ENCORE ACQUISITION CO
Form 10-Q
May 05, 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 March 31, 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 (State or other jurisdiction of incorporation)	**75-2759650** (IRS Employer Identification No.)
777 Main Street, Suite 1400, Fort Worth, Texas (Address of principal executive offices)	**76102** (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 April 29, 2005 32,868,921

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)

	March 31, 2005 (unaudited)	December 31, 2004
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,011	$ 1,103
Accounts receivable	50,849	43,839
Inventory	9,968	6,550
Derivatives	964	2,665
Deferred taxes	21,741	11,118
Other	2,504	5,842
Total current assets	87,037	71,117
Properties and equipment, at cost successful efforts method:		
Proved properties	1,210,710	1,134,220
Unproved properties	29,837	29,740
Accumulated depletion, depreciation, and amortization	(188,457)	(171,691)
	1,052,090	992,269
Other property and equipment	12,743	10,425
Accumulated depreciation	(3,859)	(3,551)
	8,884	6,874
Goodwill	37,952	37,995
Other	15,409	15,145
Total assets	$ 1,201,372	$ 1,123,400

LIABILITIES AND STOCKHOLDERS EQUITY

Current liabilities:		
Accounts payable	$ 22,498	$ 24,375
Derivatives	51,757	24,270
Accrued and other current	40,572	38,038
Total current liabilities	114,827	86,683
Derivatives	55,151	31,477
Future abandonment costs	10,539	6,601
Deferred taxes	146,765	146,064
Long-term debt	410,000	379,000
Total liabilities	737,282	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, 60,000,000 authorized, 32,868,921 and 32,654,798 issued and outstanding	329	327
Additional paid-in capital	323,124	314,736
Deferred compensation	(10,778)	(4,603)
Retained earnings	221,296	199,512
Accumulated other comprehensive loss	(69,881)	(36,397)
Total stockholders equity	464,090	473,575
Total liabilities and stockholders equity	$ 1,201,372	$ 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 March 31, 2005	Three months ended March 31, 2004
Revenues:		
Oil	$ 67,136	$ 46,764
Natural gas	24,445	12,527
Total revenues	91,581	59,291
Expenses:		
Production		
Lease operations	14,868	10,242
Production, ad valorem, and severance taxes	9,086	5,839
Depletion, depreciation, and amortization	16,683	9,263
Exploration	2,611	
General and administrative (excluding non-cash stock based compensation)	3,635	2,228
Non-cash stock based compensation	773	310
Derivative fair value loss	2,409	158
Other operating	1,599	1,002
Total expenses	51,664	29,042
Operating income	39,917	30,249
Other income (expenses):		
Interest	(6,959)	(3,906)
Other	64	51
Total other income (expenses)	(6,895)	(3,855)
Income before income taxes	33,022	26,394
Current income tax provision	(801)	(1,085)
Deferred income tax provision	(10,437)	(8,407)
Net income	$ 21,784	$ 16,902

Net income per common share:		
Basic	$ 0.67	$ 0.56
Diluted	0.66	0.55
Weighted average common shares outstanding:		
Basic	32,409	30,179
Diluted	32,933	30,567

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

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ENCORE ACQUISITION COMPANY

CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY

March 31, 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	32,655	$ 327	$ 314,736	$ (4,603)	$ 199,512	$ (36,397)	$ 473,575
Exercise of stock options	52		1,442				1,442
Deferred compensation:							
Issuance of restricted Common Stock	165	2	6,557	(6,559)			
Amortization to expense				773			773
Other changes	(3)		389	(389)			
Components of comprehensive loss:							
Net income					21,784		21,784
Change in deferred hedge loss, net of income taxes of $19,947						(33,484)	(33,484)
Total comprehensive loss							(11,700)
Balance at March 31, 2005	32,869	$ 329	$ 323,124	$ (10,778)	$ 221,296	$ (69,881)	$ 464,090

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)

	Three months ended March 31, 2005	2004
Operating activities		
Net income	$ 21,784	$ 16,902
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, and amortization	16,683	9,263
Dry hole expense	1,319	
Deferred taxes	10,437	8,407
Non-cash stock based compensation	773	310
Non-cash derivative fair value loss	4,644	1,972
Other non-cash	965	336
(Gain) loss on disposition of assets	149	(11)
Changes in operating assets and liabilities:		
Hedge margin deposit		(3,840)
Accounts receivable	(7,008)	(2,670)
Other current assets	(1,659)	(1,127)
Other assets	(3,693)	(53)
Accounts payable and accrued liabilities	10,457	1,584
Cash provided by operating activities	54,851	31,073
Investing activities		
Proceeds from disposition of assets	214	119
Purchases of other property and equipment	(2,729)	(884)
Acquisition of oil and natural gas properties	(9,354)	(1,263)
Development of oil and natural gas properties	(64,799)	(28,984)
Cash used by investing activities	(76,668)	(31,012)
Financing activities		
Proceeds from long-term debt	71,000	48,000
Payments on long-term debt	(40,000)	(48,000)
Cash overdrafts and other	(9,275)	237
Cash provided by financing activities	21,725	237
Increase (decrease) in cash and cash equivalents	(92)	298

Cash and cash equivalents, beginning of period		1,103		431
Cash and cash equivalents, end of period	$	1,011	$	729

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

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
MARCH 31, 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 are currently located in four core areas: the Cedar Creek Anticline (CCA) in the Williston Basin of Montana and North Dakota; the Permian Basin of West 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 east Texas and the Barnett Shale of north 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 our financial position as of March 31, 2005 and results of operations and cash flows for the three months ended March 31, 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.

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):

	Three months ended March 31,	
	2005	**2004**
As Reported:		
Non-cash stock based compensation (net of taxes)	$ 484	$ 192

Net income	21,784	16,902
Basic net income per common share	0.67	0.56
Diluted net income per common share	0.66	0.55
Pro Forma:		
Non-cash stock based compensation (net of taxes)	$ 647	$ 406
Net income	21,621	16,688
Basic net income per common share	0.67	0.55
Diluted net income per common share	0.66	0.55

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New Accounting Standards

Statement of Financial Accounting Standard 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 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 123R was initially scheduled to be the first reporting period beginning after June 15, 2005, which is third quarter 2005 for calendar year companies, although early adoption is allowed. However, on April 14, 2005, the Securities and Exchange Commission (SEC) announced that the effective date of SFAS 123R will be suspended until January 1, 2006, for calendar year companies.

SFAS 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 123R for all share-based payments granted after that date, and for all unvested awards granted prior to the effective date of SFAS 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 proforma disclosures made in accordance with SFAS 123.

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 123 as disclosed above under Stock-based Compensation. While SFAS 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 123R.

Under the revised standard, the pro forma disclosures previously permitted under SFAS 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 three months ended March 31, 2004 and 2005, as if the Company had used a fair-value-based method similar to the methods required under SFAS 123R to measure compensation expense for employee stock incentive awards.

SFAS 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 currently expects to adopt SFAS 123R effective January 1, 2006, based on the new effective date announced by the SEC; however, the Company has not yet determined which of the aforementioned adoption methods it will use. In addition, the Company has not yet determined the financial statement impact of adopting SFAS 123R for periods beyond 2005.

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

In April 2005, the FASB issued FASB Staff Position (FSP) FAS 19-1, Accounting for Suspended Well Costs. The FSP amends Statement of Financial Accounting Standard No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies. The FSP concludes that exploratory well costs should continue to be capitalized when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The Company is required to adopt FSP as of April 1, 2005; however, its adoption is not expected to have a material impact on the Company s results of operations, financial condition, or cash flows.

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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):

	March 31, 2005	December 31, 2004
Warehouse inventory	$ 6,914	$ 6,321
Oil in pipelines (purchased)	2,961	
Oil in pipelines (produced)	93	229
	$ 9,968	$ 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 on April 1, 2004.

The calculation of the total purchase price and the estimated allocation as of March 31, 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	5,902
Proved oil and natural gas properties	120,503
Unproved oil and natural gas properties	3,011

Goodwill	37,952
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 $38.0 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.

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5. Derivative Financial Instruments

The following tables summarize the Company s open commodity derivative instruments designated as hedges as of March 31, 2005:

Oil Derivative Instruments at March 31, 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)
April June 2005	15,500	$ 27.55	3,500	$ 31.89	1,000	$ 25.12	$ (10,604)
July Dec 2005	12,500	27.84	2,500	31.07	1,000	25.12	(17,298)
Jan June 2006	7,000	33.93	1,000	29.88	2,000	25.03	(14,634)
July Dec 2006	6,500	35.00	1,000	29.88	2,000	25.03	(13,442)
Jan Dec 2007					2,000	25.11	(18,083)

Natural Gas Derivative Instruments at March 31, 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)
April Dec 2005	17,500	$ 5.12	5,000	$ 5.97	12,500	$ 4.99	$ (11,577)
Jan Dec 2006	12,500	5.34	5,000	5.68	12,500	5.08	(13,503)
Jan Dec 2007					10,000	4.99	(6,267)

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 for 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 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 March 31, 2005, the mark-to-market value of these contracts is a gain of $0.7 million.

Interest Rate Derivatives

The following table summarizes the Company s only interest rate swap contract at March 31, 2005:

Contract Expiration	**Notional Amount**	**Encore Pays**	**Encore Receives**	**Fair Value (000s)**
June 2005	$ 80,000,000	LIBOR + 3.89%	8.375%	$ 282

This contract does not qualify for hedge accounting and; thus, the changes in its fair market value are recorded in Derivative fair value (gain) loss on the Consolidated Statements of Operations. During the quarter ended March 31, 2005, a loss of $0.2 million related to the interest rate swap was recorded in the Consolidated Statement of Operations.

The actual gains or losses the Company realizes from derivative transactions may vary significantly from the deferred loss amount recorded in stockholders equity at March 31, 2005 due to fluctuation of prices in the commodities markets.

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 March 31, 2005 (in thousands):

	Three months ended March 31, 2005
Future abandonment liability at January 1, 2005	$ 6,601
Wells drilled	165
Accretion expense	88
Plugging and abandonment costs incurred	(485)
Revision of estimates	4,170
Future abandonment liability at March 31, 2005	$ 10,539

During the first quarter of 2005, the Company increased its estimate of future plugging liability by $4.2 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. Income Taxes

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

	Three months ended March 31, 2005	Three months ended March 31, 2004
Income before income taxes	$ 33,022	$ 26,394
Tax at statutory rate	11,558	9,238
State income taxes, net of federal benefit	693	792
Section 43 credits generated	(778)	(740)
Permanent and other	(235)	202
Income tax provision	$ 11,238	$ 9,492

8. Earnings Per Share (EPS)

The following table sets forth basic and diluted EPS computations for the three months ended March 31, 2005 and 2004 (in thousands, except per share data):

	Three months ended March 31,	
	2005	**2004**
Numerator:		
Net income	$ 21,784	$ 16,902
Denominator:		
Denominator for basic earnings per share Weighted average shares outstanding	32,409	30,179
Effect of dilutive options and dilutive restricted stock (a)	524	388
Denominator for diluted earnings per share	32,933	30,567
Net income per common share:		
Basic	$ 0.67	$ 0.56
Diluted	$ 0.66	$ 0.55

(a) There were 75,357 shares underlying options and 103,460 shares of restricted stock outstanding for the three months ended March 31, 2005, which would have been antidilutive. There were no antidilutive options or shares of antidilutive restricted stock outstanding for the three months ended March 31, 2004.

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There were 164,703 shares of restricted stock granted and 75,357 stock options granted in the quarter ended March 31, 2005. During the quarter ended March 31, 2005, 388 stock options and 3,203 shares of restricted stock, which were issued and outstanding at December 31, 2004, were forfeited.

9. Comprehensive Income (Loss)

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

	Three months ended March 31,	
	2005	**2004**
Net income	$ 21,784	$ 16,902
Change in unrealized loss on derivative hedged instruments	(33,539)	(7,940)
Change in unrealized gain on interest rate swap	55	125
Comprehensive income (loss)	(11,700)	9,087

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

	March 31, 2005	December 31, 2004
Unrealized loss on derivative hedged instruments	$ (70,380)	$ (36,841)
Unrealized gain on interest rate swap	499	444
Accumulated other comprehensive loss	$ (69,881)	$ (36,397)

10. Financial Statements of Subsidiary Guarantors

As of March 31, 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.

11. Related Party Transactions

The Company paid to Hanover Compression Company $0.1 million and $0.01 million in the first quarter of 2005 and 2004, respectively, for compression services. Mr. I. Jon Brumley, the Company s Chairman, and CEO, also serves as a director of Hanover Compressor Company.

12. Subsequent Events

Amended Credit Facility. 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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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.

First Quarter 2005 Highlights

Our financial and operating results for the quarter ended March 31, 2005 included the following highlights:

- During the first quarter of 2005, we had oil and natural gas revenues of $91.6 million. This represents a 54% increase over the $59.3 million of oil and natural gas revenues reported for the first quarter of 2004. Our realized commodity prices, including the effects of hedging, averaged $39.39 per barrel and $5.49 per Mcf during the first quarter of 2005, increases of 36% and 11%, respectively, from the first quarter of 2004. On a combined basis, including the effects of hedging, prices increased 28% during the first quarter of 2005 to $37.44 per BOE from $29.19 per BOE in the first quarter of 2004.

- We reported net income of $21.8 million, or $0.66 per diluted share, in the first three months of 2005. This represents a 29% increase from the $16.9 million of net income, or $0.55 per diluted share, from the first quarter of 2004.

- Higher net income in the first quarter of 2005 resulted as production volumes for the quarter increased 22% to 27,180 BOE per day (2.4 MMBOE), compared with first quarter 2004 production of 22,322 BOE per day (2.0 MMBOE). The rise in production volumes was attributable to continued organic growth and acquisitions completed in 2004. Additionally, during the first quarter of 2005, we sold previously produced oil being held as pipeline inventory, which increased production by approximately 400 BOE per day. Oil represented 70% and 79% of our total production volumes in the first quarter of 2005 and 2004, respectively.

- We invested $74.9 million in oil and natural gas activities during the first quarter of 2005 (excluding development-related asset retirement obligations). We drilled 66 gross (49.0 net) wells and invested $65.5 million in development, exploitation, expanding our HPAI program in the CCA, and exploration activities. We also invested $9.4 million in property acquisitions and undeveloped leases. We also expensed drilling costs for five dry hole exploratory wells during the first quarter of 2005. We are currently investing capital in a thirteen-rig conventional operated drilling program on the onshore continental United States, with five rigs in Montana, three rigs in East Texas, three rigs in West Texas, and two in Oklahoma.

- We were able to fund most of the $74.9 million of investments in oil and natural gas activities made in the first quarter of 2005 using the $54.9 million of operating cash flows generated during the quarter. The remaining $20.0 million was funded through borrowings under our existing revolving credit facility. Long-term debt at March 31, 2005 increased to $410.0 million from $379.0 million at December 31, 2004.

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Results of Operations

The following table sets forth selected operating information for the periods presented:

	Three months ended March 31, 2005	Three months ended March 31, 2004	*Increase / (Decrease)*
Operating results (in thousands):			
Oil and natural gas revenues	$ 91,581	$ 59,291	*$ 32,290*
Lease operations expense	14,868	10,242	*4,626*
Production, ad valorem, and severance taxes	9,086	5,839	*3,247*
Daily production volumes:			
Oil (Bbls)	18,937	17,699	*1,238*
Natural gas (Mcf)	49,455	27,741	*21,714*
Combined (BOE)	27,180	22,322	*4,858*
Average prices:			
Oil (per Bbl)	$ 39.39	$ 29.03	*$ 10.36*
Natural gas (per Mcf)	5.49	4.96	*0.53*
Combined (per BOE)	37.44	29.19	*8.25*

Comparison of Quarter Ended March 31, 2005 to Quarter Ended March 31, 2004

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

Revenues and Production. The following table illustrates the primary components of oil and natural gas revenues for the three months ended March 31, 2005 and 2004, as well as each quarter s respective oil and natural gas volumes (in thousands, except per unit amounts):

	Three months ended March 31, 2005		2004		*Increase / (Decrease)*	
Revenues:	Revenue	$/Unit	Revenue	$/Unit	*Revenue*	*$/Unit*
Oil wellhead	$ 76,719	$ 45.01	$ 52,378	$ 32.51	*$ 24,341*	*$ 12.50*
Oil hedges	(9,583)	(5.62)	(5,614)	(3.48)	*(3,969)*	*(2.14)*
Total Oil Revenues	$ 67,136	$ 39.39	$ 46,764	$ 29.03	*$ 20,372*	*$ 10.36*
Natural gas wellhead	$ 25,676	$ 5.77	$ 12,922	$ 5.12	*$ 12,754*	*$ 0.65*
Natural gas hedges	(1,231)	(0.28)	(395)	(0.16)	*(836)*	*(0.12)*
Total Natural Gas Revenues	$ 24,445	$ 5.49	$ 12,527	$ 4.96	*$ 11,918*	*$ 0.53*
Combined wellhead	$ 102,395	$ 41.86	$ 65,300	$ 32.15	*$ 37,095*	*$ 9.71*
Combined hedges	(10,814)	(4.42)	(6,009)	(2.96)	*(4,805)*	*(1.46)*

Total Combined Revenues	$ 91,581	$ 37.44	$ 59,291	$ 29.19	*$ 32,290*	*$ 8.25*

Other data:	Production	Average NYMEX $/Unit	Production	Average NYMEX $/Unit	*Production*	*Average NYMEX $/Unit*
Oil (Bbls)	1,704	$ 49.84	1,611	$ 35.15	*93*	*$ 14.69*
Natural Gas (Mcf)	4,451	6.47	2,524	5.72	*1,927*	*0.75*
Combined (BOE)	2,446		2,031		*415*	

Oil revenues increased from first quarter 2004 to first quarter 2005 by $20.4 million, due primarily to a higher realized average oil price as production was relatively flat. Our realized average oil price increased $10.36 per Bbl in the first quarter of 2005 over the same period in 2004 as a result of an increase in our average wellhead price of $12.50 offset by an increase in hedging payments of $2.14 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 $14.69 per Bbl increase in the average NYMEX price over the same period.

Natural gas revenues increased by $11.9 million, or $0.53 per Mcf, in the first quarter of 2005 from the first quarter of 2004 due to an increase in volumes and an increase in our realized average natural gas price. Production volumes increased 1,927 MMcf in the first quarter of 2005 as compared to the first quarter of 2004 due to the Cortez and Overton acquisitions, which both closed in 2004 subsequent to the end of the first quarter. The $0.53 increase in our realized average natural gas price was due to the increase in the overall market price for natural gas as reflected in the increase in the average NYMEX price of $0.75 per Mcf from the first quarter of 2004 to the first quarter of 2005. The increase in the overall market price of natural gas gave rise to an increase of $0.65 per Mcf in our average wellhead price, as well as an increase of $0.12 per Mcf in hedging payments.

The table below illustrates the relationship between oil and natural gas wellhead prices and average NYMEX prices for the quarters ended March 31, 2005 and 2004:

	Three months ended March 31,	
	2005	**2004**
Oil wellhead ($/Bbl)	$ 45.01	$ 32.51
Average NYMEX ($/Bbl)	$ 49.84	$ 35.15
Differential to NYMEX	$ (4.83)	$ (2.64)
Oil wellhead to NYMEX percentage	90%	92%
Natural gas wellhead ($/Mcf)	$ 5.77	$ 5.12
Average NYMEX ($/Mcf)	$ 6.47	$ 5.72
Differential to NYMEX	$ (0.70)	$ (0.60)
Natural gas wellhead to NYMEX percentage	89%	90%

Management uses this wellhead to NYMEX margin analysis to assess trends in our anticipated oil and natural gas revenues. As indicated, both our oil and natural gas differential to the NYMEX price widened from the first quarter of 2004 to the first quarter of 2005. However, due to an increase in both the Company s average wellhead price received and the NYMEX price over the same period, our oil and natural gas wellhead prices as a percentage of the NYMEX price remained relatively flat between the periods.

Expenses. The following table summarizes our expenses for the quarters ended March 31, 2005 and 2004:

	Three months ended March 31,		
	2005	**2004**	***Difference***
Expenses (in thousands):			
Lease operations	$ 14,868	$ 10,242	*$ 4,626*
Production, ad valorem, and severance taxes	9,086	5,839	*3,247*
Depletion, depreciation, and amortization	16,683	9,263	*7,420*
Exploration	2,611		*2,611*
General and administrative (excluding non-cash stock based compensation)	3,635	2,228	*1,407*
Non-cash stock based compensation	773	310	*463*
Derivative fair value loss	2,409	158	*2,251*
Other operating	1,599	1,002	*597*
Interest	6,959	3,906	*3,053*
Current and deferred income tax provision	11,238	9,492	*1,746*

Expenses (per BOE):						
Lease operations	$	6.08	$	5.04	*$*	*1.04*
Production, ad valorem, and severance taxes		3.71		2.87		*0.84*
Depletion, depreciation, and amortization		6.82		4.56		*2.26*
Exploration		1.07				*1.07*
General and administrative (excluding non-cash stock based compensation)		1.49		1.10		*0.39*
Non-cash stock based compensation		0.32		0.15		*0.17*
Derivative fair value loss		0.98		0.08		*0.90*
Other operating		0.65		0.49		*0.16*
Interest		2.84		1.92		*0.92*
Current and deferred income tax provision		4.59		4.67		*(0.08)*

Lease operations expense. Lease operations expense for the first quarter of 2005 increased as compared to the first quarter of 2004 by $4.6 million. The increase in total lease operations expense resulted from an increase in production volumes as a result of our 2005 drilling program, the Elm Grove, Cortez and Overton acquisitions, and our high-pressure air injection (HPAI) program; an increase in corporate overhead due to increased staffing levels used to manage our growing asset base; higher than anticipated costs on our non-operated properties; and an increase in the per BOE rate. The increase in our average per BOE rate was attributable to acquired properties with higher per BOE expenses, an increase in prices paid for outside services, and increased salaries as the cost of experienced, quality personnel has increased across the industry.

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Production, ad valorem, and severance taxes. Production, ad valorem, and severance taxes for the first quarter of 2005 increased as compared to the same period in 2004 by approximately $3.2 million. As a percentage of oil and natural gas revenues (excluding the effects of hedges), production, ad valorem, and severance taxes for the first quarter of 2005 remained relatively flat when compared to the first quarter of 2004, at 8.9%. 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 quarter of 2005 increased, as expected, by $7.4 million as compared to the first quarter of 2004, due to a $2.26 increase in the per BOE rate and an increase in production. This per BOE rate increase was due to the acquisition of the Overton and Cortez properties, 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 $2.6 million in the first quarter of 2005, while we did not incur any exploration expense in the first quarter of 2004. During the first quarter of 2005, we expensed the cost of five exploratory dry holes for a total of $1.3 million. Out of the five exploratory dry holes expensed, one was drilled in Crockett County, Texas that was spud during the first quarter of 2005 and four were drilled in the shallow gas area of Montana that were spud during the fourth quarter of 2004. In addition to the increase in dry hole expense, the following additional exploration-related expenses were incurred in the first quarter of 2005 related to our exploration projects: abandonment and impairment of undeveloped leasehold costs of $0.5 million, delay rental expense of $0.3 million, and geological and geophysical expenses of $0.5 million.

General and administrative (G&A   ) expense. G&A expense (excluding non-cash stock based compensation) increased $1.4 million for the first quarter of 2005 as compared to the first quarter of 2004. The overall increase, as well as the $0.39 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 first quarter of 2005 increased $0.5 million as compared to the first quarter of 2004. This expense represents the amortization of deferred compensation recorded in equity related to restricted stock granted under the 2000 Incentive Stock Plan. This amount is being amortized to expense over the vesting period of the restricted stock. In the first quarter of 2005, we issued 164,703 shares of restricted stock to our employees as part of our annual incentive program. Deferred compensation of $6.6 million was reclassified within equity from additional paid in capital during the quarter ended March 31, 2005 in conjunction with the 2005 grants, and will be expensed over the related periods from the grant dates to the vesting dates. Both deferred compensation and related amortization increased from first quarter 2004 to first quarter 2005 as the Company   s stock price per share increased and the number of shares granted increased.

Derivative fair value loss. During the first quarter of 2005 we recorded a $2.4 million derivative fair value loss as compared to the $0.2 million loss recorded in the first 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 quarterly periods are as follows (in thousands):

	Three months ended March 31,	*Increase /*

	2005	**2004**	***(Decrease)***
Designated cash flow hedges:			
Ineffectiveness Commodity contracts	$ 2,726	$ 274	*$ 2,452*
Undesignated derivative contracts:			
Mark-to-market (gain) loss Interest rate swaps	180	(710)	*890*
Mark-to-market (gain) loss Commodity contracts	(497)	594	*(1,091)*
Derivative fair value loss	$ 2,409	$ 158	*$ 2,251*

Ineffectiveness loss related to our derivative commodity contracts increased $2.5 million due primarily to an increase in oil wellhead differentials on our production in the CCA.

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Other operating expense. Other operating expense for the first quarter of 2005 increased by $0.6 million when compared to the first quarter of 2004. This increase is mainly due to increase in third party natural gas transportation costs.

Interest expense. Interest expense increased $3.1 million in the quarter ended March 31, 2005 from the quarter ended March 31, 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 and third quarters of 2004 to fund the Cortez and Overton acquisitions, respectively. The weighted average interest rate, net of hedges, for the quarter ended March 31, 2005 was 7.0% compared to 8.7% for the quarter ended March 31, 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 March 31, 2005 and 2004 (in thousands):

	Three months ended March 31,		*Increase /*
	2005	**2004**	***(Decrease)***
8 3/8% notes due 2012	$ 3,141	$ 3,141	*$*
6 1/4% notes due 2014	2,344		*2,344*
Revolving credit facility	930	211	*719*
Interest rate hedges (1)	40	212	*(172)*
Debt issuance cost	249	195	*54*
Banking fees and other	255	147	*108*
Total	$ 6,959	$ 3,906	*$ 3,053*

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

Income taxes. Income tax expense for the first quarter of 2005 increased $1.7 million over the same period in 2004. This increase is due primarily to the $6.6 million increase in income before income taxes from the first quarter of 2004 to the first quarter of 2005, offset by a decrease in our effective tax rate from 36.0% for the first quarter in 2004 to 34.0% in the first quarter 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 months ended March 31, 2005 and 2004 (in thousands):

	Three months ended March 31,	
	2005	**2004**
Development, Exploitation, and Exploration Expenditures:		
Development and exploitation	$ 42,905	$ 20,266
Exploration	14,697	1,195
HPAI	7,942	7,652
Total	$ 65,544	$ 29,113

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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 expenditures for exploration investments primarily relate to drilling exploratory wells, seismic, delay rentals, and geological and geophysical costs.

For the remainder of 2005, we expect to invest $146.8 million in development, exploitation, and exploration activities. We have based our 2005 forecasts on the assumptions of at least $30.00 per Bbl and $5.00 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 have seen initial indications of positive production response in the core injection area of the project.

In the Pennel unit of the CCA, we have been operating a successful HPAI program (Phase 1) for over 2 years. In April of 2005, we successfully started its new full-scale HPAI compression facility and began injecting air in the Phase 2 project area. Full implementation of the Phase 2 HPAI project is expected to be completed by year end 2005. We expect the reservoir to pressure up in line with internal forecasts and we expect to see initial production uplift in late 2006.

For the remainder of 2005, we expect to invest $20.0 million for high-pressure air injection capital, primarily related to our Pennel program.

Acquisitions, Leasehold and Acreage Costs. Our capital expenditures for oil and natural gas proved property acquisitions during the three months ended March 31, 2005 and 2004 were as follows (in thousands):

	Three months ended March 31,	
	2005	**2004**
Acquisitions, Leasehold and Acreage Costs:		
Acquisitions	$ 5,671	$ 163
Leasehold and acreage costs	3,683	1,100
Total	$ 9,354	$ 1,263

Acquisitions. Our capital expenditures for proved oil and natural gas properties during the three months ended March 31, 2005 totaled $5.7 million as compared to $0.2 million in the first quarter of 2004. The $5.7 million of first quarter 2005 acquisition capital was invested primarily in additional working interests in our ArkLaTx region. 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 $3.2 million for leasehold and acreage costs.

Other General Property and Equipment. Our capital expenditures for other general property and equipment during the quarters ended March 31, 2005 and 2004 totaled $2.7 million and $0.9 million, respectively. The increase was due primarily to the $1.6 million invested during the first quarter of 2005 for field equipment. Capital expenditures for other general property and equipment included corporate leasehold improvements, computers, and other various equipment.

For the remainder of 2005, we expect to invest $0.6 million in other general property and equipment.

Working Capital. At March 31, 2005, our working capital was $(27.8) million while at December 31, 2004, our working capital was $(15.6) million, a decrease of $12.2 million. The decrease is primarily attributable to changes in the fair value of outstanding derivative contracts, offset by the deferred tax asset related to the deferred hedge loss in other comprehensive income.

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For 2005, we expect working capital to remain negative. Negative working capital is expected mainly due to fair values of our derivative contracts which obligations will be offset by cash flows from hedged production. We anticipate cash reserves to be close to zero as we use any excess 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. On May 3, 2005, our Board of Directors approved an increase in our 2005 capital budget from $223.0 million to $245.0 for additional projects and to reflect 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 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 March 31, 2005 (in thousands):

Contractual Obligations	**Payments Due by Period**				
			2006	**2008**	
and Capital Commitments	**Total**	**2005**	**2007**	**2009**	**Thereafter**
8 3/8% Notes (a)	$ 244,219	$ 12,563	$ 25,125	$ 25,125	$ 181,406
6 1/4% Notes (a)	239,063	9,375	18,750	18,750	192,188
Revolving credit facility (a)	128,529	3,185	8,454	116,890	
Derivative obligations (b)	106,196	39,025	42,821	24,350	
Development commitments (c)	16,218	15,318	600	300	
Operating leases (d)	12,561	1,329	2,932	2,902	5,398
Asset retirement obligations (e)	74,560	542	1,084	1,084	71,850
Totals	$ 821,346	$ 81,337	$ 99,766	$ 189,401	$ 450,842

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

(b) Derivative obligations represent liabilities for derivatives that were valued as of March 31, 2005. The ultimate settlement amounts of the remaining portions of our derivative obligations are unknown because they are subject to continuing market risk.

(c) Development commitments represent authorized purchases, $14.6 million of which represents work in process and is accrued at March 31, 2005. Development commitments in the above table also include minimum transmission payments for electricity and compression services. We also have authorized purchases not placed to vendors (authorized AFEs) which were not accrued at year-end, but are budgeted for and expected to be made during 2005 unless circumstances change.

(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 crude 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 the period after 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 quarter of 2005, cash provided by operating activities increased by $23.8 million as compared to the same period in 2004. This increase resulted mainly from increase in revenues which resulted from increased volumes and increased commodity prices.

Financing Activities. For the first quarter of 2005, we increased the level of debt outstanding under our revolving credit facility at the beginning of the period, while in the first quarter of 2004, we maintained a relatively constant level of debt under our revolving credit facility. This change reflects the change in the use of cash flows generated though operations between the two periods. We increased cash investments in the development of oil and natural gas properties by $35.8 million in the first quarter of 2005 as compared to the first quarter of 2004, which gave rise to an increase of the $31.0 million in our amount outstanding under our revolving credit facility during the first quarter of 2005. There were no substantial acquisitions in either period which required any new financing.

Capitalization. At March 31, 2005, Encore had total assets of $1.2 billion. Total capitalization was $874.1 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.

Liquidity

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 March 31, 2005, we had $110 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%.

Letters of Credit. As of April 29, 2004, we had no cash deposited and $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.

Inflation and Changes in Prices

While the general level of inflation affects certain of our costs, factors unique to the petroleum industry result in independent price fluctuations. Historically, significant fluctuations have occurred in oil and natural gas prices. In addition, changing prices often cause costs of equipment and supplies to vary as industry activity levels increase and decrease to reflect perceptions of future price levels. Although it is difficult to estimate future prices of oil and natural gas, price fluctuations have had, and will continue to have, a material effect on us.

The following table indicates the average oil and natural gas prices realized for the three months ended March 31, 2005 and 2004. Average equivalent prices for the first three months of 2005 and 2004 decreased by $4.42 and $2.96 per BOE, respectively, as a result of our hedging activities. Average prices per equivalent barrel indicate the composite impact of changes in oil and natural gas prices. Natural gas production volumes are converted to oil equivalents at the conversion rate of six Mcf per Bbl.

	Oil (per Bbl)	Natural Gas (per Mcf)	Equiv. Oil (per BOE)
Net Price Realization with Hedges			
Quarter ended March 31, 2005	$ 39.39	$ 5.49	$ 37.44
Quarter ended March 31, 2004	29.03	4.96	29.19
Average Wellhead Price			
Quarter ended March 31, 2005	$ 45.01	$ 5.77	$ 41.86
Quarter ended March 31, 2004	32.51	5.12	32.15

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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.

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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 March 31, 2005 are discussed in Note 5 to the accompanying consolidated financial statements. As of March 31, 2005, the fair value of our open commodity and interest rate derivative contracts was $(104.4) 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 March 31, 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 March 31, 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 6. Exhibits

Exhibits

3.1.1 Second Amended and Restated Certificate of Incorporation of the Company (incorporated by reference 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

3.2 Second Amended and Restated Bylaws of the Company (incorporated by reference 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).

10.1 First Amendment to Credit Agreement dated as of April 29, 2005 by and among the Company, Encore Operating, L.P., a Texas limited partnership, Bank of America, N.A., as Administrative Agent and L/C Issuer, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed with the Securities and Exchange Commission on May 4, 2005).

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: May 5, 2005	By: /s/ Roy W. Jageman Roy W. Jageman Chief Financial Officer, Treasurer, Executive Vice President, Corporate Secretary and Principal Financial Officer
Date: May 5, 2005	By: /s/ Robert C. Reeves Robert C. Reeves Vice President, Controller and Principal Accounting Officer