ENCORE ACQUISITION CO
Form 10-Q
November 07, 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 September 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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act)

Yes o No þ

Number of shares of Common Stock, $0.01 par value, outstanding as of November 4, 2005 49,372,655

ENCORE ACQUISITION COMPANY
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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain information included in this Quarterly Report on Form 10-Q and other materials filed with the SEC, or in other written or oral statements made or to be made by us, other than statements of historical fact, are forward-looking statements as defined by the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995. These forward-looking statements 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, intend, plan, believe, should, forecast 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)

	September 30, 2005 (unaudited)	December 31, 2004
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,554	$ 1,103
Hedge margin deposits	1,600	
Accounts receivable	69,385	43,839
Inventory	10,252	6,550
Derivatives	6,270	2,665
Deferred taxes	33,490	11,118
Other	4,899	5,842
Total current assets	128,450	71,117
Properties and equipment, at cost successful efforts method:		
Proved properties	1,418,591	1,134,220
Unproved properties	28,750	29,740
Accumulated depletion, depreciation, and amortization	(230,426)	(171,691)
	1,216,915	992,269
Other property and equipment	15,037	10,425
Accumulated depreciation	(4,831)	(3,551)
	10,206	6,874
Goodwill	37,908	37,995
Derivatives	11,905	1,150
Other	16,992	13,995
Total assets	$ 1,422,376	$ 1,123,400
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 22,430	$ 24,375
Derivatives	84,483	24,270

Accrued and other current	76,069	38,038
Total current liabilities	182,982	86,683
Derivatives	59,920	31,477
Future abandonment costs	11,292	6,601
Other	13,482	
Deferred taxes	169,907	146,064
Long-term debt	493,581	379,000
Total liabilities	931,164	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, 49,372,347 and 48,982,197 issued and outstanding	494	490
Additional paid-in capital	324,502	314,573
Deferred compensation	(8,964)	(4,603)
Retained earnings	265,756	199,512
Accumulated other comprehensive loss	(90,576)	(36,397)
Total stockholders equity	491,212	473,575
Total liabilities and stockholders equity	$ 1,422,376	$ 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 September 30,		Nine months ended September 30,	
	2005	**2004**	**2005**	**2004**
Revenues:				
Oil	$ 85,559	$ 58,243	$ 222,254	$ 157,892
Natural gas	42,013	21,009	96,616	50,773
Total revenues	127,572	79,252	318,870	208,665
Expenses:				
Production				
Lease operations	17,912	12,589	48,501	33,752
Production, ad valorem, and severance taxes	12,526	8,117	31,425	21,117
Depletion, depreciation, and amortization	24,222	12,750	59,943	33,262
Exploration	4,818	462	11,201	2,159
General and administrative (excluding non-cash stock based compensation)	4,030	2,858	11,236	7,616
Non-cash stock based compensation	1,544	796	3,323	1,413
Derivative fair value loss	1,612	2,301	5,713	3,424
Loss on early redemption of debt	19,477		19,477	
Other operating	2,520	1,369	5,822	3,462
Total expenses	88,661	41,242	196,641	106,205
Operating income	38,911	38,010	122,229	102,460
Other income (expenses):				
Interest	(9,264)	(6,547)	(23,671)	(16,761)
Other	580	78	729	235
Total other income (expenses)	(8,684)	(6,469)	(22,942)	(16,526)
Income before income taxes	30,227	31,541	99,287	85,934
Current income tax benefit (provision)	2,868	(1,042)	1,478	(3,046)
Deferred income tax provision	(12,241)	(9,485)	(34,459)	(26,981)
Net income	$ 20,854	$ 21,014	$ 66,306	$ 55,907

Net income per common share:				
Basic	$ 0.43	$ 0.43	$ 1.36	$ 1.20
Diluted	0.42	0.43	1.34	1.18
Weighted average common shares outstanding:				
Basic	48,703	48,446	48,659	46,611
Diluted	49,584	49,103	49,481	47,222

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

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

	Shares of Common Stock	Common Stock	Additional Paid-In Capital	Treasury Stock	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	137	1	2,381					2,382
Purchase of treasury stock				(195)				(195)
Cancellation of treasury stock	(7)		(133)	195		(62)		
Deferred compensation:								
Issuance of restricted Common Stock	270	3	7,106		(7,109)			
Amortization to expense					3,323			3,323
Other changes	(10)		575		(575)			
Components of comprehensive income:								
Net income						66,306		66,306
Change in deferred hedge loss, net of income taxes of $32,275							(54,179)	(54,179)
Total comprehensive income								12,127
Balance at September 30, 2005	49,372	$ 494	$ 324,502	$	$ (8,964)	$ 265,756	$ (90,576)	$ 491,212

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)

	Nine months ended September 30, 2005	2004
Operating activities		
Net income	$ 66,306	$ 55,907
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, and amortization	59,943	33,262
Dry hole expense	6,970	1,866
Deferred taxes	34,459	26,981
Non-cash stock based compensation	3,323	1,413
Non-cash derivative fair value loss	11,159	10,257
Loss on early redemption of debt	19,477	
Other non-cash	2,799	418
Loss on disposition of assets	328	179
Changes in operating assets and liabilities:		
Hedge margin deposit	(1,600)	(5,580)
Accounts receivable	(25,500)	(8,219)
Other current assets	(10,735)	(8,580)
Other assets	(16,359)	(341)
Accounts payable and accrued liabilities	53,622	19,537
Cash provided by operating activities	204,192	127,100
Investing activities		
Proceeds from disposition of assets	604	581
Purchases of other property and equipment	(5,663)	(7,900)
Deposit on acquisition of oil and natural gas properties	(5,186)	
Acquisition of oil and natural gas properties	(49,770)	(111,532)
Acquisition of Cortez Oil & Gas, Inc. (net of cash acquired)		(123,792)
Development and exploration of oil and natural gas properties	(237,003)	(123,171)
Cash used by investing activities	(297,018)	(365,814)
Financing activities		
Proceeds from issuance of common stock		53,900
Payment of offering costs of common stock		(677)
Proceeds from long-term debt	311,000	240,000
Payments on long-term debt	(341,000)	(204,000)
Proceeds from issuance of 6% notes	294,480	
Redemption of $8^3/^8$% notes	(165,852)	
Proceeds from issuance of $6^1/4$% notes		150,000
Payments of debt issuance costs	(739)	(4,792)

Cash overdrafts and other	(3,612)	4,944
Cash provided by financing activities	94,277	239,375
Increase in cash and cash equivalents	1,451	661
Cash and cash equivalents, beginning of period	1,103	431
Cash and cash equivalents, end of period	$ 2,554	$ 1,092

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

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
SEPTEMBER 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 September 30, 2005, results of operations for the three and nine months ended September 30, 2005 and 2004, and cash flows for the nine months ended September 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.

Certain balances reported in the Company s 2004 Annual Report on Form 10-K have been reclassified to conform prior year data to the current period presentation.

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

As discussed at Note 11, Stockholders Equity, on June 15, 2005, the Company announced that its Board of Directors approved a three-for-two split of the Company s outstanding common stock in the form of a stock dividend. The dividend was distributed on July 12, 2005, to stockholders of record at the close of business on June 27, 2005. All share and per-share information included in the accompanying consolidated financial statements and related notes thereto for all periods presented have been adjusted to retroactively reflect the stock split.

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 September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
As Reported:				
Non-cash stock based compensation (net of taxes)	$ 968	$ 494	$ 2,082	$ 876
Net income	20,854	21,014	66,306	55,907
Basic net income per common share	0.43	0.43	1.36	1.20
Diluted net income per common share	0.42	0.43	1.34	1.18
Pro Forma:				
Non-cash stock based compensation (net of taxes)	$ 1,715	$ 814	$ 3,333	$ 1,738
Net income	20,107	20,694	65,055	55,045
Basic net income per common share	0.41	0.43	1.34	1.18
Diluted net income per common share	0.41	0.42	1.31	1.17

There were 641,102 shares of restricted stock outstanding at September 30, 2005, of which 269,555 shares were granted during the nine months ended September 30, 2005. During the first nine months of 2005, 9,070 shares of restricted stock were forfeited. There were 1,496,438 stock options outstanding at September 30, 2005, of which 978,423 options were exercisable at September 30, 2005. There were 115,269 stock options granted during the nine months ended September 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 is 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 plans to adopt the requirements of SFAS No. 123R using the the modified prospective method.

The Company currently utilizes a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options when calculating 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 plans to continue using a Black-Scholes option pricing model to measure the fair value of employee stock options upon the adoption of SFAS No. 123R.

Under SFAS No. 123R, the pro forma disclosures previously permitted under SFAS No. 123 and presented above will no longer be an alternative to financial statement recognition.

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 has not yet determined the financial statement impact of adopting SFAS No. 123R for periods beyond 2005 because they depend on, among other things, the number of options granted in the future and the Company s future stock price.

FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations

In March 2005, the FASB issued FASB Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations. The interpretation clarifies the requirement to record abandonment liabilities stemming from legal obligations when the retirement depends on a conditional future event. FIN No. 47 requires that the uncertainty about the timing or method of settlement of a conditional retirement obligation be factored into the measurement of the liability when sufficient information exists. FIN No. 47 is effective for fiscal years ending after December 15, 2005. The Company does not expect FIN No. 47 to have a material impact on its results of operations, financial condition, or cash flows.

Statement of Financial Accounting Standards No. 154, Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3

In May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3 . SFAS No. 154 requires retrospective application to prior period financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS No. 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS No. 154 will become effective for the Company s fiscal year beginning January 1, 2006. The impact of SFAS No. 154 will depend on the nature and extent of any voluntary accounting changes and correction of errors after the effective date, but management does not currently expect SFAS No. 154 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 of 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 ratified Issue No. 04-13 at its September 28, 2005 meeting, which should be applied to new arrangements entered into in the first interim or annual reporting period 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. 04-13 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):

	September 30, 2005	December 31, 2004
Warehouse inventory	$ 7,208	$ 6,321
Oil in pipelines (purchased)	3,044	
Oil in pipelines (produced)		229
	$ 10,252	$ 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 of $1.8 million.

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The acquired oil and natural gas properties are located primarily in the Cedar Creek Anticline (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 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 September 30, 2005:

Oil Derivative Instruments at September 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)
Oct Dec 2005	12,500	$ 27.84	2,500	$ 31.07	1,000	$ 25.12	$ (11,837)
Jan June 2006	13,500	44.07	1,000	29.88	2,000	25.03	(18,867)
July Dec 2006	13,000	45.00	1,000	29.88	2,000	25.03	(16,058)
Jan Dec 2007	4,000	55.00			2,000	25.11	(19,536)

Natural Gas Derivative Instruments at September 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)
Oct Dec 2005	17,500	$ 5.12	5,000	$ 5.97	12,500	$ 4.99	$ (11,441)
Jan Dec 2006	32,500	6.17	5,000	5.68	12,500	5.08	(36,372)
Jan Dec 2007	12,500	6.53			10,000	4.99	(13,193)

Encore recognizes the following in its Consolidated Statements of Operations: (1) 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; (2) ineffectiveness of commodity futures contracts designated as hedges; and (3) 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 the 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 September 30, 2005, the mark-to-market value of these basis swap contracts is $1.1 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 September 30, 2005 due to fluctuation of prices in the commodities markets.

The Company recorded $17.8 million of derivative premiums payable at September 30, 2005. The premiums relate to various oil and natural gas floor contracts and are payable on a monthly basis from January 2006 to December 2007. The long-term portion of the derivatives premiums payable is $12.2 million and is recorded in Other long-term liabilities on the Company s Consolidated Balance Sheet.

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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 September 30, 2005 (in thousands):

		Nine months ended September 30, 2005
Future abandonment liability at January 1, 2005	$	6,601
Wells drilled		858
Accretion expense		366
Plugging and abandonment costs incurred		(600)
Revision of estimates		4,067
Future abandonment liability at September 30, 2005	$	11,292

During the first nine months of 2005, the Company increased its discounted estimate of future plugging liability by $4.1 million as actual plugging costs experienced during the first quarter of 2005 increased due to plugging cost escalations (which outpaced inflation), increased cost of outside services, and changes in various state regulations.

7. Capitalization of Exploratory Well Costs

The Company adopted FASB Staff Position (FSP) 19-1 Accounting for Suspended Well Costs on July 1, 2005. FSP 19-1 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 Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. Upon the adoption of FSP 19-1, the Company evaluated all existing capitalized exploratory well costs and determined that there was no impact on the Company s results of operations, financial condition, or cash flows. At September 30, 2005, the Company had $1.2 million of capitalized exploratory drilling costs. All of the costs are related to wells in progress or wells for which drilling has been completed for less than one year.

8. Debt

The Company s long-term debt consisted of the following as of the dates indicated (amounts in thousands):

		September 30, 2005		December 31, 2004
Revolving credit facility	$	49,000	$	79,000
$8^{3}/_{8}$% Senior subordinated notes				150,000
$6^{1}/_{4}$% Senior subordinated notes		150,000		150,000
6% Senior subordinated notes, net of unamortized discount of $5,419		294,581		
	$	493,581	$	379,000

Issuance of 6% Senior Subordinated Notes

On July 13, 2005, the Company issued $300.0 million of its 6% senior subordinated notes due July 15, 2015 (the 6% Notes). The offering was made through a private placement and the notes were resold by the initial purchasers pursuant to Rule 144A and Regulation S. The Company received net proceeds of approximately $294.5 million from the private placement and used approximately $165.9 million of the net proceeds to redeem all of the Company s outstanding $8^{3}/_{8}$% senior subordinated notes due 2012. The remaining net proceeds were used to reduce the balance outstanding under the Company s revolving credit facility.

The Company paid a premium of $15.9 million to redeem the outstanding $8^{3}/_{8}$% senior subordinated notes. Combined with the unamortized balance of the related debt issuance costs, the Company incurred a loss on early redemption of the debt of $19.5 million, which the Company recognized in earnings for the three and nine months ended September 30, 2005.

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The Company filed an exchange offer registration statement on Form S-4 on August 8, 2005, under which the 6% Notes would be exchanged for registered notes with substantially identical terms. The exchange offer was completed on October 7, 2005 and 100% of the notes were exchanged.

The notes mature July 15, 2015 and require semi-annual interest payments on April 15 and October 15. The indenture governing the notes contains certain affirmative and negative covenants, including, without limitation, limitations on our ability to incur additional debt, sell assets, incur liens, make investments and consolidate, merge or transfer assets.

Revolving 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%.

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 according to the terms of the credit facility.

Letters of Credit

The Company had $75.1 million of outstanding letters of credit at September 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. Any outstanding letters of credit reduce the availability under the Company s revolving credit facility. As a result, the Company s availability under its revolving credit facility was reduced to $325.9 million at September 30, 2005.

9. Income Taxes

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

	Nine months ended September 30,	
	2005	**2004**
Income before income taxes	$ 99,287	$ 85,934
Tax at statutory rate	34,750	30,077
State income taxes, net of federal benefit	1,911	2,578
Section 43 credits generated	(2,664)	(2,507)
Permanent differences and other	(1,016)	(121)
Income tax provision	$ 32,981	$ 30,027

10. Earnings Per Share (EPS)

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

	Three months ended September 30,		Nine months ended September 30,	
	2005	**2004**	**2005**	**2004**
Numerator:				
Net income	$ 20,854	$ 21,014	$ 66,306	$ 55,907
Denominator:				
Denominator for basic earnings per share Weighted average shares outstanding	48,703	48,446	48,659	46,611

Effect of dilutive options and dilutive restricted stock (a)	881	657	822	611
Denominator for diluted earnings per share	49,584	49,103	49,481	47,222
Net income per common share:				
Basic	$ 0.43	$ 0.43	$ 1.36	$ 1.20
Diluted	$ 0.42	$ 0.43	$ 1.34	$ 1.18

(a) There were no shares of antidilutive outstanding employee stock options for the quarter ended September 30, 2005. For the quarter ended September 30, 2004, outstanding employee stock options of 37,500 were excluded from the calculation of diluted earnings per share because their effect would have been antidilutive.

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11. Stockholders Equity

On June 15, 2005, the Company announced that its Board of Directors approved a three-for-two split of the Company s outstanding common stock in the form of a stock dividend. The dividend was distributed on July 12, 2005, to stockholders of record at the close of business on June 27, 2005 (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 balances of additional paid-in-capital and common stock at December 31, 2004 have been adjusted accordingly and all share and per-share information included in the accompanying consolidated financial statements and related notes thereto for all periods presented have been adjusted to retroactively reflect the stock split.

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.

12. Comprehensive Income (Loss)

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

	Three months ended September 30,		Nine months ended September 30,	
	2005	**2004**	**2005**	**2004**
Net income	$ 20,854	$ 21,014	$ 66,306	$ 55,907
Change in unrealized loss on derivative hedged instruments	(23,708)	(22,107)	(53,864)	(39,644)
Change in deferred gain on interest rate swap	(53)	68	(315)	294
Comprehensive income	$ (2,907)	$ (1,025)	$ 12,127	$ 16,557

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

	September 30, 2005	December 31, 2004
Unrealized loss on derivative hedged instruments	$ (90,705)	$ (36,841)
Deferred gain on interest rate swap	129	444
Accumulated other comprehensive loss	$ (90,576)	$ (36,397)

13. Financial Statements of Subsidiary Guarantors

As of September 30, 2005, all of the Company s subsidiaries were subsidiary guarantors of the Company s outstanding $6^1/4$% and 6% 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.

14. Related Party Transactions

The Company paid to Hanover Compressor Company $0.8 million and $0.1 million in the first nine 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.

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15. Subsequent Events

Crusader Acquisition

On October 14, 2005, the Company completed the acquisition of Crusader Energy Corporation, a privately held, independent oil and natural gas company, for a purchase price of approximately $93.5 million. Encore funded the purchase price by drawing on its revolving credit facility.

Kerr-McGee Acquisition

On October 19, 2005, the Company entered into an agreement with Kerr-McGee Corporation to acquire oil and natural gas properties for $104.0 million. The transaction is expected to close at the end of November 2005. Encore expects to fund the purchase price through internally generated cash flow and borrowings under its revolving credit facility.

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.

Introduction

This management s discussion and analysis of financial condition and results of operations is intended to provide investors with an understanding of the Company s recent performance, its financial condition and its prospects. The following will be discussed and analyzed:

- Third Quarter 2005 Highlights
- Results of Operations
  - Comparison of Quarter Ended September 30, 2005 to Quarter Ended September 30, 2004
  - Comparison of Nine Months Ended September 30, 2005 to Nine Months Ended September 30, 2004
- Capital Resources
- Capital Commitments
- Liquidity

Third Quarter 2005 Highlights

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

- During the third quarter of 2005, we had oil and natural gas revenues of $127.6 million. This represents a 61% increase over the $79.2 million of oil and natural gas revenues reported for the third quarter of 2004.

- We reported net income of $20.9 million, or $0.42 per diluted share, in the three months ended September 30, 2005. This represents a marginal decrease from the $21.0 million of net income, or $0.43 per diluted share, reported for the third quarter of 2004. The reduction in net income was due to a one-time $19.5 million loss on early redemption of debt related to redemption premiums and the expensing of unamortized debt issuance costs related to the $8^{3}/_{8}$% senior subordinated notes.

- Our realized average oil price, including the effects of hedging, increased $16.57 per Bbl in the third quarter of 2005 over the same period in 2004. Our realized average natural gas price, including the effects of hedging, increased $2.48 per Mcf in the third quarter of 2005 over the same period in 2004.

- Production volumes for the quarter increased 9% to 28,202 BOE per day (2.6 MMBOE for the quarter), compared with third quarter 2004 production of 25,779 BOE per day (2.4 MMBOE for the quarter). 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 65% and 71% of our total production volumes in the third quarter of 2005 and 2004, respectively.

- On July 13, 2005, the Company issued $300.0 million of 6% senior subordinated notes due 2015. The Company received net proceeds of approximately $294.5 million from the issuance and used approximately $165.9 million of the net proceeds to redeem all of the outstanding principal and related accrued interest of the Company s $8^{3}/_{8}$% senior subordinated notes. The remaining proceeds were used to reduce our indebtedness under our revolving credit facility.

We invested $125.0 million in oil and natural gas activities during the third quarter of 2005 (excluding development-related asset retirement obligations). We invested $92.6 million in development, exploitation, expanding our HPAI program in the CCA, and exploration activities, which yielded 84 gross (56.1 net) wells. We also invested $32.4

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million in acquiring proved properties and undeveloped leases. We are currently investing capital in an eleven-rig operated drilling program on the onshore continental United States, with four rigs in Montana, two rigs in East Texas, two rigs in West Texas, and three rigs in the Mid-Continent area.

We were able to fund $86.7 million of our investments in oil and natural gas activities using operating cash flows generated during the quarter. The remaining $38.3 million was funded through borrowings under our existing revolving credit facility. Long-term debt at September 30, 2005 increased to $493.6 million from $379.0 million at December 31, 2004.

Results of Operations

Comparison of Quarter Ended September 30, 2005 to Quarter Ended September 30, 2004

Below is a comparison of our operations during the third quarter of 2005 with the third quarter of 2004.

Revenues and Production. The following table illustrates the primary components of oil and natural gas revenues for the three months ended September 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 September 30,		Increase / (Decrease)	
	2005	**2004**	*$*	*%*
Revenues:				
Oil wellhead	$ 97,563	$ 68,484	*$ 29,079*	
Oil hedges	(12,004)	(10,241)	*(1,763)*	
Total Oil Revenues	$ 85,559	$ 58,243	*$ 27,316*	*47%*
Natural gas wellhead	$ 46,515	$ 21,551	*$ 24,964*	
Natural gas hedges	(4,502)	(542)	*(3,960)*	
Total Natural Gas Revenues	$ 42,013	$ 21,009	*$ 21,004*	*100%*
Combined wellhead	$ 144,078	$ 90,035	*$ 54,043*	
Combined hedges	(16,506)	(10,783)	*(5,723)*	
Total Combined Revenues	$ 127,572	$ 79,252	*$ 48,320*	*61%*
Revenues ($/Unit):				
Oil wellhead	$ 58.09	$ 40.41	*$ 17.68*	
Oil hedges	(7.15)	(6.04)	*(1.11)*	
Total Oil Revenues	$ 50.94	$ 34.37	*$ 16.57*	*48%*
Natural gas wellhead	$ 8.47	$ 5.30	*$ 3.17*	
Natural gas hedges	(0.82)	(0.13)	*(0.69)*	
Total Natural Gas Revenues	$ 7.65	$ 5.17	*$ 2.48*	*48%*

Combined wellhead	$ 55.52	$ 37.97	*$ 17.55*	
Combined hedges	(6.35)	(4.55)	*(1.80)*	
Total Combined Revenues	$ 49.17	$ 33.42	*$ 15.75*	*47%*
Total production volumes:				
Oil (Bbls)	1,680	1,695	*(15)*	
Natural gas (Mcf)	5,489	4,063	*1,426*	
Combined (BOE)	2,595	2,372	*223*	*9%*
Daily production volumes:				
Oil (Bbls/day)	18,257	18,419	*(162)*	
Natural gas (Mcf/day)	59,666	44,160	*15,506*	
Combined (BOE/day)	28,202	25,779	*2,423*	*9%*
NYMEX Prices:				
Oil (per Bbl)	$ 63.19	$ 43.92	*$ 19.27*	*44%*
Natural gas (per Mcf)	9.64	5.56	*4.08*	*73%*

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Oil revenues increased from third quarter 2004 to third quarter 2005 by $27.3 million, due primarily to a higher realized average oil price. Our realized average oil price increased $16.57 per Bbl in the third quarter of 2005 over the same period in 2004 as a result of an increase in our average wellhead price of $17.68 per Bbl, offset by an increase in hedging payments of $1.11 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 increase in the average NYMEX price from $43.92 for the third quarter of 2004 to $63.19 for the third quarter of 2005.

Natural gas revenues increased by $21.0 million, or $2.48 per Mcf, in the third quarter of 2005 from the third quarter of 2004 due to an increase in volumes and an increase in our realized average natural gas price. Production volumes increased 1,426 MMcf in the third quarter of 2005 as compared to the third quarter of 2004 due to drilling activities. The $2.48 per Mcf increase in our realized average natural gas price was due to the $3.17 per Mcf increase in the wellhead price for our natural gas from the third quarter of 2004 to the third quarter of 2005, offset by an increase in hedging payments of $0.69 per Mcf. The average NYMEX price for natural gas increased from $5.56 for the third quarter of 2004 to $9.64 for the third quarter of 2005.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices for the quarters ended September 30, 2005 and 2004. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Three months ended September 30,	
	2005	**2004**
Oil wellhead ($/Bbl)	$ 58.09	$ 40.41
Average NYMEX ($/Bbl)	$ 63.19	$ 43.92
Differential to NYMEX	$ (5.10)	$ (3.51)
Oil wellhead to NYMEX percentage	92%	92%
Natural gas wellhead ($/Mcf)	$ 8.47	$ 5.30
Average NYMEX ($/Mcf)	$ 9.64	$ 5.56
Differential to NYMEX	$ (1.17)	$ (0.26)
Natural gas wellhead to NYMEX percentage	88%	95%

As indicated above, our differential to the average NYMEX price of oil increased on a per unit basis while our oil wellhead price as a percentage of the average NYMEX price remained consistent from the third quarter of 2004 to the third quarter of 2005

Our natural gas wellhead price as a percentage of the average NYMEX price decreased from the third quarter of 2004 to the third quarter of 2005. The decrease is primarily due to regional natural gas spot prices lagging the significant increases in the NYMEX price during the third quarter of 2005.

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

	Three months ended September 30, 2005	2004	*Increase / (Decrease) $*	*%*
Expenses (in thousands):				
Production				
Lease operations	$ 17,912	$ 12,589	*$ 5,323*	
Production, ad valorem, and severance taxes	12,526	8,117	*4,409*	
Total production expenses	30,438	20,706	*9,732*	*47%*
Other				
Depletion, depreciation, and amortization	24,222	12,750	*11,472*	
Exploration	4,818	462	*4,356*	
General and administrative (excluding non-cash stock based compensation)	4,030	2,858	*1,172*	
Non-cash stock based compensation	1,544	796	*748*	
Derivative fair value loss	1,612	2,301	*(689)*	
Loss on early redemption of debt	19,477		*19,477*	
Other operating	2,520	1,369	*1,151*	
Total operating	88,661	41,242	*47,419*	*115%*
Interest	9,264	6,547	*2,717*	
Current and deferred income tax provision	9,373	10,527	*(1,154)*	
Total expenses	$ 107,298	$ 58,316	*$ 48,982*	*84%*
Expenses (per BOE):				
Production				
Lease operations	$ 6.90	$ 5.31	*$ 1.59*	
Production, ad valorem, and severance taxes	4.83	3.42	*1.41*	
Total production expenses	11.73	8.73	*3.00*	*34%*
Other				
Depletion, depreciation, and amortization	9.34	5.38	*3.96*	
Exploration	1.86	0.19	*1.67*	
General and administrative (excluding non-cash stock based compensation)	1.55	1.21	*0.34*	
Non-cash stock based compensation	0.59	0.34	*0.25*	
Derivative fair value loss	0.62	0.97	*(0.35)*	
Loss on early redemption of debt	7.51		*7.51*	
Other operating	0.97	0.58	*0.39*	
Total operating	34.17	17.40	*16.77*	*96%*
Interest	3.57	2.76	*0.81*	
Current and deferred income tax provision	3.61	4.44	*(0.83)*	
Total expenses	$ 41.35	$ 24.60	*$ 16.75*	*68%*

Production expenses (Lease operations and production, ad valorem, and severance taxes). Total production expenses for the third quarter of 2005 increased $9.7 million as compared to the third quarter of 2004. This increase resulted from an increase in total production volumes, as well as a $3.00 increase in production expenses per BOE in the third quarter of 2005 as compared to the third quarter of 2004. The $3.00 increase in production expenses per BOE in the third quarter of 2005 represents a 34% increase over the third quarter of 2004. The 34% increase in total production expenses per BOE is less than the 47% increase in revenues per BOE over the same period, resulting in a higher production margin.

The production expense attributable to lease operations for the third quarter of 2005 increased as compared to the third quarter of 2004 by $5.3 million. The increase in total lease operations expense resulted from: (1) an increase in production volumes as a result of our 2005 drilling program and our high-pressure air injection (HPAI) program; (2) an increase in prices paid for outside services in the current higher price environment, increased operational activity to maximize production, and the operation of higher operating cost wells as lower margin wells become more attractive in the current higher price environment; and (3) the expensing of HPAI production costs attributable to Little Beaver Phase I that previously were being capitalized during the pressurization phase.

The production expense attributable to production, ad valorem, and severance taxes for the third quarter of 2005 increased as compared to the same period in 2004 by approximately $4.4 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 third quarter of 2005 decreased to 8.7% from 9.0% in the third 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.

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Depletion, depreciation, and amortization (DD&A) expense. DD&A expense for the third quarter of 2005 increased by $11.5 million as compared to the third quarter of 2004, due to a $3.96 per BOE increase and an increase in production. This per BOE rate increase was due to the development of proved undeveloped reserves from the 2004 acquisitions and higher drilling costs per BOE of reserves than our historical DD&A rate in certain areas.

Exploration expense. Exploration expense was $4.8 million in the third quarter of 2005, while it was $0.5 million in the third quarter of 2004. During the third quarter of 2005, we expensed 21 exploratory dry holes totaling $3.6 million. Out of the 21 exploratory dry holes expensed, one was drilled in the CCA and twenty were drilled in the shallow gas area of Montana. In the third quarter of 2004, we did not expense any dry holes. The following table details our exploration-related expenses for the third quarter of 2005 and 2004 (in thousands):

	Three months ended September 30, 2005	Three months ended September 30, 2004	*Increase / (Decrease)*
Exploration expenses:			
Dry hole	$ 3,604	$	*$ 3,604*
Geological and geophysical	305	64	*241*
Seismic	352	18	*334*
Delay rental	169	40	*129*
Impairment of undeveloped leasehold	388	340	*48*
Total	$ 4,818	$ 462	*$ 4,356*

General and administrative (G&A) expense. G&A expense (excluding non-cash stock based compensation) increased $1.2 million for the third quarter of 2005 as compared to the third quarter of 2004. The overall increase, as well as the $0.34 increase in the per BOE rate, is a result of increased staffing to manage our larger asset base and higher activity levels. 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 third 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. Amortization of deferred compensation increased from the same period in 2004 primarily due to third quarter 2005 amortization related to 269,555 shares of restricted stock granted in the nine months ended September 30, 2005. In addition, certain restricted stock grants contain performance vesting provisions, which require us to recognize periodic expense based on the Company s current stock price, rather than the stock price at the day of grant. As a result, the Company s higher stock price has also resulted in increased amortization expense.

Derivative fair value loss. During the third quarter of 2005 we recorded a $1.6 million derivative fair value loss as compared to the $2.3 million loss recorded in the third 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 third quarter of 2005 and 2004 are as follows (in thousands):

	Three months ended September 30, 2005	Three months ended September 30, 2004	*Increase / (Decrease)*
Designated cash flow hedges:			
Ineffectiveness Commodity contracts	$ 2,211	$ 2,740	*$ (529)*
Undesignated derivative contracts:			

Mark-to-market (gain) loss	Interest rate swap		(383)		*383*
Mark-to-market (gain) loss	Commodity contracts	(599)	(56)		*(543)*
Derivative fair value loss		$ 1,612	$ 2,301	*$*	*(689)*

Ineffectiveness loss related to our derivative commodity contracts decreased $0.5 million due primarily to fewer loss positions on our natural gas contracts offset by an increased oil wellhead differential on our production in the CCA. We currently do not have any interest rate swap contracts outstanding as our fixed-to-floating interest rate swap expired in June 2005. The gain related to undesignated commodity contracts increased $0.5 million from the prior year three month period due to changes in the fair value of certain natural gas basis swaps.

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Loss on early redemption of debt. In the third quarter of 2005, we recorded a one-time $19.5 million loss on early redemption of debt related to the redemption premium and the expensing of unamortized debt issuance costs of the $8^3/_8$% senior subordinated notes. We redeemed the $8^3/_8$% notes with proceeds received from the issuance of our $300.0 million 6% senior subordinated notes in July 2005.

Other operating expense. Other operating expense for the third quarter 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 third quarter of 2005 over the same period in 2004.

Interest expense. Interest expense increased $2.7 million in the third quarter of 2005 compared to the third quarter of 2004. The increase is primarily due to the issuance of $300.0 million of 6% senior subordinated notes in July 2005. The increase is offset by the redemption of $150.0 million of $8^3/_8$% senior subordinated notes in August 2005. The weighted average interest rate, net of hedges, for the quarter ended September 30, 2005 was 6.9% compared to 7.1% for the quarter ended September 30, 2004. This lower weighted average interest rate is the result of the issuance of 6% notes which has a rate lower than our historical average rate.

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

	Three months ended September 30, 2005	Three months ended September 30, 2004	*Increase / (Decrease)*
$8^3/_8$% notes due 2012	$ 1,570	$ 3,141	*$ (1,571)*
$6^1/_4$% notes due 2014	2,344	2,344	
6% notes due 2015	3,937		*3,937*
Revolving credit facility	675	467	*208*
Letters of credit	219	77	*142*
Interest rate hedges (1)	(94)	109	*(203)*
Debt issuance cost	255	248	*7*
Banking fees and other	358	161	*197*
Total	$ 9,264	$ 6,547	*$ 2,717*

(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.

Income taxes. Income tax expense for the third quarter of 2005 decreased $1.2 million over the same period in 2004. This decrease is due in part to a decrease of $1.3 million in income before income taxes, resulting from a one-time loss on early redemption of debt of $19.5 million recorded in the third quarter of 2005. In addition, various permanent differences and adjustments to state tax rates in the third quarter of 2005 increased from the third quarter of 2004, resulting in a decrease in our effective tax rate from 33.4% for the third quarter of 2004 to 31.0% for the third quarter of 2005.

Included in net income tax expense for the three months ended September 30, 2005 is a current income tax benefit of $2.9 million which is driven primarily by the generation of net operating tax losses on the Company s 2004 income tax returns filed during the third quarter of 2005. The Company expects these tax losses to offset previously expected 2005 taxable income, minimizing any current year income tax liabilities.

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Comparison of Nine Months Ended September 30, 2005 to Nine Months Ended September 30, 2004

Below is a comparison of our operations during the first nine months of 2005 with the first nine months of 2004.

Revenues and Production. The following table illustrates the primary components of oil and natural gas revenues for the nine months ended September 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):

	Nine months ended September 30,		*Increase / (Decrease)*	
	2005	2004	*$*	*%*
Revenues:				
Oil wellhead	$ 254,461	$ 181,500	*$ 72,961*	
Oil hedges	(32,207)	(23,608)	*(8,599)*	
Total Oil Revenues	$ 222,254	$ 157,892	*$ 64,362*	*41%*
Natural gas wellhead	$ 104,639	$ 52,420	*$ 52,219*	
Natural gas hedges	(8,023)	(1,647)	*(6,376)*	
Total Natural Gas Revenues	$ 96,616	$ 50,773	*$ 45,843*	*90%*
Combined wellhead	$ 359,100	$ 233,920	*$ 125,180*	
Combined hedges	(40,230)	(25,255)	*(14,975)*	
Total Combined Revenues	$ 318,870	$ 208,665	*$ 110,205*	*53%*
Revenues ($/Unit):				
Oil wellhead	$ 50.07	$ 36.35	*$ 13.72*	
Oil hedges	(6.34)	(4.73)	*(1.61)*	
Total Oil Revenues	$ 43.73	$ 31.62	*$ 12.11*	*38%*
Natural gas wellhead	$ 7.04	$ 5.35	*$ 1.69*	
Natural gas hedges	(0.54)	(0.17)	*(0.37)*	
Total Natural Gas Revenues	$ 6.50	$ 5.18	*$ 1.32*	*25%*
Combined wellhead	$ 47.49	$ 35.30	*$ 12.19*	
Combined hedges	(5.32)	(3.81)	*(1.51)*	
Total Combined Revenues	$ 42.17	$ 31.49	*$ 10.68*	*34%*
Total production volumes:				
Oil (Bbls)	5,082	4,994	*88*	

Natural gas (Mcf)	14,874	9,796	*5,078*	
Combined (BOE)	7,561	6,626	*935*	*14%*
Daily production volumes:				
Oil (Bbls/day)	18,616	18,226	*390*	
Natural gas (Mcf/day)	54,482	35,751	*18,731*	
Combined (BOE/day)	27,697	24,184	*3,513*	15%
NYMEX Prices:				
Oil (per Bbl)	$ 55.40	$ 39.13	*$ 23.20*	*59%*
Natural gas (per Mcf)	7.69	5.78	*2.87*	*50%*

Oil revenues increased from the first nine months of 2004 to the first nine months of 2005 by $64.4 million, due primarily to a higher realized average oil price. Our realized average oil price increased $12.11 per Bbl in the nine months ended September 30, 2005 over the same period in 2004 as a result of an increase in our average wellhead price of $13.72 per Bbl, offset by an increase in hedging payments of $1.61 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 increase in the average NYMEX price from $39.13 for the first nine months of 2004 to $55.40 to the first nine months of 2005.

Natural gas revenues increased by $45.8 million, or $1.32 per Mcf, in the first nine months of 2005 from the first nine months of 2004 due to an increase in volumes and an increase in our realized average natural gas price. Production volumes increased 5,078 MMcf in the nine months ended September 30, 2005 as compared to the same period in 2004 due to our drilling activities and the 2004 Overton and Cortez acquisitions. The $1.32 per Mcf increase in our realized average natural gas price was due to the $1.69 per Mcf increase in the wellhead price for our natural gas from the first nine months of 2004 to the same period in

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2005, offset by an increase in hedging payments of $0.37 per Mcf. The average NYMEX price for natural gas increased from $5.78 for the first nine months of 2004 to $7.69 to the first nine months of 2005.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices for the nine months ended September 30, 2005 and 2004. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Nine months ended September 30,	
	2005	**2004**
Oil wellhead ($/Bbl)	$ 50.07	$ 36.35
Average NYMEX ($/Bbl)	$ 55.40	$ 39.13
Differential to NYMEX	$ (5.33)	$ (2.78)
Oil wellhead to NYMEX percentage	90%	93%
Natural gas wellhead ($/Mcf)	$ 7.04	$ 5.35
Average NYMEX ($/Mcf)	$ 7.69	$ 5.78
Differential to NYMEX	$ (0.65)	$ (0.43)
Natural gas wellhead to NYMEX percentage	92%	93%

As indicated above, our differentials to the average NYMEX price increased on a per unit basis while our wellhead prices as a percentage of the average NYMEX prices remained fairly consistent from the first nine months of 2004 to the first nine months of 2005.

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Expenses. The following table summarizes our expenses for the nine months ended September 30, 2005 and 2004:

	Nine months ended September 30, 2005	2004	*Increase / (Decrease $*	*%*
Expenses (in thousands):				
Production				
Lease operations	$ 48,501	$ 33,752	*$ 14,749*	
Production, ad valorem, and severance taxes	31,425	21,117	*10,308*	
Total production expenses	79,926	54,869	*25,057*	46%
Other				
Depletion, depreciation, and amortization	59,943	33,262	*26,681*	
Exploration	11,201	2,159	*9,042*	
General and administrative (excluding non-cash stock based compensation)	11,236	7,616	*3,620*	
Non-cash stock based compensation	3,323	1,413	*1,910*	
Derivative fair value loss	5,713	3,424	*2,289*	
Loss on early redemption of debt	19,477		*19,477*	
Other operating	5,822	3,462	*2,360*	
Total operating	196,641	106,205	*90,436*	85%
Interest	23,671	16,761	*6,910*	
Current and deferred income tax provision	32,981	30,027	*2,954*	
Total expenses	$ 253,293	$ 152,993	*$ 100,300*	66%
Expenses (per BOE):				
Production				
Lease operations	$ 6.41	$ 5.09	*$ 1.32*	
Production, ad valorem, and severance taxes	4.16	3.19	*0.97*	
Total production expenses	10.57	8.28	*2.29*	28%
Other				
Depletion, depreciation, and amortization	7.93	5.02	*2.91*	
Exploration	1.48	0.33	*1.15*	
General and administrative (excluding non-cash stock based compensation)	1.49	1.15	*0.34*	
Non-cash stock based compensation	0.44	0.21	*0.23*	
Derivative fair value loss	0.75	0.52	*0.23*	
Loss on early redemption of debt	2.58		*2.58*	
Other operating	0.77	0.52	*0.25*	
Total operating	26.01	16.03	*9.98*	62%
Interest	3.13	2.53	*0.60*	
Current and deferred income tax provision	4.36	4.53	*(0.17)*	
Total expenses	$ 33.50	$ 23.09	*$ 10.41*	45%

Production expenses (Lease operations and production, ad valorem, and severance taxes). Production expenses for the first nine months of 2005 increased $25.1 million as compared to the same period in 2004. This increase resulted from an increase in total production volumes, as well as a $2.29 increase in production expenses per BOE in the first nine months of 2005 as compared to the first nine months of 2004. The $2.29 increase in production expenses per BOE represents a 28% increase over the nine months ended September 30, 2004. The 28% increase in total production expenses per BOE is less than the 34% increase in revenues per BOE over the same period, resulting in a higher production margin.

The production expense attributable to lease operations for the first nine months of 2005 increased as compared to the same period in 2004 by $14.7 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, which closed at various times in the first nine months of 2004; and our high-pressure air injection program. The increase in our average per BOE rate was attributable to increases in prices paid for outside services due to a current higher price environment, increased operational activity to maximize production, and the operation of higher operating cost wells as lower margin wells become more attractive in the current higher price environment.

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The production expense attributable to production, ad valorem, and severance taxes for the nine months ended September 30, 2005 increased as compared to the same period in 2004 by approximately $10.3 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 nine months of 2005 decreased slightly from 9.0% in the first nine months of 2004 to 8.8% in the first nine 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 nine months of 2005 increased by $26.7 million as compared to the same period in 2004, due to a $2.91 per BOE increase and an increase in production. This per BOE rate increase was due to the development of proved undeveloped reserves from the 2004 acquisitions and higher drilling costs per BOE of reserves than our historical DD&A rate in certain areas.

Exploration expense. Exploration expense increased $9.0 million in the nine months ended September 30, 2005 as compared to the same period in 2004. During the first nine months of 2005, we expensed 38 exploratory dry holes totaling $6.9 million. Of the 38 exploratory dry holes expensed, one was drilled in the Permian Basin, 35 were drilled in the shallow gas area of Montana, and two were drilled in the CCA. In the first nine months 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):

	Nine months ended September 30,		
	2005	**2004**	***Increase / (Decrease)***
Exploration expenses:			
Dry hole	$ 6,935	$ 1,436	*$ 5,499*
Geological and geophysical	934	149	*785*
Seismic	1,441	19	*1,422*
Delay rental	545	65	*480*
Impairment of undeveloped leasehold	1,346	490	*856*
Total	$ 11,201	$ 2,159	*$ 9,042*

General and administrative (G&A) expense. G&A expense (excluding non-cash stock based compensation) increased $3.6 million for the first nine months of 2005 as compared to the same period in 2004. The overall increase, as well as the $0.34 increase in the per BOE rate, is a result of increased staffing to manage our larger asset base and higher activity levels. 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 nine months ended September 30, 2005 increased $1.9 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. Amortization of deferred compensation increased from the same period in 2004 primarily due to amortization recorded in the first nine months of 2005 related to 269,555 shares of restricted stock granted in the nine months ended September 30, 2005. In addition, certain restricted stock grants contain performance vesting provisions which require us to recognize periodic expense based on the Company s current stock price, rather than the stock price at the day of grant. As a result, the Company s higher stock price has also resulted in increased amortization expense.

Derivative fair value loss. During the nine months ended September 30, 2005, we recorded a $5.7 million derivative fair value loss as compared to a $3.4 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 nine months ended September 30, 2005 and 2004 are as follows (in thousands):

		Nine months ended September 30, 2005	2004	*Increase / (Decrease)*
Designated cash flow hedges:				
Ineffectiveness	Commodity contracts	$ 6,878	$ 3,195	*$ 3,683*
Undesignated derivative contracts:				
Mark-to-market (gain) loss	Interest rate swap	150	37	*113*
Mark-to-market (gain) loss	Commodity contracts	(1,315)	192	*(1,507)*
Derivative fair value loss		$ 5,713	$ 3,424	*$ 2,289*

Ineffectiveness loss related to our derivative commodity contracts increased $3.7 million due primarily to an increase in oil wellhead differentials on our production in the CCA. We currently do not have any interest rate swap contracts outstanding as our fixed-to-floating interest rate swap expired in June 2005. The ineffectiveness loss is offset by a $1.3 million gain related to undesignated commodity contracts which increased due to changes in the fair value of certain natural gas basis swaps.

Loss on early redemption of debt. In the third quarter of 2005, we recorded a one-time $19.5 million loss on early redemption of debt related to the redemption premium and the write-off of unamortized debt issuance costs of the $8^{3}/_{8}$% senior subordinated notes. We redeemed the $8^{3}/_{8}$% notes with proceeds received from the issuance of our $300.0 million 6% senior subordinated notes in July 2005.

Other operating expense. Other operating expense for the first nine months of 2005 increased by $2.4 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 nine months of 2005 over the same period in 2004.

Interest expense. Interest expense increased $6.9 million in the nine months ended September 30, 2005 from the nine months ended September 30, 2004. The increase is primarily due to the issuance of $300.0 million of 6% senior subordinated notes in July 2005 and $150.0 million of $6^{1}/_{4}$% senior subordinated notes in April 2004. These increases are offset by the redemption of $150.0 million of $8^{3}/_{8}$% senior subordinated notes in August 2005. The weighted average interest rate, net of hedges, for the nine months ended September 30, 2005 was 7.5% compared to 7.7% for the nine months ended September 30, 2004. This lower weighted average interest rate is the result of the debt issuances which haves rates lower than our historical average rate.

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

	Nine months ended September 30,		***Increase /***
	2005	**2004**	***(Decrease)***
$8^{3}/_{8}$% notes due 2012	$ 7,851	$ 9,422	*$ (1,571)*
$6^{1}/_{4}$% notes due 2014	7,031	4,661	*2,370*
6% notes due 2015	3,937		*3,937*
Revolving credit facility	2,972	908	*2,064*
Letters of credit	473	99	*374*
Interest rate hedges (1)	(126)	475	*(601)*
Debt issuance cost	783	706	*77*
Banking fees and other	750	490	*260*
Total	$ 23,671	$ 16,761	*$ 6,910*

(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.

Income taxes. Income tax expense for the first nine months of 2005 increased $3.0 million over the same period in 2004. This increase is due primarily to an increase of $13.4 million in income before income taxes, offset by a decrease in our effective tax rate from 34.9% for the first nine months of 2004 to 33.2% for the first nine months of 2005, resulting from an increase in various permanent differences and state tax rate adjustments in the third quarter of 2005.

Capital Resources

Our primary capital resources are as follows:

- Cash Flows from Operating Activities
- Cash Flows from Financing Activities
- Current Capitalization

Cash Flows from Operating Activities. Cash provided by operating activities increased $77.1 million from $127.1 million for the nine months ended September 30, 2004 to $204.2 million for the nine months ended September 30, 2005. This increase resulted mainly from increases in revenues due to increased volumes and increased commodity prices. Our production volumes increased 935 MBOE from 6,626 MBOE in the first nine months of 2004 to 7,561 MBOE in the first nine months of 2005. Our oil prices received increased $12.11 per Bbl from $31.62 per Bbl in the first nine months of 2004 to $43.73 in the same period in 2005, and our realized natural gas prices increased $1.32 per Mcf from $5.18 in the nine months ended September 30, 2004 to $6.50 in the nine months ended September 30, 2005. Oil and natural gas prices are expected to remain higher than historical averages through the end of 2005 due to limited offshore production resulting from hurricanes and a general increase in worldwide demand for oil and natural gas.

Cash Flows from Financing Activities. Our cash flows from financing activities consist primarily of proceeds from and payments on long-term debt. During the first nine months of 2005, we received net cash of $94.3 million from financing activities.

On July 13, 2005, we issued $300.0 million of 6% senior subordinated notes. We received net proceeds of approximately $294.4 million from the issuance and used approximately $165.8 million of the net proceeds to redeem all of the outstanding principal of the Company s 8 3/8% senior subordinated notes and to pay related early redemption premiums.

The remaining proceeds from the 6% senior subordinated notes were used to reduce our indebtedness under our revolving credit facility, resulting in an overall decrease in the outstanding balance of $30.0 million during the nine months ended September 30, 2005.

Current Capitalization. At September 30, 2005, Encore had total assets of $1.4 billion. Total capitalization as of September 30, 2005 was $984.8 million, of which 50% was represented by stockholders equity and 50% by long-term debt. At December 31, 2004, we had total assets of $1.1 billion. Total capitalization as of December 31, 2004 was $852.6 million, of which 56% was represented by stockholders equity and 44% by senior debt. We expect the percentage of our capitalization represented by stockholders equity to decrease and the percentage of our capitalization represented by debt to increase as a result of debt financed acquisitions in the fourth quarter of 2005.

Capital Commitments

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 and leasehold and acreage costs
- Other general property and equipment
- Funding of necessary working capital
- Payment of contractual obligations

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

	Three months ended September 30, 2005	Three months ended September 30, 2004	*Increase/ (Decrease)*	Nine months ended September 30, 2005	Nine months ended September 30, 2004	*Increase/ (Decrease)*
Development, Exploitation, and Exploration Expenditures:						
Development and exploitation	$ 67,181	$ 32,659	*$ 34,522*	$ 168,065	$ 80,814	*$ 87,251*
Exploration	16,359	10,751	*5,608*	44,762	16,427	*28,335*
HPAI	9,854	9,286	*568*	27,095	26,199	*896*
Total	$ 93,394	$ 52,696	$ *40,698*	$ 239,922	$ 123,440	*$ 116,482*

Development, Exploitation, and Exploration. Our expenditures for 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 September 30, 2005 included a total of 61 gross (36.4 net) successful wells. We did not drill any development dry holes during the third quarter of 2005.

Our development drilling capital for the first nine months of 2005 included 196 gross (121.6 net) successful development wells, and 5 gross (1.1 net) developmental dry holes. We currently have 11 operated rigs drilling on the onshore continental United States with 4 rigs in Montana, 2 rigs in East Texas, 2 rigs in West Texas, and 3 rigs running in the Mid Continent area.

Our expenditures for exploration investments primarily relate to drilling exploratory wells, seismic, delay rentals, and geological and geophysical costs. During the three months ended September 30, 2005, our exploration capital included 2 (1.2 net) exploratory wells that are productive and 21 gross (18.5 net) exploratory dry holes.

During the nine months ended September 30, 2005, our exploration capital yielded 22 (15.9 net) exploratory wells which are productive and 36 gross (31.3 net) exploratory dry holes.

The total exploratory drilling capital incurred was $15.5 million and $41.8 million for the three and nine months ended September 30, 2005, respectively, excluding $.08 million and $2.9 million in seismic, delay rentals, and geological and geophysical costs.

For the remainder of 2005, we expect to invest $88.0 million in development, exploitation, and exploration activities.

High-Pressure Air Injection Programs. 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 with a 225 barrel per day increase over the forecasted production decline prior to the initiation of the project.

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.

For the remainder of 2005, we expect to invest $7.0 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 nine months ended September 30, 2005 and 2004 (in thousands):

	Three months ended September 30,			Nine months ended September 30,		
	2005	**2004**	***Increase/ (Decrease)***	**2005**	**2004**	***Increase/ (Decrease)***
Acquisitions, Leasehold and Acreage Costs:						
Acquisitions	$ 28,890	$ (7,960)	*$ 36,850*	$ 39,547	$ 203,636	*$ (164,089)*
Leasehold and acreage costs	3,502	20,876	*(17,374)*	10,224	30,433	*(20,209)*
Total	$ 32,392	$ 12,916	*$ 19,476*	$ 49,771	$ 234,069	*$ (184,298)*

Acquisitions. Our capital expenditures for proved oil and natural gas properties during the nine months ended September 30, 2005 totaled $39.5 million as compared to $203.6 million in the same period in 2004. The $39.5 million of acquisition capital in the first nine months of 2005 was invested primarily in additional working interests in our ArkLaTx region and the Williston Basin, while the $203.6 million in the first nine months of 2004 was invested primarily in our Cortez and Overton acquisitions.

Fourth Quarter 2005 Acquisitions. On October 14, 2005, we completed the acquisition of Crusader Energy Corporation, a privately held, independent oil and natural gas company for a purchase price of approximately $93.5 million. On October 9, 2005, we entered into an agreement with Kerr-McGee Corporation to acquire oil and natural gas properties for a purchase price of approximately $104.0 million. The transaction is expected to close at the end of November 2005. 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 $0.5 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 September 30, 2005 and 2004 totaled $0.5 million and $1.3 million, respectively. The decrease was due primarily due to higher levels of field equipment purchased in 2004 in anticipation of our expected increased development activities. The $0.5 million incurred for the third quarter of 2005 primarily relate to the purchase of data processing equipment.

Our capital expenditures for other general property and equipment during the nine months ended September 30, 2005 and 2004 totaled $4.6 million and $7.9 million, respectively. The decrease was due primarily due to higher levels of field equipment purchased in 2004 in anticipation of our expected increased development activities. The $4.6 million incurred for the first nine months of 2005 primarily relate to leasehold improvements, field equipment, and data processing equipment purchased.

Funding of Necessary Working Capital. At September 30, 2005, our working capital was $(54.5) million while at December 31, 2004, our working capital was $(15.6) million, a decrease of $38.9 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 the remainder of 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 available 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 $326.0 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 market conditions. We plan to finance our ongoing expenditures using internally generated cash flow, cash on hand, and our existing credit agreement.

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

Contractual Obligations and Capital Commitments	**Payments Due by Period**				
	Total	**2005**	**2006 2007**	**2008 2009**	**Thereafter**
$6^1/4$% notes (a)	$ 234,375	$ 4,687	$ 18,750	$ 18,750	$ 192,188
6% notes (a)	480,000		36,000	36,000	408,000
Revolving credit facility (a)	57,554	663	5,261	51,630	
Derivative obligations (b) (e)	164,707	26,884	137,823		
Operating leases (c)	11,572	340	2,932	2,902	5,398
Asset retirement obligations (d)	82,512	542	1,084	1,084	79,802
Totals	$ 1,030,720	$ 33,116	$ 201,850	$ 110,366	$ 685,388

(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 September 30, 2005. The ultimate settlement amounts of the remaining portions of our derivative obligations are unknown because they are subject to continuing market risk.

(c) Operating leases represent office

space and equipment obligations that have remaining non-cancelable lease terms in excess of one year.

(d) 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.

(e) Subsequent to September 30, 2005, we entered into several additional oil and natural gas derivative contracts related to the expected production from recent acquisitions. We purchased oil swap contracts with total volumes of 1,000 barrels a day at fixed prices between \$57.53 and \$62.09 for various periods between January 2006 and June 2008. We purchased oil floor contracts with total volumes of 2,000 barrels a day with a floor price of $55.00 for the calendar year 2007. In addition, we purchased natural gas floor contracts with total volumes of 10,000 Mcf a day with floor prices between $7.40 and $7.70 for the calendar year 2007. The effects of these contracts are not included in the above table.

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 area. To a lesser extent, our production also depends on transportation through Platte Pipeline to Wood River, Illinois as well as other pipelines connected to the Guernsey, Wyoming area. Any restrictions on the available capacity to transport oil through these pipelines could have a material adverse effect on price received, production volumes, and revenues.

Letters of Credit. As of September 30, 2005, we had $75.1 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. As of November 1, 2005, we had $75.1 million of outstanding letters of credit posted in lieu of cash margin deposits.

Liquidity

Cash on hand, internally generated cash flows and the borrowing capacity under our revolving credit facility are our major sources of liquidity. We also have the ability to adjust our level of capital expenditures. We may use other sources of capital, including the issuance of additional debt securities or equity securities, to fund any major acquisitions we might secure in the future and to maintain our financial flexibility.

Internally Generated Cash Flows. Our internally generated cash flows, results of operations and financing for our operations are dependent on oil and gas prices. Realized oil and gas prices for the first nine months of 2005 were 47% and 34% percent higher, respectively, compared to the first nine months of 2004. These prices have historically fluctuated widely in response to changing market forces. For the first nine months of 2005, approximately 67% of our production was oil. We believe that our cash flows and unused availability under our revolving credit facility are sufficient to fund our planned capital expenditures for the foreseeable future. To the extent oil and gas prices decline, our earnings, cash flows from operations, and availability under our revolving credit facility may be adversely impacted. Prolonged periods of low oil and gas prices could cause us to not be in compliance with maintenance covenants under our revolving credit facility and thereby affect our 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 $400.0 million and may be increased to up to $750.0 million. On April 29, 2005, we amended the credit facility to increase the borrowing base to $500.0 million. In addition, the facility was amended to 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%. Upon the issuance of our $300.0 million 6% senior subordinated notes due July 15, 2015, the borrowing base was decreased according to the terms of the facility to $450.0 million. The amended and restated credit facility matures on August 19, 2009.

On September 30, 2005, we had $49.0 million outstanding under the credit facility. On October 14, 2005, Encore completed the acquisition of Crusader Energy Corporation and funded the purchase price of approximately $93.5 million with borrowings from our credit facility. As a result, we had $149.0 million outstanding under the credit facility at November 1, 2005. On October 19, 2005, Encore entered into an agreement with Kerr-McGee to purchase oil and natural gas properties for a purchase price of $104.0 million. We expect to close the transaction at the end of November 2005 and fund the purchase price with internally generated cash flow and borrowings from our available credit facility.

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.

New Accounting Pronouncements

The effects of new accounting pronouncements are discussed in Note 2 to our unaudited consolidated financial statements included elsewhere in this Form 10-Q.

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 September 30, 2005 are discussed in Note 5 to the accompanying consolidated financial statements. As of September 30, 2005, the fair value of our open commodity derivative contracts was a liability of $126.2 million.

At September 30, 2005, we had total long-term debt of $493.6 million. Included in this amount is $300.0 million senior subordinated debt and $150.0 million senior subordinated debt that bears interest at fixed rates of 6% and $6^1/4$%, respectively. The $300.0 million debt is recorded net of a related discount of $5.4 million. In addition, we had $49.0 million outstanding under our revolving credit facility that bears interest at a fluctuating rate that is linked to LIBOR.

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 September 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.

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There has been no change in our internal control over financial reporting that occurred during the three months ended September 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 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).
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.

Date: November 7, 2005	By: /s/ Robert C. Reeves
	Robert C. Reeves
	Senior Vice President and Chief Accounting Officer