CONTINENTAL RESOURCES INC
Form 10-Q
August 05, 2011
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# UNITED STATES

# SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# FORM 10-Q

**(Mark One)**

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the quarterly period ended June 30, 2011**

**or**

¨ **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: 001-32886**

# CONTINENTAL RESOURCES, INC.

**(Exact name of registrant as specified in its charter)**

| | |
|---|---|
| **Oklahoma** | **73-0767549** |
| **(State or other jurisdiction of incorporation or organization)** | **(I.R.S. Employer Identification No.)** |
| **302 N. Independence, Suite 1500, Enid, Oklahoma** | **73701** |
| **(Address of principal executive offices)** | **(Zip Code)** |

**Registrant s telephone number, including area code: (580) 233-8955**

**Former name, former address and former fiscal year, if changed since last report: Not applicable**

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 x No ¨

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

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

| | | | |
|---|---|---|---|
| Large accelerated filer | x | 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 Exchange Act). Yes ¨ No x

180,525,143 shares of our $0.01 par value common stock were outstanding on July 31, 2011.

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When we refer to us, we, our, Company, or Continental we are describing Continental Resources, Inc. and/or our subsidiaries.

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**Glossary of Crude Oil and Natural Gas Terms**

The terms defined in this section are used throughout this report.

*Bbl* One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

*Boe* Barrels of crude oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of crude oil based on the average equivalent energy content of the two commodities.

*Bopd* Barrels of crude oil per day.

*Completion* The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

*Conventional play* An area that is believed to be capable of producing crude oil and natural gas occurring in discrete accumulations in structural and stratigraphic traps.

*DD&A* Depreciation, depletion, amortization and accretion.

*Developed acreage* The number of acres that are allocated or assignable to productive wells or wells capable of production.

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

*Dry hole* Exploratory or development well that does not produce crude oil and/or natural gas in economically producible quantities.

*Enhanced recovery* The recovery of crude oil and natural gas through the injection of liquids or gases into the reservoir. Enhanced recovery methods are often applied when production slows due to depletion of the natural pressure.

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

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

*Formation* A layer of rock which has distinct characteristics that differ from nearby rock.

*Horizontal drilling* A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

*Injection well* A well into which liquids or gases are injected in order to push additional crude oil or natural gas out of underground reservoirs and into the wellbores of producing wells. Typically considered an enhanced recovery process.

*MBbl* One thousand barrels of crude oil, condensate or natural gas liquids.

*MBoe* One thousand Boe.

*Mcf* One thousand cubic feet of natural gas.

*MMBtu* One million British thermal units. A British thermal unit represents the amount of energy needed to heat one pound of water by one degree Fahrenheit and can be used to describe the energy content of fuels.

*MMcf* One million cubic feet of natural gas.

*NYMEX* The New York Mercantile Exchange.

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*Play* A portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential crude oil and natural gas reserves.

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

*Prospect* A potential geological feature or formation which geologists and geophysicists believe may contain hydrocarbons. A prospect can be in various stages of evaluation, ranging from a prospect that has been fully evaluated and is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation.

*Proved developed reserves* Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

*Proved reserves* The quantities of crude 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.

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

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

*Royalty interest* Refers to the ownership of a percentage of the resources or revenues that are produced from a crude oil or natural gas property. A royalty interest owner does not bear any of the exploration, development, or operating expenses associated with drilling and producing a crude oil or natural gas property.

*Unconventional play* An area that is believed to be capable of producing crude oil and/or natural gas occurring in accumulations that are regionally extensive, but require recently developed technologies to achieve profitability. These areas tend to have low permeability and may be closely associated with source rock as is the case with gas shale, tight oil and gas sands and coalbed methane.

*Undeveloped acreage* Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and/or natural gas.

*Unit* The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

*Working interest* The right granted to the lessee of a property to explore for and to produce and own crude 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.

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**Cautionary Statement Regarding Forward-Looking Statements**

Certain statements and information in this report may constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements other than statements of historical fact included in this report are forward-looking statements. When used in this report, the words could, may, believe, anticipate, intend, estimate, expect, project and similar expressions are inte identify forward-looking statements, although not all forward-looking statements contain such identifying words. Forward-looking statements are based on the Company s current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading *Item 1A. Risk Factors* included in this report and in our Annual Report on Form 10-K for the year ended December 31, 2010.

Without limiting the generality of the foregoing, certain statements incorporated by reference, if any, or included in this report constitute forward-looking statements.

Forward-looking statements may include statements about:

- our business strategy;
- our future operations;
- our reserves;
- our technology;
- our financial strategy;
- crude oil and natural gas prices;
- the timing and amount of future production of crude oil and natural gas;
- the amount, nature and timing of capital expenditures;
- estimated revenues and results of operations;
- drilling of wells;
- competition;
- marketing of crude oil and natural gas;

- exploitation or property acquisitions;
- costs of exploiting and developing our properties and conducting other operations;
- our financial position;
- general economic conditions;
- credit markets;
- our liquidity and access to capital;
- the impact of regulatory and legal proceedings involving us and of scheduled or potential regulatory changes;
- our future operating results; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for, and development, production, and sale of, crude oil and natural gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating crude oil and natural gas reserves and in projecting future rates of production, cash flows and access to capital, the timing of development expenditures, and the other risks described under *Part II, Item 1A. Risk Factors* in this report, our Annual Report on Form 10-K for the year ended December 31, 2010, registration statements filed from time to time with the SEC, and other announcements we make from time to time.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements to reflect events or circumstances after the date of this report.

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**PART I. Financial Information**

**ITEM 1. Financial Statements**

**Continental Resources, Inc. and Subsidiaries**

**Condensed Consolidated Balance Sheets**

| | June 30, 2011 *(Unaudited)* | December 31, 2010 |
|---|---|---|
| | *In thousands, except par values and share data* | |
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 261,408 | $ 7,916 |
| Receivables: | | |
| Crude oil and natural gas sales | 264,668 | 208,211 |
| Affiliated parties | 22,562 | 20,156 |
| Joint interest and other, net | 325,309 | 254,471 |
| Derivative assets | 13,700 | 21,365 |
| Inventories | 50,840 | 38,362 |
| Deferred and prepaid taxes | 44,199 | 22,672 |
| Prepaid expenses and other | 8,815 | 9,173 |
| Total current assets | 991,501 | 582,326 |
| Net property and equipment, based on successful efforts method of accounting | 3,635,046 | 2,981,991 |
| Debt issuance costs, net | 25,535 | 27,468 |
| Noncurrent derivative assets | 289 | |
| Total assets | $ 4,652,371 | $ 3,591,785 |
| **Liabilities and shareholders equity** | | |
| Current liabilities: | | |
| Accounts payable trade | $ 441,305 | $ 390,892 |
| Revenues and royalties payable | 177,025 | 133,051 |
| Payables to affiliated parties | 6,632 | 4,438 |
| Accrued liabilities and other | 111,857 | 94,829 |
| Derivative liabilities | 119,273 | 76,771 |
| Current portion of asset retirement obligations | 2,464 | 2,241 |
| Total current liabilities | 858,556 | 702,222 |
| Long-term debt | 896,141 | 925,991 |
| Other noncurrent liabilities: | | |
| Deferred income tax liabilities | 664,518 | 582,841 |
| Asset retirement obligations, net of current portion | 56,228 | 54,079 |
| Noncurrent derivative liabilities | 195,818 | 112,940 |
| Other noncurrent liabilities | 5,422 | 5,557 |
| Total other noncurrent liabilities | 921,986 | 755,417 |
| Commitments and contingencies (Note 7) | | |
| Shareholders equity: | | |
| Preferred stock, $0.01 par value; 25,000,000 shares authorized; no shares issued and outstanding | | |

| | | | | |
|---|---|---|---|---|
| Common stock, $0.01 par value; 500,000,000 shares authorized; 180,526,914 shares issued and outstanding at June 30, 2011; 170,408,652 shares issued and outstanding at December 31, 2010 | | 1,805 | | 1,704 |
| Additional paid-in capital | | 1,105,339 | | 439,900 |
| Retained earnings | | 868,544 | | 766,551 |
| Total shareholders equity | | 1,975,688 | | 1,208,155 |
| Total liabilities and shareholders equity | $ | 4,652,371 | $ | 3,591,785 |

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

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**Continental Resources, Inc. and Subsidiaries**

**Unaudited Condensed Consolidated Statements of Income**

| | Three months ended June 30, 2011 | Three months ended June 30, 2010 | Six months ended June 30, 2011 | Six months ended June 30, 2010 |
|---|---|---|---|---|
| | *In thousands, except per share data* | | | |
| **Revenues:** | | | | |
| Crude oil and natural gas sales | $ 378,388 | $ 211,204 | $ 695,128 | $ 419,263 |
| Crude oil and natural gas sales to affiliates | 10,396 | 8,222 | 20,123 | 17,287 |
| Gain (loss) on derivative instruments, net | 204,453 | 55,465 | (164,850) | 81,809 |
| Crude oil and natural gas service operations | 9,655 | 5,077 | 16,281 | 9,877 |
| Total revenues | 602,892 | 279,968 | 566,682 | 528,236 |
| **Operating costs and expenses:** | | | | |
| Production expenses | 31,444 | 21,259 | 59,842 | 40,418 |
| Production expenses to affiliates | 917 | 1,089 | 1,789 | 4,531 |
| Production taxes and other expenses | 33,491 | 18,231 | 61,053 | 34,238 |
| Exploration expenses | 5,034 | 2,269 | 11,846 | 4,055 |
| Crude oil and natural gas service operations | 8,064 | 4,091 | 13,515 | 8,047 |
| Depreciation, depletion, amortization and accretion | 83,501 | 58,822 | 159,151 | 111,409 |
| Property impairments | 19,242 | 19,514 | 40,090 | 34,689 |
| General and administrative expenses | 17,209 | 11,494 | 33,556 | 23,343 |
| Gain on sale of assets | (318) | (33,124) | (15,575) | (33,346) |
| Total operating costs and expenses | 198,584 | 103,645 | 365,267 | 227,384 |
| Income from operations | 404,308 | 176,323 | 201,415 | 300,852 |
| Other income (expense): | | | | |
| Interest expense | (18,785) | (11,903) | (37,756) | (20,263) |
| Other | 1,022 | 78 | 1,531 | 784 |
| | (17,763) | (11,825) | (36,225) | (19,479) |
| Income before income taxes | 386,545 | 164,498 | 165,190 | 281,373 |
| Provision for income taxes | 147,351 | 62,757 | 63,197 | 107,167 |
| Net income | $ 239,194 | $ 101,741 | $ 101,993 | $ 174,206 |
| Basic net income per share | $ 1.33 | $ 0.60 | $ 0.58 | $ 1.03 |
| Diluted net income per share | $ 1.33 | $ 0.60 | $ 0.58 | $ 1.03 |

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

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**Continental Resources, Inc. and Subsidiaries**

**Condensed Consolidated Statements of Shareholders Equity**

| | Shares outstanding | Common stock | Additional paid-in capital | Retained earnings | Total shareholders equity |
|---|---|---|---|---|---|
| | | *In thousands, except share data* | | | |
| Balance, December 31, 2010 | 170,408,652 | $ 1,704 | $ 439,900 | $ 766,551 | $ 1,208,155 |
| Net income (unaudited) | | | | 101,993 | 101,993 |
| Public offering of common stock (unaudited) | 10,080,000 | 101 | 659,131 | | 659,232 |
| Stock-based compensation (unaudited) | | | 7,497 | | 7,497 |
| Stock options: | | | | | |
| Exercised (unaudited) | 12,470 | | 9 | | 9 |
| Repurchased and canceled (unaudited) | (2,495) | | (150) | | (150) |
| Restricted stock: | | | | | |
| Issued (unaudited) | 59,740 | | | | |
| Repurchased and canceled (unaudited) | (16,153) | | (1,048) | | (1,048) |
| Forfeited (unaudited) | (15,300) | | | | |
| Balance, June 30, 2011 | 180,526,914 | $ 1,805 | $ 1,105,339 | $ 868,544 | $ 1,975,688 |

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

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**Continental Resources, Inc. and Subsidiaries**

**Unaudited Condensed Consolidated Statements of Cash Flows**

| | Six months ended June 30, 2011 | Six months ended June 30, 2010 |
|---|---|---|
| **Cash flows from operating activities:** | *In thousands* | |
| Net income | $ 101,993 | $ 174,206 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation, depletion, amortization and accretion | 161,184 | 111,417 |
| Property impairments | 40,090 | 34,689 |
| Change in fair value of derivatives | 132,756 | (64,714) |
| Stock-based compensation | 7,497 | 5,970 |
| Provision for deferred income taxes | 62,237 | 95,500 |
| Dry hole costs | 3,370 | 409 |
| Gain on sale of assets | (15,575) | (33,346) |
| Other, net | 1,799 | 2,746 |
| Changes in assets and liabilities: | | |
| Accounts receivable | (129,701) | (104,885) |
| Inventories | (12,478) | (12,507) |
| Prepaid expenses and other | (1,665) | 2,387 |
| Accounts payable trade | 16,712 | 153,063 |
| Revenues and royalties payable | 43,974 | 13,053 |
| Accrued liabilities and other | 16,779 | 11,065 |
| Other noncurrent liabilities | (6) | 1,172 |
| Net cash provided by operating activities | 428,966 | 390,225 |
| **Cash flows from investing activities:** | | |
| Exploration and development | (797,414) | (469,484) |
| Purchase of crude oil and natural gas properties | (149) | (151) |
| Purchase of other property and equipment | (28,837) | (14,261) |
| Proceeds from sale of assets | 22,784 | 21,332 |
| Net cash used in investing activities | (803,616) | (462,564) |
| **Cash flows from financing activities:** | | |
| Revolving credit facility borrowings | 135,000 | 169,000 |
| Repayment of revolving credit facility | (165,000) | (281,000) |
| Proceeds from issuance of Senior Notes | | 194,210 |
| Proceeds from issuance of common stock | 659,736 | |
| Debt issuance costs | (37) | (7,876) |
| Equity issuance costs | (368) | |
| Repurchase of equity grants | (1,198) | (985) |
| Dividends to shareholders | | (3) |
| Exercise of stock options | 9 | 3 |
| Net cash provided by financing activities | 628,142 | 73,349 |
| Net change in cash and cash equivalents | 253,492 | 1,010 |
| Cash and cash equivalents at beginning of period | 7,916 | 14,222 |
| Cash and cash equivalents at end of period | $ 261,408 | $ 15,232 |

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

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**Continental Resources, Inc. and Subsidiaries**

**Notes to Unaudited Condensed Consolidated Financial Statements**

***Note 1. Organization and Nature of Business***

*Description of the Company*

Continental s principal business is crude oil and natural gas exploration, development and production with operations in the North, South, and East regions of the United States. The North region consists of properties north of Kansas and west of the Mississippi river and includes North Dakota Bakken, Montana Bakken, the Red River units and the Niobrara play in Colorado and Wyoming. The South region includes Kansas and all properties south of Kansas and west of the Mississippi river including the Anadarko Woodford and Arkoma Woodford plays in Oklahoma. The East region consists of properties east of the Mississippi river including the Illinois Basin and the state of Michigan.

***Note 2. Basis of Presentation and Significant Accounting Policies***

*Basis of presentation*

The consolidated financial statements include the accounts of Continental and its wholly owned subsidiaries after all significant inter-company accounts and transactions have been eliminated.

This report has been prepared pursuant to the rules and regulations of the Securities and Exchange Commission ( SEC ) applicable to interim financial information. Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by accounting principles generally accepted in the United States ( U.S. GAAP ), although the Company believes that the disclosures are adequate to make the information not misleading. You should read this Form 10-Q along with the Company s Annual Report on Form 10-K for the year ended December 31, 2010 ( 2010 Form 10-K ), which includes a summary of the Company s significant accounting policies and other disclosures.

The financial statements as of June 30, 2011 and for the three and six month periods ended June 30, 2011 and 2010 are unaudited. The condensed consolidated balance sheet as of December 31, 2010 was derived from the audited balance sheet filed in the 2010 Form 10-K. The Company has evaluated events or transactions through the date this report on Form 10-Q was filed with the SEC in conjunction with its preparation of these financial statements.

The preparation of financial statements in conformity with 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 period. Actual results could differ from those estimates. The most significant of the estimates and assumptions that affect reported results is the estimate of the Company s crude oil and natural gas reserves, which is used to compute depreciation, depletion, amortization and impairment on producing crude oil and natural gas properties. In the opinion of management, all adjustments (consisting only of normal recurring adjustments) necessary for a fair presentation in accordance with U.S. GAAP have been included in these unaudited interim condensed consolidated financial statements. The results of operations for any interim period are not necessarily indicative of the results of operations that may be expected for any other interim period or for the entire year.

*Inventories*

Inventories are stated at the lower of cost or market and consist of the following:

| **In thousands** | **June 30, 2011** | **December 31, 2010** |
|---|---|---|
| Tubular goods and equipment | $ 20,632 | $ 16,306 |
| Crude oil | 30,208 | 22,056 |
| Total | $ 50,840 | $ 38,362 |

Crude oil inventories, including line fill, are valued at the lower of cost or market using the first-in, first-out inventory method. Crude oil inventories consist of the following volumes:

| In barrels | June 30, 2011 | December 31, 2010 |
|---|---|---|
| Crude oil line fill requirements | 390,000 | 257,000 |
| Temporarily stored crude oil | 144,000 | 148,000 |
| Total | 534,000 | 405,000 |

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**Continental Resources, Inc. and Subsidiaries**

**Notes to Unaudited Condensed Consolidated Financial Statements**

*Earnings per share*

Basic net income per share is computed by dividing net income by the weighted-average number of shares outstanding for the period. Diluted net income per share reflects the potential dilution of non-vested restricted stock awards and dilutive stock options, which are calculated using the treasury stock method as if the awards and options were exercised. The following is the calculation of basic and diluted weighted average shares outstanding and net income per share for the three and six months ended June 30, 2011 and 2010:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| | *In thousands, except per share data* | | | |
| Income (numerator): | | | | |
| Net income - basic and diluted | $ 239,194 | $ 101,741 | $ 101,993 | $ 174,206 |
| Weighted average shares (denominator): | | | | |
| Weighted average shares - basic | 179,424 | 168,887 | 175,598 | 168,872 |
| Nonvested restricted stock | 707 | 744 | 703 | 704 |
| Employee stock options | 98 | 301 | 99 | 302 |
| Weighted average shares - diluted | 180,229 | 169,932 | 176,400 | 169,878 |
| Net income per share: | | | | |
| Basic | $ 1.33 | $ 0.60 | $ 0.58 | $ 1.03 |
| Diluted | $ 1.33 | $ 0.60 | $ 0.58 | $ 1.03 |

*Recent accounting pronouncements*

In May 2011, the Financial Accounting Standards Board ( FASB ) issued Accounting Standards Update ( ASU ) No. 2011-04, *Fair Value Measurement (Topic 820) Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs.* ASU No. 2011-04 amends certain fair value principles in U.S. GAAP to conform with the measurement and disclosure principles in International Financial Reporting Standards ( IFRS ). The amendments in ASU No. 2011-04 are the result of the work by the FASB and the International Accounting Standards Board to develop common global requirements for measuring fair value and for disclosing information about fair value measurements to improve the comparability of financial statements prepared in accordance with U.S. GAAP and IFRS. Many of the amendments in ASU No. 2011-04 offer clarification to existing guidance and are not intended to result in significant changes in the application of the fair value measurement guidance of U.S. GAAP. The new standard is effective for the first interim or annual reporting period beginning after December 15, 2011 and is required to be applied prospectively. The Company will adopt the requirements of ASU No. 2011-04 on January 1, 2012, which will require additional disclosures and is not expected to have a material effect on the Company s financial position, results of operations or cash flows.

In June 2011, the FASB issued ASU No. 2011-05, *Comprehensive Income (Topic 220) Presentation of Comprehensive Income.* ASU No. 2011-05 is intended to improve the quality of financial reporting by increasing the prominence of items reported in other comprehensive income ( OCI ). Under ASU No. 2011-05, an entity will have the option to present the components of net income, the components of other comprehensive income, and the total of comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. Companies will no longer be allowed to present OCI in the statement of stockholders equity. The amendments do not change the items that must be reported in OCI nor do they affect how earnings per share is calculated or presented. For public entities, the new standard is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011 and is required to be applied retrospectively. The Company will adopt the requirements of ASU No. 2011-05 on January 1, 2012, which is not currently expected to have an effect on its financial reporting as the Company currently has no items of OCI.

***Note 3. Supplemental Cash Flow Information***

The following table discloses supplemental cash flow information about cash paid for interest and income taxes. Also disclosed is information about investing activities that affects recognized liabilities but does not result in cash receipts or payments.

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**Continental Resources, Inc. and Subsidiaries**

**Notes to Unaudited Condensed Consolidated Financial Statements**

| | Six months ended June 30, 2011 | Six months ended June 30, 2010 |
|---|---|---|
| | *In thousands* | |
| Supplemental cash flow information: | | |
| Cash paid for interest | $ 35,658 | $ 15,742 |
| Cash paid for income taxes | $ 3,164 | $ 5,804 |
| Cash received for income tax refunds | $ (116) | $ (1,288) |
| Non-cash investing activities: | | |
| Asset retirement obligations | $ 1,071 | $ 697 |

***Note 4. Derivative Instruments***

The Company is required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the realized and unrealized changes in fair value of derivative instruments in the unaudited condensed consolidated statements of income under the caption Gain (loss) on derivative instruments, net.

The Company has utilized swap and collar derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of future crude oil and natural gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, their use also limits future revenues from favorable price movements.

During the six months ended June 30, 2011, the Company entered into several new swap and collar derivative contracts covering a portion of its crude oil and natural gas production for 2011, 2012 and 2013. The new contracts were entered into in the ordinary course of business and the Company may enter into additional similar contracts during the year. None of the new contracts have been designated for hedge accounting.

With respect to a fixed price swap contract, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the swap price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. For a basis swap contract, which guarantees a price differential between the NYMEX prices and the Company s physical pricing points, the Company receives a payment from the counterparty if the settled price differential is greater than the stated terms of the contract and the Company pays the counterparty if the settled price differential is less than the stated terms of the contract. For a collar contract, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price, the Company is required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price, and neither party is required to make a payment to the other party if the settlement price for any settlement period is between the floor price and the ceiling price.

All of the Company s derivative contracts are carried at their fair value on the condensed consolidated balance sheets under the captions Derivative assets , Noncurrent derivative assets , Derivative liabilities , and Noncurrent derivative liabilities . Derivative assets and liabilities with the same counterparty and subject to contractual terms which provide for net settlement are reported on a net basis on the condensed consolidated balance sheets. Substantially all of the crude oil and natural gas derivative contracts are settled based upon reported prices on the NYMEX. The estimated fair value of these contracts is based upon various factors, including closing exchange prices on the NYMEX, over-the-counter quotations, and, in the case of collars, volatility, the risk-free interest rate, and the time to expiration. The calculation of the fair value of collars requires the use of an option-pricing model. See *Note 5. Fair Value Measurements*.

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At June 30, 2011, the Company had outstanding contracts with respect to future production as set forth in the tables below.

*Crude Oil*

| | | | Collars | | | |
|---|---|---|---|---|---|---|
| | | Swaps | Floors | | Ceilings | |
| **Period and Type of Contract** | **Bbls** | **Weighted Average** | **Range** | **Weighted Average** | **Range** | **Weighted Average** |
| July 2011 - September 2011 | | | | | | |
| Swaps | 460,000 | $ 85.64 | | | | |
| Collars | 2,622,000 | | $ 75.00-$80.00 | $ 79.39 | $ 89.00-$97.25 | $ 91.27 |
| October 2011 - December 2011 | | | | | | |
| Swaps | 644,000 | $ 86.25 | | | | |
| Collars | 2,622,000 | | $ 75.00-$80.00 | $ 79.39 | $ 89.00-$97.25 | $ 91.27 |
| January 2012 - December 2012 | | | | | | |
| Swaps | 9,150,000 | $ 90.17 | | | | |
| Collars | 5,332,620 | | $ 80.00 | $ 80.00 | $ 93.25-$97.00 | $ 94.71 |
| January 2013 - December 2013 | | | | | | |
| Swaps | 5,110,000 | $ 88.63 | | | | |
| Collars | 8,760,000 | | $ 80.00-$95.00 | $ 86.92 | $ 92.30-$110.33 | $ 99.46 |

*Natural Gas*

| **Period and Type of Contract** | **MMBtus** | **Swaps Weighted Average** |
|---|---|---|
| July 2011 - September 2011 | | |
| Swaps | 6,900,000 | $ 5.42 |
| October 2011 - December 2011 | | |
| Swaps | 7,222,000 | $ 5.40 |
| January 2012 - December 2012 | | |
| Swaps | 3,660,000 | $ 5.07 |

*Derivative Fair Value Gain (Loss)*

The following table presents realized and unrealized gains and losses on derivative instruments for the periods presented.

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | **2011** | **2010** | **2011** | **2010** |
| | *In thousands* | | | |
| Realized gain (loss) on derivatives: | | | | |
| Crude oil fixed price swaps | $ (4,881) | $ 4,898 | $ (7,976) | $ 7,430 |
| Crude oil collars | (29,394) | 1,059 | (39,641) | 1,059 |
| Natural gas fixed price swaps | 7,397 | 7,534 | 15,523 | 10,255 |
| Natural gas basis swaps | | (688) | | (1,649) |
| Unrealized gain (loss) on derivatives | | | | |

| | | | | |
|---|---|---|---|---|
| Crude oil fixed price swaps | 87,179 | 13,023 | (77,864) | 10,811 |
| Crude oil collars | 147,572 | 39,634 | (47,516) | 35,085 |
| Natural gas fixed price swaps | (3,420) | (11,031) | (7,376) | 17,294 |
| Natural gas basis swaps | | 1,036 | | 1,524 |
| Gain (loss) on derivative instruments, net | $ 204,453 | $ 55,465 | $ (164,850) | $ 81,809 |

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The table below provides data about the fair value of derivatives that are not accounted for using hedge accounting.

| | June 30, 2011 | | | December 31, 2010 | | |
|---|---|---|---|---|---|---|
| ***In thousands*** | **Assets Fair Value** | **(Liabilities) Fair Value** | **Net Fair Value** | **Assets Fair Value** | **(Liabilities) Fair Value** | **Net Fair Value** |
| Commodity swaps and collars | $ 13,989 | $ (315,091) | $ (301,102) | $ 21,365 | $ (189,711) | $ (168,346) |

***Note 5. Fair Value Measurements***

The Company is required to calculate fair value based on a hierarchy which prioritizes the inputs to valuation techniques used to measure fair value into three levels. The fair value hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 inputs are inputs, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly. As Level 1 inputs generally provide the most reliable evidence of fair value, the Company uses Level 1 inputs when available.

*Assets and Liabilities Measured at Fair Value on a Recurring Basis*

Certain assets and liabilities are reported at fair value on a recurring basis. 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. In determining the fair value of fixed price swaps and basis swaps, due to the unavailability of relevant comparable market data for the Company s exact contracts, a discounted cash flow method is used. The discounted cash flow method estimates future cash flows based on quoted market prices for future commodity prices, observable inputs relating to basis differentials and a risk-adjusted discount rate. The fair value of fixed price swaps and basis swap derivatives is calculated using mainly significant observable inputs (Level 2). The calculation of the fair value of collar contracts requires the use of an option-pricing model with significant unobservable inputs (Level 3). The valuation model for option derivative contracts is an industry-standard model that considers various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The Company s calculation for each of its derivative positions is compared to the counterparty valuation for reasonableness.

The following tables summarize the valuation of financial instruments by pricing levels that were accounted for at fair value on a recurring basis as of June 30, 2011 and December 31, 2010. There were no transfers between Level 1 and Level 2 of the fair value hierarchy during the six months ended June 30, 2011. Further, there were no transfers in and/or out of Level 3 of the fair value hierarchy during the six months ended June 30, 2011.

| | December 31, | December 31, | December 31, | December 31, |
|---|---|---|---|---|
| | Fair value measurements at June 30, 2011 using: | | | |
| **Description** | **Level 1** | **Level 2** | **Level 3** | **Total** |
| | | *In thousands* | | |
| Derivative assets (liabilities): | | | | |
| Fixed price swaps | $ | $ (150,169) | $ | $ (150,169) |
| Collars | | | (150,933) | (150,933) |
| Total | $ | $ (150,169) | $ (150,933) | $ (301,102) |

| | Fair value measurements at December 31, 2010 using: | | | |
|---|---|---|---|---|
| **Description** | **Level 1** | **Level 2** | **Level 3** | **Total** |

| | | | | |
|---|---|---|---|---|
| | | ***In thousands*** | | |
| Derivative assets (liabilities): | | | | |
| Fixed price swaps | $ | $ (64,928) | $ | $ (64,928) |
| Collars | | | (103,418) | (103,418) |
| Total | $ | $ (64,928) | $ (103,418) | $ (168,346) |

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The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the indicated periods:

| | 2011 | 2010 |
|---|---|---|
| | *In thousands* | |
| Balance at January 1 | $ (103,418) | $ (3,275) |
| Total realized or unrealized gains (losses), net: | | |
| Included in earnings | (195,088) | (4,549) |
| Included in other comprehensive income | | |
| Purchases | | |
| Sales | | |
| Issuances | | |
| Settlements | | |
| Transfers into Level 3 | | |
| Transfers out of Level 3 | | |
| Balance at March 31 | $ (298,506) | $ (7,824) |
| Total realized or unrealized gains (losses), net: | | |
| Included in earnings | 147,573 | 39,634 |
| Included in other comprehensive income | | |
| Purchases | | |
| Sales | | |
| Issuances | | |
| Settlements | | |
| Transfers into Level 3 | | |
| Transfers out of Level 3 | | |
| Balance at June 30 | $ (150,933) | $ 31,810 |
| Change in unrealized gains (losses) relating to derivatives still held at June 30 | $ (49,102) | $ 35,271 |

Gains and losses included in earnings for the three and six month periods ended June 30, 2011 and 2010 attributable to the change in unrealized gains and losses relating to derivatives held at June 30, 2011 and 2010 are reported in Revenues Gain (loss) on derivative instruments, net .

*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 condensed consolidated financial statements. The following methods and assumptions were used to estimate the fair values for those assets and liabilities.

*Asset Impairments* Proved crude oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such property. The estimated future cash flows expected in connection with the property are compared to the carrying amount of the property to determine if the carrying amount is recoverable. If the carrying amount of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property is reduced to its estimated fair value. Due to the unavailability of relevant comparable market data, a discounted cash flow method is used to determine the fair value of proved properties. The discounted cash flow method estimates future cash flows based on management s estimates of future crude oil and natural gas production, commodity prices based on commodity futures price strips, operating and development costs, and a risk-adjusted discount rate. The fair value of proved crude oil and natural gas properties is calculated using significant unobservable inputs (Level 3).

Non-producing crude oil and natural gas properties, which primarily consist of undeveloped leasehold costs and costs associated with the purchase of proved undeveloped reserves, are assessed for impairment on a property-by-property basis for individually significant balances, if any, and on an aggregate basis by prospect for individually insignificant balances. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance at the level consistent with the level at which impairment was

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assessed. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms, and potential shifts in business strategy employed by management. For individually insignificant non-producing properties, the amount of the impairment loss recognized is determined by amortizing the portion of the properties costs which management estimates will not be transferred to proved properties over the life of the lease based on experience of successful drilling and the average holding period. The fair value of non-producing properties is calculated using significant unobservable inputs (Level 3).

Proved properties were reviewed for impairment at June 30, 2011. No impairment provisions were recorded for the Company s proved crude oil and natural gas properties for the three or six month periods ended June 30, 2011. For those periods, future cash flows were determined to be in excess of cost basis, therefore no impairment was necessary. Certain non-producing properties were impaired at June 30, 2011, reflecting amortization of leasehold costs. The following table sets forth the pre-tax non-cash impairments of both proved and non-producing properties for the indicated periods. Proved and non-producing property impairments are recorded under the caption Property impairments in the unaudited condensed consolidated statements of income.

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| | *In thousands* | | | |
| Proved property impairments | $ | $ 729 | $ | $ 1,704 |
| Non-producing property impairments | 19,242 | 18,785 | 40,090 | 32,985 |
| Total | $ 19,242 | $ 19,514 | $ 40,090 | $ 34,689 |

*Asset Retirement Obligations* The fair value of asset retirement obligations (AROs) is estimated 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, estimated probabilities, amounts and timing of settlements, the credit-adjusted risk-free rate to be used, and inflation rates. The fair values of ARO additions were $1.7 million for the six months ended June 30, 2011, which are reflected in the caption Asset retirement obligations, net of current portion in the condensed consolidated balance sheets. The fair values of AROs are calculated using significant unobservable inputs (Level 3).

*Financial Instruments Not Recorded at Fair Value*

The following table sets forth the fair values of financial instruments that are not recorded at fair value in the condensed consolidated financial statements.

| | June 30, 2011 | | December 31, 2010 | |
|---|---|---|---|---|
| ***In thousands*** | **Carrying Amount** | **Fair Value** | **Carrying Amount** | **Fair Value** |
| Long-term debt | | | | |
| Revolving credit facility | $ | $ | $ 30,000 | $ 30,000 |
| 8 1/4% Senior Notes due 2019 | 297,786 | 327,250 | 297,696 | 331,500 |
| 7 3/8% Senior Notes due 2020 | 198,355 | 212,833 | 198,295 | 213,000 |
| 7 1/8% Senior Notes due 2021 | 400,000 | 421,367 | 400,000 | 419,333 |
| Total | $ 896,141 | $ 961,450 | $ 925,991 | $ 993,833 |

The fair value of the revolving credit facility approximates its carrying value based on the borrowing rates available to the Company for bank loans with similar terms and maturities. The fair values of the 8 1/4% Senior Notes due 2019, the 7 3/8% Senior Notes due 2020 and the 7 1/8% Senior Notes due 2021 are based on quoted market prices (Level 1).

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The carrying values of all classes of cash and cash equivalents, trade receivables, and trade payables are considered to be representative of their respective fair values due to the short term maturities of those instruments.

***Note 6. Long-Term Debt***

Long-term debt consists of the following:

| *In thousands* | June 30, 2011 | December 31, 2010 |
|---|---|---|
| Revolving credit facility | $ | $ 30,000 |
| 8 1/4% Senior Notes due 2019 (1) | 297,786 | 297,696 |
| 7 3/8% Senior Notes due 2020 (2) | 198,355 | 198,295 |
| 7 1/8% Senior Notes due 2021 (3) | 400,000 | 400,000 |
| Total long-term debt | $ 896,141 | $ 925,991 |

(1) The carrying amount is net of discounts of $2.2 million and $2.3 million at June 30, 2011 and December 31, 2010, respectively.
(2) The carrying amount is net of discounts of $1.6 million and $1.7 million at June 30, 2011 and December 31, 2010, respectively.
(3) The notes were sold at par and are recorded at 100% of face value.

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*Revolving credit facility*

The Company had no debt outstanding at June 30, 2011 on its revolving credit facility which matures on July 1, 2015. At December 31, 2010, the Company had $30.0 million of outstanding borrowings on its revolving credit facility. The credit facility has aggregate commitments of $750.0 million and a borrowing base of $2.0 billion, subject to semi-annual redetermination. The most recent borrowing base redetermination was completed in June 2011, whereby the lenders approved an increase in the borrowing base from $1.5 billion to $2.0 billion. The terms of the facility provide that the commitment level can be increased up to the lesser of the borrowing base then in effect or $2.5 billion. Borrowings under the facility bear interest, payable quarterly, at a rate per annum equal to the London Interbank Offered Rate (LIBOR) for one, two, three or six months, as elected by the Company, plus a margin ranging from 175 to 275 basis points, depending on the percentage of the borrowing base utilized, or the lead bank s reference rate (prime) plus a margin ranging from 75 to 175 basis points. Borrowings are secured by the Company s interest in at least 85% (by value) of all of its proved reserves and associated crude oil and natural gas properties.

The Company had $747.6 million of unused commitments (after considering outstanding letters of credit) under its revolving credit facility at June 30, 2011 and incurs commitment fees of 0.50% per annum of the daily average amount of unused borrowing availability. The credit agreement contains certain restrictive covenants including a requirement that the Company maintain a current ratio of not less than 1.0 to 1.0 and a ratio of total funded debt to EBITDAX of no greater than 3.75 to 1.0. As defined by the credit agreement, the current ratio represents the ratio of current assets to current liabilities, inclusive of available borrowing capacity under the credit agreement and exclusive of current balances associated with derivative contracts and asset retirement obligations. EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, unrealized derivative gains and losses and non-cash equity compensation expense. EBITDAX is not a measure of net income or cash flows as determined by U.S. GAAP. A reconciliation of net income to EBITDAX is provided in *Part I, Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Non-GAAP Financial Measures*. The total funded debt to EBITDAX ratio represents the sum of outstanding borrowings and letters of credit on the revolving credit facility plus the Company s senior note obligations, divided by total EBITDAX for the most recent four quarters. The Company was in compliance with all covenants at June 30, 2011.

*Senior Notes*

The 8 1/4% Senior Notes due 2019 (the 2019 Notes ), the 7 3/8% Senior Notes due 2020 (the 2020 Notes ), and the 7 1/8% Senior Notes due 2021 (the 2021 Notes ) (collectively, the Notes ) will mature on October 1, 2019, October 1, 2020, and April 1, 2021, respectively. Interest on the Notes is payable semi-annually on April 1 and October 1 of each year, with the payment of interest on the 2021 Notes having commenced on April 1, 2011. The Company has the option to redeem all or a portion of the 2019 Notes, 2020 Notes, and 2021 Notes at any time on or after October 1, 2014, October 1, 2015, and April 1, 2016, respectively, at the redemption prices specified in the Notes respective indentures (together, the Indentures ) plus accrued and unpaid interest. The Company may also redeem the Notes, in whole or in part, at the make-whole redemption prices specified in the Indentures plus accrued and unpaid interest at any time prior to October 1, 2014, October 1, 2015, and April 1, 2016 for the 2019 Notes, 2020 Notes, and 2021 Notes, respectively. In addition, the Company may redeem up to 35% of the 2019 Notes, 2020 Notes, and 2021 Notes prior

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to October 1, 2012, October 1, 2013, and April 1, 2014, respectively, under certain circumstances with the net cash proceeds from certain equity offerings. The Notes are not subject to any mandatory redemption or sinking fund requirements.

The Indentures contain certain restrictions on the Company s ability to incur additional debt, pay dividends on common stock, make certain investments, create certain liens on assets, engage in certain transactions with affiliates, transfer or sell certain assets, consolidate or merge, or sell substantially all of the Company s assets. These covenants are subject to a number of important exceptions and qualifications. The Company was in compliance with these covenants at June 30, 2011. One of the Company s subsidiaries, Banner Pipeline Company, L.L.C., which currently has no independent assets or operations, fully and unconditionally guarantees the Notes. The Company s other subsidiary, whose assets and operations are minor, does not guarantee the Notes.

***Note 7. Commitments and Contingencies***

*Drilling commitments* As of June 30, 2011, the Company had drilling rig contracts with various terms extending through December 2012. These contracts were entered into in the ordinary course of business to ensure rig availability to allow the Company to execute its business objectives in its key strategic plays. These drilling commitments are not recorded in the accompanying condensed consolidated balance sheets. Future commitments as of June 30, 2011 total approximately $96 million, of which $64 million is for contracts that expire in 2011 and $32 million is for contracts that expire in 2012.

*Fracturing and well stimulation services arrangement* In August 2010, the Company entered into an agreement with a third party whereby the third party will provide, on a take-or-pay basis, hydraulic fracturing services and related equipment to service certain of the Company s properties in North Dakota and Montana. The arrangement has a term of three years, beginning in October 2010, with two one-year extensions available to the Company at its discretion. Pursuant to the take-or-pay arrangement, the Company is to pay a fixed rate per day for a minimum number of days per calendar quarter over the three-year term regardless of whether or not the services are provided. The arrangement also stipulates the Company will bear the cost of certain products and materials used. Fixed commitments amount to $4.9 million per quarter, or $19.5 million annually, for total commitments of $58.5 million over the three-year term. Future commitments remaining as of June 30, 2011 amount to $43.9 million. The commitments under this arrangement are not recorded in the accompanying condensed consolidated balance sheets. Since the inception of this arrangement, the Company has been using the services more than the minimum number of days each quarter.

*Delivery commitments* In 2010, the Company signed a throughput and deficiency agreement with a third party crude oil pipeline company committing to ship 10,000 barrels of crude oil per day for five years at a tariff of $1.85 per barrel. The third party system commenced operations in June 2011. The Company will use this system to move some of its North region crude oil to market. Further, in 2011 the Company entered into crude oil rail delivery commitments with third parties committing to deliver a total of 16,500 barrels of crude oil per day to third party rail systems through the end of 2011. The Company will use the rail systems to move a portion of its North region crude oil to various markets.

*Litigation* In November 2010, an alleged class action was filed against the Company alleging the Company improperly deducted post-production costs from royalties paid to plaintiffs and other royalty interest owners from crude oil and natural gas wells located in Oklahoma. The plaintiffs seek recovery of compensatory damages, interest, punitive damages and attorney fees on behalf of the alleged class. The Company has responded to the petition, denied the allegations and raised a number of affirmative defenses. The action is in preliminary stages and discovery has recently commenced. The Company is not currently able to estimate what impact, if any, the action will have on its financial condition, results of operations or cash flows given the preliminary status of the matter and uncertainties with respect to, among other things, the nature of the claims and defenses, the potential size of the class, the scope and types of the properties and agreements involved, the production years involved, and the ultimate potential outcome of the matter.

The Company is involved in various other legal proceedings such as commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims and similar matters. While the outcome of these legal matters cannot be predicted with certainty, the Company does not expect them to have a material adverse effect on its financial condition, results of operations or cash flows. As of June 30, 2011 and December 31, 2010, the Company has recorded a liability in Other noncurrent liabilities of $4.4 million and $4.6 million, respectively, for various matters, none of which are believed to be individually significant.

*Employee retirement plan* The Company maintains a defined contribution retirement plan for its employees and makes discretionary contributions to the plan, up to the contribution limits established by the Internal Revenue Service, based on a percentage of each eligible employee s compensation. During 2010, contributions to the plan were 5% of eligible employees compensation, excluding bonuses. Effective January 1, 2011, the Company s contributions to the plan represent 3% of eligible employees compensation, including bonuses, in addition to matching 50% of eligible employees contributions up to 6%. Expenses associated with the plan amounted to $1.5 million and $0.8 million for the six months ended June 30, 2011, and 2010, respectively.

*Employee health claims* The Company generally self-insures employee health claims up to the first $125,000 per employee per year. The Company generally self-insures employee workers compensation claims up to the first $300,000 per employee per claim. Any amounts paid

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above these levels are reinsured through third-party providers. The Company accrues for claims that have been incurred but not yet reported based on a review of claims filed versus expected claims based on claims history. The accrued liability for health and workers compensation claims was $2.4 million and $1.9 million at June 30, 2011, and December 31, 2010, respectively.

*Environmental Risk* Due to the nature of the crude oil and natural gas business, the Company is exposed to possible environmental risks. The Company is not aware of any material environmental issues or claims.

***Note 8. Stock-Based Compensation***

The Company has granted stock options and restricted stock to employees and directors pursuant to the Continental Resources, Inc. 2000 Stock Option Plan ( 2000 Plan ) and the Continental Resources, Inc. 2005 Long-Term Incentive Plan ( 2005 Plan ) as discussed below. The Company s associated compensation expense, which is included in the caption General and administrative expenses in the unaudited condensed consolidated statements of income, is reflected in the table below for the periods presented.

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| | *In thousands* | | | |
| Non-cash equity compensation | $3,855 | $3,118 | $7,497 | $5,970 |

*Stock Options*

Effective October 1, 2000, the Company adopted the 2000 Plan and granted stock options to certain eligible employees. These grants consisted of either incentive stock options, nonqualified stock options or a combination of both. The granted stock options vest ratably over either a three or five-year period commencing on the first anniversary of the grant date and expire ten years from the date of grant. On November 10, 2005, the 2000 Plan was terminated. As of June 30, 2011, options covering 2,221,163 shares had been exercised and 540,868 had been canceled.

The Company s stock option activity under the 2000 Plan for the six months ended June 30, 2011 is presented below:

| | Outstanding | | Exercisable | |
|---|---|---|---|---|
| | Number of stock options | Weighted average exercise price | Number of stock options | Weighted average exercise price |
| Outstanding at December 31, 2010 | 104,970 | $ 0.71 | 104,970 | $ 0.71 |
| Exercised | (12,470) | 0.71 | (12,470) | 0.71 |
| Outstanding at June 30, 2011 | 92,500 | $ 0.71 | 92,500 | $ 0.71 |

The intrinsic value of a stock option is the amount by which the value of the underlying stock exceeds the exercise price of the stock option at its exercise date. The total intrinsic value of stock options exercised during the six months ended June 30, 2011 was approximately $0.7 million. At June 30, 2011, all stock options were exercisable and had a weighted average remaining life of 9 months with an aggregate intrinsic value of $5.9 million.

*Restricted Stock*

On October 3, 2005, the Company adopted the 2005 Plan and reserved a maximum of 5,500,000 shares of common stock that may be issued pursuant to the 2005 Plan. As of June 30, 2011, the Company had 2,970,061 shares of restricted stock available to grant to directors, officers and key employees under the 2005 Plan. Restricted stock is awarded in the name of the recipient and except for the right of disposal, constitutes issued and outstanding shares of the Company s common stock for all corporate purposes during the period of restriction including the right to receive dividends, subject to forfeiture. Restricted stock grants generally vest over periods ranging from one to three years.

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A summary of changes in the non-vested shares of restricted stock for the six months ended June 30, 2011 is presented below:

| | Number of non-vested shares | Weighted average grant-date fair value |
|---|---|---|
| Non-vested restricted shares at December 31, 2010 | 1,108,077 | $ 35.72 |
| Granted | 59,740 | 67.88 |
| Vested | (73,630) | 34.10 |
| Forfeited | (15,300) | 37.81 |
| Non-vested restricted shares at June 30, 2011 | 1,078,887 | $ 37.58 |

The fair value of restricted stock represents the average of the high and low intraday market prices of the Company s common stock on the date of grant. Compensation expense for a restricted stock grant is a fixed amount determined at the grant date fair value and is recognized ratably over the vesting period as services are rendered by employees and directors. The expected life of restricted stock is based on the non-vested period that remains subsequent to the date of grant. There are no post-vesting restrictions related to the Company s restricted stock. The fair value of the restricted stock that vested during the six months ended June 30, 2011 at the vesting date was $4.8 million. As of June 30, 2011, there was $23.7 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized ratably over a weighted average period of 1.3 years.

***Note 9. Sale of Common Stock***

On March 9, 2011, the Company and certain selling shareholders completed a public offering of an aggregate of 10,000,000 shares of the Company s common stock, including 9,170,000 shares issued and sold by the Company and 830,000 shares sold by the selling shareholders, at a price of $68.00 per share ($65.45 per share, net of the underwriting discount). The net proceeds to the Company from the offering amounted to approximately $599.7 million after deducting the underwriting discount and offering-related expenses. The Company did not receive any proceeds from the sale of shares by the selling shareholders. In connection with the offering, the Company granted the underwriters a 30-day overallotment option to purchase up to an additional 1,500,000 shares of common stock at the public offering price, less the underwriting discount, to cover overallotments, if any.

On March 25, 2011, the Company completed the sale of an additional 910,000 shares of its common stock at a price of $68.00 per share ($65.45 per share, net of the underwriting discount) in connection with the underwriters partial exercise of the overallotment option granted by the Company. The Company received additional net proceeds of approximately $59.5 million, after deducting the underwriting discount, from the partial exercise of the overallotment option. The selling shareholders did not participate in the partial exercise of the overallotment option.

The Company used $659.2 million of the total net proceeds from the offering to repay all amounts outstanding under its revolving credit facility and used the remaining net proceeds to fund a portion of its 2011 capital budget.

***Note 10. Asset Disposition***

In March 2011, the Company assigned certain non-strategic leaseholds located in the state of Michigan to a third party for cash proceeds of $22.0 million. In connection with the transaction, the Company recognized a pre-tax gain of $15.3 million which is included in the caption Gain on sale of assets in the unaudited condensed consolidated statements of income. The assignment involved undeveloped acreage with no proved reserves and no production or revenues.

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**ITEM 2. Management s Discussion and Analysis of Financial Condition and Results of Operations**

The following discussion and analysis should be read in conjunction with our historical consolidated financial statements and the notes included in our Annual Report on Form 10-K for the year ended December 31, 2010. Our operating results for the periods discussed may not be indicative of future performance. The following discussion and analysis includes forward-looking statements and should be read in conjunction with Risk Factors under Part II, Item 1A of this report, along with Cautionary Statement Regarding Forward-Looking Statements at the beginning of this report, for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

**Overview**

We are engaged in crude oil and natural gas exploration, exploitation and production activities in the North, South, and East regions of the United States. The North region consists of properties north of Kansas and west of the Mississippi river and includes North Dakota Bakken, Montana Bakken, the Red River units and the Niobrara play in Colorado and Wyoming. The South region includes Kansas and all properties south of Kansas and west of the Mississippi river including the Anadarko Woodford and Arkoma Woodford plays in Oklahoma. The East region contains properties east of the Mississippi river including the Illinois Basin and the state of Michigan.

We focus our exploration activities in large new or developing plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. We have been successful in targeting large repeatable resource plays where horizontal drilling, advanced fracture stimulation and enhanced recovery technologies provide the means to economically develop and produce crude oil and natural gas reserves from unconventional formations. We derive the majority of our operating income and cash flows from the sale of crude oil and natural gas. We expect that growth in our revenues and operating income will primarily depend on product prices and our ability to increase our crude oil and natural gas production. In recent months and years, there has been significant volatility in crude oil and natural gas prices due to a variety of factors we cannot control or predict, including political and economic events, weather conditions, and competition from other energy sources. These factors impact supply and demand for crude oil and natural gas, which affects crude oil and natural gas prices. In addition, the prices we realize for our crude oil and natural gas production are affected by location differences in market prices.

For the first six months of 2011, our crude oil and natural gas production increased to 9,562 MBoe (52,830 Boe per day), up 2,289 MBoe, or 31%, from the first six months of 2010. The increase in 2011 production was primarily driven by an increase in production from our properties in the North Dakota Bakken field and the Anadarko Woodford play in Oklahoma due to the continued success of our drilling programs in those areas. Our Bakken production in North Dakota increased to 3,795 MBoe for the six months ended June 30, 2011, an 82% increase over the comparable 2010 period. Our production in the Anadarko Woodford play totaled 608 MBoe in the first half of 2011, 235% higher than the first half of 2010.

Our 2011 second quarter operations were adversely impacted by the heavy rainfall, power outages and unusual flooding that occurred in North Dakota during the quarter. Because of the adverse weather conditions, various counties in North Dakota imposed road restrictions on heavy trucks, causing us and other similarly situated operators to shut-in certain wells and delay certain drilling and completion projects, which hindered our production. Crude oil and natural gas production was 4,912 MBoe for the second quarter of 2011, a 6% increase over production of 4,650 MBoe for the first quarter of 2011 and a 29% increase over production of 3,815 MBoe for the second quarter of 2010. Our 2011 second quarter production was positively impacted by the continued success of our drilling programs in the Bakken Field and Anadarko Woodford play in Oklahoma, which offset the impact of the adverse weather conditions in North Dakota during the quarter.

Our crude oil and natural gas revenues for the first six months of 2011 increased 64% to $715.3 million due to a 26% increase in realized commodity prices along with increased production compared to the same period in 2010. Our realized price per Boe increased $15.71 to $75.63 for the six months ended June 30, 2011 compared to the six months ended June 30, 2010. At various times, we have stored crude oil due to pipeline line fill requirements, low commodity prices, or transportation constraints or we have sold crude oil from inventory. These actions result in differences between our produced and sold crude oil volumes. For the six months ended June 30, 2011, crude oil sales volumes were 104 MBbls less than crude oil production, and crude oil sales volumes were 13 MBbls more than crude oil production for the same period in 2010.

Our cash flows from operating activities for the six months ended June 30, 2011 were $429.0 million, an increase from $390.2 million provided by our operating activities during the comparable 2010 period. The increase in operating cash flows was primarily due to increased crude oil and natural gas revenues as a result of increased commodity prices and sales volumes, partially offset by an increase in realized losses on derivatives and higher production expenses, production taxes, and other operating expenses associated with the growth of our operations in the current year.

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In March 2011, our Board of Directors increased our 2011 capital expenditures budget from $1.36 billion to $1.75 billion to further accelerate our drilling program and increase our acreage positions in strategic plays in the United States. In early August 2011, our Board of Directors further increased our 2011 budget by $250 million to $2.0 billion. We plan to focus the additional investment primarily on increased drilling in the Bakken and Anadarko Woodford plays. Several changes contributed to the increased 2011 budget, including the success of our drilling program over the first six months of 2011, expected increases in the costs of well completion services attributed to an increase in the number of completion stages now being used on our North Dakota Bakken wells, our ability to secure more drilling rigs in the Anadarko Woodford play than we had initially budgeted, and an expected increase in the number of Bakken drilling sites to be pre-built in 2011 prior to the onset of winter weather. During the six months ended June 30, 2011, we have invested $868.5 million (including increased accruals for capital expenditures of $35.9 million and $6.2 million of seismic costs) in our capital program, concentrating mainly in the North Dakota Bakken field and the Anadarko Woodford play.

Due to the volatility of crude oil and natural gas prices and our desire to develop our substantial inventory of undeveloped reserves as part of our capital program, we have hedged a substantial portion of our forecasted production from our estimated proved reserves through 2013. We expect our cash flows from operations, our remaining cash balance, and the availability under our revolving credit facility will be sufficient to meet our capital expenditure needs for the next 12 months.

*How We Evaluate Our Operations*

We use a variety of financial and operating measures to assess our performance. Among these measures are:

- volumes of crude oil and natural gas produced,
- crude oil and natural gas prices realized,
- per unit operating and administrative costs, and
- EBITDAX (a non-GAAP financial measure).

The following table contains financial and operating highlights for the periods presented.

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | **2011** | **2010** | **2011** | **2010** |
| Average daily production: | | | | |
| Crude oil (Bbl per day) | 40,382 | 31,611 | 39,420 | 30,373 |
| Natural gas (Mcf per day) | 81,609 | 61,815 | 80,459 | 58,844 |
| Crude oil equivalents (Boe per day) | 53,984 | 41,913 | 52,830 | 40,180 |
| Average sales prices: (1) | | | | |
| Crude oil ($/Bbl) | $ 95.88 | $ 68.44 | $ 90.78 | $ 69.87 |
| Natural gas ($/Mcf) | 5.47 | 4.33 | 5.29 | 4.84 |
| Crude oil equivalents ($/Boe) | 79.86 | 57.94 | 75.63 | 59.92 |
| Production expenses ($/Boe) (1) | 6.65 | 5.90 | 6.52 | 6.17 |
| General and administrative expenses ($/Boe) (1) (2) | 3.53 | 3.03 | 3.55 | 3.20 |
| Net income (in thousands) | $ 239,194 | $ 101,741 | $ 101,993 | $ 174,206 |
| Diluted net income per share | 1.33 | 0.60 | 0.58 | 1.03 |
| EBITDAX (in thousands) (3) | $ 285,631 | $ 217,462 | $ 554,286 | $ 393,045 |

(1) Average sales prices and per unit expenses have been calculated using sales volumes and exclude any effect of derivative transactions.

(2) General and administrative expense ($/Boe) includes non-cash equity compensation expense of $0.79 per Boe and $0.82 per Boe for the three and six months ended June 30, 2011 and 2010.

(3) EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, unrealized derivative gains and losses and non-cash equity compensation expense. EBITDAX is not a measure of net income or cash flows as determined by U.S. GAAP. A reconciliation of net income to EBITDAX is provided subsequently under the heading *Non-GAAP Financial Measures*.

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**Three months ended June 30, 2011 compared to the three months ended June 30, 2010**

***Results of Operations***

The following table presents selected financial and operating information for each of the periods presented.

| | Three months ended June 30, 2011 | Three months ended June 30, 2010 |
|---|---|---|
| | *In thousands, except sales price data* | |
| Crude oil and natural gas sales | $ 388,784 | $ 219,426 |
| Gain on derivative instruments, net [1] | 204,453 | 55,465 |
| Total revenues | 602,892 | 279,968 |
| Operating costs and expenses [2] | 198,584 | 103,645 |
| Other expenses, net | 17,763 | 11,825 |
| Income before income taxes | 386,545 | 164,498 |
| Provision for income taxes | 147,351 | 62,757 |
| Net income | $ 239,194 | $ 101,741 |
| Production volumes: | | |
| Crude oil (MBbl) [3] | 3,675 | 2,877 |
| Natural gas (MMcf) | 7,426 | 5,625 |
| Crude oil equivalents (MBoe) | 4,912 | 3,815 |
| Sales volumes: | | |
| Crude oil (MBbl) [3] | 3,631 | 2,849 |
| Natural gas (MMcf) | 7,426 | 5,625 |
| Crude oil equivalents (MBoe) | 4,869 | 3,788 |
| Average sales prices: [4] | | |
| Crude oil ($/Bbl) | $ 95.88 | $ 68.44 |
| Natural gas ($/Mcf) | $ 5.47 | $ 4.33 |
| Crude oil equivalents ($/Boe) | $ 79.86 | $ 57.94 |

(1) Amounts include unrealized non-cash mark-to-market gains on derivative instruments of $231.3 million and $42.7 million for the three months ended June 30, 2011 and 2010, respectively.

(2) Net of gain on sale of assets of $0.3 million and $33.1 million for the three months ended June 30, 2011 and 2010, respectively. In June 2010, we sold certain non-strategic leaseholds located in Desoto Parish, Louisiana to a third party for cash proceeds of $35.4 million. In connection with the sale, we recognized a pre-tax gain of $31.7 million in the second quarter of 2010.

(3) At various times we have stored crude oil due to pipeline line fill requirements, low commodity prices, or transportation constraints or we have sold crude oil from inventory. These actions result in differences between our produced and sold crude oil volumes. Crude oil sales volumes were 44 MBbls less than crude oil production for the three months ended June 30, 2011 and 28 MBbls less than crude oil production for the three months ended June 30, 2010.

(4) Average sales prices have been calculated using sales volumes and exclude any effect of derivative transactions.

***Production***

The following tables reflect our production by product and region for the periods presented.

| | Three months ended June 30, 2011 Volume | 2011 Percent | 2010 Volume | 2010 Percent | Volume increase | Percent increase |
|---|---|---|---|---|---|---|
| Crude oil (MBbl) | 3,675 | 75% | 2,877 | 75% | 798 | 28% |

| | | | | | | |
|---|---|---|---|---|---|---|
| Natural Gas (MMcf) | 7,426 | 25% | 5,625 | 25% | 1,801 | 32% |
| Total (MBoe) | 4,912 | 100% | 3,815 | 100% | 1,097 | 29% |

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| | Three months ended June 30, 2011 | | 2010 | | Volume increase | Percent increase |
|---|---|---|---|---|---|---|
| | MBoe | Percent | MBoe | Percent | (decrease) | (decrease) |
| North Region | 3,870 | 79% | 3,033 | 80% | 837 | 28% |
| South Region | 945 | 19% | 675 | 17% | 270 | 40% |
| East Region | 97 | 2% | 107 | 3% | (10) | (9)% |
| Total | 4,912 | 100% | 3,815 | 100% | 1,097 | 29% |

Crude oil production volumes increased 28% during the three months ended June 30, 2011 compared to the three months ended June 30, 2010. Production increases in the North Dakota Bakken field and the Anadarko Woodford play contributed incremental production volumes in 2011 of 730 MBbls, a 70% increase over production for the second quarter of 2010. Favorable drilling results have been the primary contributors to production growth in these areas and have offset the reduced production resulting from the adverse weather conditions in North Dakota during the quarter.

Natural gas production volumes increased 1,801 MMcf, or 32%, during the three months ended June 30, 2011 compared to the same period in 2010. Natural gas production in the North Dakota Bakken field in the North region increased 498 MMcf, or 54%, for the three months ended June 30, 2011 compared to the same period in 2010 due to new wells being completed and gas from existing wells being connected in North Dakota. We expect natural gas production growth in North Dakota Bakken to be further enhanced by the increased capacity of natural gas processing plants in the play, which will enable us to deliver more natural gas to market and reduce natural gas flaring at well sites. Natural gas production in the Anadarko Woodford play increased 1,446 MMcf, or 285%, due to additional wells being completed and producing in the three months ended June 30, 2011 compared to the same period in 2010. The increased natural gas production in the North Dakota Bakken and Anadarko Woodford plays was partially offset by decreases in natural gas volumes of 216 MMcf in the Cedar Hills field due to the conversion of producing wells to injection wells.

***Revenues***

Our total revenues are comprised of sales of crude oil and natural gas, revenues associated with crude oil and natural gas service operations, and realized and unrealized changes in the fair value of our derivative instruments. Throughout 2010 and 2011 we entered into a series of derivative instruments, including fixed price swaps and zero-cost collars, to reduce the uncertainty of future cash flows in order to underpin our capital expenditures and our accelerated drilling program over the next three years. The changes in commodity futures price strips during the second quarter of 2011 had a positive impact on the fair value of our derivatives, which resulted in positive revenue adjustments of $204.5 million for the three months ended June 30, 2011. The $204.5 million positive adjustment to revenues for the 2011 second quarter includes $231.3 million of unrealized non-cash mark-to-market gains on open derivative instruments partially offset by $26.8 million of realized losses on derivatives during the quarter. The unrealized mark-to-market gain relates to derivative instruments with various terms that are scheduled to be realized over the period from July 2011 through December 2013. Over this period, actual realized derivative settlements may differ significantly from the unrealized mark-to-market valuation at June 30, 2011. We expect our revenues will continue to be significantly impacted, either positively or negatively, by changes in the fair value of our derivative instruments as a result of volatility in crude oil and natural gas prices.

*Crude Oil and Natural Gas Sales.* Crude oil and natural gas sales for the three months ended June 30, 2011 were $388.8 million, a 77% increase from sales of $219.4 million for the same period in 2010. Our sales volumes increased 1,081 MBoe, or 29%, over the same period in 2010 due to the continuing success of our drilling programs in the North Dakota Bakken field and Anadarko Woodford play. Our realized price per Boe increased $21.92 to $79.86 for the three months ended June 30, 2011 from $57.94 for the three months ended June 30, 2010. The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the three months ended June 30, 2011 was $6.59 compared to $9.59 for the three months ended June 30, 2010 and $9.02 for the year ended December 31, 2010. Factors contributing to the changing differentials included greater reliance on rail delivery systems, the disruption in Canadian synthetic crude oil manufacturing, and the increase in the spread between Brent and West Texas Intermediate crude oil prices. Pipeline capacity constraints, demand fluctuations, and the disruptive effects on production from the severe winter and spring weather in the North region also continue to have an impact on pricing differentials.

*Derivatives.* We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the realized and unrealized changes in fair value of derivative instruments in the unaudited condensed consolidated statements of income under the caption Gain (loss) on derivative instruments, net , which is a component of our total revenues.

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During the three months ended June 30, 2011, we realized losses on crude oil derivatives of $34.2 million and realized gains on natural gas derivatives of $7.4 million. During the three months ended June 30, 2011, we reported an unrealized non-cash mark-to-market gain on crude oil derivatives of $234.7 million and an unrealized non-cash mark-to-market loss on natural gas derivatives of $3.4 million. During the three months ended June 30, 2010, we realized gains on crude oil derivatives of $6.0 million and realized gains on natural gas derivatives of $6.8 million. During the three months ended June 30, 2010, we reported an unrealized non-cash mark-to-market gain on crude oil derivatives of $52.7 million and an unrealized non-cash mark-to-market loss on natural gas derivatives of $10.0 million.

*Crude Oil and Natural Gas Service Operations.* Our crude oil and natural gas service operations consist primarily of the treatment and sale of lower quality crude oil, or reclaimed crude oil. The table below shows the volumes and prices for the sale of reclaimed crude oil for the periods presented.

| | Three months ended June 30, | | |
|---|---|---|---|
| **Reclaimed crude oil sales** | **2011** | **2010** | **Increase** |
| Average sales price ($/Bbl) | $ 99.36 | $ 74.81 | $ 24.55 |
| Sales volumes (barrels) | 74,165 | 60,065 | 14,100 |

Prices for reclaimed crude oil sold from our central treating units were $24.55 per barrel higher for the three months ended June 30, 2011 than the comparable 2010 period, which contributed to an increase in reclaimed crude oil revenue of $2.9 million to $7.4 million and contributed to an overall increase in crude oil and natural gas service operations revenue of $4.6 million for the three months ended June 30, 2011. Also contributing to the increase in crude oil and natural gas service operations revenue was a $1.5 million increase in saltwater disposal income resulting from increased activity. Associated crude oil and natural gas service operations expenses increased $4.0 million to $8.1 million during the three months ended June 30, 2011 from $4.1 million during the three months ended June 30, 2010 due mainly to an increase in the costs of purchasing and treating reclaimed crude oil for resale and in providing saltwater disposal services.

***Operating Costs and Expenses***

*Production Expenses and Production Taxes and Other Expenses.* Production expenses increased 45% to $32.4 million during the three months ended June 30, 2011 from $22.3 million during the three months ended June 30, 2010. This increase is primarily the result of higher production volumes from an increase in the number of producing wells in the current period. Production expenses per Boe increased to $6.65 for the three months ended June 30, 2011 from $5.90 per Boe for the three months ended June 30, 2010. The per-unit increase was primarily due to increases in well site and road maintenance costs and saltwater disposal costs, all resulting from the heavy snowmelt, rainfall and resulting flooding in North Dakota during the second quarter. These increased costs, coupled with reduced production from curtailed and shut-in wells in North Dakota, resulted in higher per-unit production expenses. Also contributing to the per-unit increase were higher workover expenditures from increased activity as well as general inflationary pressure on the costs of oilfield services and equipment.

Production taxes and other expenses increased $15.3 million, or 84%, to $33.5 million during the three months ended June 30, 2011 compared to the three months ended June 30, 2010 as a result of higher crude oil and natural gas revenues resulting from increased commodity prices and sales volumes along with the expiration of various tax incentives. Production taxes and other expenses in the unaudited condensed consolidated statements of income include other charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Oklahoma Woodford and North Dakota Bakken areas of $2.7 million and $2.3 million for the three months ended June 30, 2011 and 2010, respectively. Production taxes, excluding other charges, as a percentage of crude oil and natural gas revenues were 7.9% for the three months ended June 30, 2011 compared to 7.4% for the three months ended June 30, 2010. The increase is due to the expiration of various tax incentives coupled with higher taxable revenues in North Dakota, our most active area, which has production tax rates of up to 11.5% of crude oil revenues. Production taxes are generally based on the wellhead values of production and vary by state. Additionally, some states offer exemptions or reduced production tax rates for wells that produce less than a certain quantity of crude oil or natural gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana and Oklahoma, new horizontal wells qualify for a tax incentive and are taxed at a lower rate during their initial months of production. After the incentive period expires, the tax rate increases to the statutory rate. Our overall production tax rate is expected to further increase as we continue to expand our operations in North Dakota and as production tax incentives we currently receive for horizontal wells reach the end of their incentive periods.

On a unit of sales basis, production expenses and production taxes and other expenses were as follows:

| *$/Boe* | Three months ended June 30, 2011 | 2010 |
|---|---|---|
| Production expenses | $ 6.65 | $ 5.90 |
| Production taxes and other expenses | 6.88 | 4.81 |
| Production expenses, production taxes and other expenses | $ 13.53 | $ 10.71 |

*Exploration Expenses*. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses increased $2.8 million in the three months ended June 30, 2011 to $5.0 million due primarily to a $1.5 million increase in dry hole expenses and a $1.0 million increase in seismic expenses resulting from higher acquisitions of seismic data in the current year in connection with our increased capital budget for 2011.

*Depreciation, Depletion, Amortization and Accretion ( DD&A ).* Total DD&A increased $24.7 million, or 42%, in the second quarter of 2011 compared to the second quarter of 2010, primarily due to a 29% increase in production volumes. The following table shows the components of our DD&A on a unit of sales basis.

| *$/Boe* | Three months ended June 30, 2011 | 2010 |
|---|---|---|
| Crude oil and natural gas | $ 16.66 | $ 15.12 |
| Other equipment | 0.33 | 0.24 |
| Asset retirement obligation accretion | 0.16 | 0.17 |
| Depreciation, depletion, amortization and accretion | $ 17.15 | $ 15.53 |

The increase in DD&A per Boe is partially the result of a gradual shift in our production base from our historic production base of the Red River units in the Cedar Hills field to newer production bases in the Bakken and Oklahoma Woodford plays. The producing properties in our newer areas typically carry a higher DD&A rate due to the higher costs of developing reserves in those areas in recent years compared to our older, more mature properties that were less expensive to develop.

*Property Impairments.* Property impairments decreased in the three months ended June 30, 2011 by $0.3 million to $19.2 million compared to $19.5 million for the three months ended June 30, 2010.

Impairment of non-producing properties increased $0.4 million during the three months ended June 30, 2011 to $19.2 million compared to $18.8 million for the three months ended June 30, 2010 reflecting higher amortization of leasehold costs resulting from a larger base of amortizable costs. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually insignificant non-producing properties are amortized on an aggregate basis based on our estimated experience of successful drilling and the average holding period. We currently have no individually significant non-producing properties that are assessed for impairment on a property-by-property basis.

We evaluate our proved crude oil and natural gas properties for impairment by comparing their cost basis to the estimated future cash flows on a field basis. If the cost basis is in excess of estimated future cash flows, then we impair it based on an estimate of fair value based on discounted cash flows. We did not record any impairment provisions for proved oil and gas properties for the three months ended June 30, 2011. For that period, future cash flows were determined to be in excess of cost basis, therefore no impairment was necessary. Impairment provisions for proved crude oil and natural gas properties were $0.7 million for the three months ended June 30, 2010, reflecting uneconomic operating results for certain wells in our East region.

*General and Administrative Expenses.* General and administrative expenses increased $5.7 million to $17.2 million during the three months ended June 30, 2011 from $11.5 million during the comparable period in 2010. General and administrative expenses include non-cash charges for stock-based compensation of $3.9 million and $3.1 million for the three months ended June 30, 2011 and 2010, respectively. General and administrative expenses excluding stock-based compensation increased $4.9 million for the three months ended June 30, 2011 compared to the same period in 2010. The increase was primarily related to an increase in personnel costs and office-related expenses associated with the growth of our Company. Over the past year, our Company has grown from having 442 total employees in June 2010 to 545 total employees in June

2011, a 23% increase. On a volumetric basis, general and administrative expenses increased $0.50 to $3.53 per Boe for the three months ended June 30, 2011 compared to $3.03 per Boe for the three months ended June 30, 2010.

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*Interest Expense.* Interest expense increased $6.9 million, or 58%, for the three months ended June 30, 2011 compared to the three months ended June 30, 2010 due to an increase in our outstanding debt balance and higher rates of interest on our senior notes in the current year compared to lower interest rates on our credit facility borrowings in the prior year. We recorded $17.4 million in interest expense on the outstanding senior notes for the three months ended June 30, 2011 compared with $10.0 million for the same period in 2010. Our weighted average interest rate for the three months ended June 30, 2011 was 7.6% with a weighted average outstanding long-term debt balance of $900 million compared to a weighted average interest rate of 7.1% with a weighted average outstanding long-term debt balance of $598.7 million for the same period in 2010.

We had no outstanding borrowings on our revolving credit facility as of June 30, 2011 or during the three months then ended, while our weighted average outstanding revolving credit facility balance amounted to $98.7 million for the three months ended June 30, 2010.

*Income Taxes.* We recorded income tax expense for the three months ended June 30, 2011 of $147.4 million compared with income tax expense of $62.8 million for the three months ended June 30, 2010. We provide for income taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences.

**Six months ended June 30, 2011 compared to the six months ended June 30, 2010**

***Results of Operations***

The following table presents selected financial and operating information for each of the periods presented.

| | Six months ended June 30, 2011 | Six months ended June 30, 2010 |
|---|---|---|
| | *In thousands, except sales price data* | |
| Crude oil and natural gas sales | $ 715,251 | $ 436,550 |
| Gain (loss) on derivative instruments, net (1) | (164,850) | 81,809 |
| Total revenues | 566,682 | 528,236 |
| Operating costs and expenses (2) | 365,267 | 227,384 |
| Other expenses, net | 36,225 | 19,479 |
| Income before income taxes | 165,190 | 281,373 |
| Provision for income taxes | 63,197 | 107,167 |
| Net income | $ 101,993 | $ 174,206 |
| Production volumes: | | |
| Crude oil (MBbl) (3) | 7,135 | 5,497 |
| Natural gas (MMcf) | 14,563 | 10,651 |
| Crude oil equivalents (MBoe) | 9,562 | 7,273 |
| Sales volumes: | | |
| Crude oil (MBbl) (3) | 7,031 | 5,510 |
| Natural gas (MMcf) | 14,563 | 10,651 |
| Crude oil equivalents (MBoe) | 9,458 | 7,286 |
| Average sales prices: (4) | | |
| Crude oil ($/Bbl) | $ 90.78 | $ 69.87 |
| Natural gas ($/Mcf) | $ 5.29 | $ 4.84 |
| Crude oil equivalents ($/Boe) | $ 75.63 | $ 59.92 |

(1) Amounts include an unrealized non-cash mark-to-market loss on derivative instruments of $132.8 million for the six months ended June 30, 2011 and an unrealized non-cash mark-to-market gain on derivative instruments of $64.7 million for the six months ended June 30, 2010.

(2) Net of gain on sale of assets of $15.6 million and $33.3 million for the six months ended June 30, 2011 and 2010, respectively. In March 2011, we assigned certain non-strategic leaseholds in the state of Michigan to a third party for cash proceeds of $22.0 million. In connection with the transaction, we recognized a pre-tax gain of $15.3 million in the first quarter of 2011. In June 2010, we sold certain

non-strategic leaseholds located in DeSoto Parish, Louisiana to a third party for cash proceeds of $35.4 million. In connection with the sale, we recognized a pre-tax gain of $31.7 million in the second quarter of 2010. These transactions involved undeveloped acreage with no proved reserves and no production or revenues.

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(3) At various times we have stored crude oil due to pipeline line fill requirements, low commodity prices, or transportation constraints or we have sold crude oil from inventory. These actions result in differences between our produced and sold crude oil volumes. Crude oil sales volumes were 104 MBbls less than crude oil production for the six months ended June 30, 2011 and 13 MBbls more than crude oil production for the six months ended June 30, 2010.

(4) Average sales prices have been calculated using sales volumes and exclude any effect of derivative transactions.

***Production***

The following tables reflect our production by product and region for the periods presented.

| | Six months ended June 30, 2011 | | Six months ended June 30, 2010 | | Volume | Percent |
|---|---|---|---|---|---|---|
| | Volume | Percent | Volume | Percent | increase | increase |
| Crude oil (MBbl) | 7,135 | 75% | 5,497 | 76% | 1,638 | 30% |
| Natural Gas (MMcf) | 14,563 | 25% | 10,651 | 24% | 3,912 | 37% |
| Total (MBoe) | 9,562 | 100% | 7,273 | 100% | 2,289 | 31% |

| | Six months ended June 30, 2011 | | Six months ended June 30, 2010 | | Volume increase | Percent increase |
|---|---|---|---|---|---|---|
| | MBoe | Percent | MBoe | Percent | (decrease) | (decrease) |
| North Region | 7,530 | 79% | 5,739 | 79% | 1,791 | 31% |
| South Region | 1,831 | 19% | 1,303 | 18% | 528 | 41% |
| East Region | 201 | 2% | 231 | 3% | (30) | (13)% |
| Total | 9,562 | 100% | 7,273 | 100% | 2,289 | 31% |

Crude oil production volumes increased 30% during the six months ended June 30, 2011 compared to the six months ended June 30, 2010. Production increases in the North Dakota Bakken field and the Anadarko Woodford play contributed incremental production volumes in 2011 of 1,554 MBbls, an 84% increase over production for the same period in 2010. Favorable drilling results have been the primary contributors to production growth in these areas and have offset the reduced production resulting from the adverse weather conditions in North Dakota in 2011.

Natural gas production volumes increased 3,912 MMcf, or 37%, during the six months ended June 30, 2011 compared to the same period in 2010. Natural gas production in the North Dakota Bakken field in the North region was up 1,149 MMcf, or 71%, for the six months ended June 30, 2011 compared to the same period in 2010 due to new wells being completed and gas from existing wells being connected in North Dakota. We expect natural gas production growth in North Dakota Bakken to be further enhanced by the increased capacity of natural gas processing plants in the play, which will enable us to deliver more natural gas to market and reduce natural gas flaring at well sites. Natural gas production in the Anadarko Woodford play increased 2,317 MMcf, or 246%, due to additional wells being completed and producing in the six months ended June 30, 2011 compared to the same period in 2010. Further, natural gas production increased 296 MMcf in a non-Woodford area of our South region due to the completion of new wells during the period. The increased natural gas production in these areas was partially offset by decreases in natural gas production of 291 MMcf in the Cedar Hills field due to the conversion of producing wells to injection wells.

***Revenues***

Our total revenues are comprised of sales of crude oil and natural gas, revenues associated with crude oil and natural gas service operations, and realized and unrealized changes in the fair value of our derivative instruments. Throughout 2010 and 2011 we entered into a series of derivative instruments, including fixed price swaps and zero-cost collars, to reduce the uncertainty of future cash flows in order to underpin our capital expenditures and our accelerated drilling program over the next three years. The increase in the price of crude oil during the six months ended June 30, 2011 had an adverse impact on the fair value of our derivative instruments, which resulted in negative revenue adjustments of $164.9 million for the six months ended June 30, 2011. The $164.9 million negative adjustment to revenue for the first half of 2011 includes $32.1 million of realized losses on derivatives during the period and

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$132.8 million of unrealized non-cash mark-to-market losses on open derivative instruments. The unrealized mark-to-market loss relates to derivative instruments with various terms that are scheduled to be realized over the period from July 2011 through December 2013. Over this period, actual realized derivative settlements may differ significantly from the unrealized mark-to-market valuation at June 30, 2011. We expect our revenues will continue to be significantly impacted, either positively or negatively, by changes in the fair value of our derivative instruments as a result of volatility in crude oil and natural gas prices. While the existence of historically high commodity prices over a prolonged period could continue to have an adverse impact on the fair value of our derivative instruments and derivative settlements, such an adverse impact would be partially mitigated by increased revenues from higher realized sales prices of crude oil and natural gas at the wellhead.

*Crude Oil and Natural Gas Sales.* Crude oil and natural gas sales for the six months ended June 30, 2011 were $715.3 million, a 64% increase from sales of $436.5 million for the same period in 2010. Our sales volumes increased 2,172 MBoe, or 30%, over the same period in 2010 due to the continuing success of our drilling programs in the North Dakota Bakken field and Anadarko Woodford play. Our realized price per Boe increased $15.71 to $75.63 for the six months ended June 30, 2011 from $59.92 for the six months ended June 30, 2010. The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the six months ended June 30, 2011 was $7.86 compared to $8.54 for the six months ended June 30, 2010 and $9.02 for the year ended December 31, 2010. Factors contributing to the changing differentials included greater reliance on rail delivery systems, the disruption in Canadian synthetic crude oil manufacturing, and the increase in the spread between Brent and West Texas Intermediate crude oil prices. Pipeline capacity constraints, demand fluctuations, and the disruptive effects on production from the severe winter and spring weather in the North region also continue to have an impact on pricing differentials.

*Derivatives.* We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the realized and unrealized changes in fair value of derivative instruments in the unaudited condensed consolidated statements of income under the caption Gain (loss) on derivative instruments, net , which is a component of our total revenues.

During the six months ended June 30, 2011, we realized losses on crude oil derivatives of $47.6 million and realized gains on natural gas derivatives of $15.5 million. During the six months ended June 30, 2011, we reported an unrealized non-cash mark-to-market loss on crude oil derivatives of $125.4 million and an unrealized non-cash mark-to-market loss on natural gas derivatives of $7.4 million. During the six months ended June 30, 2010, we realized gains on crude oil derivatives of $8.5 million and realized gains on natural gas derivatives of $8.6 million. During the six months ended June 30, 2010, we reported an unrealized non-cash mark-to-market gain on crude oil derivatives of $45.9 million and an unrealized non-cash mark-to-market gain on natural gas derivatives of $18.8 million.

*Crude Oil and Natural Gas Service Operations.* Our crude oil and natural gas service operations consist primarily of the treatment and sale of lower quality crude oil, or reclaimed crude oil. The table below shows the volumes and prices for the sale of reclaimed crude oil for the periods presented.

| **Reclaimed crude oil sales** | **Six months ended June 30, 2011** | **Six months ended June 30, 2010** | **Increase** |
|---|---|---|---|
| Average sales price ($/Bbl) | $ 95.25 | $ 75.24 | $ 20.01 |
| Sales volumes (barrels) | 126,302 | 115,426 | 10,876 |

Prices for reclaimed crude oil sold from our central treating units were $20.01 per barrel higher for the six months ended June 30, 2011 than the comparable 2010 period, which contributed to an increase in reclaimed crude oil revenue of $3.3 million to $12.0 million and contributed to an overall increase in crude oil and natural gas service operations revenue of $6.4 million for the six months ended June 30, 2011. Also contributing to the increase in crude oil and natural gas service operations revenue was a $2.5 million increase in saltwater disposal income resulting from increased activity. Associated crude oil and natural gas service operations expenses increased $5.5 million to $13.5 million during the six months ended June 30, 2011 from $8.0 million during the six months ended June 30, 2010 due mainly to an increase in the costs of purchasing and treating reclaimed crude oil for resale and in providing saltwater disposal services.

***Operating Costs and Expenses***

*Production Expenses and Production Taxes and Other Expenses.* Production expenses increased 37% to $61.6 million during the six months ended June 30, 2011 from $44.9 million during the six months ended June 30, 2010. This increase is primarily the result of higher production volumes from an increase in the number of producing wells in the current period. Production expenses per Boe increased to $6.52 for the six months ended June 30, 2011 from $6.17 per Boe for the six months ended June 30, 2010. The per-unit increase was primarily due to increases in well site and road maintenance costs and saltwater disposal costs, all resulting from adverse weather conditions in North Dakota during the current year. These increased costs, coupled with reduced production from curtailed and shut-in wells in North Dakota, resulted in higher per-unit production expenses. Also contributing to the per-unit increase were higher workover expenditures from increased activity as well as general inflationary pressure on the costs of oilfield services and equipment.

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Production taxes and other expenses increased $26.8 million, or 78%, to $61.1 million during the six months ended June 30, 2011 compared to the six months ended June 30, 2010 as a result of higher crude oil and natural gas revenues resulting from increased commodity prices and sales volumes along with the expiration of various tax incentives. Production taxes and other expenses on the unaudited condensed consolidated statements of income include other charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Oklahoma Woodford and North Dakota Bakken areas of $4.9 million and $3.4 million for the six months ended June 30, 2011 and 2010, respectively. Production taxes, excluding other charges, as a percentage of crude oil and natural gas revenues were 7.8% for the six months ended June 30, 2011 compared to 7.2% for the six months ended June 30, 2010. The increase is due to the expiration of various tax incentives coupled with higher taxable revenues in North Dakota, our most active area, which has production tax rates of up to 11.5% of crude oil revenues. Production taxes are generally based on the wellhead values of production and vary by state. Additionally, some states offer exemptions or reduced production tax rates for wells that produce less than a certain quantity of crude oil or natural gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana and Oklahoma, new horizontal wells qualify for a tax incentive and are taxed at a lower rate during their initial months of production. After the incentive period expires, the tax rate increases to the statutory rate. Our overall production tax rate is expected to further increase as we continue to expand our operations in North Dakota and as production tax incentives we currently receive for horizontal wells reach the end of their incentive periods.

On a unit of sales basis, production expenses and production taxes and other expenses were as follows:

| ***$/Boe*** | **Six months ended June 30, 2011** | **2010** |
|---|---|---|
| Production expenses | $ 6.52 | $ 6.17 |
| Production taxes and other expenses | 6.46 | 4.70 |
| Production expenses, production taxes and other expenses | $ 12.98 | $ 10.87 |

*Exploration Expenses*. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses increased $7.8 million in the six months ended June 30, 2011 to $11.8 million due primarily to a $3.0 million increase in dry hole expenses and a $4.3 million increase in seismic expenses resulting from higher acquisitions of seismic data in the current year in connection with our increased capital budget for 2011.

*Depreciation, Depletion, Amortization and Accretion.* Total DD&A increased $47.7 million, or 43%, in the first half of 2011 compared to the first half of 2010 primarily due to a 31% increase in production volumes. The following table shows the components of our DD&A on a unit of sales basis.

| ***$/Boe*** | **Six months ended June 30, 2011** | **2010** |
|---|---|---|
| Crude oil and natural gas | $ 16.37 | $ 14.88 |
| Other equipment | 0.29 | 0.23 |
| Asset retirement obligation accretion | 0.17 | 0.18 |
| Depreciation, depletion, amortization and accretion | $ 16.83 | $ 15.29 |

The increase in DD&A per Boe is partially the result of a gradual shift in our production base from our historic production base of the Red River units in the Cedar Hills field to newer production bases in the Bakken and Oklahoma Woodford plays. The producing properties in our newer areas typically carry a higher DD&A rate due to the higher costs of developing reserves in those areas in recent years compared to our older, more mature properties that were less expensive to develop.

*Property Impairments.* Property impairments increased in the six months ended June 30, 2011 by $5.4 million to $40.1 million compared to $34.7 million for the six months ended June 30, 2010.

Impairment of non-producing properties increased $7.1 million during the six months ended June 30, 2011 to $40.1 million compared to $33.0 million for the six months ended June 30, 2010 reflecting higher amortization of leasehold costs resulting from a larger base of amortizable costs. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually insignificant non-producing properties are amortized on an aggregate basis based on our estimated experience of successful drilling and the average holding period. We currently have no individually significant non-producing properties that are assessed for impairment on a property-by-property basis.

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We evaluate our proved crude oil and natural gas properties for impairment by comparing their cost basis to the estimated future cash flows on a field basis. If the cost basis is in excess of estimated future cash flows, then we impair it based on an estimate of fair value based on discounted cash flows. We did not record any impairment provisions for proved oil and gas properties for the six months ended June 30, 2011. For that period, future cash flows were determined to be in excess of cost basis, therefore no impairment was necessary. Impairment provisions for proved crude oil and natural gas properties were $1.7 million for the six months ended June 30, 2010, reflecting uneconomic operating results for certain wells in the East region and a non-Bakken Montana field in the North region.

*General and Administrative Expenses.* General and administrative expenses increased $10.3 million to $33.6 million during the six months ended June 30, 2011 from $23.3 million during the comparable period in 2010. General and administrative expenses include non-cash charges for stock-based compensation of $7.5 million and $6.0 million for the six months ended June 30, 2011 and 2010, respectively. General and administrative expenses excluding stock-based compensation increased $8.8 million for the six months ended June 30, 2011 compared to the same period in 2010. The increase was primarily related to an increase in personnel costs and office-related expenses associated with the growth of our Company. Over the past year, our Company has grown from having 442 total employees in June 2010 to 545 total employees in June 2011, a 23% increase. On a volumetric basis, general and administrative expenses increased $0.35 to $3.55 per Boe for the six months ended June 30, 2011 compared to $3.20 per Boe for the six months ended June 30, 2010.

*Interest Expense.* Interest expense increased $17.5 million, or 86%, for the six months ended June 30, 2011 compared to the same period in 2010 due to an increase in our outstanding debt balance and higher rates of interest on our senior notes in the current year compared to lower interest rates on our credit facility borrowings in the prior year. We recorded $34.5 million in interest expense on the outstanding senior notes for the six months ended June 30, 2011 compared with $16.4 million for the same period in 2010. Including the interest on both the senior notes and revolving credit facility borrowings, our weighted average interest rate for the six months ended June 30, 2011 was 7.4% with a weighted average outstanding long-term debt balance of $939.3 million compared to a weighted average interest rate of 6.8% with a weighted average outstanding long-term debt balance of $657.3 million for the same period in 2010.

Our weighted average outstanding revolving credit facility balance decreased to $39.3 million for the six months ended June 30, 2011 compared to $157.3 million for the six months ended June 30, 2010. The weighted average interest rate on our revolving credit facility borrowings was lower at 2.60% for the six months ended June 30, 2011 compared to 2.65% for the same period in 2010. At June 30, 2011, we had no outstanding borrowings on our revolving credit facility.

*Income Taxes.* We recorded income tax expense for the six months ended June 30, 2011 of $63.2 million compared with income tax expense of $107.2 million for the six months ended June 30, 2010. We provide for income taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences.

**Liquidity and Capital Resources**

Our primary sources of liquidity have been cash flows generated from operating activities, financing provided by our revolving credit facility and the issuance of debt and equity securities. During the first six months of 2011, our average realized sales price was $15.71 per Boe higher than the first six months of 2010. The increase in realized commodity prices in the current year, coupled with our 30% increase in sales volumes for the first six months of 2011 compared to the comparable 2010 period, resulted in improved cash flows from operations and better liquidity. Further, our liquidity has improved in 2011 as we have more borrowing availability on our revolving credit facility as a result of repaying our credit facility borrowings through the issuance and sale of common stock in March 2011 as discussed below under the heading *Sale of Common Stock*.

At June 30, 2011, we had approximately $261.4 million of cash and cash equivalents and approximately $747.6 million of net available liquidity under our revolving credit facility (after considering outstanding letters of credit).

**Cash Flows**

***Cash Flows from Operating Activities***

Our net cash provided by operating activities was $429.0 million and $390.2 million for the six months ended June 30, 2011 and 2010, respectively. The increase in operating cash flows was primarily due to higher crude oil and natural gas revenues as a result of higher commodity prices and sales volumes, partially offset by an increase in realized losses on derivatives and increases in production expenses, production taxes, and other operating expenses associated with the growth of our operations in the current year.

*Cash Flows from Investing Activities*

During the six months ended June 30, 2011 and 2010, we had cash flows used in investing activities (excluding asset sales) of $826.4 million and $483.9 million, respectively, related to our capital program, inclusive of dry hole costs. The increase in our cash flows used in investing activities in 2011 was due to the continued acceleration of our drilling program, primarily in the North Dakota Bakken field and the Anadarko Woodford play in Oklahoma.

*Cash Flows from Financing Activities*

Net cash provided by financing activities for the six months ended June 30, 2011 was $628.1 million and was mainly the result of the issuance and sale of an aggregate 10,080,000 shares of our common stock in March 2011 for total net proceeds of approximately $659.4 million, after deducting underwriting discounts and offering-related expenses, along with borrowings on our credit facility, partially offset by amounts repaid under our credit facility. Net cash provided by financing activities of $73.3 million for the six months ended June 30, 2010 was mainly the result of the issuance of the 2020 Notes in April 2010 along with borrowings on our revolving credit facility, partially offset by amounts repaid under our revolving credit facility.

**Future Sources of Financing**

We believe that funds from operating cash flows, our remaining cash balance, and our revolving credit facility should be sufficient to meet our cash requirements inclusive of, but not limited to, normal operating needs, debt service obligations, planned capital expenditures, and commitments and contingencies for the next 12 months.

Based on our planned production growth and derivative contracts we have in place to limit the downside risk of adverse price movements associated with the forecasted sale of future production, we currently anticipate we will be able to generate or obtain funds sufficient to meet our short-term and long-term cash requirements. We intend to finance our future capital expenditures primarily through cash flows from operations and through borrowings under our revolving credit facility, but we may also issue debt or equity securities or sell assets. The issuance of additional debt requires that a portion of our cash flows from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of our common stock.

*Sale of Common Stock*

On March 9, 2011, we and certain selling shareholders completed a public offering of an aggregate of 10,000,000 shares of our common stock, including 9,170,000 shares issued and sold by us and 830,000 shares sold by the selling shareholders, at a price of $68.00 per share ($65.45 per share, net of the underwriting discount). Our net proceeds from the offering amounted to approximately $599.7 million after deducting the underwriting discount and offering-related expenses. We did not receive any proceeds from the sale of shares by the selling shareholders. In connection with the offering, we granted the underwriters a 30-day overallotment option to purchase up to an additional 1,500,000 shares of common stock at the public offering price, less the underwriting discount, to cover overallotments, if any.

On March 25, 2011, we completed the sale of an additional 910,000 shares of our common stock at a price of $68.00 per share ($65.45 per share, net of the underwriting discount) in connection with the underwriters partial exercise of the overallotment option. We received additional net proceeds of approximately $59.5 million, after deducting the underwriting discount, from the partial exercise of the overallotment option. The selling shareholders did not participate in the partial exercise of the overallotment option.

After deducting underwriting discounts and offering-related expenses, we received total net proceeds from the offering of approximately $659.2 million, a portion of which was used to repay all amounts then outstanding under our revolving credit facility. The remaining net proceeds were used to fund a portion of our 2011 capital budget.

*Revolving Credit Facility*

We have a revolving credit facility with aggregate lender commitments totaling $750 million and a current borrowing base of $2.0 billion, subject to semi-annual redetermination. The most recent borrowing base redetermination was completed in June 2011, whereby the lenders approved an increase in the borrowing base from $1.5 billion to $2.0 billion. The aggregate commitment level may be increased at our option from time to time (provided no default exists) up to the lesser of $2.5 billion or the borrowing base then in effect. Borrowings under the facility bear interest, payable quarterly, at a rate per annum equal to the London Interbank Offered Rate (LIBOR) for one, two, three or six months, as elected by us, plus a margin ranging from 175 to 275 basis points, depending on the percentage of the borrowing base utilized, or the lead bank s reference rate (prime) plus a margin ranging from 75 to 175 basis points.

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The commitments under our credit facility, which matures on July 1, 2015, are from a syndicate of 14 banks and financial institutions. We believe that each member of the current syndicate has the capability to fund its commitment. If one or more lenders cannot fund its commitment, we would not have the full availability of the $750 million commitment.

We had no outstanding borrowings under our credit facility at June 30, 2011 and $30.0 million outstanding at December 31, 2010. As of June 30, 2011, we had $747.6 million of borrowing availability under our credit facility (after considering outstanding letters of credit). As previously discussed, we issued and sold an aggregate 10,080,000 shares of our common stock in March 2011 and received total net proceeds of approximately $659.2 million after deducting underwriting discounts and offering-related expenses. The net proceeds were used to repay all borrowings then outstanding under our credit facility, which had a balance prior to payoff of $155 million, with the remaining net proceeds being used to fund a portion of our 2011 capital budget. As of July 31, 2011, we continued to have no outstanding borrowings and $747.6 million of borrowing availability under our credit facility.

Our credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, change material contracts, incur liens and engage in certain other transactions without the prior consent of the lenders. Our credit agreement also contains requirements that we maintain a current ratio of not less than 1.0 to 1.0 and a ratio of total funded debt to EBITDAX of no greater than 3.75 to 1.0. As defined by our credit agreement, the current ratio represents our ratio of current assets to current liabilities, inclusive of available borrowing capacity under the credit agreement and exclusive of current balances associated with derivative contracts and asset retirement obligations. EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, unrealized derivative gains and losses and non-cash equity compensation expense. EBITDAX is not a measure of net income or cash flows as determined by U.S. GAAP. A reconciliation of net income to EBITDAX is provided subsequently under the caption *Non-GAAP Financial Measures*. The total funded debt to EBITDAX ratio represents the sum of outstanding borrowings and letters of credit under our revolving credit facility plus our senior note obligations, divided by total EBITDAX for the most recent four quarters. We were in compliance with these covenants at June 30, 2011 and we expect to maintain compliance for at least the next 12 months. We do not believe the restrictive covenants will limit, or are reasonably likely to limit, our ability to undertake additional debt or equity financing to a material extent.

In the future, we may not be able to access adequate funding under our credit facility as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base redetermination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. We expect the next borrowing base redetermination to occur in the fourth quarter of 2011. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base.

If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, complete new property acquisitions to replace our reserves, take advantage of business opportunities, respond to competitive pressures, or refinance our debt obligations as they come due, any of which could have a material adverse effect on our operations and financial results.

***Derivative Activities***

As part of our risk management program, we hedge a portion of our anticipated future crude oil and natural gas production to achieve more predictable cash flows and to reduce our exposure to fluctuations in crude oil and natural gas prices. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital program. Our decision on the quantity and price at which we choose to hedge our future production is based in part on our view of current and future market conditions and our desire to have the cash flows needed to fund the development of our inventory of undeveloped crude oil and natural gas reserves in conjunction with our growth strategy. While the use of hedging arrangements limits the downside risk of adverse price movements, their use also limits future revenues from favorable price movements. Substantially all of our hedging transactions are settled based upon reported settlement prices on the NYMEX.

We have hedged a significant portion of our forecasted production through 2013. Please see *Note 4. Derivative Instruments* in *Notes to Unaudited Condensed Consolidated Financial Statements* for further discussion of the accounting applicable to our derivative instruments, a listing of open contracts at June 30, 2011 and the estimated fair value of those contracts as of that date.

**Future Capital Requirements**

***Capital Expenditures***

We evaluate opportunities to purchase or sell crude oil and natural gas properties and could participate as a buyer or seller of properties at various times. We seek acquisitions that utilize our technical expertise or offer opportunities to expand our existing core areas. Acquisition expenditures are not budgeted.

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In March 2011, our Board of Directors increased our 2011 capital expenditures budget from $1.36 billion to $1.75 billion to further accelerate our drilling program and increase our acreage positions in strategic plays in the United States. In early August 2011, our Board of Directors further increased our 2011 budget by $250 million to $2.0 billion. We plan to focus the additional investment primarily on increased drilling in the Bakken and Anadarko Woodford plays. Several changes contributed to the increased 2011 budget, including the success of our drilling program over the first six months of 2011, expected increases in the costs of well completion services attributed to an increase in the number of completion stages now being used on our North Dakota Bakken wells, our ability to secure more drilling rigs in the Anadarko Woodford play than we had initially budgeted, and an expected increase in the number of Bakken drilling sites to be pre-built in 2011 prior to the onset of winter weather.

Our revised 2011 planned capital expenditures are expected to be allocated as follows:

| | **Amount** *in millions* |
|---|---|
| Exploration and development drilling | $ 1,735 |
| Land costs | 165 |
| Capital facilities, workovers and re-completions | 53 |
| Buildings, vehicles, computers and other equipment | 32 |
| Seismic | 15 |
| Total | $ 2,000 |

During the first six months of 2011, we participated in the completion of 215 gross (69.2 net) wells and invested a total of $868.5 million (including increases in accruals for capital expenditures of $35.9 million and $6.2 million of seismic costs) in our capital program as shown in the following table.

| | **Amount** *in millions* |
|---|---|
| Exploration and development drilling | $ 711.5 |
| Land costs | 101.3 |
| Capital facilities, workovers and re-completions | 17.1 |
| Buildings, vehicles, computers and other equipment | 29.0 |
| Seismic | 6.2 |
| Dry holes | 3.4 |
| Total | $ 868.5 |

Our 2011 capital program focuses primarily on increased development in the North Dakota Bakken field and the Anadarko Woodford play in western Oklahoma.

Although we cannot provide any assurance, assuming successful implementation of our strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe our remaining cash balance, cash flows from operations and available borrowing capacity under our revolving credit facility will be sufficient to fund our 2011 capital budget. The actual amount and timing of our capital expenditures may differ materially from our estimates as a result of, among other things, available cash flows, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

***Commitments***

As of June 30, 2011, we had drilling rig contracts with various terms extending through December 2012. These contracts were entered into in the ordinary course of business to ensure rig availability to allow us to execute our business objectives in our key strategic plays. These drilling commitments are not recorded in the accompanying condensed consolidated balance sheets. Future drilling commitments as of June 30, 2011 total approximately $96 million, of which $64 million is for contracts that expire in 2011 and $32 million is for contracts that expire in 2012. We expect to continue to enter into additional drilling rig contracts to help mitigate the risk of experiencing equipment shortages and rising costs that could delay our drilling projects or that could cause us to incur expenditures that are not provided for in our capital budget.

In August 2010, we entered into an agreement with a third party whereby the third party will provide, on a take-or-pay basis, hydraulic fracturing services and related equipment to service certain of our properties in North Dakota and Montana. The arrangement has a term of three years, beginning in October 2010, with two one-year extensions available to us at our discretion. Pursuant to the take-or-pay arrangement, we will pay a fixed rate per day for a minimum number of days per calendar quarter over the three-year term regardless of whether or not the services are provided. Fixed commitments amount to $4.9 million per quarter, or $19.5 million annually, for total commitments of $58.5 million over the three-year term. Future commitments remaining at June 30, 2011 amount to $43.9 million. The commitments under this arrangement are not recorded in the accompanying condensed consolidated balance sheets. Since the inception of this arrangement, we have been using the services more than the minimum number of days each quarter.

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In 2010, the Company signed a throughput and deficiency agreement with a third party crude oil pipeline company committing to ship 10,000 barrels of crude oil per day for five years at a tariff of $1.85 per barrel. The third party system commenced operations in June 2011. The Company will use this system to move some of its North region crude oil to market.

In 2011, the Company entered into crude oil rail delivery commitments with third parties committing to deliver a total of 16,500 barrels of crude oil per day to third party rail systems through the end of 2011. The Company will use the rail systems to move a portion of its North region crude oil to various markets.

We believe our cash flows from operations, our remaining cash balance, and available borrowing capacity under our revolving credit facility will be sufficient to satisfy the above commitments.

*Corporate Relocation*

On March 21, 2011, we announced plans to relocate our corporate headquarters from Enid, Oklahoma to Oklahoma City, Oklahoma. The move is a key element of our growth strategy of tripling our production and reserves between 2009 and 2014. The relocation is expected to provide more convenient access to our operations across the country, to our business partners and to an expanded pool of technical talent. The transition is expected to be completed during 2012. In connection with the relocation, we acquired an office building in Oklahoma City, Oklahoma in March 2011 for approximately $22.9 million to serve as our new headquarters. Currently, the relocation is in the early stages and no significant restructuring costs or liabilities have been incurred or recognized as of June 30, 2011. We currently estimate we may incur approximately $15 million to $25 million of costs in conjunction with our relocation. These costs will be incurred over the next 18 months through the end of 2012, with the majority of such costs expected to be incurred in the first nine months of 2012. Over the next 18 months, we generally expect to recognize the majority of relocation costs in our financial statements when incurred.

**Critical Accounting Policies**

There has been no change in our critical accounting policies from those disclosed in our Form 10-K for the year ended December 31, 2010.

**Recent Accounting Pronouncements Not Yet Adopted**

In May 2011, the Financial Accounting Standards Board ( FASB ) issued Accounting Standards Update ( ASU ) No. 2011-04, *Fair Value Measurement (Topic 820) Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs.* ASU No. 2011-04 amends certain fair value principles in U.S. GAAP to conform with the measurement and disclosure principles in International Financial Reporting Standards ( IFRS ). The amendments in ASU No. 2011-04 are the result of the work by the FASB and the International Accounting Standards Board ( IASB ) to develop common global requirements for measuring fair value and for disclosing information about fair value measurements to improve the comparability of financial statements prepared in accordance with U.S. GAAP and IFRS. Many of the amendments in ASU No. 2011-04 offer clarification to existing guidance and are not intended to result in significant changes in the application of the fair value measurement guidance of U.S. GAAP. The new standard is effective for the first interim or annual reporting period beginning after December 15, 2011 and is required to be applied prospectively. We will adopt the requirements of ASU No. 2011-04 on January 1, 2012, which will require additional disclosures and is not expected to have a material effect on our financial position, results of operations or cash flows.

In June 2011, the FASB issued ASU No. 2011-05, *Comprehensive Income (Topic 220) Presentation of Comprehensive Income.* ASU No. 2011-05 is intended to improve the quality of financial reporting by increasing the prominence of items reported in other comprehensive income ( OCI ). Under ASU No. 2011-05, an entity will have the option to present the components of net income, the components of other comprehensive income, and the total of comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. Companies will no longer be allowed to present OCI in the statement of stockholders equity. The amendments do not change the items that must be reported in OCI nor do they affect how earnings per share is calculated or presented. For public entities, the new standard is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011 and is required to be applied retrospectively. We will adopt the requirements of ASU No. 2011-05 on January 1, 2012, which is not currently expected to have an effect on our financial reporting as we currently have no items of OCI.

We continue to closely monitor the joint standard-setting efforts of the FASB and the IASB. There are a number of pending accounting standards that are being targeted for completion in 2011 and beyond, including, but not limited to, standards relating to revenue recognition, accounting for leases, accounting for financial instruments, balance sheet offsetting, disclosure of loss contingencies and financial statement presentation. Because these pending standards have not yet been finalized, at this time we are not able to determine the potential future impact that these standards will have, if any, on our financial position, results of operations or cash flows.

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**Non-GAAP Financial Measures**

EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, unrealized derivative gains and losses, and non-cash equity compensation expense. EBITDAX is not a measure of net income or cash flows as determined by U.S. GAAP. Management believes EBITDAX is useful because it allows them to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. EBITDAX should not be considered as an alternative to, or more meaningful than, net income or cash flows as determined in accordance with U.S. GAAP or as an indicator of a company s operating performance or liquidity. 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 costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. Our revolving credit facility requires that we maintain a total funded debt to EBITDAX ratio of no greater than 3.75 to 1.0 on a rolling four-quarter basis. This ratio represents the sum of outstanding borrowings and letters of credit under our revolving credit facility plus our senior note obligations, divided by total EBITDAX for the most recent four quarters. We were in compliance with this covenant at June 30, 2011. A violation of this covenant in the future could result in a default under our revolving credit facility. In the event of such default, the lenders under our revolving credit facility could elect to terminate their commitments thereunder, cease making further loans, and could declare all outstanding amounts, if any, to be due and payable. If we had any outstanding borrowings under our credit facility and such indebtedness were to be accelerated, our assets may not be sufficient to repay in full such indebtedness. Our revolving credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us. The following table provides a reconciliation of our net income to EBITDAX for the periods presented.

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| *in thousands* | **2011** | **2010** | **2011** | **2010** |
| Net income | $ 239,194 | $ 101,741 | $ 101,993 | $ 174,206 |
| Interest expense | 18,785 | 11,903 | 37,756 | 20,263 |
| Provision for income taxes | 147,351 | 62,757 | 63,197 | 107,167 |
| Depreciation, depletion, amortization and accretion | 83,501 | 58,822 | 159,151 | 111,409 |
| Property impairments | 19,242 | 19,514 | 40,090 | 34,689 |
| Exploration expenses | 5,034 | 2,269 | 11,846 | 4,055 |
| Unrealized (gains) losses on derivatives | (231,331) | (42,662) | 132,756 | (64,714) |
| Non-cash equity compensation | 3,855 | 3,118 | 7,497 | 5,970 |
| EBITDAX | $ 285,631 | $ 217,462 | $ 554,286 | $ 393,045 |

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**ITEM 3. Quantitative and Qualitative Disclosures About Market Risk**

*General.* We are exposed to a variety of market risks including commodity price risk, credit risk and interest rate risk. We address these risks through a program of risk management which may include the use of derivative instruments.

*Commodity Price Risk.* Our primary market risk exposure is in the pricing applicable to our crude oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our U.S. natural gas production. Pricing for crude oil and natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index prices. Based on our average daily production for the six months ended June 30, 2011, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $143.9 million for each $10.00 per barrel change in crude oil prices and $29.4 million for each $1.00 per Mcf change in natural gas prices. To partially reduce price risk caused by these market fluctuations, we periodically hedge a portion of our anticipated crude oil and natural gas production as part of our risk management program and to provide greater certainty in our cash flows to support our capital expenditure program.

For the six months ended June 30, 2011, we realized a net loss on crude oil and natural gas derivatives of $32.1 million and reported an unrealized non-cash mark-to-market loss on derivatives of $132.8 million. The fair value of our derivative instruments at June 30, 2011 was a net liability of $301.1 million. An assumed increase in the forward commodity prices used in the June 30, 2011 valuation of our derivative instruments of $10.00 per barrel for crude oil and $1.00 per MMBtu for natural gas would increase our net derivative liability to approximately $638 million at June 30, 2011. Conversely, an assumed decrease in forward commodity prices of $10.00 per barrel for crude oil and $1.00 per MMBtu for natural gas would change our derivative valuation to a net asset of approximately $18 million at June 30, 2011.

Throughout 2010 and 2011 we entered into a series of derivative instruments, including fixed price swaps and zero-cost collars, to reduce the uncertainty of future cash flows in order to underpin our capital expenditures and our accelerated drilling program over the next three years. The increase in the price of crude oil during the six months ended June 30, 2011 had an adverse impact on the fair value of our derivative instruments, which resulted in the recognition of a $132.8 million unrealized mark-to-market loss on derivative instruments for the first six months of 2011. The unrealized mark-to-market loss relates to derivative instruments with various terms that are scheduled to be realized over the period from July 2011 through December 2013. Over this period, actual realized derivative settlements may differ significantly, either positively or negatively, from the unrealized mark-to-market valuation at June 30, 2011. While the existence of historically high commodity prices over a prolonged period could continue to have an adverse impact on the fair value of our derivative instruments and derivative settlements, such an adverse impact would be partially mitigated by increased cash flows from higher realized sales prices of crude oil and natural gas at the wellhead.

*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 crude oil and natural gas production, which we market to energy marketing companies, refineries and affiliates ($270.0 million in receivables at June 30, 2011), our joint interest receivables ($342.5 million at June 30, 2011), and counterparty credit risk associated with our derivative instrument receivables ($14.0 million at June 30, 2011).

We monitor our exposure to counterparties on crude oil and natural gas sales primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty s credit worthiness. We have not generally required our counterparties to provide collateral to support crude oil and natural gas sales receivables owed to us. Historically, our credit losses on crude oil and natural gas sales receivables have been immaterial.

Joint interest receivables arise from billing entities which own a partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases included in units on which we wish to drill. We can do very little to choose who participates in our wells. In order to minimize our exposure to credit risk we generally request prepayment of drilling costs where it is allowed by contract or state law. For such prepayments, a liability is recorded and subsequently reduced as the associated work is performed. This liability was $60.3 million at June 30, 2011, which will be used to offset future capital costs when billed. In this manner, we reduce credit risk. We also have the right to place a lien on our co-owners interest in the well to redirect production proceeds in order to secure payment or, if necessary, foreclose on the interest. Historically, our credit losses on joint interest receivables have been immaterial.

Our use of derivative instruments involves the risk that our counterparties will be unable to meet their commitments under the arrangements. We manage this risk by using multiple counterparties who we consider to be financially strong in order to minimize our exposure to credit risk with any individual counterparty. Currently, all of our derivative contracts are with parties that are lenders (or affiliates of lenders) under our revolving credit agreement.

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*Interest Rate Risk.* Our exposure to changes in interest rates relates primarily to any variable-rate borrowings we may have outstanding from time to time under our revolving credit facility. We manage our interest rate exposure by monitoring both the effects of market changes in interest rates and the proportion of our debt portfolio that is variable-rate versus fixed-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 may be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We currently have no interest rate derivatives. We had no outstanding borrowings under our revolving credit facility at June 30, 2011 or July 31, 2011.

## ITEM 4. Controls and Procedures

### Evaluation of Disclosure Controls and Procedures

Based on management s evaluation, under the supervision and with the participation of our principal executive officer and principal financial officer, as of the end of the period covered by this report, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures (which are defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act )) were effective as of June 30, 2011. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that the information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding required disclosures and is recorded, processed, summarized and reported within the time period in the rules and forms of the SEC.

### Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2011, there were no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

### Inherent Limitations on Controls and Procedures

A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. 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 risks that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Accordingly, even an effective system of internal control will provide only reasonable assurance that the objectives of the internal control system are met.

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**PART II. Other Information**

**ITEM 1. Legal Proceedings**

During the six months ended June 30, 2011, there have been no material changes with respect to the legal proceedings previously disclosed in our 2010 Form 10-K that was filed with the SEC on February 25, 2011. See *Note 7. Commitments and Contingencies* in *Notes to Unaudited Condensed Consolidated Financial Statements* of this Form 10-Q.

**ITEM 1A. Risk Factors**

There have been no material changes in our risk factors from those disclosed in our 2010 Form 10-K that was filed with the SEC on February 25, 2011.

In addition to the information set forth in this Form 10-Q, you should carefully consider the factors discussed in *Part I, Item 1A. Risk Factors* in our 2010 Form 10-K, which could materially affect our business, financial condition or future results. The risks described in this Form 10-Q and in our 2010 Form 10-K are not the only risks facing our Company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.

**ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds**

(a) Not applicable.

(b) Not applicable.

(c) Purchases of Equity Securities by the Issuer and Affiliated Purchasers.

The following table provides information about purchases of equity securities that are registered by us pursuant to Section 12 of the Exchange Act during the quarter ended June 30, 2011:

| **Period** | **Total number of shares purchased (1)** | **Average price paid per share (2)** | **Total number of shares purchased as part of publicly announced plans or programs** | **Maximum number of shares that may yet be purchased under the plans or program (3)** |
|---|---|---|---|---|
| April 1, 2011 to April 30, 2011 | 2,418 | $ 72.07 | | |
| May 1, 2011 to May 31, 2011 | 4,745 | $ 64.19 | | |
| June 1, 2011 to June 30, 2011 | 8,313 | $ 61.59 | | |
| Total | 15,476 | $ 64.02 | | |

(1) In connection with stock option exercises or restricted stock grants under the Continental Resources, Inc. 2000 Stock Option Plan ( 2000 Plan ) and the Continental Resources, Inc. 2005 Long-Term Incentive Plan ( 2005 Plan ), we adopted a policy that enables employees to surrender shares to cover their tax liability. All shares purchased above represent shares surrendered to cover tax liabilities. We paid the associated taxes to the Internal Revenue Service.

(2) The price paid per share was the closing price of our common stock on the date of exercise or the date the restrictions lapsed on such shares, as applicable.

(3) We are unable to determine at this time the total amount of securities or approximate dollar value of those securities that could potentially be surrendered to us pursuant to our policy that enables employees to surrender shares to cover their tax liability associated with the exercise of options or vesting of restrictions on shares under the 2000 Plan and 2005 Plan.

**ITEM 3. Defaults Upon Senior Securities**

Not applicable.

**ITEM 4. (Removed and Reserved)**

**ITEM 5. Other Information**

Not applicable.

**ITEM 6. Exhibits**

The exhibits required to be filed pursuant to Item 601 of Regulation S-K are set forth in the Index to Exhibits accompanying this report and are incorporated herein by reference.

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## SIGNATURE

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

| | |
|---|---|
| | CONTINENTAL RESOURCES, INC. |
| Date: August 5, 2011 | By: /s/ John D. Hart<br>John D. Hart<br>Sr. Vice President, Chief Financial Officer and Treasurer<br><br>(Duly Authorized Officer and Principal Financial Officer) |

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*Index to Exhibits*

| | |
|---|---|
| 3.1 | Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc. filed as Exhibit 3.1 to the Company s Current Report on Form 8-K (Commission File No. 001-32886) filed May 22, 2007 and incorporated herein by reference. |
| 3.2 | Second Amended and Restated Bylaws of Continental Resources, Inc. filed as Exhibit 3.2 to the Company s Current Report on Form 8-K (Commission File No. 001-32886) filed May 22, 2007 and incorporated herein by reference. |
| 31.1* | Certification of the Company s Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241). |
| 31.2* | Certification of the Company s Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241). |
| 32** | Certification of the Company s Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350). |
| 101.INS** | XBRL Instance Document |
| 101.SCH** | XBRL Taxonomy Extension Schema Document |
| 101.CAL** | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.DEF** | XBRL Taxonomy Extension Definition Linkbase Document |
| 101.LAB** | XBRL Taxonomy Extension Label Linkbase Document |
| 101.PRE** | XBRL Taxonomy Extension Presentation Linkbase Document |

* Filed herewith
** Furnished herewith