value of the Company's credit facility is estimated by discounting the principal and interest payments at the Company's credit-adjusted discount rate at the reporting date.

Senior notes. The fair values of the Company's 8.625%, 7.0%, 6.5% and both series of 5.5% senior notes are based on quoted market prices.

F-22

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Derivative instruments. The fair value of the Company's derivative instruments is estimated by management considering various factors, including closing exchange and over-the-counter quotations and the time value of the underlying commitments. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The following table summarizes (i) the valuation of each of the Company's financial instruments by required fair value hierarchy levels and (ii) the gross fair value by the appropriate balance sheet classification, even when the derivative instruments are subject to netting arrangements and qualify for net presentation in the Company's consolidated balance sheets at December 31, 2012 and 2011:

(in thousands)	Fair Value Measurements Using			Total Fair Value at December 31, 2012
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
Assets (a)				
Current:(b)				
Commodity derivative price swap contracts	\$ -	\$ 56,471	\$ -	\$ 56,471
	-	56,471	-	56,471
Noncurrent:(c)				
Commodity derivative price swap contracts	-	12,108	-	12,108
	-	12,108	-	12,108
Liabilities (a)				
Current:(b)				
Commodity derivative price swap contracts	-	(22,113)	-	(22,113)

	-	(22,113)	-	(22,113)
Noncurrent:(c)				
Commodity derivative price swap contracts				
	-	(21,388)	-	(21,388)
	-	(21,388)	-	(21,388)
Net financial assets				
	\$ -	\$ 25,078	\$ -	\$ 25,078
(b) Total current financial assets, gross basis			\$	34,358
(c) Total noncurrent financial liabilities, gross basis				(9,280)
Net financial assets			\$	25,078

F-23

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Fair Value Measurements Using

(in thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)		Significant Unobservable Inputs (Level 3)	Total Fair Value at December 31, 2011
Assets (a)					
Current:(b)					
Commodity derivative price swap contracts	\$ -	\$ 28,485	\$ -	\$ -	\$ 28,485
	-	28,485	-	-	28,485
Noncurrent:(c)					
Commodity derivative price swap contracts	-	19,122	-	-	19,122
	-	19,122	-	-	19,122
Liabilities (a)					
Current:(b)					
Commodity derivative price swap contracts	-	(83,005)	-	-	(83,005)
	-	(83,005)	-	-	(83,005)
Noncurrent:(c)					
Commodity derivative price swap contracts	-	(43,432)	-	-	(43,432)
	-	(43,432)	-	-	(43,432)
Net financial liabilities	\$ -	\$ (78,830)	\$ -	\$ -	\$ (78,830)
(b) Total current financial liabilities, gross basis					\$ (54,520)
(c) Total noncurrent financial liabilities, gross basis					(24,310)
Net financial liabilities					\$ (78,830)

- (a) The fair value of derivative instruments reported in the Company's consolidated balance sheets is subject to netting arrangements and qualifies for net presentation. The following table reports the net basis derivative fair values as reported in the consolidated balance sheets at December 31, 2012 and 2011:

(in thousands)	December 31,	
	2012	2011
Consolidated Balance Sheets Classification:		
<i>Current derivative contracts:</i>		
Assets		
.....	\$ 35,942	\$ 1,698
Liabilities		
.....	(1,584)	(56,218)
Net current		
.....	\$ 34,358	\$ (54,520)
<i>Noncurrent derivative contracts:</i>		
Assets		
.....	\$ 2,769	\$ 7,944
Liabilities		
.....	(12,049)	(32,254)
Net noncurrent		
.....	\$ (9,280)	\$ (24,310)

Concho Resources Inc.**Notes to Consolidated Financial Statements****December 31, 2012, 2011 and 2010****Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis**

Certain assets and liabilities are reported at fair value on a nonrecurring basis in the Company's consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Impairments of long-lived assets – The Company reviews its long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset. The Company reviews its oil and natural gas properties by depletion base or by individual well for those wells not constituting part of a depletion base. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value (discounted future cash flows) of the properties would be recognized at that time. Estimating future cash flows involves the use of judgments, including estimation of the proved and unproved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs.

The Company periodically reviews its proved oil and natural gas properties for impairment. Impairment expense is caused primarily due to declines in commodity prices and well performance. The Company did not recognize any impairment charges for the year ended December 31, 2012. The following table reports the carrying amounts, estimated fair values and impairment expense of long-lived assets for continuing and discontinued operations for the years ended December 31, 2011 and 2010:

(in thousands)	Carrying Amount	Estimated Fair Value
Year ended December 31, 2011.....	\$ 457	\$ 18

Year ended December 31,
2010..... \$ 27,888 \$ 12,707

Asset retirement obligations – The Company estimates the fair value of Asset Retirement Obligations (“AROs”) based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; amounts and timing of settlements; the credit-adjusted risk-free rate to be used and inflation rates. See Note E for a summary of changes in AROs.

F-25

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

The following table sets forth the measurement information for assets and liabilities measured at fair value on a nonrecurring basis:

Fair Value Measurements Using

(in thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Impairment Loss
Year ended December 31, 2012				
Impairment of long-lived assets	\$ -	\$ -	\$ -	-
Asset retirement obligations incurred or assumed	\$ -	\$ -	\$ 36,842	
Year ended December 31, 2011				
Impairment of long-lived assets	\$ -	\$ -	\$ 18	439
Asset retirement obligations incurred or assumed	\$ -	\$ -	\$ 7,705	
Year ended December 31, 2010				
Impairment of long-lived assets	\$ -	\$ -	\$ 12,707	15,181
Asset retirement obligations incurred or assumed	\$ -	\$ -	\$ 11,327	

Note H. *Derivative financial instruments*

The Company uses derivative financial contracts to manage its exposure to commodity price and interest rate fluctuations. Commodity hedges are used to (i) reduce the effect of the volatility of price changes on the oil and natural gas the Company produces and sells, (ii) support the Company's capital budget and expenditure plans and (iii) support the economics associated with acquisitions. The Company does not enter into derivative financial instruments for speculative or trading purposes. The Company may also enter into physical delivery contracts to effectively provide commodity price hedges. Because these contracts are not expected to be net cash settled, they are considered to be normal sales contracts and not derivatives. Therefore, these contracts are not recorded in the Company's consolidated financial statements.

Currently, the Company does not designate its derivative instruments to qualify for hedge accounting. Accordingly, the Company reflects changes in the fair value of its derivative instruments in its statements of operations as they occur.

F-26

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Commodity derivative contracts at December 31, 2012. The following table sets forth the Company's outstanding derivative contracts at December 31, 2012. When aggregating multiple contracts, the weighted average contract price is disclosed.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Swaps: (a)					
2013:					
Volume (Bbl)	3,747,000	3,417,000	3,178,000	2,988,000	13,330,000
Price per Bbl	\$ 95.96	\$ 95.98	\$ 95.66	\$ 95.39	\$ 95.77
2014:					
Volume (Bbl)	2,835,000	2,704,000	2,073,000	2,071,000	9,683,000
Price per Bbl	\$ 93.55	\$ 92.17	\$ 89.95	\$ 89.94	\$ 91.62
2015:					
Volume (Bbl)	420,000	420,000	119,000	117,000	1,076,000
Price per Bbl	\$ 85.91	\$ 85.91	\$ 89.44	\$ 89.43	\$ 86.69
2016:					
Volume (Bbl)	108,000	108,000	108,000	105,000	429,000
Price per Bbl	\$ 88.32	\$ 88.32	\$ 88.32	\$ 88.28	\$ 88.31
2017:					
Volume (Bbl)	84,000	84,000	-	-	168,000
Price per Bbl	\$ 87.00	\$ 87.00	\$ -	\$ -	\$ 87.00

(a) The index prices for the oil price swaps are based on the NYMEX – West Texas Intermediate monthly average futures price.

F-27

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

The following table summarizes the gains and losses reported in earnings related to the commodity and interest rate derivative instruments for the years ended December 31, 2012, 2011 and 2010:

(in thousands)

Gain (loss) on derivatives not designated as hedges:

Cash (payments on) receipts from derivatives not designated as hedges:

Commodity derivatives:

Interest rate derivatives

Mark-to-market gain (loss):

Commodity derivatives:

Interest rate derivatives

All of the Company's derivative contracts at December 31, 2012 are expected to settle by June 30, 2017.

Note I. Debt

The Company's debt consists of the following at December 31, 2012 and 2011:

(in thousands)

Credit facility	2
.....	3
8.625% unsecured senior notes due 2017	\$ 3
.....	3
7.0% unsecured senior notes due 2021	6
.....	6
6.5% unsecured senior notes due 2022	6
.....	6
5.5% unsecured senior notes due 2022	6
.....	7
5.5% unsecured senior notes due 2023	7
.....	7
Unamortized original issue discount, net	(
.....)
Less: current portion
.....
Total long-term debt	\$ 3,1
.....

F-28

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Credit facility. The Company's credit facility, as amended (the "Credit Facility"), has a maturity date of April 25, 2016. The Company's borrowing base is \$3.0 billion until the next scheduled borrowing base redetermination in April 2013, and commitments from the Company's 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.

Advances on the Credit Facility bear interest, at the Company's 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). At December 31, 2012, the 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 per annum, respectively, depending on the debt balance outstanding. At December 31, 2012, the Company paid commitment fees on the unused portion of the available commitments ranging from 37.5 to 50 basis points per annum.

The Credit Facility also includes a same-day advance facility under which the Company may borrow funds from the administrative agent. Same-day advances cannot exceed \$25 million, and the maturity dates cannot exceed fourteen days. The interest rate on this facility is the JPM Prime Rate plus the applicable interest margin.

The Company's obligations under the Credit Facility are secured by a first lien on substantially all of its oil and natural gas properties. In addition, all of the Company's subsidiaries are guarantors and have had their equity pledged to secure borrowings under the Credit Facility.

The Credit Facility contains various restrictive covenants and compliance requirements which include:

- maintenance of certain financial ratios, including (i) maintenance of a quarterly ratio of total debt to consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other noncash income and expenses to be no greater than 4.0 to 1.0, and (ii) maintenance of a ratio of current assets to current liabilities, excluding noncash assets and liabilities related to financial derivatives and asset retirement obligations and including the unfunded amounts under the Credit Facility, to be not less than 1.0 to 1.0;

- limits on the incurrence of additional indebtedness and certain types of liens;
- restrictions as to mergers, combinations and dispositions of assets; and
- restrictions on the payment of cash dividends.

Senior notes. Interest on the Company's senior notes is paid in arrears semi-annually. The senior notes are fully and unconditionally guaranteed on a senior unsecured basis by the Company's subsidiaries. In August 2012, the Company issued \$700 million of 5.5% senior notes due 2023 at par. In March 2012, the Company issued \$600 million of 5.5% senior notes due 2022 at par.

At December 31, 2012, the Company was in compliance with the covenants under its debt instruments.

F-29

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

The following table summarizes future interest expense from the net original issue discount at December 31, 2012:

(in thousands)

2013

.....
2014

.....
2015

.....
2016

.....
2017

.....
Total

Principal maturities of long-term debt. Principal maturities of long-term debt outstanding at December 31, 2012 are as follows:

(in thousands)

2013

.....
2014

.....
2015

.....
2016

.....
2017

Thereafter

Total

Interest expense. The following amounts have been incurred and charged to interest expense for the years ended December 31, 2012, 2011 and 2010:

(in thousands)	Years Ended December 31,		
	2012	2011	2010
Cash payments for interest	\$ 158,715	\$ 77,921	\$ 48,052
Amortization of original issue discount	462	133	185
Amortization of deferred loan origination costs	11,958	11,653	6,595
Write-off of deferred loan origination costs and original issue premium	-	(8,513)	-
Net changes in accruals	11,570	37,239	5,439
Interest costs incurred	182,705	118,433	60,271
Less: capitalized interest	-	(73)	(184)
Total interest expense	\$ 182,705	\$ 118,360	\$ 60,087

F-30

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Note J. Commitments and contingencies

Severance agreements. The Company has entered into severance and change in control agreements with all of its officers. The current annual salaries for the Company's officers covered under such agreements total approximately \$4.6 million.

Indemnifications. The Company has agreed to indemnify its directors and officers with respect to claims and damages arising from certain acts or omissions taken in such capacity.

Legal actions. The Company is a party to proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to any such proceedings or claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future results of operations. The Company will continue to evaluate proceedings and claims involving the Company on a regular basis and will establish and adjust any reserves as appropriate to reflect its assessment of the then current status of the matters.

Contractual drilling commitments. The Company periodically enters into contractual arrangements under which the Company is committed to expend funds to drill wells in the future, including agreements to secure drilling rig services, which require the Company to make future minimum payments to the rig operators. The Company records drilling commitments in the periods in which well capital is incurred or rig services are provided. The following table summarizes the Company's future drilling commitments at December 31, 2012:

	Payments Due By Period			
	Total	Less than	1-3	3-5
(in thousands)		1 year	years	years
Contractual drilling commitments	\$ 11,951	\$ 11,083	\$ 868	\$ -
.....				

Operating leases. The Company leases vehicles, equipment and office facilities under non-cancellable operating leases. Lease payments associated with these operating leases for the years ended December 31, 2012, 2011 and 2010 were approximately \$4.7 million, \$3.6 million and \$2.8 million, respectively.

Future minimum lease commitments under non-cancellable operating leases at December 31, 2012 are as follows:

(in thousands)

2013

.....
2014

.....
2015

.....
2016

.....
2017

.....
Thereafter

.....
Total

.....
F-31

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Note K. *Income taxes*

The Company uses an asset and liability approach for financial accounting and reporting for income taxes. The Company's objectives of accounting for income taxes are to recognize (i) the amount of taxes payable or refundable for the current year and (ii) deferred tax liabilities and assets for the future tax consequences of events that have been recognized in its financial statements or tax returns. The Company and its subsidiaries file a federal corporate income tax return on a consolidated basis. The tax returns and the amount of taxable income or loss are subject to examination by federal and state taxing authorities. At December 31, 2012 the Company had current income taxes payable of approximately \$2.1 million. At December 31, 2011, the Company had current income taxes receivable of approximately \$3.9 million and current income taxes payable of approximately \$0.8 million.

The Company continually assesses both positive and negative evidence to determine whether it is more likely than not that deferred tax assets can be realized prior to their expiration. Management monitors company-specific, oil and natural gas industry and worldwide economic factors and assesses the likelihood that the Company's net operating loss carryforwards ("NOLs"), if any, and other deferred tax attributes in the United States, state, and local tax jurisdictions will be utilized prior to their expiration. At December 31, 2012 and 2011, the Company had no valuation allowances related to its deferred tax assets.

At December 31, 2012, the Company did not have any significant uncertain tax positions requiring recognition in the financial statements. The tax years 2009 through 2012 remain subject to examination by the major tax jurisdictions.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Income tax provision. The Company's income tax provision and amounts separately allocated were attributable to the following items for the years ended December 31, 2012, 2011 and 2010:

(in thousands)	Years Ended December 31,		
	2012	2011	2010
Income tax expense (benefit) attributable to:			
Income from continuing operations.....	\$ 251,041	\$ 261,800	\$ 101,613
Income from discontinued operations	14,519	78,224	33,992
Changes in stockholders' equity:			
Excess tax benefits related to stock-based compensation	(18,963)	(24,037)	(11,346)
	\$ 246,597	\$ 315,987	\$ 124,259

The Company's income tax provision attributable to income from continuing operations consisted of the following for the years ended December 31, 2012, 2011 and 2010:

(in thousands)

Current:

U.S. federal

U.S. state and local

Total current income tax provision.....

Deferred:

U.S. federal

.....
U.S. state and local

.....
Total deferred income tax provision

.....
Total income tax provision attributable to income from
continuing
operations.....

F-33

Concho Resources Inc.**Notes to Consolidated Financial Statements****December 31, 2012, 2011 and 2010**

The reconciliation between the income tax expense computed by multiplying pretax income from continuing operations by the United States federal statutory rate and the reported amounts of income tax expense from continuing operations is as follows:

(in thousands)	Years Ended December 31,		
	2012	2011	2010
Income at U.S. federal statutory rate	\$ 230,745	\$ 238,467	\$ 87,164
State income taxes (net of federal tax effect)	21,192	22,002	8,007
Revisions of previous estimates	219	-	(1,521)
Statutory depletion	(261)	(204)	(179)
Change in effective statutory state income tax	-	-	8,278
Nondeductible expense & other	(854)	1,535	(136)
Income tax expense	\$ 251,041	\$ 261,800	\$ 101,613
Effective tax rate	38.1%	38.4%	40.8%

The Company's income tax provision attributable to income from discontinued operations consisted of the following for the years ended December 31, 2012, 2011 and 2010:

(in thousands)	Years Ended December 31,		
	2012	2011	2010

Current:

Edgar Filing: CONCHO RESOURCES INC - Form 10-K

U.S. federal			
.....	\$ 14,023	\$ 8,638	\$ 11,393
U.S. state and local			
.....	1,667	103	81
Total current income tax expense			
.....	15,690	8,741	11,474
Deferred:			
U.S. federal			
.....	(1,392)	59,417	18,178
U.S. state and local			
.....	221	10,066	4,340
Total deferred income tax provision			
.....	(1,171)	69,483	22,518
Total income tax provision attributable to income from discontinued operations			
.....	\$ 14,519	\$ 78,224	\$ 33,992

F-34

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities were as follows:

(in thousands)

Deferred tax assets:

Stock-based compensation

.....
Derivative instruments

.....
Asset retirement obligation

.....
Other

.....
Total deferred tax assets

Deferred tax liabilities:

Oil and natural gas properties, principally due to differences in basis and
depreciation and the deduction of intangible drilling costs for tax
purposes.....

Intangible assets - operating rights

.....
Derivative instruments

.....
Other

.....
Total deferred tax liability

.....
Net deferred tax liability

Note L. Major customers and derivative counterparties

Sales to major customers. The Company's share of oil and natural gas production is sold to various purchasers. The Company is of the opinion that the loss of any one purchaser would not have a material adverse effect on the ability of the Company to sell its oil and natural gas production.

The following purchasers individually accounted for 10 percent or more of the consolidated oil and natural gas revenues, including the revenues from discontinued operations, during the years ended December 31, 2012, 2011 and 2010:

Holly Frontier Refining and Marketing, LLC
.....

Phillips
66.....

DCP Midstream, LP
.....

At December 31, 2012, the Company had receivables from Holly Frontier Refining and Marketing, LLC, Phillips 66 (formerly the ConocoPhillips Company) and DCP Midstream, LP of \$34.4 million, \$23.7 million and \$17.7 million, respectively, which are reflected in accounts receivable — oil and natural gas in the accompanying consolidated balance sheets.

Derivative counterparties. The Company uses credit and other financial criteria to evaluate the credit standing of, and to select, counterparties to its derivative instruments. The Company's Credit Facility requires that the senior unsecured debt ratings of the Company's derivative counterparties be (i) not less than either A- by Standard & Poor's Rating Group rating system or A3 by Moody's Investors Service, Inc. rating system or (ii) a lender under the Company's Credit Facility. At December 31, 2012 and 2011, the counterparties with whom the Company had outstanding derivative contracts met or exceeded these criteria. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative instruments, management believes the associated credit risk is mitigated by the Company's credit risk policies and procedures and by the criteria of the Company's Credit Facility.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Note M. Related party transactions

The following tables summarize charges incurred with and payments made to the Company's related parties and reported in the consolidated statements of operations, as well as outstanding payables included in the consolidated balance sheets for the periods presented:

(in thousands)	Years Ended December 31,		
	2012	2011	2010
Charges incurred with Chase Oil and affiliates (a)			\$ 34,263
Overriding royalty interest paid to Chase Oil affiliates (b)			\$ 2,078
Royalty interests paid to a director and certain officers of the Company (c)	\$ 2,521	\$ 721	\$ 154
Amounts paid under consulting agreement with Steven L. Beal (d)	\$ 251	\$ 250	\$ 254

(in thousands)	December 31,	
	2012	2011
Amounts included in accounts payable - related parties:		
Royalty interests of a director and certain officers of the Company (c)	\$ 185	\$ 154

(a) The Company incurred charges for services rendered in the ordinary course of business from Chase Oil Corporation and its affiliates ("Chase Oil"), including a drilling contractor, an oilfield services company, a supply

company, a drilling fluids supply company, a pipe and tubing supplier, a fixed base operator of aircraft services and a software company. The Company also operates oil and natural gas wells in which Chase Oil owns a working interest. The tables above summarize the charges incurred. At January 1, 2011, Chase Oil was no longer considered a related party due to the decrease in their ownership.

(b) Certain persons affiliated with Chase Oil own overriding royalty interests in certain of the Company's properties. The tables above summarize the amounts paid attributable to such interests. At January 1, 2011, Chase Oil was no longer considered a related party due to the decrease in their ownership.

(c) Royalties are paid (i) on certain properties to a partnership of which one of the Company's directors is the general partner and owns a 3.5 percent partnership interest and (ii) to certain officers of the Company who own an overriding royalty interest in properties owned by the Company. The tables above summarize the amounts paid and amounts due at period end.

(d) On June 30, 2009, Steven L. Beal, the Company's then-president and chief operating officer, retired from such positions. On June 9, 2009, the Company entered into a consulting agreement (the "Consulting Agreement") with Mr. Beal, under which Mr. Beal began serving as a consultant to the Company on July 1, 2009. Either the Company or Mr. Beal may terminate the consulting relationship at any time by giving ninety days written notice to the other party; however, the Company may terminate the relationship immediately for cause. During the term of the consulting relationship, Mr. Beal will receive a consulting fee of \$20,000 per month and a monthly reimbursement for his medical and dental coverage costs. If Mr. Beal dies during the term of the Consulting Agreement, his estate will receive a \$60,000 lump sum payment. As part of the consulting agreement, certain of Mr. Beal's stock-based awards were modified to permit vesting and exercise under the original terms of the stock-based awards as if Mr. Beal were still an employee of the Company while he is performing consulting services for the Company. The tables above summarize the Company's activities pursuant to the consulting agreement with Mr. Beal.

Purchase of residence. During 2010, the Company purchased the residence of an officer of the Company. To effectuate the purchase, the Company engaged a third-party relocation company, who executed the purchase for \$0.9 million and subsequently sold the officer's residence. The third-party relocation company appraised the fair value of the residence at \$0.9 million.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Note N. *Discontinued operations*

In December 2012, the Company sold certain non-core assets for cash consideration of approximately \$488.1 million, subject to customary post-closing adjustments. The Company recognized a pre-tax loss on the disposition of assets in discontinued operations of approximately \$18.7 million.

In March 2011, the Company sold its Bakken assets for cash consideration of approximately \$195.9 million. The Company recognized a pre-tax gain on the disposition of assets in discontinued operations of approximately \$135.9 million.

In December 2010, the Company sold certain of its non-core Permian Basin assets for cash consideration of approximately \$103.3 million. The Company recorded a pre-tax gain on the disposition of assets in discontinued operations of approximately \$29.1 million.

The Company reflected the result of operations of these divestitures as discontinued operations, rather than as a component of continuing operations. The following table represents the components of the Company's discontinued operations for the years ended December 31, 2012, 2011 and 2010:

(in thousands)

Operating revenues:

Oil sales

.....
Natural gas sales

.....
Total operating
revenues.....

Operating costs and expenses:

Oil and natural gas production

Exploration and abandonments
Depreciation, depletion and amortization (a)
Accretion of discount on asset retirement obligations (a)
Impairment of long-lived assets (a)
General and administrative (b)
Total operating costs and expenses.....
Income from operations
Other income (expense):	
Other
Gain (loss) on disposition of assets, net (a)
Income from discontinued operations before income taxes
Income tax benefit (expense):	
Current
Deferred (a)
Income from discontinued operations, net of tax

(a) Represents the significant non-cash components of discontinued operations.

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

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Note O. *Net income per share*

Basic net income per share is computed by dividing net income applicable to common shareholders by the weighted average number of common shares treated as outstanding for the period.

The computation of diluted net income per share reflects the potential dilution that could occur if securities or other contracts to issue common stock that are dilutive to income were exercised or converted into common stock or resulted in the issuance of common stock that would then share in the earnings of the Company. These amounts include unexercised stock options and restricted stock. Potentially dilutive effects are calculated using the treasury stock method.

The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding for years ended December 31, 2012, 2011 and 2010:

(in thousands)

Weighted average common shares outstanding:

Basic

.....
Dilutive common stock options

.....
Dilutive restricted stock

.....
Diluted

The following table is a summary of the common stock options and restricted stock which were not included in the computation of diluted net income per share, as inclusion of these items would be antidilutive:

(in thousands)	Years Ended December 31, 2012 2011 2010		
<i>Number of antidilutive common shares:</i>			
Antidilutive common stock options	-	-	1
Antidilutive restricted stock	95	27	7

F-38

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Note P. *Other current liabilities*

The following table provides the components of the Company's other current liabilities at December 31, 2012 and 2011:

(in thousands)

Other current liabilities:

Accrued production costs

.....
Payroll related matters

.....
Accrued interest

.....
Asset retirement obligations

.....
Other

.....
Other current liabilities

Note Q. *Subsidiary guarantors*

Certain of the Company's wholly-owned and controlled subsidiaries have fully and unconditionally guaranteed the Company's senior notes. The indentures governing the Company's senior notes provide that the guarantees of its subsidiary guarantors will be released in certain customary circumstances including (i) in connection with any sale, exchange or other disposition, whether by merger, consolidation or otherwise, of the capital stock of that guarantor to a person that is not the Company or a restricted subsidiary of the Company, such that, after giving effect to such transaction, such guarantor would no longer constitute a subsidiary of the Company, (ii) in connection with any sale, exchange or other disposition (other than a lease) of all or substantially all of the assets of that guarantor to a person

that is not the Company or a restricted subsidiary of the Company, (iii) upon the merger of a guarantor into the Company or any other guarantor or the liquidation or dissolution of a guarantor, (iv) if the Company designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the indenture, (v) upon legal defeasance or satisfaction and discharge of the indenture and (vi) upon written notice of such release or discharge by the Company to the trustee following the release or discharge of all guarantees by such guarantor of any indebtedness that resulted in the creation of such guarantee, except a discharge or release by or as a result of payment under such guarantee.

See Note I for a summary of the Company's senior notes. In accordance with practices accepted by the SEC, the Company has prepared condensed consolidating financial statements in order to quantify the assets, results of operations and cash flows of such subsidiaries as subsidiary guarantors. One of the entities included in the Company's consolidated financial statements was formed to effectuate a tax-free exchange of assets. The third-party conveyed ownership to the Company upon completion of the tax-free exchange process. This entity did not guarantee the Company's senior notes until the conveyance was completed and is referred to as a "Non-Guarantor Subsidiary" in the tables below.

The following condensed consolidating balance sheets at December 31, 2012 and 2011, condensed consolidating statements of operations and consolidating condensed statements of cash flows for the years ended December 31, 2012, 2011 and 2010, present financial information for Concho Resources Inc. as the Parent on a stand-alone basis (carrying any investments in subsidiaries under the equity method), financial information for the subsidiary guarantors on a stand-alone basis (carrying any investment in non-guarantor subsidiaries under the equity method), financial information for the subsidiary non-guarantor on a stand-alone basis and the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis. All current and deferred income taxes are recorded on Concho Resources Inc., as the subsidiaries are flow-through entities for income tax purposes. The subsidiary guarantors and subsidiary non-guarantor are not restricted from making distributions to the Company.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

**Condensed Consolidating Balance Sheet
December 31, 2012**

(in thousands)

ASSETS

Accounts receivable - related parties

Other current assets

Oil and natural gas properties, net

Property and equipment, net

Investment in subsidiaries

Other long-term assets

Total assets

LIABILITIES AND EQUITY

Accounts payable - related parties

Other current liabilities

Other long-term liabilities

Long-term debt

Equity

Total liabilities and equity

Condensed Consolidating Balance Sheet

December 31, 2011

(in thousands)

ASSETS

Accounts receivable - related parties

Other current assets

Oil and natural gas properties, net

Property and equipment, net

Investment in subsidiaries

Other long-term assets

Total assets

LIABILITIES AND EQUITY

Accounts payable - related parties

Other current liabilities

Other long-term liabilities

Long-term debt

Equity

Total liabilities and equity

F-40

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

**Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2012**

(in thousands)

Total operating revenues

.....
Total operating costs and expenses

.....
Income from operations

.....
Interest expense

.....
Other, net

.....
Income (loss) before income taxes

.....
Income tax expense

.....
Income (loss) from continuing operations

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

.....
Net income (loss)

**Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2011**

(in thousands)

Total operating revenues

.....
Total operating costs and expenses

Income (loss) from operations

Interest expense

Other, net

Income before income taxes

Income tax expense

Income from continuing operations

Income (loss) from discontinued operations, net of tax

Net income

**Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2010**

(in thousands)

Total operating revenues

Total operating costs and expenses

Income (loss) from operations

Interest expense

Other, net

Income before income taxes

Income tax expense

Income from continuing operations

Income (loss) from discontinued operations, net of tax

Net income

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

**Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2011**

(in thousands)

Net cash flows provided by (used in)	operating activities
.....	
Net cash flows provided by (used in)	investing activities
.....	
Net cash flows provided by (used in)	financing activities
.....	
Net increase in cash and cash equivalents	
.....	
Cash and cash equivalents at beginning of period	
.....	
Cash and cash equivalents at end of period	
.....	

**Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2011**

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Net cash flows provided by (used in) operating activities	\$ (345,991)	\$ 1,545,449	\$ -	\$ 1,199,458
.....				
Net cash flows used in investing activities	(79,046)	(1,572,372)	-	(1,651,418)
.....				
Net cash flows provided by financing activities	424,991	26,927	-	451,918
.....	(46)	4	-	

Net increase (decrease) in cash and cash equivalents				
.....				
Cash and cash equivalents at beginning of period				
.....	46	338		-
Cash and cash equivalents at end of period				
.....	\$ -	\$ 342	\$ -	\$ -

**Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2010**

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	
Net cash flows provided by (used in) operating activities	\$ (1,369,316)	\$ 2,020,898	\$ -	\$ -
.....				
Net cash flows used in investing activities	(10,812)	(2,032,645)	-	(2,043,457)
.....				
Net cash flows provided by financing activities	1,380,126	8,899	-	1,389,025
.....				
Net decrease in cash and cash equivalents	(2)	(2,848)	-	-
.....				
Cash and cash equivalents at beginning of period	48	3,186	-	-
.....				
Cash and cash equivalents at end of period	\$ 46	\$ 338	\$ -	\$ -
.....				

F-42

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Note R. *Subsequent events*

New commodity derivative contracts. After December 31 2012, the Company entered into the following additional oil related price swaps to hedge additional amounts of its 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.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Capitalized costs

(in thousands)	December 31,	
	2012	2011
<i>Oil and natural gas properties:</i>		
Proved	\$ 8,402,154	\$ 6,551,396
Unproved	1,053,445	796,064
Less: accumulated depletion	(1,565,316)	(1,116,545)
Net capitalized costs for oil and natural gas properties	\$ 7,890,283	\$ 6,230,915

Costs incurred for oil and natural gas producing activities (a)

(in thousands)

Property acquisition costs:	
Proved	\$
Unproved	\$
Exploration	
Development	
Total costs incurred for oil and natural gas properties	\$ 2

(a) The costs incurred for oil and natural gas producing activities includes the following amounts of asset retirement obligations

(in thousands)

	Proved property acquisition costs	\$
.....	Exploration
costs.....	Development
costs.....	Total asset retirement obligations
		\$

F-44

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Reserve Quantity Information

The following information represents estimates of the Company's proved reserves as of December 31, 2012. The pricing that was used for estimates of the Company's reserves as of December 31, 2012 was based on SEC pricing of \$91.21 per Bbl West Texas Intermediate posted oil price and \$2.76 per MMBtu Henry Hub spot natural gas price, see table below.

Subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This rule limited, and may continue to limit, the Company's potential to record additional proved undeveloped reserves as it pursues its drilling program, particularly as it develops its significant acreage in the Permian Basin of Southeast New Mexico and West Texas. Moreover, the Company may be required to write down its proved undeveloped reserves if it does not drill on those reserves with the required five-year timeframe. The Company does not have any proved undeveloped reserves which have remained undeveloped for five years or more.

The Company's proved oil and natural gas reserves are all located in the United States, primarily in the Permian Basin of Southeast New Mexico and West Texas. All of the estimates of the proved reserves at December 31, 2012, 2011 and 2010 are based on reports prepared by Cawley, Gillespie & Associates, Inc. ("Cawley") and Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers. Proved reserves were estimated in accordance with the guidelines established by the SEC and the FASB.

The following table summarizes the prices utilized in the reserve estimates for 2012, 2011 and 2010. Commodity prices utilized for the reserve estimates were adjusted for location, grade and quality are as follows:

Prices utilized in the reserve estimates before adjustments:

Oil per Bbl

.....
Gas per MMBtu
.....

Oil and natural gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

F-45

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

The following table provides a rollforward of the total proved reserves for the years ended December 31, 2012, 2011 and 2010, as well as proved developed and proved undeveloped reserves at the beginning and end of each respective year. Oil and condensate volumes are expressed in MBbls and natural gas volumes are expressed in MMcf.

Total Proved Reserves:

Balance, January 1

.....
Purchases of minerals-in-place

.....
Sales of minerals-in-place

.....
Extensions and discoveries (a)

.....
Revisions of previous estimates

.....
Production

.....
Balance, December 31

Proved Developed Reserves:

January 1

.....
December 31

Proved Undeveloped Reserves:

January 1

December 31

(a) The 2012, 2011 and 2010 extensions and discoveries included 47,506, 55,444, and 24,960 MBoe, respectively, related to ad

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is computed by applying the 12-month unweighted average of the first-day-of-the-month pricing for oil and natural gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and natural gas reserves less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and natural gas properties plus available carryforwards and credits and applying the current tax rates to the difference.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of oil and natural gas properties. Estimates of fair value would also consider probable and possible reserves, anticipated future oil and natural gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is necessarily subjective and imprecise.

F-46

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

The following table provides the standardized measure of discounted future net cash flows at December 31, 2012, 2011 and 2010:

(in thousands)

Oil and gas producing activities:

Future cash inflows	\$
.....	
Future production costs	
.....	
Future development and abandonment costs (a)	
.....	
Future income tax expense	
.....	
10% annual discount factor	
.....	
Standardized measure of discounted future net cash flows	\$
.....	

(a) Includes \$154.0 million, \$116.3 million and \$49.6 million of undiscounted asset retirement cash outflow estimated at December 31, 2012, 2011 and 2010, respectively, using current estimated of future salvage values less future abandonment costs. See note E for corresponding information re asset retirement obligations.

Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table provides a rollforward of the standardized measure of discounted future net cash flows for the years ended December 31, 2012, 2011 and 2010:

(in thousands)

Oil and natural gas producing activities:

Purchases of minerals-in-place	\$ 87
.....	
Sales of minerals-in-place	(614)
.....	
Extensions and discoveries	1,88
.....	
Net changes in prices and production costs	(601)
.....	
Oil and natural gas sales, net of production costs	(1,561)
.....	
Changes in future development costs	10
.....	
Revisions of previous quantity estimates	(520)
.....	
Accretion of discount	88
.....	
Changes in production rates, timing and other	(515)
.....	
Change in present value of future net revenues	(72)
.....	
Net change in present value of future income taxes	15
.....	
Balance, beginning of year	5,70
.....	
Balance, end of year	\$ 5,78
.....	

F-47

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2012, 2011 and 2010

Selected Quarterly Financial Results

The following table provides selected quarterly financial results for the years ended December 31, 2012 and 2011:

(in thousands, except per share data)

Year ended December 31, 2012:

Total operating revenues	
Operating costs and expenses (excluding gains (losses))	
Gains (losses) on derivatives not designated as hedges	
Income from operations	
Net income	
Net income per common share - Basic	
Net income per common share - Diluted	

Year ended December 31, 2011: (a)

Total operating revenues	
Operating costs and expenses (excluding gains (losses))	
Gains (losses) on derivatives not designated as hedges	
Income (loss) from operations	
Net income (loss)	
Net income (loss) per common share - Basic	
Net income (loss) per common share - Diluted	

(a) Retrospectively adjusted for presentation of discontinued operations.

F-48

Concho Resources Inc.

Unaudited Supplementary Data

December 31, 2012, 2011 and 2010

Exhibit
Number

- 2.1 Purchase Agreement, dated May 11, 2012, by and among COG Operating LLC, as purchaser, and Three Rivers May 11, 2012, and incorporated herein by reference).
- 3.1 Restated Certificate of Incorporation (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on Aug
- 3.2 Second Amended and Restated Bylaws of Concho Resources Inc., as amended November 7, 2012 (filed as Exhi
- 4.1 (a) Specimen Common Stock Certificate.
- 4.2 Indenture, dated September 18, 2009, between Concho Resources Inc., the subsidiary guarantors named therein, 2009, and incorporated herein by reference).
- 4.3 First Supplemental Indenture, dated September 18, 2009, between Concho Resources Inc., the subsidiary guaran September 22, 2009, and incorporated herein by reference).
- 4.4 Second Supplemental Indenture, dated November 3, 2010, between Concho Resources Inc., the subsidiary guar Company's Registration Statement on Form S-3 on December 7, 2010, and incorporated herein by reference).
- 4.5 Third Supplemental Indenture, dated December 14, 2010, between Concho Resources Inc., the subsidiary guar December 14, 2010, and incorporated herein by reference).
- 4.6 Fourth Supplemental Indenture, dated May 23, 2011, between Concho Resources Inc., the subsidiary guarantors May 23, 2011, and incorporated herein by reference).
- 4.7 Fifth Supplemental Indenture, dated December 12, 2011, between Concho Resources Inc., the subsidiary guaran February 24, 2012, and incorporated herein by reference).
- 4.8 Sixth Supplemental Indenture, dated March 12, 2012, between Concho Resources Inc., the subsidiary guarantor March 12, 2012, and incorporated herein by reference).
- 4.9 Seventh Supplemental Indenture, dated August 17, 2012, between Concho Resources Inc., the subsidiary guaran August 17, 2012, and incorporated herein by reference).
- 4.10 Form of 8.625% Senior Notes due 2017 (included in Exhibit 4.2 to the Company's Current Report on Form 8-K
- 4.11 Form of 7.0% Senior Notes due 2021 (included in Exhibit 4.1 to the Company's Current Report on Form 8-K or
- 4.12 Form of 6.5% Senior Notes due 2022 (included in Exhibit 4.1 to the Company's Current Report on Form 8-K or
- 4.13 Form of 5.5% Senior Notes due 2022 (included in Exhibit 4.2 to the Company's Current Report on Form 8-K or
- 4.14 Form of 5.5% Senior Notes due 2023 (included in Exhibit 4.1 to the Company's Current Report on Form 8-K or
- 10.1 (a)** Form of Restricted Stock Agreement (for officers).
- 10.2 (a)** Separation and Release Agreement dated January 2, 2013, between Concho Resources Inc. and Jack F. Harper.
- 10.3 ** Form of Performance Unit Award Agreement (filed as Exhibit 10.1 to the Company's Current Report on Form 8
- 10.4 ** Amended and Restated Concho Resources Inc. 2006 Stock Incentive Plan (filed as Exhibit 10.1 to the Company
- 10.5 ** Form of Nonstatutory Stock Option Agreement (filed as Exhibit 10.16 to the Company's Annual Report on Form
- 10.6 ** Form of Restricted Stock Agreement (for employees) (filed as Exhibit 10.16 to the Company's Registration Stat
- 10.7 ** Form of Restricted Stock Agreement (for non-officer employees) (filed as Exhibit 10.36 to the Company's Ann
- 10.8 ** Form of Restricted Stock Agreement (for non-employee directors) (filed as Exhibit 10.18 to the Company's Ann
- 10.9 ** Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Timothy A. Leach (file
- 10.10 ** Employment Agreement dated December 19, 2008, between Concho Resources Inc. and E. Joseph Wright (filed
- 10.11 ** Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Darin G. Holderness (f
- 10.12 ** Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Matthew G. Hyde (file
- 10.13 ** Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Jack F. Harper (filed as

Edgar Filing: CONCHO RESOURCES INC - Form 10-K

- 10.14 ** Employment Agreement dated November 5, 2009, between Concho Resources Inc. and C. William Giraud (filed as Exhibit 10.14 to the Company's Current Report on Form 8-K on November 10, 2009, and incorporated herein by reference).
- 10.15 ** Form of First Amendment to Employment Agreement between Concho Resources Inc. and each of Messrs. Leif A. Johnson and C. William Giraud (filed as Exhibit 10.15 to the Company's Current Report on Form 8-K on November 10, 2009, and incorporated herein by reference).
- 10.16 ** Form of Indemnification Agreement between Concho Resources Inc. and each of the officers and directors thereof (filed as Exhibit 10.16 to the Company's Current Report on Form 8-K on November 10, 2009, and incorporated herein by reference).
- 10.17 ** Indemnification Agreement, dated February 27, 2008, by and between Concho Resources, Inc. and William H. Johnson (filed as Exhibit 10.17 to the Company's Current Report on Form 8-K on February 27, 2008, and incorporated herein by reference).
- 10.18 ** Indemnification Agreement, dated May 21, 2008, by and between Concho Resources, Inc. and Matthew G. Hyatt (filed as Exhibit 10.18 to the Company's Current Report on Form 8-K on May 21, 2008, and incorporated herein by reference).
- 10.19 ** Indemnification Agreement, dated August 25, 2008, by and between Concho Resources, Inc. and Darin G. Holdrege (filed as Exhibit 10.19 to the Company's Current Report on Form 8-K on August 25, 2008, and incorporated herein by reference).
- 10.20 ** Indemnification Agreement, dated November 5, 2009, by and between Concho Resources, Inc. and Mark B. Pugh (filed as Exhibit 10.20 to the Company's Current Report on Form 8-K on November 10, 2009, and incorporated herein by reference).
- 10.21 ** Indemnification Agreement, dated November 5, 2009, by and between Concho Resources, Inc. and C. William Giraud (filed as Exhibit 10.21 to the Company's Current Report on Form 8-K on November 10, 2009, and incorporated herein by reference).
- 10.22 ** Indemnification Agreement, dated January 10, 2012, between Concho Resources Inc. and Gary A. Merriman (filed as Exhibit 10.22 to the Company's Current Report on Form 8-K on January 10, 2012, and incorporated herein by reference).
- 10.23 ** Consulting Agreement dated June 9, 2009, by and between Concho Resources Inc. and Steven L. Beal (filed as Exhibit 10.23 to the Company's Current Report on Form 8-K on June 9, 2009, and incorporated herein by reference).
- 10.24 Amended and Restated Credit Agreement, dated July 31, 2008, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A. and certain other lenders party thereto (filed as Exhibit 10.24 to the Company's Current Report on Form 8-K on August 6, 2008, and incorporated herein by reference).
- 10.25 First Amendment to Amended and Restated Credit Agreement dated as of April 7, 2009, to the Amended and Restated Credit Agreement dated July 31, 2008, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., Citibank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.25 to the Company's Current Report on Form 8-K on April 7, 2009, and incorporated herein by reference).
- 10.26 Limited Consent and Waiver, dated September 4, 2009, to the Amended and Restated Credit Agreement dated July 31, 2008, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., Citibank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on September 4, 2009, and incorporated herein by reference).
- 10.26 Second Amendment to Amended and Restated Credit Agreement, dated April 26, 2010, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., Citibank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on April 26, 2010, and incorporated herein by reference).
- 10.27 Third Amendment to Amended and Restated Credit Agreement and Limited Waiver, dated June 16, 2010, among Concho Resources Inc., JP Morgan Chase Bank, N.A., Citibank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K on June 16, 2010, and incorporated herein by reference).
- 10.28 Fourth Amendment to Amended and Restated Credit Agreement, dated October 7, 2010, among Concho Resources Inc., JP Morgan Chase Bank, N.A., Citibank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K on October 13, 2010, and incorporated herein by reference).
- 10.29 Fifth Amendment to Amended and Restated Credit Agreement and Limited Waiver, dated as of December 7, 2010, among Concho Resources Inc., JP Morgan Chase Bank, N.A., Citibank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.5 to the Company's Current Report on Form 8-K on December 10, 2010, and incorporated herein by reference).
- 10.30 Sixth Amendment to Amended and Restated Credit Agreement, dated as of April 25, 2011, among Concho Resources Inc., JP Morgan Chase Bank, N.A., Citibank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.6 to the Company's Current Report on Form 8-K on April 27, 2011, and incorporated herein by reference).
- 10.31 Seventh Amendment to Amended and Restated Credit Agreement, dated as of October 12, 2011, among Concho Resources Inc., JP Morgan Chase Bank, N.A., Citibank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.7 to the Company's Current Report on Form 8-K on October 14, 2011, and incorporated herein by reference).
- 10.32 Eighth Amendment to Amended and Restated Credit Agreement, dated as of April 12, 2012, among Concho Resources Inc., JP Morgan Chase Bank, N.A., Citibank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.8 to the Company's Current Report on Form 8-K on April 16, 2012, and incorporated herein by reference).
- 10.33 Ninth Amendment to Amended and Restated Credit Agreement, dated as of May 31, 2012, among Concho Resources Inc., JP Morgan Chase Bank, N.A., Citibank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.9 to the Company's Current Report on Form 8-K on June 5, 2012, and incorporated herein by reference).
- 10.34 Tenth Amendment to Amended and Restated Credit Agreement, dated as of October 26, 2012, among Concho Resources Inc., JP Morgan Chase Bank, N.A., Citibank, N.A., ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.10 to the Company's Current Report on Form 8-K on October 29, 2012, and incorporated herein by reference).
- 10.35 Registration Rights Agreement dated February 27, 2006, among Concho Resources Inc. and the other signatories thereto (filed as Exhibit 10.35 to the Company's Current Report on Form 8-K on February 27, 2006, and incorporated herein by reference).
- 12.1 (a) Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preferred Stock Dividends.
- 21.1 (a) Subsidiaries of Concho Resources Inc.
- 23.1 (a) Consent of Grant Thornton LLP.
- 23.2 (a) Consent of Netherland, Sewell & Associates, Inc.
- 23.3 (a) Consent of Cawley, Gillespie & Associates, Inc.
- 31.1 (a) Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- 31.2 (a) Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- 32.1 (b) Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- 32.2 (b) Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- 99.1 (a) Netherland, Sewell & Associates, Inc. Reserve Report.
- 99.2 (a) Cawley, Gillespie & Associates, Inc. Reserve Report.
- 101.INS (a) XBRL Instance Document.
- 101.SCH (a) XBRL Schema Document.
- 101.CAL (a) XBRL Calculation Linkbase Document.
- 101.DEF (a) XBRL Definition Linkbase Document.

101.LAB(a) XBRL Labels Linkbase Document.

101.PRE (a) XBRL Presentation Linkbase Document.

(a) Filed herewith.

(b) Furnished herewith.

** Management contract or compensatory plan or arrangement.

F-49
