ENCORE ACQUISITION CO
Form 10-Q
August 08, 2005

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**UNITED STATES**
**SECURITIES AND EXCHANGE COMMISSION**
**WASHINGTON, D. C. 20549**
**FORM 10-Q**

(Mark One)

þ **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
**For the quarterly period ended June 30, 2005**
**or**

o **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
**For the transition period from _______ to ________**
**Commission file number 1-16295**

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

| | |
|---|---|
| **Delaware** | **75-2759650** |
| (State or other jurisdiction of incorporation) | (IRS Employer Identification No.) |
| **777 Main Street, Suite 1400, Fort Worth, Texas** | **76102** |
| (Address of principal executive offices) | (Zip Code) |

Registrant s telephone number, including area code: **(817) 877-9955**

Not applicable
(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act)

Yes þ No o

Number of shares of Common Stock, $0.01 par value, outstanding as of July 29, 2005 ....................... 49,327,156

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**ENCORE ACQUISITION COMPANY**
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**CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION**

This Quarterly Report on Form 10-Q contains forward-looking statements, which give our current expectations or forecasts of future events. You can identify our forward-looking statements by the fact that they do not relate strictly to historical or current facts. These statements may include words such as anticipate, estimate, expect, project, int plan, believe, should and other words and terms of similar meaning. Our actual results may differ significantly from the results discussed in the forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, the matters discussed in the subsection entitled Factors That May Affect Future Results and Financial Condition in our Annual Report on Form 10-K and in our other filings with the Securities and Exchange Commission. If one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement. We undertake no responsibility to update forward-looking statements for changes related to these or any other factors that may occur subsequent to this filing for any reason.

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## PART I. FINANCIAL INFORMATION

### Item 1. Financial Statements

## ENCORE ACQUISITION COMPANY
## CONSOLIDATED BALANCE SHEETS

(in thousands except shares and per share amounts)

| | June 30, 2005 (unaudited) | December 31, 2004 |
|---|---|---|
| ASSETS | | |
| Current assets: | | |
| Cash and cash equivalents | $ 1,023 | $ 1,103 |
| Accounts receivable | 50,944 | 43,839 |
| Inventory | 10,191 | 6,550 |
| Derivatives | 776 | 2,665 |
| Deferred taxes | 20,869 | 11,118 |
| Other | 3,124 | 5,842 |
| Total current assets | 86,927 | 71,117 |
| Properties and equipment, at cost successful efforts method: | | |
| Proved properties | 1,295,489 | 1,134,220 |
| Unproved properties | 30,825 | 29,740 |
| Accumulated depletion, depreciation, and amortization | (206,655) | (171,691) |
| | 1,119,659 | 992,269 |
| Other property and equipment | 14,495 | 10,425 |
| Accumulated depreciation | (4,288) | (3,551) |
| | 10,207 | 6,874 |
| Goodwill | 37,908 | 37,995 |
| Other | 15,110 | 15,145 |
| Total assets | $1,269,811 | $1,123,400 |
| LIABILITIES AND STOCKHOLDERS EQUITY | | |
| Current liabilities: | | |
| Accounts payable | $ 18,221 | $ 24,375 |
| Derivatives | 49,977 | 24,270 |
| Accrued and other current | 42,327 | 38,038 |

| | | |
|---|---|---|
| Total current liabilities | 110,525 | 86,683 |
| | | |
| Derivatives | 54,865 | 31,477 |
| Future abandonment costs | 11,161 | 6,601 |
| Other | 1,336 | |
| Deferred taxes | 159,907 | 146,064 |
| Long-term debt | 440,000 | 379,000 |
| Total liabilities | 777,794 | 649,825 |
| | | |
| Commitments and contingencies | | |
| Stockholders equity: | | |
| Preferred stock, $.01 par value, 5,000,000 shares authorized, none issued and outstanding | | |
| Common stock, $.01 par value, 144,000,000 authorized, 49,338,036 and 48,982,197 issued and outstanding | 493 | 490 |
| Additional paid-in capital | 323,631 | 314,573 |
| Deferred compensation | (10,256) | (4,603) |
| Retained earnings | 244,964 | 199,512 |
| Accumulated other comprehensive loss | (66,815) | (36,397) |
| Total stockholders equity | 492,017 | 473,575 |
| Total liabilities and stockholders equity | $1,269,811 | $1,123,400 |

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

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**ENCORE ACQUISITION COMPANY**
**CONSOLIDATED STATEMENTS OF OPERATIONS**
(in thousands except per share amounts)
(unaudited)

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2005 | 2004 | 2005 | 2004 |
| Revenues: | | | | |
| Oil | $ 69,559 | $52,885 | $136,695 | $ 99,649 |
| Natural gas | 30,158 | 17,237 | 54,603 | 29,764 |
| Total revenues | 99,717 | 70,122 | 191,298 | 129,413 |
| Expenses: | | | | |
| Production | | | | |
| Lease operations | 15,721 | 10,921 | 30,589 | 21,163 |
| Production, ad valorem, and severance taxes | 9,813 | 7,161 | 18,899 | 13,000 |
| Depletion, depreciation, and amortization | 19,038 | 11,249 | 35,721 | 20,512 |
| Exploration | 3,772 | 1,697 | 6,383 | 1,697 |
| General and administrative (excluding non-cash stock based compensation) | 3,571 | 2,530 | 7,206 | 4,758 |
| Non-cash stock based compensation | 1,006 | 307 | 1,779 | 617 |
| Derivative fair value loss | 1,692 | 965 | 4,101 | 1,123 |
| Other operating | 1,703 | 1,091 | 3,302 | 2,093 |
| Total expenses | 56,316 | 35,921 | 107,980 | 64,963 |
| Operating income | 43,401 | 34,201 | 83,318 | 64,450 |
| Other income (expenses): | | | | |
| Interest | (7,448) | (6,308) | (14,407) | (10,214) |
| Other | 85 | 106 | 149 | 157 |
| Total other income (expenses) | (7,363) | (6,202) | (14,258) | (10,057) |
| Income before income taxes | 36,038 | 27,999 | 69,060 | 54,393 |
| Current income tax provision | (589) | (919) | (1,390) | (2,004) |
| Deferred income tax provision | (11,781) | (9,089) | (22,218) | (17,496) |
| Net income | $ 23,668 | $17,991 | $ 45,452 | $ 34,893 |

Net income per common share:

| | | | | |
|---|---|---|---|---|
| Basic | $ 0.49 | $ 0.39 | $ 0.93 | $ 0.76 |
| Diluted | 0.48 | 0.39 | 0.92 | 0.75 |
| | | | | |
| Weighted average common shares outstanding: | | | | |
| Basic | 48,660 | 46,089 | 48,636 | 45,684 |
| Diluted | 49,458 | 46,680 | 49,429 | 46,271 |

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

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**ENCORE ACQUISITION COMPANY**
**CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY**
**June 30, 2005**
(in thousands)
(unaudited)

| | Shares of Common Stock | Common Stock | Additional Paid-In Capital | Deferred Compensation | Retained Earnings | Accumulated Other Comprehensive Loss | Total Stockholders Equity |
|---|---|---|---|---|---|---|---|
| Balance at December 31, 2004 | 48,982 | $490 | $314,573 | $ (4,603) | $199,512 | $(36,397) | $473,575 |
| Exercise of stock options | 92 | | 1,629 | | | | 1,629 |
| Deferred compensation: | | | | | | | |
| Issuance of restricted Common Stock | 270 | 3 | 7,106 | (7,109) | | | |
| Amortization to expense | | | | 1,779 | | | 1,779 |
| Other changes | (6) | | 323 | (323) | | | |
| Components of comprehensive income: | | | | | | | |
| Net income | | | | | 45,452 | | 45,452 |
| Change in deferred hedge loss, net of income taxes of $18,120 | | | | | | (30,418) | (30,418) |
| Total comprehensive income | | | | | | | 15,034 |
| Balance at June 30, 2005 | 49,338 | $493 | $323,631 | $(10,256) | $244,964 | $(66,815) | $492,017 |

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

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**ENCORE ACQUISITION COMPANY**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
(in thousands)
(unaudited)

| | Six months ended June 30, 2005 | Six months ended June 30, 2004 |
|---|---|---|
| Operating activities | | |
| Net income | $ 45,452 | $ 34,893 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depletion, depreciation, and amortization | 35,721 | 20,512 |
| Dry hole expense | 3,329 | 1,697 |
| Deferred taxes | 22,218 | 17,496 |
| Non-cash stock based compensation | 1,779 | 617 |
| Non-cash derivative fair value loss | 8,278 | 6,106 |
| Other non-cash | 1,844 | 779 |
| Loss on disposition of assets | 160 | 109 |
| Changes in operating assets and liabilities: | | |
| Accounts receivable | (7,059) | (3,882) |
| Other current assets | (2,952) | (8,357) |
| Other assets | (4,113) | (309) |
| Accounts payable and accrued liabilities | 12,808 | 4,829 |
| Cash provided by operating activities | 117,465 | 74,490 |
| Investing activities | | |
| Proceeds from disposition of assets | 424 | 425 |
| Purchases of other property and equipment | (4,714) | (6,597) |
| Acquisition of oil and natural gas properties | (17,379) | (98,608) |
| Acquisition of Cortez Oil & Gas, Inc. (net of cash acquired) | | (123,023) |
| Development and exploration of oil and natural gas properties | (144,434) | (70,573) |
| Cash used by investing activities | (166,103) | (298,376) |
| Financing activities | | |
| Proceeds from issuance of common stock | | 53,900 |
| Payment of offering cost of common stock | | (900) |
| Proceeds from long-term debt | 195,000 | 169,000 |
| Payments on long-term debt | (134,000) | (145,000) |
| Proceeds from issuance of $6^1/4$% notes | | 150,000 |
| Payments of debt issuance costs | (204) | (3,128) |
| Cash overdrafts and other | (12,238) | 2,374 |
| Cash provided by financing activities | 48,558 | 226,246 |

| | | |
|---|---|---|
| Increase (decrease) in cash and cash equivalents | (80) | 2,360 |
| Cash and cash equivalents, beginning of period | 1,103 | 431 |
| Cash and cash equivalents, end of period | $ 1,023 | $ 2,791 |

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

# ENCORE ACQUISITION COMPANY
# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
# JUNE 30, 2005
(unaudited)

## 1. Formation of Encore

Encore Acquisition Company, a Delaware corporation ( Encore or the Company ), is a growing independent energy company engaged in the acquisition, development, exploitation, exploration, and production of onshore North American oil and natural gas reserves. Since the Company s inception in 1998, Encore has sought to acquire high-quality assets with potential for upside through low-risk development drilling projects. Encore s properties currently are located in four core areas: the Cedar Creek Anticline ( CCA ) in the Williston Basin of Montana and North Dakota; the Permian Basin of western Texas and southeastern New Mexico; the Mid-Continent area, which includes the Arkoma and Anadarko Basins of Oklahoma, the ArkLaTx region of northern Louisiana and eastern Texas and the Barnett Shale of northern Texas; and the Rockies, which includes non-CCA assets in the Williston and Powder River Basins of Montana, and the Paradox Basin of southeastern Utah.

## 2. Basis of Presentation

In the opinion of management, the accompanying unaudited consolidated financial statements of Encore include all adjustments necessary to present fairly, in all material respects, our financial position as of June 30, 2005, results of operations for the three and six months ended June 30, 2005 and 2004, and cash flows for the six months ended June 30, 2005 and 2004. All adjustments are of a recurring nature. These interim results are not necessarily indicative of results for an entire year.

Certain amounts and disclosures have been condensed or omitted from these consolidated financial statements pursuant to the rules and regulations of the Securities and Exchange Commission. Therefore, these consolidated financial statements should be read in conjunction with the consolidated financial statements and related notes thereto included in the Company s 2004 Annual Report on Form 10-K.

### *Presentation of Number of Shares of Common Stock and Per Share Information*

As discussed at Note 10, Stockholders Equity, during the three months ended June 30, 2005, the Company s Board of Directors approved a three-for-two stock split in the form of a stock dividend to shareholders of record on June 27, 2005. All share and per-share information for all periods presented in the accompanying financial statements and related notes thereto have been restated to reflect the stock split that occurred on July 12, 2005.

### *Stock-based Compensation*

Employee stock options and restricted stock awards are accounted for under the provisions of Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees ( APB 25 ). Accordingly, no compensation is recorded for stock options that are granted to employees or non-employee directors with an exercise price equal to or above the common stock price on the grant date. However, compensation expense is recorded for the fair value of the restricted stock granted to employees.

If compensation expense for the stock based awards had been determined using the provisions of Statement of Financial Accounting Standards ( SFAS ) No. 123, Accounting for Stock-Based Compensation, the Company s net income and net income per share would have been adjusted to the pro forma amounts indicated below (in thousands, except per share amounts):

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| | Three months ended June 30, 2005 | Three months ended June 30, 2004 | Six months ended June 30, 2005 | Six months ended June 30, 2004 |
|---|---|---|---|---|
| As Reported: | | | | |
| Non-cash stock based compensation (net of taxes) | $ 630 | $ 190 | $ 1,114 | $ 383 |
| Net income | 23,668 | 17,991 | 45,452 | 34,893 |
| Basic net income per common share | 0.49 | 0.39 | 0.93 | 0.76 |
| Diluted net income per common share | 0.48 | 0.39 | 0.92 | 0.75 |
| Pro Forma: | | | | |
| Non-cash stock based compensation (net of taxes) | $ 971 | $ 518 | $ 1,618 | $ 924 |
| Net income | 23,327 | 17,663 | 44,948 | 34,352 |
| Basic net income per common share | 0.48 | 0.38 | 0.92 | 0.75 |
| Diluted net income per common share | 0.47 | 0.38 | 0.91 | 0.74 |

There were 269,555 shares of restricted stock granted during the six months ended June 30, 2005, of which 266,636 shares are outstanding at June 30, 2005. During the first half of 2005, 2,536 shares of restricted stock, which were issued and outstanding at December 31, 2004, were forfeited. There were 115,284 shares of stock options granted in the six months ended June 30, 2005, of which 114,375 shares of stock options are outstanding at June 30, 2005.

***New Accounting Standards***

*Statement of Financial Accounting Standards No. 123R, Share-Based Payment*

In December 2004, the Financial Accounting Standards Board ( FASB ) issued SFAS No. 123R, Share-Based Payment. SFAS No. 123R is a revision of SFAS No. 123, Accounting for Stock Based Compensation, and supersedes APB 25. SFAS No. 123R eliminates the option of using the intrinsic value method of accounting previously available, and requires companies to recognize in the financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. The effective date of SFAS No. 123R was initially scheduled to be the first reporting period beginning after June 15, 2005, which is third quarter 2005 for calendar year companies. However, on April 14, 2005, the Securities and Exchange Commission ( SEC ) announced that the effective date of SFAS No. 123R will be delayed until January 1, 2006, for calendar year companies.

SFAS No. 123R permits companies to adopt its requirements using either a modified prospective method, or a modified retrospective method. Under the modified prospective method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS No. 123R for all share-based payments granted after that date, and for all unvested awards granted prior to the effective date of SFAS No. 123R. Under the modified retrospective method, the requirements are the same as under the modified prospective method, but it also permits entities to restate financial statements of previous periods based on pro-forma disclosures made in accordance with SFAS No. 123. The Company has not yet determined which of the aforementioned adoption methods it will use.

The Company currently utilizes a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees to calculate the pro-forma effect of applying the fair value provisions of SFAS No. 123 as disclosed above under Stock-based Compensation. While SFAS No. 123R permits entities to continue to use such a model, the standard also permits the use of a lattice model. The Company has not yet determined which model it will use to measure the fair value of employee stock options upon the adoption of SFAS No. 123R.

Under the revised standard, the pro forma disclosures previously permitted under SFAS No. 123 no longer will be an alternative to financial statement recognition. See the discussion of stock-based compensation above for the pro forma net income and net income per share amounts for the three and six months ended June 30, 2004 and 2005, as if the Company had used a fair-value-based method similar to the methods required under SFAS No. 123R to measure compensation expense for employee stock incentive awards.

SFAS No. 123R also requires that the benefits associated with the tax deductions in excess of recognized compensation cost be reported as a financing cash flow. This requirement will reduce net operating cash flows and increase net financing cash flows in periods after the effective date. These future amounts cannot be estimated because they depend on, among other things, when employees exercise stock options and the Company s stock price at that time.

The Company plans to adopt SFAS No. 123R effective January 1, 2006, based on the new effective date announced by the SEC. The Company has not yet determined the financial statement impact of adopting SFAS No. 123R for periods beyond 2005.

*FASB Staff Position 19-1, Accounting for Suspended Well Costs*

On April 4, 2005 the FASB adopted FASB Staff Position ( FSP ) 19-1 Accounting for Suspended Well Costs that amends SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, to permit the continued capitalization of exploratory well costs beyond one year if the well found a sufficient quantity of reserves to justify its completion as a producing well and the entity is making sufficient progress assessing the reserves and the economic and operating viability of the project. FSP 19-1 is effective for the first reporting period beginning after April 4, 2005, which for the Company will be the third quarter of 2005. Its adoption is not expected to have a material impact on the Company s results of operations, financial condition, or cash flows.

*Emerging Issues Task Force (EITF) Issue 04-13 Accounting for Purchases and Sales of Inventory with the Same Counterparty*

The Emerging Issues Task Force considered Issue No. 04-13 in its May 17, 2005 and June 16, 2005 meetings to discuss inventory sales to another entity in the same line of business from which it also purchases inventory. The Task Force reached consensus on the issue that purchases and sales of inventory with the same counterparty should be combined as a single nonmonetary transaction (net) and noted factors that may indicate that transactions were entered into in contemplation for one another. The Task Force also concluded that transfers of finished goods inventory in exchange for work-in-progress or raw materials should be recognized at fair value and prescribes additional disclosures. The Task Force is expected to ratify Issue No. 04-15 at its September 2005 meeting, which would be applicable for transactions completed in reporting periods beginning after March 15, 2006. The Company has previously reported transactions of this nature on a net basis; therefore, the Company does not expect Issue No. 04-15 to have a material impact on the Company s results of operations, financial condition, or cash flows.

**3. Inventories**

Inventories are comprised principally of materials and supplies and oil in pipelines, which are stated at the lower of cost (determined on an average basis) or market. Oil produced at the lease which resides unsold in pipelines is carried at an amount equal to its operating costs to produce. Oil in pipelines purchased from third parties is carried at average purchase price. The Company s inventories consisted of the following as of the dates indicated (amounts in thousands):

| | June 30, 2005 | December 31, 2004 |
|---|---|---|
| Warehouse inventory | $ 6,952 | $ 6,321 |
| Oil in pipelines (purchased) | 3,239 | |
| Oil in pipelines (produced) | | 229 |
| | $ 10,191 | $ 6,550 |

**4. Cortez Acquisition and Goodwill**

On April 14, 2004, the Company purchased all of the outstanding capital stock of Cortez Oil & Gas, Inc. ( Cortez ), a privately held, independent oil and natural gas company, for a total purchase price of $127.0 million, which includes cash paid to Cortez former shareholders of $85.8 million, the repayment of $39.4 million of Cortez debt, and transaction costs incurred of $1.8 million.

The acquired oil and natural gas properties are located primarily in the CCA of Montana, the Permian Basin of West Texas and Southeastern New Mexico and in the Mid-Continent area, including the Anadarko and Arkoma Basins of Oklahoma and the Barnett Shale north of Fort Worth, Texas. Cortez operating results are included in the Company s Consolidated Statement of Operations beginning in April 2004.

The calculation of the total purchase price and the allocation as of June 30, 2005 to the fair value of net assets acquired at April 14, 2004, are as follows (in thousands):

| | |
|---|---|
| Calculation of total purchase price: | |
| Cash paid to Cortez former owners | $ 85,805 |
| Cortez debt repaid | 39,449 |
| Transaction costs | 1,760 |
| Total purchase price | $127,014 |
| Allocation of purchase price to the fair value of net assets acquired: | |
| Cash | $ 3,206 |
| Current assets, excluding cash | 5,946 |
| Proved oil and natural gas properties | 120,503 |
| Unproved oil and natural gas properties | 3,011 |
| Goodwill | 37,908 |
| Total assets acquired | 170,574 |
| Current liabilities | (5,673) |
| Non-current liabilities | (996) |
| Deferred income taxes | (36,891) |
| Total liabilities assumed | (43,560) |
| Fair value of net assets acquired | $127,014 |

The purchase price allocation resulted in $37.9 million of goodwill primarily as the result of the difference between the fair value of acquired oil and natural gas properties and their lower carryover tax basis, which resulted in deferred taxes of $36.9 million. Management believes the goodwill will be recovered through operating synergies resulting from the close proximity of the properties acquired to existing operations, particularly the additional interest in the CCA and Permian properties. None of the goodwill is deductible for income tax purposes.

**5. Derivative Financial Instruments**

The following tables summarize the Company s open commodity derivative instruments designated as hedges as of June 30, 2005:

***Oil Derivative Instruments at June 30, 2005***

| Period | Daily Floor Volume (Bbls) | Floor Price (per Bbl) | Daily Cap Volume (Bbls) | Cap Price (per Bbl) | Daily Swap Volume (Bbls) | Swap Price (per Bbl) | Fair Value (000s) |
|---|---|---|---|---|---|---|---|
| July Dec 2005 | 12,500 | $27.84 | 2,500 | $31.07 | 1,000 | $25.12 | $(18,513) |
| Jan June 2006 | 7,000 | 33.93 | 1,000 | 29.88 | 2,000 | 25.03 | (16,927) |
| July Dec 2006 | 6,500 | 35.00 | 1,000 | 29.88 | 2,000 | 25.03 | (16,233) |

| | | | |
|---|---|---|---|
| Jan Dec 2007 | 2,000 | 25.11 | (22,001) |

***Natural Gas Derivative Instruments at June 30, 2005***

| Period | Daily Floor Volume (Mcf) | Floor Price (per Mcf) | Daily Cap Volume (Mcf) | Cap Price (per Mcf) | Daily Swap Volume (Mcf) | Swap Price (per Mcf) | Fair Value (000s) |
|---|---|---|---|---|---|---|---|
| July Dec 2005 | 17,500 | $5.12 | 5,000 | $5.97 | 12,500 | $4.99 | $ (6,004) |
| Jan Dec 2006 | 12,500 | 5.34 | 5,000 | 5.68 | 12,500 | 5.08 | (15,576) |
| Jan Dec 2007 | | | | | 10,000 | 4.99 | (8,458) |

Encore recognizes in the Consolidated Statements of Operations derivative fair value gains and losses related to changes in the mark-to-market value of basis swaps and certain other commodity derivatives that are not designated for hedge accounting; ineffectiveness of commodity futures contracts designated as hedges; and changes in the mark-to-market value of its interest rate swap.

In order to more effectively hedge the cash flows received on oil and natural gas production, the Company enters into financial instruments, commonly called basis swaps, whereby Encore swaps certain per Bbl or per Mcf floating market indices for a fixed amount. These market indices are a component of the price the Company is paid on its actual production and by fixing this component of the Company s marketing price, Encore is able to realize a net price with a more consistent differential to

NYMEX. Since NYMEX is the basis of all the Company s derivative oil hedging contracts and some of Company s natural gas contracts, a more consistent differential results in more effective hedges. However, management has elected not to use hedge accounting for certain of these contracts. Instead, the Company marks these contracts to market each quarter through Derivative fair value (gain) loss in the Consolidated Statements of Operations. Thus, as these contracts do not change the Company s overall hedged volumes, average prices presented in the table above are exclusive of any effect of these non-hedge instruments. As of June 30, 2005, the mark-to-market value of these contracts is $0.5 million.

The actual gains or losses the Company realizes from derivative transactions may vary significantly from the deferred loss amount recorded in stockholders equity at June 30, 2005 due to fluctuation of prices in the commodities markets.

***Interest Rate Derivatives***

The Company does not currently have any interest rate swap contracts outstanding. During the quarter ended June 30, 2005, a gain of $0.03 million related to an interest rate swap that expired in June 2005 was recorded in the Consolidated Statement of Operations.

**6. Asset Retirement Obligations**

The Company s primary asset retirement obligations relate to future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal. The Company does not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined. The following table summarizes the changes in the Company s future abandonment liability recorded in Future abandonment costs on the Company s Consolidated Balance Sheet for the period from January 1, 2005 through June 30, 2005 (in thousands):

| | **Six months ended June 30, 2005** |
|---|---|
| Future abandonment liability at January 1, 2005 | $ 6,601 |
| Wells drilled | 564 |
| Accretion expense | 224 |
| Plugging and abandonment costs incurred | (530) |
| Revision of estimates | 4,302 |
| Future abandonment liability at June 30, 2005 | $ 11,161 |

During the first half of 2005, the Company increased its discounted estimate of future plugging liability by $4.3 million as actual plugging costs experienced during the first quarter of 2005 increased due to plugging cost escalations (which outpaced inflation), the cost of outside services, and changes in various state regulations.

**7. Debt**

***Issuance of 6% Senior Subordinated Notes***

On June 30, 2005, the Company priced $300.0 million of 6% senior subordinated notes due July 15, 2015 (the 6% notes ). The Company issued and sold the notes on July 13, 2005. The offering was made through a private placement pursuant to Rule 144A and Regulation S. The Company estimates net proceeds of approximately $293.5 million after paying all costs associated with the offering. The net proceeds are expected to be used to redeem all $150.0 million of the Company s outstanding $8\frac{3}{8}$% senior subordinated notes due 2012, and to reduce outstanding indebtedness under the Company s existing revolving credit facility. Concurrently with the issuance of the 6% notes, the Company entered into a registration rights agreement whereby the Company agreed to file a registration statement offering to exchange the 6% notes for publicly registered notes with substantially identical terms.

The 6% notes mature on July 15, 2015 and all amounts then outstanding will be due and payable at that time. Interest is paid semi-annually on July 15 and January 15. The indenture governing the 6% notes contains substantially the same covenants and restrictions as the Company s outstanding $6\frac{1}{4}$% senior subordinated notes due 2014.

***Line of Credit***

On April 29, 2005, the Company amended its existing credit facility to increase the borrowing base from $400.0 million to $500.0 million. Other changes to the facility include a change in the definition of EBITDA to add back exploration expense (EBITDAX), and an increase in the availability of letters of credit from 15% of the borrowing base to 20%.

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Upon the issuance of the 6% notes on July 13, 2005 (see above), the Company s borrowing base was reduced from $500.0 million to $450.0 million.

***Letters of Credit***

The Company had $56.1 million of outstanding letters of credit at June 30, 2005. These letters of credit are posted primarily with two counterparties to the Company s hedging contracts and are used in lieu of cash margin deposits with those counterparties.

**8. Income Taxes**

Reconciliation of income tax expense with tax at the Federal statutory rate is as follows (in thousands):

| | Six months ended June 30, | |
|---|---|---|
| | **2005** | **2004** |
| Income before income taxes | $69,060 | $54,393 |
| Tax at statutory rate | 24,171 | 19,038 |
| State income taxes, net of federal benefit | 1,371 | 1,632 |
| Section 43 credits generated | (1,446) | (1,663) |
| Permanent differences and other | (488) | 493 |
| Income tax provision | $23,608 | $19,500 |

**9. Earnings Per Share (EPS)**

The following table sets forth basic and diluted EPS computations for the three and six months ended June 30, 2005 and 2004 (in thousands, except per share data):

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | **2005** | **2004** | **2005** | **2004** |
| **Numerator:** | | | | |
| Net income | $23,668 | $17,991 | $45,452 | $34,893 |
| **Denominator:** | | | | |
| Denominator for basic earnings per share | | | | |
| Weighted average shares outstanding | 48,660 | 46,089 | 48,636 | 45,684 |
| Effect of dilutive options and dilutive restricted stock (a) | 798 | 591 | 793 | 587 |
| Denominator for diluted earnings per share | 49,458 | 46,680 | 49,429 | 46,271 |
| **Net income per common share:** | | | | |
| Basic | $ 0.49 | $ 0.39 | $ 0.93 | $ 0.76 |
| Diluted | $ 0.48 | $ 0.39 | $ 0.92 | $ 0.75 |

(a) For the quarter ended June 30, 2005 and 2004, outstanding employee stock options of 114,375 and 37,500 were excluded from the calculation of diluted earnings per share because their effect would have been antidilutive.

As discussed in Note 10, Stockholders Equity, during the three months ended June 30, 2005, the Company s Board of Directors approved a three-for-two stock split in the form of a stock dividend to shareholders of record on June 27, 2005. All share and per-share information in the table above have been restated to reflect the stock split.

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**10. Stockholders Equity**

During the three months ended June 30, 2005, the Company s Board of Directors approved a three-for-two stock split in the form of a stock dividend on each share of common stock outstanding as of the close of business on June 27, 2005 (the Record Date ). The stock dividend was distributed on July 12, 2005 to stockholders of record as of the Record Date. In lieu of issuing fractional shares, the Company paid cash for such fractional shares based on the closing price of the common stock on the record date.

The pro-forma effect of the stock split on the December 31, 2004 balance sheet is to reduce additional paid-in-capital by $0.2 million and increase common stock by $0.2 million. The beginning balances of additional paid-in-capital and common stock at December 31, 2004 have been adjusted in the June 30, 2005 Consolidated Balance Sheet and Consolidated Statement of Stockholders Equity to reflect this pro-forma effect of the stock split. All share and per-share information have been restated to reflect the stock split that became effective July 12, 2005.

On May 3, 2005, the Company s stockholders approved an amendment to the Company s Second Amended and Restated Certificate of Incorporation to increase the authorized number of shares of common stock, par value $.01 per share, from 60 million to 144 million.

**11. Comprehensive Income (Loss)**

Components of comprehensive income (loss), net of related tax, are as follows (in thousands):

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | **2005** | **2004** | **2005** | **2004** |
| Net income | $23,668 | $17,991 | $ 45,452 | $ 34,893 |
| Change in unrealized loss on derivative hedged instruments | 3,383 | (9,854) | (30,156) | (17,794) |
| Change in deferred gain on interest rate swap | (317) | 358 | (262) | 483 |
| Comprehensive income | 26,734 | 8,495 | 15,034 | 17,582 |

The components of accumulated other comprehensive loss, net of related tax, are as follows (in thousands):

| | June 30, 2005 | December 31, 2004 |
|---|---|---|
| Unrealized loss on derivative hedged instruments | $(66,997) | $ (36,841) |
| Deferred gain on interest rate swap | 182 | 444 |
| Accumulated other comprehensive loss | $(66,815) | $ (36,397) |

**12. Financial Statements of Subsidiary Guarantors**

As of June 30, 2005, all of the Company s subsidiaries were subsidiary guarantors of the Company s outstanding $8^3/_8$% and $6^1/4$% notes. Since (i) each subsidiary guarantor is 100% owned by the Company, (ii) the Company has no assets or operations that are independent of its subsidiaries, (iii) the subsidiary guarantees are full and unconditional and joint and several and (iv) all of the Company s subsidiaries are subsidiary guarantors, the Company has not included the financial statements of each subsidiary in this report. The subsidiary guarantors may, without restriction, transfer funds to the Company in the form of cash dividends, loans, and advances.

**13. Related Party Transactions**

The Company paid to Hanover Compressor Company $0.4 million and $0.01 million in the first six months of 2005 and 2004, respectively, for field compression services. Mr. I. Jon Brumley, the Company s Chairman, and CEO, also serves as a director of Hanover Compressor Company.

**14. Subsequent Events**

**$8^3/_8$% Notes**

On July 13, 2005, the Company issued a notice of redemption (the Redemption Notice ) pursuant to the provisions of the Indenture, dated as of June 25, 2002, among the Company, certain subsidiaries of the Company and Wells Fargo Bank, National

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Association, as Trustee (the Trustee ), pursuant to which the 8$^{3}/_{8}$% senior subordinated notes of the Company (the 8$^{3}/_{8}$% notes ) were issued. In the Redemption Notice, the Company indicated that it was exercising its right to redeem on August 15, 2005 (the Redemption Date ) all $150 million aggregate principal amount of 8$^{3}/_{8}$% notes currently outstanding. The Company expects the redemption price to approximate $168.6 million, including a make-whole premium and accrued interest through the redemption date. The exact redemption price will be determined in part using the latest Treasury yields at the redemption date and, thus, it will not be known until that time. However, the Company does not expect the estimate to change materially.

Combined with the unamortized balance of debt issuance costs of the 8$^{3}/_{8}$% notes, the Company estimates a pre-tax charge to earnings from the redemption to be recorded in the third quarter of 2005 of $21.8 million at June 30, 2005.

## Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

This document contains forward-looking statements, which give our current expectations or forecasts of future events. Actual results may differ materially from those discussed in our forward-looking statements due to many factors, including, but not limited to, those set forth under FACTORS THAT MAY AFFECT FUTURE RESULTS AND FINANCIAL CONDITION contained in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations, in Encore s 2004 Annual Report on Form 10-K. The following discussion should be read in conjunction with the consolidated financial statements and notes thereto included in this document and Encore s 2004 Form 10-K.

### Second Quarter 2005 Highlights

Our financial and operating results for the quarter ended June 30, 2005 included the following highlights:

During the second quarter of 2005, we had oil and natural gas revenues of $99.7 million. This represents a 42% increase over the $70.1 million of oil and natural gas revenues reported for the second quarter of 2004. Our realized commodity prices, including the effects of hedging, averaged $40.96 per barrel and $6.11 per Mcf during the second quarter of 2005, increases of 31% and 14%, respectively, from the second quarter of 2004. On a combined basis, including the effects of hedging, prices increased 25% during the second quarter of 2005 to $39.56 per BOE from $31.54 per BOE in the second quarter of 2004.

We reported net income of $23.7 million, or $0.48 per diluted share, in the three months ended June 30, 2005. This represents a 32% increase from the $17.9 million of net income, or $0.39 per diluted share, reported for the second quarter of 2004.

Higher net income in the second quarter of 2005 resulted as production volumes for the quarter increased 13% to 27,697 BOE per day (2.5 MMBOE), compared with second quarter 2004 production of 24,434 BOE per day (2.2 MMBOE). The rise in production volumes was attributable to the continued success of our drilling program, uplift from our HPAI tertiary recovery project on the CCA, and acquisitions completed in 2004. Oil represented 67% and 76% of our total production volumes in the second quarter of 2005 and 2004, respectively.

We invested $89.0 million in oil and natural gas activities during the second quarter of 2005 (excluding development-related asset retirement obligations). We invested $81.0 million in development, exploitation, expanding our HPAI program in the CCA, and exploration activities yielding 110 gross (65.7 net) wells. We also invested $8.0 million in acquiring proved properties and undeveloped leases. We are currently investing capital in an eleven-rig conventional operated drilling program on the onshore continental United States, with five rigs in Montana, three rigs in East Texas, two rigs in West Texas, and one rig in Oklahoma.

We were able to fund the majority of the $89.0 million of investments in oil and natural gas activities made in the second quarter of 2005 using the $62.6 million of operating cash flows generated during the quarter. The remaining $26.4 million was funded through borrowings under our existing revolving credit facility. Long-term debt at June 30, 2005 increased to $440.0 million from $379.0 million at December 31, 2004.

On June 30, 2005, we priced the sale of $300.0 million 6% senior subordinated debt. We issued and sold the notes on July 13, 2005. We expect to redeem our $8^3/_8$% notes during the third quarter of 2005, and use the remaining net cash received to reduce amounts outstanding under our existing revolving credit facility.

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**Results of Operations**

**Comparison of Quarter Ended June 30, 2005 to Quarter Ended June 30, 2004**

Set forth below is our comparison of operations during the second quarter of 2005 with the second quarter of 2004.

***Revenues and Production.*** The following table illustrates the primary components of oil and natural gas revenues for the three months ended June 30, 2005 and 2004, as well as each quarter s respective oil and natural gas volumes (in thousands, except per unit and per day amounts):

| | Three months ended June 30, | | *Increase / (Decrease)* | |
|---|---|---|---|---|
| | 2005 | 2004 | *$* | *%* |
| **Revenues:** | | | | |
| Oil wellhead | $ 80,178 | $60,638 | $*19,540* | |
| Oil hedges | (10,619) | (7,753) | *(2,866)* | |
| Total Oil Revenues | $ 69,559 | $52,885 | *$16,674* | *32%* |
| Natural gas wellhead | $ 32,448 | $17,948 | $*14,500* | |
| Natural gas hedges | (2,290) | (711) | *(1,579)* | |
| Total Natural Gas Revenues | $ 30,158 | $17,237 | *$12,921* | *75%* |
| Combined wellhead | $112,626 | $78,586 | $*34,040* | |
| Combined hedges | (12,909) | (8,464) | *(4,445)* | |
| Total Combined Revenues | $ 99,717 | $70,122 | *$29,595* | *42%* |
| **Revenues ($/Unit):** | | | | |
| Oil wellhead | $ 47.21 | $ 35.90 | *$ 11.31* | |
| Oil hedges | (6.25) | (4.58) | *(1.67)* | |
| Total Oil Revenues | $ 40.96 | $ 31.32 | *$ 9.64* | *31%* |
| Natural gas wellhead | $ 6.57 | $ 5.59 | *$ 0.98* | |
| Natural gas hedges | (0.46) | (0.22) | *(0.24)* | |
| Total Natural Gas Revenues | $ 6.11 | $ 5.37 | *$ 0.74* | *14%* |
| Combined wellhead | $ 44.69 | $ 35.35 | *$ 9.34* | |
| Combined hedges | (5.13) | (3.81) | *(1.32)* | |
| Total Combined Revenues | $ 39.56 | $ 31.54 | *$ 8.02* | *25%* |

| | Three months ended June 30, | | *Increase /* |
|---|---|---|---|
| | 2005 | 2004 | *(Decrease)* |

| | | | |
|---|---|---|---|
| **Total production volumes:** | | | |
| Oil (Bbls) | 1,698 | 1,689 | *9* |
| Natural gas (Mcf) | 4,933 | 3,209 | *1,724* |
| Combined (BOE) | 2,520 | 2,223 | *297* |
| **Daily production volumes:** | | | |
| Oil (Bbls/day) | 18,662 | 18,557 | *105* |
| Natural gas (Mcf/day) | 54,213 | 35,260 | *18,953* |
| Combined (BOE/day) | 27,697 | 24,434 | *3,263* |
| **NYMEX Prices:** | | | |
| Oil (per Bbl) | $ 53.17 | $ 38.32 | *$ 14.85* |
| Natural gas (per Mcf) | 6.95 | 6.07 | *0.88* |

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Oil revenues increased from second quarter 2004 to second quarter 2005 by $16.7 million, due primarily to a higher realized average oil price. Our realized average oil price increased $9.64 per Bbl in the second quarter of 2005 over the same period in 2004 as a result of an increase in our average wellhead price of $11.31 per Bbl, offset by an increase in hedging payments of $1.67 per Bbl. The increase in our average wellhead price and hedging payments resulted from the increase in the overall market price for oil as reflected in the $14.85 per Bbl increase in the average NYMEX price over the same period.

Natural gas revenues increased by $12.9 million, or $0.74 per Mcf, in the second quarter of 2005 from the second quarter of 2004 due to an increase in volumes and an increase in our realized average natural gas price. Production volumes increased 1,724 MMcf in the second quarter of 2005 as compared to the second quarter of 2004 due to our drilling activities and the Overton acquisition, which closed on June 17, 2004, and is included in our financial statements beginning July 1, 2004. The $0.74 per Mcf increase in our realized average natural gas price was due to the $0.98 per Mcf increase in the wellhead price for our natural gas from the second quarter of 2004 to the second quarter of 2005. The NYMEX price for natural gas increased by $0.88 per Mcf over the same period.

The table below illustrates the relationship between oil and natural gas wellhead prices and average NYMEX prices for the quarters ended June 30, 2005 and 2004:

| | **Three months ended June 30,** | |
|---|---|---|
| | **2005** | **2004** |
| Oil wellhead ($/Bbl) | $ 47.21 | $ 35.90 |
| Average NYMEX ($/Bbl) | $ 53.17 | $ 38.32 |
| Differential to NYMEX | $ (5.96) | $ (2.42) |
| Oil wellhead to NYMEX percentage | 89% | 94% |
| | | |
| Natural gas wellhead ($/Mcf) | $ 6.57 | $ 5.59 |
| Average NYMEX ($/Mcf) | $ 6.95 | $ 6.07 |
| Differential to NYMEX | $ (0.38) | $ (0.48) |
| Natural gas wellhead to NYMEX percentage | 95% | 92% |

Management uses this wellhead to NYMEX margin analysis to assess trends in our anticipated oil and natural gas revenues. As indicated, our oil differential to the NYMEX price widened from the second quarter of 2004 to the second quarter of 2005 as NYMEX increased at a higher rate than our average wellhead price increased. This oil differential between our wellhead price received and NYMEX has been wider primarily as differentials tend to widen in a period of higher general oil prices. We also have been adversely affected by wider differentials in the market price for our production in two particular areas: the Permian Basin, where much of our production has been tied to a West Texas Sour price, and the Rockies, where much of our production has been tied to a Wyoming Sweet price. Both the West Texas Sour differential and the Wyoming Sweet differential have widened in the second quarter of 2005 versus the second quarter of 2004, and each has therefore contributed to a widening of our overall oil wellhead differential to NYMEX.

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***Expenses.*** The following table summarizes our expenses for the quarters ended June 30, 2005 and 2004:

| | Three months ended June 30, | | *Increase/ (Decrease)* | |
|---|---|---|---|---|
| | **2005** | **2004** | *$* | *%* |
| **Expenses (in thousands):** | | | | |
| Production | | | | |
| Lease operations | $15,721 | $10,921 | *$ 4,800* | |
| Production, ad valorem, and severance taxes | 9,813 | 7,161 | *2,652* | |
| Total production expenses | 25,534 | 18,082 | *7,452* | *41%* |
| Other | | | | |
| Depletion, depreciation, and amortization | 19,038 | 11,249 | *7,789* | |
| Exploration | 3,772 | 1,697 | *2,075* | |
| General and administrative (excluding non-cash stock based compensation) | 3,571 | 2,530 | *1,041* | |
| Non-cash stock based compensation | 1,006 | 307 | *699* | |
| Derivative fair value loss | 1,692 | 965 | *727* | |
| Other operating | 1,703 | 1,091 | *612* | |
| Total operating | 56,316 | 35,921 | *20,395* | *57%* |
| Interest | 7,448 | 6,308 | *1,140* | |
| Current and deferred income tax provision | 12,370 | 10,008 | *2,362* | |
| Total expenses | $76,134 | $52,237 | *$23,897* | *46%* |
| **Expenses (per BOE):** | | | | |
| Production | | | | |
| Lease operations | $ 6.24 | $ 4.91 | *$ 1.33* | |
| Production, ad valorem, and severance taxes | 3.89 | 3.22 | *0.67* | |
| Total production expenses | 10.13 | 8.13 | *2.00* | *25%* |
| Other | | | | |
| Depletion, depreciation, and amortization | 7.55 | 5.06 | *2.49* | |
| Exploration | 1.50 | 0.76 | *0.74* | |
| General and administrative (excluding non-cash stock based compensation) | 1.42 | 1.14 | *0.28* | |
| Non-cash stock based compensation | 0.40 | 0.14 | *0.26* | |
| Derivative fair value loss | 0.67 | 0.43 | *0.24* | |
| Other operating | 0.68 | 0.50 | *0.18* | |
| Total operating | 22.35 | 16.16 | *6.19* | *38%* |
| Interest | 2.96 | 2.84 | *0.12* | |
| Current and deferred income tax provision | 4.91 | 4.50 | *0.41* | |
| Total expenses | $ 30.22 | $ 23.50 | *$ 6.72* | *29%* |

***Production expenses (Lease operations and production, ad valorem, and severance taxes).*** Total production expenses for the second quarter of 2005 increased $7.5 million as compared to the second quarter of 2004. This increase resulted from an increase in total production volumes, as well as a $2.00 increase in production expenses per BOE in the second quarter of 2005 as compared to the second quarter of 2004. The $2.00 increase in production expenses per BOE in the second quarter of 2005 represents a 25% increase over the second quarter of 2004. This increase is in line with the 25% increase in revenues per BOE over the same period, giving rise to a 26% increase in our production margin (revenues less production expenses) per BOE, which increased from $23.41 in the second quarter of 2004 to $29.43 in the second quarter of 2005.

The production expense attributable to lease operations for the second quarter of 2005 increased as compared to the second quarter of 2004 by $4.8 million. The increase in total lease operations expense resulted from an increase in production volumes as a result of our 2005 drilling program, the Overton acquisition, and our high-pressure air injection ( HPAI ) program; and an increase in the per BOE rate. The increase in our average per BOE rate was attributable to increase in prices paid for outside services due to a current higher price environment, increased operational activity to maximize production, and the addition of higher operating cost barrels as lower margin wells are operated in the current higher price environment. LOE expenses are expected to increase because of a continued high-price environment and in the third quarter we expect to begin expensing HPAI costs attributable to Little Beaver Phase 1 that previously have been capitalized during the pressurization phase. We expect additional LOE costs for HPAI to be approximately $0.7 million in the third quarter of 2005.

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The production expense attributable to production, ad valorem, and severance taxes for the second quarter of 2005 increased as compared to the same period in 2004 by approximately $2.7 million due to an increase in total revenues. As a percentage of oil and natural gas revenues (excluding the effects of hedges), production, ad valorem, and severance taxes for the second quarter of 2005 decreased to 8.7% from 9.1% in the second quarter of 2004 as a result of higher production levels in states with lower production, ad valorem, and severance taxes. The effect of hedges is excluded from oil and natural gas revenues in the calculation of these percentages because this method more closely reflects the method used to calculate actual production, ad valorem, and severance taxes paid to taxing authorities.

***Depletion, depreciation, and amortization (  DD&A  ) expense.*** DD&A expense for the second quarter of 2005 increased by $7.8 million as compared to the second quarter of 2004, due to a $2.49 increase in the per BOE rate and an increase in production. This per BOE rate increase was due to the 2004 acquisitions, which had higher acquisition costs than our historical average, as well as higher drilling costs per BOE of reserves than our historical DD&A rate in certain areas.

***Exploration expense.*** Exploration expense was $3.8 million in the second quarter of 2005, while it was $1.7 million in the second quarter of 2004. During the second quarter of 2005, we expensed twelve exploratory dry holes totaling $2.0 million. Out of the twelve exploratory dry holes expensed, one was drilled in the CCA and eleven were drilled in the shallow gas area of Montana. In the second quarter of 2004, we had one dry hole drilled in the Barnett Shale area that was spud by Cortez and acquired in the Cortez acquisition. The following table details our exploration-related expenses for the second quarter of 2005 and 2004 (in thousands):

| | **Three months ended June 30,** | | ***Increase /*** |
|---|---|---|---|
| | **2005** | **2004** | ***(Decrease)*** |
| Exploration expenses: | | | |
| Dry hole | $2,010 | $1,697 | *$ 313* |
| Geological and geophysical | 278 | | *278* |
| Seismic | 965 | | *965* |
| Delay rental | 108 | | *108* |
| Impairment of undeveloped leasehold | 411 | | *411* |
| Total | $3,772 | $1,697 | *$2,075* |

***General and administrative (  G&A  ) expense.*** G&A expense (excluding non-cash stock based compensation) increased $1.0 million for the second quarter of 2005 as compared to the second quarter of 2004. The overall increase, as well as the $0.28 increase in the per BOE rate, is a result of increased staffing to manage our larger asset base, higher rent expense for our corporate office, and higher directors  and officers  insurance costs. Additionally, we have experienced increased competition for human resources from other companies within the industry that has increased the cost to hire and retain experienced industry personnel.

***Non-cash stock based compensation expense.*** Non-cash stock based compensation expense for the second quarter of 2005 increased $0.7 million as compared to the same period in 2004. This expense represents the amortization of deferred compensation recorded in equity related to restricted stock granted under the 2000 Incentive Stock Plan. Both deferred compensation and related amortization increased from second quarter 2004 to second quarter 2005 as the Company s stock price per share increased and the number of shares granted in the second quarter of 2005 increased as compared to the second quarter of 2004.

***Derivative fair value loss.*** During the second quarter of 2005 we recorded a $1.7 million derivative fair value loss as compared to the $1.0 million loss recorded in the second quarter of 2004. This derivative fair value loss represents the ineffective portion of the mark-to-market loss on our derivative hedging instruments, settlements received on our fixed-to-floating interest rate swap, (gains) losses related to commodity derivatives not designated as hedges, and changes in the mark-to-market value of our fixed  to-floating interest rate swap.

The components of the derivative fair value (gain) loss reported in the second quarter of 2005 and 2004 are as follows (in thousands):

| | Three months ended June 30, 2005 | Three months ended June 30, 2004 | *Increase / (Decrease)* |
|---|---|---|---|
| Designated cash flow hedges: | | | |
| Ineffectiveness Commodity contracts | $1,942 | $ 181 | *$ 1,761* |
| Undesignated derivative contracts: | | | |
| Mark-to-market (gain) loss Interest rate swap | (31) | 1,130 | *(1,161)* |
| Mark-to-market (gain) loss Commodity contracts | (219) | (346) | *127* |
| Derivative fair value loss | $1,692 | $ 965 | *$ 727* |

Ineffectiveness loss related to our derivative commodity contracts increased $1.8 million due primarily to an increase in oil wellhead differentials on our production in the CCA.

***Other operating expense.*** Other operating expense for the second quarter of 2005 increased by $0.6 million when compared to the same period in 2004. This increase is mainly due to an increase in third party natural gas transportation costs attributable to higher production volumes for the second quarter of 2005 over the same period in 2004.

***Interest expense.*** Interest expense increased $1.1 million in the quarter ended June 30, 2005 from the quarter ended June 30, 2004. This increase is due primarily to an increase in debt outstanding under our credit facility, offset slightly by a decrease in our weighted average interest rate from period to period. We incurred additional debt in the second quarter of 2004 to fund the Cortez and Overton acquisitions and to fund the Company s development, exploitation, and exploration capital programs. The weighted average interest rate, net of hedges, for the quarter ended June 30, 2005 was 7.0% compared to 7.9% for the quarter ended June 30, 2004. This lower weighted average interest rate is the result of the issuance of $150 million aggregate principal amount of $6^1/4$% senior subordinated notes in April 2004. The following table illustrates the components of interest expense for the three months ended June 30, 2005 and 2004 (in thousands):

| | Three months ended June 30, 2005 | Three months ended June 30, 2004 | *Increase / (Decrease)* |
|---|---|---|---|
| $8^3/_8$% notes due 2012 (2) | $3,141 | $3,141 | *$* |
| $6^1/4$% notes due 2014 | 2,344 | 2,318 | *26* |
| Revolving credit facility | 1,367 | 230 | *1,137* |
| Interest rate hedges (1) | (72) | 153 | *(225)* |
| Debt issuance cost | 277 | 262 | *15* |
| Banking fees and other | 391 | 204 | *187* |
| Total | $7,448 | $6,308 | *$1,140* |

(1) Amount represents non-cash amortization of the deferred (gain) loss on

interest rate swaps from other comprehensive income to interest expense. This deferred (gain) loss relates to previously outstanding interest rate swaps. We have since cash settled these interest rate swaps and the swaps are no longer outstanding.

(2) On July 13, 2005 we issued \$300 million of 6% senior subordinated notes and issued a redemption notice on our $8^{3}/_{8}$% notes. Giving effect to the issuance of the 6% notes and the use of proceeds therefrom, we expect a decrease in our future weighted average interest rate.

***Income taxes.*** Income tax expense for the second quarter of 2005 increased \$2.4 million over the same period in 2004. This increase is due primarily to the \$8.0 million increase in income before income taxes from the second quarter of 2004 to the second quarter of 2005, offset by a decrease in our effective tax rate from 35.7% for the second quarter in 2004 to 34.3% in the second quarter of 2005.

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**Comparison of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2004**

Set forth below is our comparison of operations during the first six months of 2005 with the first six months of 2004.

***Revenues and Production.*** The following table illustrates the primary components of oil and natural gas revenues for the six months ended June 30, 2005 and 2004, as well as each period s respective oil and natural gas volumes (in thousands, except per unit amounts and per day amounts):

| | Six months ended June 30, 2005 | Six months ended June 30, 2004 | *Increase / (Decrease)* *$* | *%* |
|---|---|---|---|---|
| **Revenues:** | | | | |
| Oil wellhead | $156,898 | $113,017 | *$43,881* | |
| Oil hedges | (20,203) | (13,368) | *(6,835)* | |
| Total Oil Revenues | $136,695 | $ 99,649 | *$37,046* | *37%* |
| Natural gas wellhead | $ 58,124 | $ 30,870 | *$27,254* | |
| Natural gas hedges | (3,521) | (1,106) | *(2,415)* | |
| Total Natural Gas Revenues | $ 54,603 | $ 29,764 | *$24,839* | *83%* |
| Combined wellhead | $215,022 | $143,887 | *$71,135* | |
| Combined hedges | (23,724) | (14,474) | *(9,250)* | |
| Total Combined Revenues | $191,298 | $129,413 | *$61,885* | *48%* |
| **Revenues ($/Unit):** | | | | |
| Oil wellhead | $ 46.11 | $ 34.25 | *$ 11.86* | |
| Oil hedges | (5.94) | (4.05) | *(1.89)* | |
| Total Oil Revenues | $ 40.17 | $ 30.20 | *$ 9.97* | *33%* |
| Natural gas wellhead | $ 6.20 | $ 5.38 | *$ 0.82* | |
| Natural gas hedges | (0.38) | (0.19) | *(0.19)* | |
| Total Natural Gas Revenues | $ 5.82 | $ 5.19 | *$ 0.63* | *12%* |
| Combined wellhead | $ 43.30 | $ 33.82 | *$ 9.48* | |
| Combined hedges | (4.78) | (3.40) | *(1.38)* | |
| Total Combined Revenues | $ 38.52 | $ 30.42 | *$ 8.10* | *27%* |

| | **Six months ended June 30,** | *Increase /* |
|---|---|---|

| | 2005 | 2004 | *(Decrease)* |
|---|---|---|---|
| **Total production volumes:** | | | |
| Oil (Bbls) | 3,403 | 3,299 | *104* |
| Natural gas (Mcf) | 9,384 | 5,733 | *3,651* |
| Combined (BOE) | 4,967 | 4,255 | *712* |
| | | | |
| **Daily production volumes:** | | | |
| Oil (Bbls/day) | 18,799 | 18,128 | *671* |
| Natural gas (Mcf/day) | 51,847 | 31,501 | *20,346* |
| Combined (BOE/day) | 27,440 | 23,378 | *4,062* |
| | | | |
| **NYMEX Prices:** | | | |
| Oil (per Bbl) | $ 51.51 | $ 36.73 | *$ 14.78* |
| Natural gas (per Mcf) | 6.71 | 5.90 | *0.81* |

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Oil revenues increased from the first six months of 2004 to the first six months of 2005 by $37.0 million, due primarily to a higher realized average oil price. Our realized average oil price increased $9.97 per Bbl in the six months ended June 30, 2005 over the same period in 2004 as a result of an increase in our average wellhead price of $11.86 per Bbl, offset by an increase in hedging payments of $1.89 per Bbl. The increase in our average wellhead price and hedging payments resulted from the increase in the overall market price for oil as reflected in the $14.78 per Bbl increase in the average NYMEX price over the same period.

Natural gas revenues increased by $24.8 million, or $0.63 per Mcf, in the first six months of 2005 from the first six months of 2004 due to an increase in volumes and an increase in our realized average natural gas price. Production volumes increased 3,651 MMcf in the six months ended June 30, 2005 as compared to the same period in 2004 due to our drilling activities and the 2004 acquisitions. The $0.63 per Mcf increase in our realized average natural gas price was due to the $0.82 per Mcf increase in the wellhead price for our natural gas from the first six months of 2004 to the same period in 2005. The NYMEX price for natural gas increased by $0.81 per Mcf over the same period.

The table below illustrates the relationship between oil and natural gas wellhead prices and average NYMEX prices for the six months ended June 30, 2005 and 2004:

| | **Six months ended June 30,** | |
|---|---|---|
| | **2005** | **2004** |
| Oil wellhead ($/Bbl) | $46.11 | $34.25 |
| Average NYMEX ($/Bbl) | $51.51 | $36.73 |
| Differential to NYMEX | $ (5.40) | $ (2.48) |
| Oil wellhead to NYMEX percentage | 90% | 93% |
| | | |
| Natural gas wellhead ($/Mcf) | $ 6.20 | $ 5.38 |
| Average NYMEX ($/Mcf) | $ 6.71 | $ 5.90 |
| Differential to NYMEX | $ (0.51) | $ (0.52) |
| Natural gas wellhead to NYMEX percentage | 92% | 91% |

Management uses this wellhead to NYMEX margin analysis to assess trends in our anticipated oil and natural gas revenues. As indicated, our oil differential to the NYMEX price widened from the first half of 2004 to the first half of 2005 as NYMEX increased at a higher rate than our average wellhead price increased. This oil differential between our wellhead price received and NYMEX has been wider primarily as differentials tend to widen in a period of higher general oil prices. We also have been adversely affected by wider differentials in the market price for our production in two particular areas: the Permian Basin, where much of our production has been tied to a West Texas Sour price, and the Rockies, where much of our production has been tied to a Wyoming Sweet price. Both the West Texas Sour differential and the Wyoming Sweet differential have widened in the first half of 2005 versus the same period in 2004, and each has therefore contributed to a widening of our overall oil wellhead differential to NYMEX.

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***Expenses.*** The following table summarizes our expenses for the six months ended June 30, 2005 and 2004:

| | Six months ended June 30, 2005 | 2004 | *Increase / (Decrease* *$* | *%* |
|---|---|---|---|---|
| **Expenses (in thousands):** | | | | |
| Production | | | | |
| Lease operations | $ 30,589 | $21,163 | *$ 9,426* | |
| Production, ad valorem, and severance taxes | 18,899 | 13,000 | *5,899* | |
| Total production expenses | 49,488 | 34,163 | *15,325* | 45% |
| Other | | | | |
| Depletion, depreciation, and amortization | 35,721 | 20,512 | *15,209* | |
| Exploration | 6,383 | 1,697 | *4,686* | |
| General and administrative (excluding non-cash stock based compensation) | 7,206 | 4,758 | *2,448* | |
| Non-cash stock based compensation | 1,779 | 617 | *1,162* | |
| Derivative fair value loss | 4,101 | 1,123 | *2,978* | |
| Other operating | 3,302 | 2,093 | *1,209* | |
| Total operating | 107,980 | 64,963 | *43,017* | 66% |
| Interest | 14,407 | 10,214 | *4,193* | |
| Current and deferred income tax provision | 23,608 | 19,500 | *4,108* | |
| Total expenses | $145,995 | $94,677 | *$51,318* | 54% |
| **Expenses (per BOE):** | | | | |
| Production | | | | |
| Lease operations | $ 6.16 | $ 4.97 | *$ 1.19* | |
| Production, ad valorem, and severance taxes | 3.81 | 3.06 | *0.75* | |
| Total production expenses | 9.97 | 8.03 | *1.94* | 24% |
| Other | | | | |
| Depletion, depreciation, and amortization | 7.19 | 4.82 | *2.37* | |
| Exploration | 1.29 | 0.40 | *0.89* | |
| General and administrative (excluding non-cash stock based compensation) | 1.45 | 1.12 | *0.33* | |
| Non-cash stock based compensation | 0.36 | 0.15 | *0.21* | |
| Derivative fair value loss | 0.83 | 0.26 | *0.57* | |
| Other operating | 0.66 | 0.49 | *0.17* | |
| Total operating | 21.75 | 15.27 | *6.48* | 42% |
| Interest | 2.90 | 2.40 | *0.50* | |
| Current and deferred income tax provision | 4.75 | 4.58 | *0.17* | |
| Total expenses | $ 29.40 | $ 22.25 | *$ 7.15* | 32% |

***Production expenses (Lease operations and production, ad valorem, and severance taxes).*** Production expenses for the first half of 2005 increased $15.3 million as compared to the same period in 2004. This increase resulted from an increase in total production volumes, as well as a $1.94 increase in production expenses per BOE in the second quarter of 2005 as compared to the second quarter of 2004. The $1.94 increase in production expenses per BOE in the six months ended June 30, 2005 represents a 24% increase over the six months ended June 30, 2004. This increase is in line with the 27% increase in revenues per BOE over the same period, giving rise to a 28% increase in our production margin (revenues less production expenses) per BOE, which increased from $22.39 in the six months ended June 30, 2004 to $28.55 in the six months ended June 30, 2005.

The production expense attributable to lease operations for the first six months of 2005 increased as compared to the same period in 2004 by $9.4 million. The increase in total lease operations expense resulted from an increase in production volumes as a result of our 2005 drilling program, the 2004 acquisitions, and our high-pressure air injection program. The increase in our average per BOE rate was attributable to increase in prices paid for outside services due to a current higher price environment, increased operational activity to maximize production, and the addition of higher operating cost barrels as lower margin wells are operated in the current higher price environment.

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The production expense attributable to production, ad valorem, and severance taxes for the six months ended June 30, 2005 increased as compared to the same period in 2004 by approximately $5.9 million due to an increase in total revenues. As a percentage of oil and natural gas revenues (excluding the effects of hedges), production, ad valorem, and severance taxes for the first six months of 2005 decreased slightly from 9.0% in the first half of 2004 to 8.8% in the first six months of 2005. The effect of hedges is excluded from oil and natural gas revenues in the calculation of these percentages because this method more closely reflects the method used to calculate actual production, ad valorem, and severance taxes paid to taxing authorities.

***Depletion, depreciation, and amortization (  DD&A  ) expense.*** DD&A expense for the first six months of 2005 increased by $15.2 million as compared to the same period in 2004, due to a $2.37 increase in the per BOE rate and an increase in production. This per BOE rate increase was due to the 2004 acquisitions, which had higher acquisition costs than our historical average, as well as higher drilling costs per BOE of reserves than our historical DD&A rate in certain areas.

***Exploration expense.*** Exploration expense increased $4.7 million in the six months ended June 30, 2005 as compared to the same period in 2004. During the first six months of 2005, we expensed seventeen exploratory dry holes totaling $3.3 million. Of the seventeen exploratory dry holes expensed, one was drilled in Crockett County, Texas, fifteen were drilled in the shallow gas area of Montana, and one was drilled in the CCA. In the first half of 2004, we had one dry hole drilled in the Barnett Shale area that was spud by Cortez and acquired in the Cortez acquisition. The following table details our exploration-related expenses (in thousands):

| | **Six months ended June 30,** | | ***Increase /*** |
|---|---|---|---|
| | **2005** | **2004** | ***(Decrease)*** |
| Exploration expenses: | | | |
| Dry hole | $3,329 | $1,697 | *$1,632* |
| Geological and geophysical | 630 | | *630* |
| Seismic | 1,091 | | *1,091* |
| Delay rental | 375 | | *375* |
| Impairment of undeveloped leasehold | 958 | | *958* |
| Total | $6,383 | $1,697 | *$4,686* |

***General and administrative (  G&A  ) expense.*** G&A expense (excluding non-cash stock based compensation) increased $2.4 million for the first six months of 2005 as compared to the same period in 2004. The overall increase, as well as the $0.33 increase in the per BOE rate, is a result of increased staffing to manage our larger asset base, higher rent expense for our corporate office, and higher directors  and officers  insurance costs. Additionally, we have experienced increased competition for human resources from other companies within the industry that has increased the cost to hire and retain experienced industry personnel.

***Non-cash stock based compensation expense.*** Non-cash stock based compensation expense for the six months ended June 30, 2005 increased $1.2 million as compared to the same period in 2004. This expense represents the amortization of deferred compensation recorded in equity related to restricted stock granted under the 2000 Incentive Stock Plan. Both deferred compensation and related amortization increased from the six months ended June 30, 2004 to the same period in 2005 as the Company s stock price per share increased and the number of shares granted from the first half of 2004 to the second half of 2005 increased.

***Derivative fair value loss.*** During the six months ended June 30, 2005 we recorded a $4.1 million derivative fair value loss as compared to the $1.1 million loss recorded in the same period in 2004. This derivative fair value loss represents the ineffective portion of the mark-to-market loss on our derivative hedging instruments, settlements received on our fixed-to-floating interest rate swap, (gains) losses related to commodity derivatives not designated as hedges, and changes in the mark-to-market value of our fixed-to-floating interest rate swap. The components of the derivative fair value (gain) loss reported in the six months ended June 30, 2005 and 2004 are as follows (in thousands):

| | | **Six months ended June 30,** | | ***Increase /*** |
|---|---|---|---|---|
| | | **2005** | **2004** | ***(Decrease)*** |
| Designated cash flow hedges: | | | | |
| Ineffectiveness | Commodity contracts | $4,667 | $ 455 | *$4,212* |
| Undesignated derivative contracts: | | | | |
| Mark-to-market (gain) loss | Interest rate swap | 150 | 420 | *(270)* |
| Mark-to-market (gain) loss | Commodity contracts | (716) | 248 | *(964)* |
| Derivative fair value loss | | $4,101 | $1,123 | *$2,978* |

Ineffectiveness loss related to our derivative commodity contracts increased $4.2 million due primarily to an increase in oil
wellhead differentials on our production in the CCA.

***Other operating expense.*** Other operating expense for the first six months of 2005 increased by $1.2 million when compared to the same period in 2004. This increase is mainly due to an increase in third party natural gas transportation costs attributable to higher production volumes for the first half of 2005 over the same period in 2004.

***Interest expense.*** Interest expense increased $4.2 million in the six months ended June 30, 2005 from the six months ended June 30, 2004. This increase is due primarily to an increase in debt outstanding under our credit facility and the new $6^1/4$% notes, offset slightly by a decrease in our weighted average interest rate from period to period. We incurred additional debt in the second quarter of 2004 to fund the Cortez and Overton acquisitions. The weighted average interest rate, net of hedges, for the six months ended June 30, 2005 was 7.0% compared to 8.1% for the six months ended June 30, 2004. This lower weighted average interest rate is the result of the issuance of $150 million aggregate principal amount of $6^1/4$% senior subordinated notes in April 2004.

The following table illustrates the components of interest expense for the six months ended June 30, 2005 and 2004 (in thousands):

| | **Six months ended June 30,** | | ***Increase/*** |
|---|---|---|---|
| | **2005** | **2004** | ***(Decrease)*** |
| $8^3/_8$% notes due 2012 (2) | $ 6,281 | $ 6,281 | *$* |
| $6^1/4$% notes due 2014 | 4,688 | 2,318 | *2,370* |
| Revolving credit facility | 2,297 | 442 | *1,855* |
| Interest rate hedges (1) | (32) | 365 | *(397)* |
| Debt issuance cost | 527 | 457 | *70* |
| Banking fees and other | 646 | 351 | *295* |
| Total | $14,407 | $10,214 | *$4,193* |

(1) Amount represents non-cash

amortization of the deferred (gain) loss on interest rate swaps from other comprehensive income to interest expense. This deferred (gain) loss relates to previously outstanding interest rate swaps. We have since cash settled these interest rate swaps and the swaps are no longer outstanding.

(2) On July 13, 2005 we issued \$300 million of 6% senior subordinated notes and issued a redemption notice on our $8^{3}/_{8}$% notes. Giving effect to the issuance of the 6% notes and the use of proceeds therefrom, we expect a decrease in our future weighted average interest rate.

***Income taxes.*** Income tax expense for the first six months of 2005 increased \$4.1 million over the same period in 2004. This increase is due primarily to the \$14.7 million increase in income before income taxes from the six months ended June 30, 2004 to the six months ended June 30, 2005, offset by a decrease in our effective tax rate from 35.9% for the first six months of 2004 to 34.2% in the first six months of 2005.

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

**Capital Resources and Capital Commitments**

Our primary capital resources are net cash provided by operating activities and proceeds from financing activities. Our primary needs for cash are as follows:

Development, exploitation, and exploration of our existing oil and natural gas properties

High-pressure air injection programs on our CCA properties

Acquisitions of oil and natural gas properties

Leasehold and acreage costs

Other general property and equipment

Funding of necessary working capital

Payment of contractual obligations

***Development, Exploitation, and Exploration.*** The following table summarizes our costs incurred (excluding asset retirement obligations) related to development, exploitation, and exploration activities during the three and six months ended June 30, 2005 and 2004 (in thousands):

| | **Three months ended June 30,** | | ***Increase/*** | **Six months ended June 30,** | | ***Increase/*** |
|---|---|---|---|---|---|---|
| | **2005** | **2004** | ***(Decrease)*** | **2005** | **2004** | ***(Decrease)*** |
| **Development, Exploitation, and Exploration Expenditures:** | | | | | | |
| Development and exploitation | $57,979 | $27,889 | *$30,090* | $100,884 | $48,155 | *$52,729* |
| Exploration | 13,706 | 4,481 | *9,225* | 28,403 | 5,676 | *22,727* |
| HPAI | 9,299 | 9,261 | *38* | 17,241 | 16,913 | *328* |
| Total | $80,984 | $41,631 | *$39,353* | $146,528 | $70,744 | *$75,784* |

*Development, Exploitation, and Exploration*. Our expenditures for conventional development and exploitation investments primarily relate to drilling development and infill wells, workovers of existing wells, and field related facilities (excluding development-related asset retirement obligations).

Our development and exploitation capital for the three months ended June 30, 2005 included a total of 76 gross (39.4 net) successful wells. We also drilled 3 gross (2.1 net) development dry holes during the second quarter of 2005.

Our development drilling capital for the first half of 2005 included 132 gross (80.7 net) successful development wells, and 3 gross (2.9 net) developmental dry holes. We currently have 11 operated rigs drilling on the onshore continental United States with 5 rigs in Montana, 3 rigs in East Texas, 2 rigs in West Texas, and 1 rig running in Oklahoma.

Our expenditures for exploration investments primarily relate to drilling exploratory wells, seismic, delay rentals, and geological and geophysical costs. During the three months ended June 30, 2005, our exploration capital included 19 (14.2 net) exploratory wells which are productive and 12 gross (10.0 net) exploratory dry holes.

During the six months ended June 30, 2005, our exploration capital yielded 24 (17.1 net) exploratory wells which are productive and 17 gross (14.8 net) exploratory dry holes.

The total exploratory drilling capital incurred was $12.3 million and $26.3 million for the three and six months ended June 30, 2005, respectively, excluding $1.4 million and $2.1 million in seismic, delay rentals, and geological and geophysical costs.

For the remainder of 2005, we expect to invest $147.2 million in development, exploitation, and exploration activities. We have based our 2005 forecasts on the assumptions of $36.00 per Bbl and $6.00 per Mcf NYMEX prices. If NYMEX prices trend downward below our base prices, we may reevaluate capital projects and may adjust the capital budgeted for development and exploitation investments accordingly.

*High-Pressure Air Injection.* High-pressure air injection in the Little Beaver unit of the CCA was initiated in late 2003, and full implementation of the project was completed in the fourth quarter of 2004. We continue to see positive production response in line with expectations. Total production in the Little Beaver HPAI project area has stabilized, and is projected to increase from current levels in the future.

In the Pennel and Coral Creek area of the CCA, where we have been operating a successful HPAI appraisal project (Phase 1) for nearly three years, we have continued to expand the Phase 2 portion of the HPAI project. We have been injecting air in the Phase 2 project area since April 2005, and expect full implementation of the Phase 2 HPAI project to be completed by year-end 2005. We estimate that production will respond on a timetable similar to the Little Beaver project, with positive production indications initially expected by late 2006.

For the remainder of 2005, we expect to invest $10.8 million for high-pressure air injection capital, primarily related to our Pennel program.

***Acquisitions, Leasehold and Acreage Costs.*** The following table summarizes our costs incurred (excluding asset retirement obligations) for oil and natural gas proved property acquisitions during the three and six months ended June 30, 2005 and 2004 (in thousands):

| | **Three months ended June 30,** | | *Increase/* | **Six months ended June 30,** | | *Increase/* |
|---|---|---|---|---|---|---|
| | **2005** | **2004** | *(Decrease)* | **2005** | **2004** | *(Decrease)* |
| **Acquisitions, Leasehold and Acreage Costs:** | | | | | | |
| Acquisitions | $4,986 | $211,433 | *$(206,447)* | $10,657 | $211,596 | *$(200,939)* |
| Leasehold and acreage costs | 3,039 | 8,457 | *(5,418)* | 6,722 | 9,557 | *(2,835)* |
| Total | $8,025 | $219,890 | *$(211,865)* | $17,379 | $221,153 | *$(203,774)* |

*Acquisitions.* Our capital expenditures for proved oil and natural gas properties during the three months ended June 30, 2005 totaled $5.0 million as compared to $211.4 million in the same period in 2004. The $5.0 million of the acquisition capital in the second quarter of 2005 was invested primarily in additional working interests in our Mid-Continent region, while the $211.4 million in the second quarter of 2004 was invested in our Cortez and Overton acquisitions. We do not budget for acquisitions but we will continue to evaluate acquisition opportunities as they arise in 2005 with the same disciplined commitment to acquire assets that fit our portfolio and create value. We will continue to pursue acquisitions of properties with similar upside potential to our current producing properties portfolio.

*Leasehold and Acreage Costs*. For the remainder of 2005, we expect to invest an additional $2.3 million for leasehold and acreage costs.

***Other General Property and Equipment.*** Our capital expenditures for other general property and equipment during the three months ended June 30, 2005 and 2004 totaled $2.0 million and $5.7 million, respectively. The decrease was due primarily due to higher levels of field equipment purchased in the second quarter of 2004 in anticipation of our expected increased development activities. The $2.0 million incurred for the second quarter of 2005 primarily relate to leasehold improvements.

Our capital expenditures for other general property and equipment during the six months ended June 30, 2005 and 2004 totaled $4.7 million and $6.6 million, respectively. The decrease was due primarily due to higher levels of field equipment purchased in the second quarter of 2004 in anticipation of our expected increased development activities. The $4.7 million incurred for the first half of 2005 primarily relate to leasehold improvements and field equipment purchased.

***Working Capital.*** At June 30, 2005, our working capital was $(23.6) million while at December 31, 2004, our working capital was $(15.6) million, a decrease of $8.0 million. The decrease is primarily attributable to changes in the fair value of outstanding derivative contracts, net of the deferred tax effect of marking these contracts to market.

For 2005, we expect working capital to remain negative. Negative working capital is expected mainly due to fair values of our derivative contracts, which hedge settlements will be offset by cash flows from hedged production. We anticipate cash reserves to be close to zero as we use any cash to fund capital obligations, with any excess cash being used to pay down our existing credit facility. We do not plan to pay cash dividends in the foreseeable future. The overall 2005 commodity prices for oil and natural gas will be the largest variable driving the different components of working capital. Our operating cash flow is determined in a large part by commodity prices. Assuming moderate to high commodity prices, our operating cash flow should remain positive for the foreseeable future. For the full year 2005, Encore s Board of Directors has approved an increase in development and exploration and other capital to $315.0 million, reflecting an increase in activity levels and the current industry cost environment. The level of these and other future expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly, depending on available opportunities, timing of projects, and

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market conditions. We plan to finance our ongoing expenditures using internally generated cash flow, cash on hand, and our existing credit agreement.

***Contractual Obligations.*** The following table illustrates our contractual obligations and commercial commitments outstanding at June 30, 2005 (in thousands):

| Contractual Obligations | | Payments Due by Period | | | |
|---|---|---|---|---|---|
| **and Capital Commitments** | **Total** | **2005** | **2006 2007** | **2008 2009** | **Thereafter** |
| $8^3/_8$% notes (a,b) | $237,937 | $ 6,281 | $ 25,125 | $ 25,125 | $181,406 |
| $6^1/4$% notes (a) | 234,375 | 4,687 | 18,750 | 18,750 | 192,188 |
| Revolving credit facility (a,b) | 164,604 | 3,000 | 11,903 | 149,701 | |
| Derivative obligations (c) | 104,119 | 24,317 | 79,802 | | |
| Operating leases (d) | 11,908 | 676 | 2,932 | 2,902 | 5,398 |
| Asset retirement obligations (e) | 77,500 | 542 | 1,084 | 1,084 | 74,790 |
| Totals | $830,443 | $39,503 | $139,596 | $197,562 | $453,782 |

(a) Amounts included in the table above include both principal and projected interest payments.

(b) On July 13, 2005 we issued $300 million of 6% senior subordinated notes and issued a redemption notice on our $8^3/_8$% notes. Giving effect to the issuance of the 6% notes and the use of proceeds therefrom, our pro-forma contractual obligations and commitments by period is as follows (in thousands):

| **Contractual Obligations and Capital Commitments** | **Total** | **Payments Due by Period 2005** | **2006 2007** | **2008 2009** | **Thereafter** |
|---|---|---|---|---|---|
| 6% notes | $480,000 | $ | $ 36,000 | $36,000 | $408,000 |
| $6^{1}/4$% notes | 234,375 | 4,687 | 18,750 | 18,750 | 192,188 |
| Revolving credit facility | 17,998 | 324 | 1,284 | 16,390 | |
| Derivative obligations | 104,119 | 24,317 | 79,802 | | |
| Operating leases | 11,908 | 676 | 2,932 | 2,902 | 5,398 |
| Asset retirement obligations | 77,500 | 542 | 1,084 | 1,084 | 74,790 |
| Totals | $925,900 | $30,546 | $139,852 | $75,126 | $680,376 |

(c) Derivative obligations represent liabilities for derivatives that were valued as of June 30, 2005. The ultimate settlement amounts of the remaining portions of our derivative obligations are unknown because they are subject to continuing market risk.

(d) Operating leases represent office space and equipment obligations that have remaining non-cancelable lease terms in excess of one year.

(e) Asset retirement obligations represent the undiscounted future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal at the completion of field life.

*Other Contingencies and Commitments.* In order to facilitate ongoing sales of our oil production in the CCA, we ship a portion of our production on pipelines downstream and sell to purchasers at major U.S. market hubs. From time to time, shipping delays or purchaser stipulations may require that we sell our oil production in periods subsequent to the period in which it is produced. In such case, the deferred sale would have an adverse effect in the prior period on reported production volumes, revenues, and costs as measured on a unit-of-production basis.

The sale of our CCA oil production is dependent on transportation through Butte Pipeline to markets in Guernsey, Wyoming. To a lesser extent, our production also depends on transportation through Platte Pipeline to Wood River, Illinois. Any restrictions on the available capacity for us to transport oil through these pipelines could have a material adverse effect on price received, production volumes, and revenues.

**Capital Resources**

Our primary capital resource is net cash provided by operating activities and proceeds from financing activities, which are used to fund our capital commitments. Our primary needs for cash include development, exploitation, and exploration of our existing oil and natural gas properties, including our high-pressure air injection program in the CCA; acquisitions of oil and natural gas properties; acquisition of leasehold and acreage interest; funding of necessary working capital; and payment of contractual obligations.

***Operating Activities*.** For the first six months of 2005, cash provided by operating activities increased by $43.0 million as compared to the same period in 2004. This increase resulted mainly from increases in revenues due to increased volumes and increased commodity prices. Our production volumes increased 712 MBOE from 4,255 MBOE in the first half of 2004 to 4,967 MBOE in the first half of 2005, our oil prices received increased $9.97 per Bbl from $30.20 per Bbl in the first six months of

2004 to $40.17 in the same period in 2005, our realized natural gas prices increased $0.63 per Mcf from $5.19 in the six months ended June 30, 2004 to $5.82 in the six months ended June 30, 2005, increasing our cash flows from operations $43.0 million from $74.5 million in the first half of 2004 to $117.5 million in the first half of 2005.

***Financing Activities.*** For the first six months of 2005, we increased the level of debt outstanding under our revolving credit facility at the beginning of the period by $61 million, while in the first six months of 2004 we increased our debt outstanding by $24 million and issued our $150 million $6^{1}/4$% notes to finance our Cortez and Overton acquisitions.

*Issuance of 6% Senior Subordinated Notes Due 2015.* On June 30, 2005, we priced the sale of $300.0 million of 6% senior subordinated notes due July 15, 2015 (the 6% notes ). We issued and sold the notes on July 13, 2005. The offering was made through a private placement pursuant to Rule 144A and Regulation S. We estimate net proceeds of approximately $293.5 million after paying all costs associated with the offering. The net proceeds are expected to be used to redeem all $150.0 million of our outstanding $8^{3}/_{8}$% senior subordinated notes due 2012 at an estimated cost of $168.6 million, and to reduce outstanding indebtedness under our existing revolving credit facility. Concurrently with the issuance of the 6% notes, we entered into a registration rights agreement whereby Encore agreed to file a registration statement, offering to exchange the 6% notes for publicly registered notes with substantially identical terms.

The 6% notes mature on July 15, 2015, and all amounts then outstanding will be due and payable at that time. Interest is paid semi-annually on July 15 and January 15. The indenture governing the 6% notes contains substantially the same covenants and restrictions as our outstanding $6^{1}/4$% senior subordinated notes due 2014.

*Redemption of $8^{3}/_{8}$% Senior Subordinated Notes Due 2012.* On July 13, 2005, we issued a notice of redemption (the Redemption Notice ) pursuant to the provisions of the Indenture, dated as of June 25, 2002, among the Company, certain subsidiaries of the Company and Wells Fargo Bank, National Association, as Trustee (the Trustee ), pursuant to which the $8^{3}/_{8}$% senior subordinated notes due 2012 (the $8^{3}/_{8}$% notes ) were issued. In the Redemption Notice, we indicated that we were exercising our right to redeem on August 15, 2005 (the Redemption Date ) all $150 million aggregate principal amount of $8^{3}/_{8}$% notes currently outstanding. We expect the redemption price to approximate $168.6 million, including a make-whole premium and accrued interest through the redemption date. The exact redemption price will be determined in part using the latest Treasury yields at the redemption date and, thus, it will not be known until that time. However, we do not expect the estimate to change materially.

Combined with the unamortized balance of debt issuance costs of the $8^{3}/_{8}$% notes, we estimate a pre-tax charge to earnings from the redemption to be recorded in the third quarter of 2005 of $21.8 million at June 30, 2005.

***Capitalization.*** At June 30, 2005, Encore had total assets of $1.3 billion. Total capitalization was $932.0 million, of which 53% was represented by stockholders equity and 47% by long-term debt. At December 31, 2004, we had total assets of $1.1 billion. Total capitalization was $852.6 million, of which 56% was represented by stockholders equity and 44% by senior debt.

On July 13, 2005, we issued $300 million of 6% senior subordinated notes and issued a redemption notice on our $8^{3}/_{8}$% notes. Giving effect to the issuance of the 6% notes and the use of proceeds therefrom, our pro-forma total capitalization at June 30, 2005 would have been $938.0 million, of which 51% would have been represented by stockholders equity and 49% by long-term debt.

**Liquidity**

***Revolving Credit Facility.*** Our principal source of short-term liquidity is our revolving credit facility. We amended and restated our revolving credit facility on August 19, 2004. Borrowings under the facility are secured by a first priority lien on our proved oil and natural gas reserves. Availability under the facility is determined through semi-annual borrowing base determinations and may be increased or decreased. The initial borrowing base was $400 million and may be increased to up to $750 million. On June 30, 2005, we had $140 million outstanding under the credit facility. The amended and restated credit facility matures on August 19, 2009.

On April 29, 2005, we amended our existing credit facility to increase the borrowing base from $400 million to $500 million. Other changes to the facility include a change in the definition of EBITDA to add back exploration expense (EBITDAX), and an increase in the availability of letters of credit from 15% of the borrowing base to 20%. After the issuance of our $300.0 million

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6% senior subordinated notes due July 15, 2015 (see above), the borrowing base was reduced according to the terms of the credit facility to $450 million from $500 million.

***Letters of Credit.*** As of July 29, 2005, we had $56.0 million in letters of credit posted with two of our commodity derivative contract counterparties. At any point in time, we have hedge margin deposits and letters of credit equal to the amount by which the current mark-to-market liability of our commodity derivative contracts exceeds the margin maintenance thresholds we have negotiated with our counterparties. Once a margin threshold is reached, we are required to maintain cash reserves in an account with the counterparty or post letters of credit in lieu of cash to ensure future settlement is made pursuant to our contracts. These funds are released back to us as our mark-to-market liability decreases due to either a drop in the futures price of oil and natural gas or due to the passage of time as settlements are made.

***Description of Critical Accounting Estimates***

Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Description of Critical Accounting Estimates in Encore s 2004 Annual Report on Form 10-K for more information. There have been no material changes to our critical accounting estimates since December 31, 2004.

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

The information included in Quantitative and Qualitative Disclosures about Market Risk in Encore s 2004 Annual Report on Form 10-K is incorporated herein by reference. Such information includes a description of Encore s potential exposure to market risks, including commodity price risk and interest rate risk. The Company s outstanding derivative contracts as of June 30, 2005 are discussed in Note 5 to the accompanying consolidated financial statements. As of June 30, 2005, the fair value of our open commodity derivative contracts was a liability of $103.2 million.

**Item 4. Controls and Procedures**

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2005 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms.

There has been no change in our internal controls over financial reporting that occurred during the three months ended June 30, 2005 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

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## PART II. OTHER INFORMATION

### Item 4. Submission of Matters to a Vote of Security Holders

The Company s annual meeting of stockholders was held Tuesday, May 3, 2005. The items submitted to stockholders for vote were the election of seven nominees to serve on the Company s Board of Directors during 2005 and until the Company s next annual meeting, to amend the Company s Second Amended and Restated Certificate of Incorporation, and to ratify the appointment of the independent registered public accounting firm for 2005. Notice of the meeting and proxy information was distributed to stockholders prior to the meeting in accordance with law. There were no solicitations in opposition to the nominees or amendment of the Company s Second Amended and Restated Certificate of Incorporation. Out of a total of 32,870,815 shares of the Company s Common Stock outstanding and entitled to vote, 29,856,946 shares (90.8%) were present at the meeting in person or by proxy.

*Election of Directors*

There were seven nominees for election as directors of the Company. The vote tabulation with respect to each nominee to Encore s Board of Directors was as follows:

| NOMINEE | FOR | WITHHELD |
|---|---|---|
| I. Jon Brumley | 29,446,013 | 410,933 |
| Jon S. Brumley | 29,580,878 | 276,068 |
| Martin C. Bowen | 29,585,269 | 271,677 |
| Ted Collins, Jr. | 29,580,569 | 276,377 |
| Ted A. Gardner | 29,586,019 | 270,927 |
| John V. Genova | 29,575,869 | 281,077 |
| James A. Winne III | 29,583,269 | 273,677 |

*Second Amended and Restated Certificate of Incorporation*

The Board of Directors recommended that the Company s stockholders approve amendments to the Company s Second Amended and Restated Certificate of Incorporation. The vote tabulation with respect to the amendments to the Company s Second Amended and Restated Certificate of Incorporation was as follows:

| | FOR | AGAINST | ABSTAIN |
|---|---|---|---|
| Increase the number of shares of the Company s common stock from 60 million to 144 million | 27,883,927 | 1,952,515 | 20,504 |
| Deletion of Article Six in its entirety (outdated provision) | 29,772,743 | 47,620 | 36,583 |

*Appointment of Independent Registered Public Accounting Firm*

The Board of Directors recommended that the Company s stockholders to ratify the appointment of Ernst & Young LLP as the Company s independent registered public accounting firm. The vote tabulation with respect to the ratification of the appointment of independent registered public accounting firm was as follows:

| | FOR | AGAINST | ABSTAIN |
|---|---|---|---|
| Appointment of Ernst & Young LLP as the Company s independent registered public accounting firm | 29,774,885 | 76,369 | 5,692 |

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## Item 6. Exhibits

Exhibits

3.1.1 Second Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001, filed with the SEC on November 7, 2001).

3.1.2 Certificate of Amendment to Second Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1.2 to the Company Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2005, filed with the SEC on May 5, 2005).

3.2 Second Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.2 to the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001, filed with the SEC on November 7, 2001).

4.1 Indenture dated as of July 13, 2005 among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association with respect to the 6% Senior Subordinated Notes due 2015 (incorporated by reference to Exhibit 4.1 to the Company s Current Report on Form 8-K, filed with the SEC on July 13, 2005).

4.2 Form of 6% Senior Subordinated Note due 2015 (included Exhibit A to Exhibit 4.1 above).

4.3 Registration Rights Agreement dated as of July 13, 2005 among the Company, the subsidiary guarantors party thereto and Credit Suisse First Boston LLC (incorporated by reference to Exhibit 4.3 to the Company s Current Report on Form 8-K, filed with the SEC on July 13, 2005).

10.1 Purchase Agreement dated as of June 30, 2005, among the Company, the subsidiary guarantors party thereto and Credit Suisse First Boston LLC

31.1 Rule 13a-14(a)/15d-14(a) Certification (Principal Executive Officer)

31.2 Rule 13a-14(a)/15d-14(a) Certification (Principal Financial Officer)

32.1 Section 1350 Certification (Principal Executive Officer)

32.2 Section 1350 Certification (Principal Financial Officer)

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SIGNATURES

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

| | |
|---|---|
| | ENCORE ACQUISITION COMPANY |
| Date: August 8, 2005 | By: /s/ Roy W. Jageman |
| | Roy W. Jageman<br>Chief Financial Officer, Executive Vice President,<br>Corporate Secretary and Principal Financial Officer |
| Date: August 8, 2005 | By: /s/ Robert C. Reeves |
| | Robert C. Reeves<br>Vice President, Controller and Principal Accounting Officer |

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