ENCORE ACQUISITION CO
Form 10-Q
November 08, 2006

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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, 2006

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 a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

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

Number of shares of common stock, $0.01 par value, outstanding as of November 2, 2006 52,973,05

ENCORE ACQUISITION COMPANY
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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain information included in this Quarterly Report on Form 10-Q (the   Report   ) and other materials filed with the Securities and Exchange Commission (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 ,   int   plan ,   believe ,   should ,   forecast ,   budget   , and other words and terms of similar meaning. Our actual results may dif 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   Item 1A. Risk Factors   in our Annual Report on Form 10-K for the fiscal year ended December 31, 2005 and in our other filings with the SEC. 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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ENCORE ACQUISITION COMPANY
GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and natural gas industry and in this Report:

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bbl/D. One Bbl per day.

BOE. One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.

BOE/D. One BOE per day.

Encore or the Company. Encore Acquisition Company, a Delaware corporation, together with its subsidiaries.

Gross Wells. The total wells, as the case may be, in which we have a working interest.

LIBOR. London Interbank Offered Rate.

MBbl. One thousand Bbls.

Mcf. One thousand cubic feet of natural gas.

Mcf/D. One Mcf per day.

MBOE. One thousand BOE.

MMBOE. One million BOE.

MMcf. One million Mcf.

Net Wells. Gross wells multiplied, as the case may be, by the percentage working interest owned by us.

NYMEX. New York Mercantile Exchange.

See the Company s Annual Report on Form 10-K for the year ended December 31, 2005 for definitions of additional oil and natural gas terms that may be used in this Report.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

ENCORE ACQUISITION COMPANY
CONSOLIDATED BALANCE SHEETS

(in thousands, except share and per share amounts)

	September 30, 2006 (unaudited)	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 539	$ 1,654
Accounts receivable, net of allowance for doubtful accounts of $365 and $347, respectively	65,612	76,960
Inventory	15,434	11,231
Derivatives	15,837	8,826
Deferred taxes	24,034	29,030
Prepaid expenses	4,432	5,656
Total current assets	125,888	133,357
Properties and equipment, at cost successful efforts method:		
Proved properties	1,929,604	1,691,175
Unproved properties	48,550	37,646
Accumulated depletion, depreciation, and amortization	(335,891)	(255,564)
	1,642,263	1,473,257
Other property and equipment	17,732	15,894
Accumulated depreciation	(7,085)	(5,366)
	10,647	10,528
Goodwill	57,819	59,046
Derivatives	45,076	17,316
Other	22,586	12,201
Total assets	$ 1,904,279	$ 1,705,705
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 16,904	$ 27,281
Accrued and other current	93,148	86,399
Derivatives	41,315	68,850
Deferred premiums on derivative contracts	19,994	7,665

Total current liabilities	171,361	190,195
Derivatives	18,013	44,087
Future abandonment cost	14,865	14,430
Deferred taxes	273,935	213,268
Long-term debt	593,567	673,189
Deferred premiums on derivative contracts	36,109	22,476
Other	1,189	1,279
Total liabilities	1,109,039	1,158,924
Commitments and contingencies (see Note 14)		
Stockholders equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none issued and outstanding		
Common stock, $.01 par value, 144,000,000 shares authorized, 52,973,057 and 48,784,846 issued and outstanding, respectively	530	488
Additional paid-in capital	454,355	316,619
Treasury stock, at cost, none and 11,169 shares, respectively		(375)
Retained earnings	384,825	302,875
Accumulated other comprehensive loss	(44,470)	(72,826)
Total stockholders equity	795,240	546,781
Total liabilities and stockholders equity	$ 1,904,279	$ 1,705,705

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, 2006	Three months ended September 30, 2005	Nine months ended September 30, 2006	Nine months ended September 30, 2005
Revenues:				
Oil	$ 99,516	$ 85,559	$ 268,066	$ 222,254
Natural gas	32,177	42,013	109,050	96,616
Oil marketing	46,004		106,036	
Total revenues	177,697	127,572	483,152	318,870
Expenses:				
Production:				
Lease operations	24,478	18,410	70,332	49,627
Production, ad valorem, and severance taxes	13,560	12,526	38,382	31,425
Depletion, depreciation, and amortization	27,471	24,222	82,479	59,943
Exploration	12,322	4,830	18,347	11,238
General and administrative	6,250	5,064	18,199	13,396
Oil marketing	48,001		105,661	
Derivative fair value loss (gain)	(33,363)	1,612	(20,263)	5,713
Loss on early redemption of debt		19,477		19,477
Other operating	976	2,520	3,573	5,822
Total expenses	99,695	88,661	316,710	196,641
Operating income	78,002	38,911	166,442	122,229
Other income (expenses):				
Interest	(11,261)	(9,264)	(33,766)	(23,671)
Other	463	580	1,012	729
Total other income (expenses)	(10,798)	(8,684)	(32,754)	(22,942)
Income before income taxes	67,204	30,227	133,688	99,287
Current income tax benefit (provision)	(1,607)	2,868	(2,709)	1,478
Deferred income tax provision	(23,462)	(12,241)	(48,673)	(34,459)
Net income	$ 42,135	$ 20,854	$ 82,306	$ 66,306

Net income per common share:				
Basic	$ 0.80	$ 0.43	$ 1.60	$ 1.36
Diluted	$ 0.78	$ 0.42	$ 1.57	$ 1.34
Weighted average common shares outstanding:				
Basic	52,968	48,703	51,481	48,659
Diluted	53,776	49,584	52,375	49,481

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, 2006
(in thousands)
(unaudited)

	Shares of Common Stock	Common Stock	Additional Paid-in Capital	Shares of Treasury Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders Equity
Balance at December 31, 2005	48,785	$ 488	$ 316,619	(11)	$ (375)	$ 302,875	$ (72,826)	$ 546,781
Exercise of stock options and vesting of restricted stock	206	2	3,325					3,327
Purchase of treasury stock				(7)	(176)			(176)
Cancellation of treasury stock	(18)		(195)	18	551	(356)		
Issuance of common stock	4,000	40	127,061					127,101
Non-cash stock-based compensation			7,545					7,545
Components of comprehensive income:								
Net income						82,306		82,306
Change in deferred hedge gain/loss (net of income taxes of $16,834)							28,356	28,356
Total comprehensive income								110,662
Balance at September 30, 2006	52,973	$ 530	$ 454,355		$	$ 384,825	$ (44,470)	$ 795,240

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, 2006	2005
Cash flows from operating activities:		
Net income	$ 82,306	$ 66,306
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, and amortization	82,479	59,943
Dry hole expense	12,542	6,970
Deferred taxes	48,673	34,459
Non-cash stock-based compensation expense	6,797	3,323
Non-cash derivative	(13,013)	11,159
Loss on early redemption of debt		19,477
Other non-cash expense	5,644	2,799
Loss on disposition of assets	395	328
Changes in operating assets and liabilities:		
Accounts receivable	11,579	(25,500)
Other assets	(33,794)	(28,694)
Accounts payable	(2,047)	2,716
Other liabilities	32,821	50,906
Net cash provided by operating activities	234,382	204,192
Cash flows from investing activities:		
Purchases of other property and equipment	(3,450)	(5,663)
Deposit on acquisition of oil and natural gas properties		(5,186)
Acquisition of oil and natural gas properties	(22,809)	(49,770)
Development of oil and natural gas properties	(241,502)	(237,003)
Other	(9,510)	604
Net cash used in investing activities	(277,271)	(297,018)
Cash flows from financing activities:		
Proceeds from issuance of common stock	128,000	
Offering costs paid	(899)	
Proceeds from long-term debt	165,000	311,000
Payments on long-term debt	(245,000)	(341,000)
Proceeds from issuance of 6% notes		294,480
Redemption of 8 3/8% notes		(165,852)
Payments of debt issuance costs	(147)	(739)
Cash overdrafts	(8,331)	(4,892)
Exercise of stock options and other	3,151	1,280

Net cash provided by financing activities		41,774		94,277
Increase (decrease) in cash and cash equivalents		(1,115)		1,451
Cash and cash equivalents, beginning of period		1,654		1,103
Cash and cash equivalents, end of period	$	539	$	2,554

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, 2006
(unaudited)

Note 1. Formation of Encore

Encore 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 drilling, waterflood, and tertiary 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 North Louisiana Salt Basin, the East Texas Basin, 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 North Dakota, and the Paradox Basin of southeastern Utah.

Note 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, 2006, results of operations for the three and nine months ended September 30, 2006 and 2005, and cash flows for the nine months ended September 30, 2006 and 2005. All adjustments are of a normal 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 SEC. Therefore, these consolidated financial statements should be read in conjunction with the consolidated financial statements and related notes thereto included in the Company s 2005 Annual Report on Form 10-K. Certain amounts in prior periods have been reclassified to conform to the current period presentation. Specifically, the Company reclassified the net gain/loss from the purchases and sales of third party oil volumes from Oil Revenues to Oil Marketing Revenues and Oil Marketing Expense and reclassified the related marketing transportation costs from Other Operating Expense to Oil Marketing Expense in the Company s Consolidated Statements of Operations for the first and second quarter of 2006. These are changes in presentation only and do not affect previously reported Net Income or Earnings per Share for either period. The following table details the affected line items from the Company s Consolidated Statements of Operations for the three months ended June 30, 2006 and March 31, 2006:

	Three months ended June 30, 2006	**Three months ended March 31, 2006**
	(in thousands)	
As Reported:		
Oil revenues	$94,128	$ 78,686
Oil marketing revenues	$	$
Oil marketing expenses	$	$
Other operating expenses	$ 1,960	$ 2,529
As Reclassified:		
Oil revenues	$92,434	$ 76,115
Oil marketing revenues	$25,716	$ 34,316
Oil marketing expenses	$24,914	$ 32,746
Other operating expenses	$ 1,068	$ 1,528

Oil Marketing Revenues and Expenses

Oil Marketing Revenues derived from sales of oil purchased from third parties is recognized when persuasive evidence of a sales arrangement exists, delivery has occurred, the sales price is fixed or determinable, and collectibility is reasonably assured. Oil Marketing Expenses includes the cost of oil volumes purchased from third parties, as well as, transportation charges related to the purchased volumes, mostly in the form of pipeline tariffs. As the Company takes title to the oil and has risks and rewards of ownership, these transactions are presented gross in the Consolidated Statements of Operations, unless they meet the criteria for netting as outlined in Emerging Issues Task Force (EITF) Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty (EITF 04-13). (See Buy/Sell transactions below).

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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(unaudited)

Buy/Sell Transactions

EITF 04-13 requires that two or more inventory purchase and sale transactions with the same counterparty that are entered into in contemplation of one another be viewed as a single exchange transaction and netted in accordance with the provisions of Accounting Principles Board (APB) Opinion No. 29, Accounting for Nonmonetary Transactions . These types of transactions are commonly referred to as Buy/Sell transactions in the oil and gas industry.

Produced Volumes. The net gain/loss from Buy/Sell transactions with produced oil volumes incurred by the Company is recorded as an adjustment to Oil Revenues. To qualify for this net treatment the sale and purchase must be with the same counterparty and be entered into in contemplation of each other.

Third Party Marketing Volumes. The net gain/loss from Buy/Sell transactions with purchased oil volumes from third parties incurred by the Company is recorded as an adjustment to Oil Marketing Revenues. To qualify for this net treatment the sale and purchase must be with the same counterparty and be entered into in contemplation of each other.

Stock-based Compensation

On January 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 123 (revised 2004), *Share-Based Payment* (SFAS 123R) using the modified prospective method. SFAS 123R is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation* (SFAS 123) and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25). See Note 11. Incentive Stock Plan for more information.

During the three and nine months ended September 30, 2005, if compensation expense for the stock-based awards had been determined using the provisions of SFAS 123R, the Company s net income and net income per share would have been adjusted to the pro forma amounts indicated below:

	Three months ended September 30, 2005	Nine months ended September 30, 2005
	(in thousands, except per share amounts)	
As Reported:		
Non-cash stock-based compensation expense (net of taxes)	$ 968	$ 2,082
Net income	$ 20,854	$ 66,306
Basic net income per common share	$ 0.43	$ 1.36
Diluted net income per common share	$ 0.42	$ 1.34
Pro Forma:		
Non-cash stock-based compensation expense (net of taxes)	$ 1,715	$ 3,333
Net income	$ 20,107	$ 65,055
Basic net income per common share	$ 0.41	$ 1.34
Diluted net income per common share	$ 0.41	$ 1.31

New Accounting Pronouncements

SFAS No. 157, Fair Value Measurement (SFAS 157)

In September 2006, the Financial Accounting Standards Board issued SFAS 157. SFAS 157 clarifies the principle that fair value should be based on the assumptions market participants would use when pricing an asset or liability and establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. Under SFAS 157, fair value measurements would be separately disclosed by level within the fair value hierarchy. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Early adoption is permitted. Encore has not yet determined the impact, if any, that the implementation of SFAS 157 will have on its results of operations or financial condition.

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ENCORE ACQUISITION COMPANY
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Note 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. The Company s inventories consisted of the following as of the dates indicated:

	September 30, 2006	December 31, 2005
	(in thousands)	
Warehouse inventory	$ 11,599	$ 9,019
Oil in pipelines	3,835	2,212
Total	$ 15,434	$ 11,231

Note 4. Crusader Acquisition and Goodwill

On October 14, 2005, the Company purchased all of the outstanding capital stock of Crusader Energy Corporation (Crusader), a privately held, independent oil and natural gas company, for a purchase price of approximately $109.6 million, which includes cash paid to Crusader s former shareholders of $79.1 million, the repayment of $29.7 million of Crusader s debt, and transaction costs incurred of $0.7 million.

The calculation of the total purchase price and the estimated allocation as of September 30, 2006 to the fair value of net assets acquired at October 14, 2005, are as follows (in thousands):

Calculation of total purchase price:

Cash paid to Crusader s former owners	$ 79,142
Crusader debt repaid	29,732
Transaction costs	707
Total purchase price	$ 109,581
Allocation of purchase price to the fair value of assets acquired:	
Cash	$ 18,592
Other current assets	3,362
Proved oil and natural gas properties	85,388
Unproved oil and natural gas properties	6,863
Goodwill	19,911
Total assets acquired	134,116
Current liabilities	(7,485)
Non-current liabilities	(1,190)
Deferred taxes	(15,860)
Total liabilities assumed	(24,535)

Fair value of net assets acquired	$ 109,581

The purchase price allocation resulted in $19.9 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 $15.9 million. Management believes the goodwill will be recovered through operating synergies resulting from the close proximity of the properties acquired to our existing operations. None of the goodwill is deductible for income tax purposes.

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
September 30, 2006
(unaudited)

Note 5. Derivative Financial Instruments

Commodity Contracts Mark-to-Market Accounting: Previously designated as hedges

Prior to July 2006, the Company used hedge accounting for certain of its derivative contracts, whereby the effective portion of changes in the fair value of the contract was deferred in accumulated other comprehensive loss (AOCL) included in stockholders equity in the accompanying Consolidated Balance Sheets rather than recognized in current period earnings. During July 2006, the Company elected to discontinue hedge accounting prospectively for all commodity derivatives which were previously accounted for as hedges. While this change has no effect on cash flows, results of operations are affected by mark-to-market gains and losses, which fluctuate with the swings in oil and natural gas prices. At the point of dedesignation, the gains and losses to be amortized to oil and natural gas revenues as effective hedges were established and deferred in AOCL. The amortization of these amounts is included in oil and natural gas revenues with the revenues from the hedged production. All mark-to-market gains and losses from July 2006 forward are recognized in earnings through Derivative fair value loss (gain) in the accompanying Consolidated Statements of Operations rather than deferring such amounts in AOCL.

The following tables summarize the Company s open commodity derivative instruments as of September 30, 2006:

Oil Derivative Instruments at September 30, 2006

Period	Daily Floor Volume (Bbl)	Average Floor Price (per Bbl)	Daily Short Floor Volume (Bbl)	Average Short Floor Price (per Bbl)	Daily Cap Volume (Bbl)	Average Cap Price (per Bbl)	Daily Swap Volume (Bbl)	Average Swap Price (per Bbl)	Fair Market Value (in thousands)
Oct. Dec. 2006	13,000	$ 45.00		$	1,000	$ 29.88	3,000	$ 37.27	$ (10,438)
Jan. Dec. 2007	8,000	53.75					3,000	36.75	(28,973)
Jan. June 2008	12,000	64.17	(4,000)	50.00			1,000	58.59	8,336
July Dec. 2008	8,000	66.25	(4,000)	50.00					8,535
Jan. Dec. 2009	5,000	70.00	(5,000)	50.00					13,717
									$ (8,823)

Natural Gas Derivative Instruments at September 30, 2006

Period	Daily Floor Volume (Mcf)	Average Floor Price (per Mcf)	Daily Short Floor Volume (Mcf)	Average Short Floor Price (per Mcf)	Daily Cap Volume (Mcf)	Average Cap Price (per Mcf)	Daily Swap Volume (Mcf)	Average Swap Price (per Mcf)	Fair Market Value (in thousands)
Oct. Dec. 2006	32,500	$ 6.17		$	5,000	$ 5.68	12,500	$ 5.02	$ 3,149

Jan. Dec. 2007	32,500	6.74	10,000	4.99		4,230
Jan. Dec. 2008	10,000	6.25				2,651
					$	10,030

Commodity Contracts Mark-to-Market Accounting: Floor Spreads

In order to partially finance the cost of premiums on certain purchased floors, the Company may sell floors with a strike price below the strike price of the purchased floor. Together the two floors, known as a floor spread or put spread, have a lower premium cost than a traditional floor contract but provide price protection only down to the strike price of the short floor. During the third quarter of 2006, the Company entered into floor spreads with a $70 per Bbl purchased floor and a $50 per Bbl short floor for 4,000 Bbls per day in 2008 and 5,000 Bbls per day in 2009. As with the Company s other derivative contracts, these are marked-to-market each quarter through Derivative fair value loss (gain) in the accompanying Consolidated Statements of Operations. In the above table, the purchased floor component of these floor spreads has been included with the Company s other floor contracts and the short floor component is shown separately as negative volumes. The net cash flows per Bbl upon settlement of the contracts and payment of the related premiums when viewed together change depending on the NYMEX oil price as follows:

- When the NYMEX oil price is greater than $70 per Bbl, the Company pays the net purchased floor premium cost per Bbl.
- When the NYMEX oil price is greater than $50 per Bbl but less than $70 per Bbl, the Company receives settlements of $70 per Bbl less the NYMEX oil price and pays the net purchased floor premium cost per Bbl.
- When the NYMEX oil price is below $50 per Bbl, the Company receives $20 per Bbl less the net purchased floor premium cost per Bbl.

Commodity Contracts Mark-to-Market Accounting: Basis Swaps

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. The Company marks these contracts to market each quarter through Derivative fair value loss (gain) in the accompanying Consolidated Statements of Operations. Thus, as these contracts do not change the Company s overall hedged volumes, amounts presented in the tables above are exclusive of any effect of these derivative instruments. As of September 30, 2006, the mark-to-market value of these basis swap contracts was a $0.4 million asset.

Commodity Contracts Current Period Impact

As a result of hedging transactions for oil and natural gas, the Company recognized a pre-tax reduction in oil and natural gas revenues of approximately $45.7 million and $40.2 million in the nine months ended September 30, 2006 and 2005, respectively,

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ENCORE ACQUISITION COMPANY
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September 30, 2006
(unaudited)

and $14.4 million and $16.5 million for the three months ended September 30, 2006 and 2005, respectively. The Company also recognized in the accompanying Consolidated Statements of Operations derivative fair value gains and losses related to (i) changes in the market value since the date of dedesignation of derivative contracts which were previously designated as hedges, (ii) changes in the market value of basis swaps and certain other commodity derivatives that are not designated as hedges, (iii) settlements on derivative contracts not designated as hedges, (iv) and ineffectiveness of derivative contracts designated as hedges prior to July 2006. The following table summarizes the components of derivative fair value gains and losses for the three and nine months ended September 30, 2006 and 2005:

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(in thousands)			
Designated cash flow hedges:				
Ineffectiveness Derivative commodity contracts	$	$ 2,212	$ 1,748	$ 6,878
Undesignated derivative contracts:				
Mark-to-market loss (gain):				
Interest rate swap				462
Commodity contracts	(34,280)	(573)	(20,819)	(707)
Settlements:				
Interest rate swap				(312)
Commodity contracts	917	(27)	(1,192)	(608)
Total derivative fair value loss (gain)	$ (33,363)	$ 1,612	$ (20,263)	$ 5,713

The Company had $56.1 million of derivative premiums payable recorded at September 30, 2006, of which $36.1 million is considered long-term and is recorded in Deferred premiums on derivatives contracts in the Company s Consolidated Balance Sheets. The premiums relate to various oil and natural gas floor contracts and are payable on a monthly basis from October 2006 to January 2010.

Commodity Contracts Future Period Impact

The components of AOCL consisted of the following as of the dates indicated:

	September 30, 2006	December 31, 2005
	(in thousands)	
Deferred loss on commodity derivatives, net of tax	$ (44,470)	$ (72,918)
Deferred gain on interest rate swap, net of tax		92
Accumulated other comprehensive loss	$ (44,470)	$ (72,826)

During the twelve months ending September 30, 2007, the Company expects to reclassify $54.9 million of net deferred losses associated with its dedesignated commodity contracts from AOCL to oil and natural gas revenues. The Company also expects to reclassify approximately $20.5 million of net deferred income tax benefits during the twelve months ending September 30, 2007 from AOCL to income tax benefit.

Note 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 cost on the Company s Consolidated Balance Sheets for the period from January 1, 2006 through September 30, 2006 (in thousands):

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	Nine months ended September 30, 2006
Future abandonment liability at January 1, 2006	$ 14,430
Wells drilled	107
Accretion expense	492
Plugging and abandonment costs incurred	(1,200)
Revision of estimates	1,036
Future abandonment liability at September 30, 2006	$ 14,865

Note 7. Debt

The Company s long-term debt consisted of the following as of the dates indicated:

	September 30, 2006	December 31, 2005
	(in thousands)	
Revolving credit facility	$	$ 80,000
6 1/4% Senior Subordinated Notes due 2014 (the 6 1/4% Notes)	150,000	150,000
6% Senior Subordinated Notes due 2015 (the 6% Notes), net of unamortized discount of $5,000 and $5,317, respectively	295,000	294,683
7 1/4% Senior Subordinated Notes due 2017 (the 7 1/4% Notes), net of unamortized discount of $1,433 and $1,494, respectively	148,567	148,506
Total	$ 593,567	$ 673,189

The Company had $26.7 million of outstanding letters of credit at September 30, 2006. 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 $523.3 million at September 30, 2006.

On April 4, 2006, the Company closed a public offering of its common stock for net proceeds of approximately $127.1 million, a portion of which was used to reduce borrowings under the revolving credit facility. See Note 10. Public Offering of Common Stock for more information.

Note 8. Income Taxes

The following table reconciles income tax expense with tax at the Federal statutory rate:

	Nine months ended September 30, 2006	2005
	(in thousands)	
Income before income taxes	$ 133,688	$ 99,287
Tax at statutory rate	$ 46,791	$ 34,750

State income taxes, net of federal benefit	3,118	1,911
Change in Texas franchise tax law	1,389	
Section 43 credits		(2,664)
Permanent and other	84	(1,016)
Income tax provision	$ 51,382	$ 32,981

The Company s effective tax rate increased to 38.4 percent for the nine months ended September 30, 2006, as compared to 33.2 percent for the nine months ended September 30, 2005. The Enhanced Oil Recovery credits available under Section 43 are fully phased out for the 2006 tax year due to high oil prices in 2005. Therefore, no credits were generated during the nine months ended September 30, 2006. In addition, a Texas franchise tax reform measure was signed into law on May 18, 2006, which caused the Texas franchise tax to be applicable to numerous types of entities that previously were not subject to the tax, including several of our subsidiaries. The Company adjusted its net deferred tax balances using the new higher marginal tax rate it expects to be effective when those deferred taxes become current resulting in a charge of $1.4 million during the nine months ended September 30, 2006.

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Note 9. Earnings Per Share (EPS)

The following table sets forth basic and diluted EPS computations for the three and nine months ended September 30, 2006 and 2005:

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(in thousands, except per share data)			
Numerator:				
Net income	$ 42,135	$ 20,854	$ 82,306	$ 66,306
Denominator:				
Denominator for basic EPS:				
Weighted average shares outstanding	52,968	48,703	51,481	48,659
Effect of dilutive options and diluted restricted stock (a)	808	881	894	822
Denominator for diluted EPS	53,776	49,584	52,375	49,481
Net income per common share:				
Basic	$ 0.80	$ 0.43	$ 1.60	$ 1.36
Diluted	$ 0.78	$ 0.42	$ 1.57	$ 1.34

(a) For the three months ended September 30, 2006, there were 106,274 employee stock options that were excluded from the calculation of diluted EPS because their effect would have been antidilutive. There were no shares of antidilutive outstanding employee stock options for the three months ended September 30, 2005. Effect of dilutive options and diluted restricted stock for the nine months ended September 30, 2006 and 2005 is an average of the effect of dilutive options and diluted restricted stock for the first three quarters of each respective year.

Note 10. Public Offering of Common Stock

On April 4, 2006, the Company s common stock at a price of $32.00 per share. The net proceeds of the offering, after deducting underwriting discounts and commissions and expenses of the offering, were approximately $127.1 million. The Company used the net proceeds to reduce borrowings under its revolving credit facility, to invest in oil and natural gas activities, and to pay general corporate expenses.

Note 11. Incentive Stock Plan

During 2000, the Company s Board of Directors (the Board) and stockholders approved the 2000 Incentive Stock Plan (the Plan). The Plan was amended and restated effective March 18, 2004. The purpose of the Plan is to attract, motivate, and retain selected employees of the Company and to provide the Company with the ability to offer incentives more directly linked to the profitability of the business and increases in shareholder value. All directors and full-time regular employees of the Company and its subsidiaries and affiliates are eligible to be granted awards under the Plan. The total number of shares of common stock reserved for issuance pursuant to the Plan is 4,500,000. As of September 30, 2006, there were 1,298,672 shares remaining under the Plan. The Plan provides for the granting of cash awards, incentive stock options, non-qualified stock options, restricted stock, and stock appreciation rights at the discretion of the Compensation Committee of the Board.

The Plan contains the following individual limits:

an employee may not be awarded more than 150,000 shares of common stock in any calendar year;

a non-employee director may not be awarded more than 10,000 shares of common stock in any calendar year; and

an employee may not receive awards consisting of cash (including cash awards that are granted as performance awards) in respect of any calendar year having a value determined on the grant date in excess of $1.0 million.

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All options that have been granted under the Plan have a strike price equal to the fair market value of our common stock on the date of grant. Additionally, all options have a ten-year life and vest equally over a three-year period. Restricted stock granted under the Plan vests over varying periods from one to five years, subject to performance-based vesting for certain members of senior management.

Adoption of SFAS 123R

As previously discussed, on January 1, 2006, the Company adopted the provisions of SFAS 123R. SFAS 123R eliminates the option of using the intrinsic value method of accounting previously available, and requires companies to recognize in the financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards.

The Company adopted the provisions of SFAS 123R using the modified prospective method, under which compensation cost is recognized in the financial statements for (i) share-based payments granted after January 1, 2006 based on the requirements of SFAS 123R, and (ii) all unvested awards granted prior to January 1, 2006 based on criteria established in SFAS 123. As a result, the Company did not record a cumulative effect of accounting change related to the adoption.

Under SFAS 123R, equity instruments are not considered issued until all vesting conditions lapse. This differs from APB 25, which required the recording of restricted stock to equity with an off-setting contra-equity account which was amortized to expense over the vesting period. Because unvested restricted stock is no longer considered issued, the contra-equity account, Deferred compensation , is no longer reported as a separate component of stockholders equity. Certain equity balances as originally reported in the Company s 2005 Annual Report on Form 10-K have been retroactively restated to reflect the change. The following table summarizes the balances at December 31, 2005 as originally reported and as restated:

	December 31, 2005	
	As Originally Reported	As Restated
	(in thousands)	
Shares of common stock outstanding	49,368	48,785
Common stock	$ 494	$ 488
Additional paid-in capital	$325,620	$316,619
Deferred compensation	$ (9,007)	$
Total stockholders equity	$546,781	$546,781

As a result of adopting SFAS 123R, the Company s income before income taxes and net income for the nine months ended September 30, 2006 are $1.1 million and $0.7 million lower, respectively, than if it had continued to account for share-based compensation under APB 25. Basic and diluted EPS for the nine months ended September 30, 2006 are each $0.01 per share lower than if the Company had continued to account for share-based compensation under APB 25.

The compensation cost and income tax benefit related to the Plan that has been recorded in the accompanying Consolidated Statements of Operations for the nine months ended September 30, 2006 was $6.6 million and $2.4 million, respectively. During the nine months ended September 30, 2006, the Company also capitalized $0.9 million of stock-based compensation cost as a component of Properties and equipment in the accompanying Consolidated Balance Sheets. Stock-based compensation expense has been allocated to lease operations expense (LOE), general and administrative (G&A) expense, and exploration expense based on the allocation of the respective cash compensation.

Stock Options

The fair value of each option award granted during the nine months ended September 30, 2006 and 2005 was estimated on the date of grant using a Black-Scholes option valuation model based on the assumptions noted in the following table. The expected volatility is based on a combination of the historical volatility of the Company s stock and the historical stock volatility of certain peer companies for a period of time commensurate with the expected term of the award. For options granted in the nine months ended September 30, 2006 and 2005, the Company used the simplified method prescribed by SEC Staff Accounting Bulletin No. 107 to estimate the expected term of the options. The risk-free rate is based on the U.S Treasury yield curve in effect at the time of grant for periods commensurate with the expected terms of the options.

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	Nine months ended September 30,	
	2006	**2005**
Expected volatility	42.8%	46.0%
Expected dividend yield	0.0%	0.0%
Expected term (in years)	6.0	6.0
Risk-free interest rate	4.6%	3.7%

A summary of options outstanding as of September 30, 2006, and changes during the nine months then ended is presented below:

	Number of Options	Weighted Average Strike Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (in thousands)
Outstanding at January 1, 2006	1,440,812	$ 13.20		
Granted	122,890	31.10		
Forfeited	(46,837)	24.51		
Exercised	(178,024)	13.15		
Outstanding at September 30, 2006	1,338,841	14.46	6.3	$ 14,138
Exercisable at September 30, 2006	1,070,165	11.89	5.8	13,389

The weighted average fair value of individual options granted during the nine months ended September 30, 2006 was $14.96 per share. The total intrinsic value of options exercised during the nine months ended September 30, 2006 and 2005 was $2.4 million and $2.6 million, respectively. The Company received proceeds from the exercise of stock options of $2.3 million and $1.2 million and realized tax benefits related to the exercises of $0.9 million and $2.3 million during the nine months ended September 30, 2006 and 2005, respectively. At September 30, 2006, the Company had $2.1 million of total unrecognized compensation cost related to unvested stock options, which is expected to be recognized over a weighted average period of 1.9 years.

Restricted Stock

As of September 30, 2006, there were 842,107 shares of unvested restricted stock outstanding, dependent only on continued employment for vesting. Of this amount, 331,209 shares were granted during the nine months ended September 30, 2006. Additionally, as of September 30, 2006, there were 67,202 shares of unvested restricted stock outstanding that depend on continued employment and certain performance measures for vesting, all of which were granted during the nine months ended September 30, 2006.

A summary of the status of the Company s unvested restricted stock outstanding as of September 30, 2006, and changes during the nine months then ended, is presented below:

	Weighted Average

	Number of Shares	Grant Date Fair Value
Outstanding at January 1, 2006	583,274	$20.53
Granted	428,609	31.17
Vested	(27,909)	18.60
Forfeited	(74,665)	24.92
Outstanding at September 30, 2006	909,309	25.25

As of September 30, 2006, there was $12.8 million of total unrecognized compensation cost related to unvested, outstanding restricted stock, which is expected to be recognized over a weighted average period of 3.0 years. During the nine months ended

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September 30, 2006 and 2005, there were 27,909 shares and 28,590 shares, respectively, that vested. Employees elected to satisfy minimum tax withholding obligations related to the vested restricted stock by allowing the Company to withhold 6,553 and 7,128 shares of common stock during the nine months ended September 30, 2006 and 2005, respectively.

Note 12. Comprehensive Income (Loss)

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

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(in thousands)			
Net income	$ 42,135	$ 20,854	$ 82,306	$ 66,306
Change in deferred loss on commodity derivatives	8,894	(23,708)	28,448	(53,864)
Change in deferred gain on interest rate swap	(63)	(53)	(92)	(315)
Comprehensive income (loss)	$ 50,966	$ (2,907)	$ 110,662	$ 12,127

See Note 5 above for a discussion on the Company s discontinuance of hedge accounting.

Note 13. Financial Statements of Subsidiary Guarantors

As of September 30, 2006, all of the Company s subsidiaries were subsidiary guarantors of the Company s outstanding notes. Since (i) each subsidiary guarantor is 100 percent 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.

Note 14. Commitments and Contingencies

In August 2006, the Company entered into a fourth amendment to its non-cancelable operating lease for additional office space at its corporate headquarters. Payments due under the fourth amendment begin in May 2007 and continue through November 2013.

In March 2006, the Company entered into a joint development agreement with a major oil company to develop seven natural gas fields in West Texas. The Company is required to drill a total of 24 commitment wells and may be required to advance funds to pay the partner s 70 percent share of drilling costs for each well. Should the Company advance funds, repayment will only be made through the monthly receipt of future proceeds of oil and natural gas sales.

Note 15. Related Party Transactions

The Company paid $2.8 million and $0.8 million to affiliates of Hanover Compressor Company (Hanover) in the nine months ended September 30, 2006 and 2005, respectively, for compressors and field compression services. Mr. I. Jon Brumley, the Chairman of the Board, also serves as a director of Hanover.

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

This document contains forward-looking statements, which give our current expectations or forecasts of future events. Actual results may differ materially from those discussed in our forward-looking statements due to many factors, including, but not limited to, those set forth under Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2005. The following discussion should be read in conjunction with the consolidated financial statements and notes thereto included in Item 1. Financial Statements of this Report and in Item 8. Financial Statements and Supplementary Data of our 2005 Annual Report on Form 10-K.

Introduction

This management s discussion and analysis of financial condition and results of operations is intended to provide investors with information regarding our financial condition and results of operations. The following will be discussed and analyzed:

- Third Quarter 2006 Highlights
- Results of Operations
  - Comparison of Quarter Ended September 30, 2006 to Quarter Ended September 30, 2005
  - Comparison of Nine Months Ended September 30, 2006 to Nine Months Ended September 30, 2005
- Capital Resources
- Capital Commitments
- Liquidity
- Contingencies
- Critical Accounting Policies and Estimates
- New Accounting Pronouncements

Third Quarter 2006 Highlights

Our financial and operating results for the quarter ended September 30, 2006 included the following highlights:

- During the third quarter of 2006, we had oil and natural gas revenues of $131.7 million. This represents a 3 percent increase over the $127.6 million of oil and natural gas revenues reported for the third quarter of 2005.

- Our realized average oil price for the third quarter of 2006, including the effects of hedging, increased $3.86 per Bbl to $54.80 per Bbl as compared to $50.94 per Bbl in the third quarter of 2005. Our realized average natural gas price for the third quarter of 2006, including the effects of hedging, decreased $1.77 per Mcf to $5.88 per Mcf as compared to $7.65 per Mcf in the third quarter of 2005.

- As expected, our oil wellhead differential to the average NYMEX price improved in the third quarter of 2006 as compared to the second quarter of 2006. The narrowing of our oil wellhead differential was due to improving market conditions in the Rocky Mountain refining area, which has positively affected the wellhead price we received on our CCA and Williston Basin properties.

- Production volumes for the third quarter of 2006 increased 5 percent to 29,651 BOE/D (2.7 MMBOE for the quarter), compared with third quarter 2005 production of 28,202 BOE/D (2.6 MMBOE for the quarter). The rise in production volumes was attributable to our development program and acquisitions completed in the second half of 2005. Oil represented 67 percent and 65 percent of our total production volumes in the third quarter of 2006 and 2005, respectively.

During the third quarter of 2006, we generated cash flows from operating activities of $102.9 million. This represents a 19 percent increase over the $86.7 million of cash flows from operating activities we reported for the third quarter of 2005.

We reported net income of $42.1 million, or $0.78 per diluted share, in the third quarter of 2006, as compared to $20.9 million of net income, or $0.42 per diluted share, for the third quarter of 2005. The increase in net income was due primarily to net pre-tax derivative fair value gains of $33.4 million, increasing net income by approximately $0.39 per diluted share.

We invested $102.1 million in oil and natural gas activities during the third quarter of 2006 (excluding related asset retirement obligations). Of this amount, we invested $95.2 million in development, exploitation, high-pressure air injection (HPAI) expansion, and exploration activities, which yielded 65 gross (17.8 net) productive wells, and $6.9 million in acquiring proved properties and undeveloped leases. We operated between 9 and 12 drilling rigs during the third quarter of 2006, including 4 rigs related to our West Texas joint development agreement.

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Results of Operations

Comparison of Quarter Ended September 30, 2006 to Quarter Ended September 30, 2005

Below is a comparison of our operations during the third quarter of 2006 with the third quarter of 2005.

Revenues and production. The following table illustrates the primary components of oil and natural gas revenues for the three months ended September 30, 2006 and 2005, as well as each quarter s respective oil and natural gas volumes:

	Three months ended September 30, 2006	Three months ended September 30, 2005	*Increase / (Decrease)*	
	(in thousands, except per unit and per day amounts)			
Revenues:				
Oil wellhead	$ 112,959	$ 97,563	*$ 15,396*	
Oil hedges	(13,443)	(12,004)	*(1,439)*	
Total oil revenues	$ 99,516	$ 85,559	*$ 13,957*	*16%*
Natural gas wellhead	$ 33,144	$ 46,515	*$ (13,371)*	
Natural gas hedges	(967)	(4,502)	*3,535*	
Total natural gas revenues	$ 32,177	$ 42,013	*$ (9,836)*	*-23%*
Combined wellhead	$ 146,103	$ 144,078	*$ 2,025*	
Combined hedges	(14,410)	(16,506)	*2,096*	
Total combined oil and natural gas revenues	131,693	127,572	*4,121*	*3%*
Oil marketing revenues	46,004		*46,004*	
Total revenues	$ 177,697	$ 127,572	*$ 50,125*	

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Oil revenues increased $14.0 million from $85.6 million in the third quarter of 2005 to $99.5 million in the third quarter of 2006. The increase is due primarily to an increase in oil production volumes of 136 MBbls, which contributed approximately $7.9 million in additional oil revenues, and higher realized average oil prices, which contributed approximately $6.1 million in additional oil revenues. The increase in production volumes is the result of our development program and the integration of our acquisitions during the second half of 2005. The increase in realized average oil prices consists of a $7.5 million increase resulting from higher average oil wellhead prices, offset by increased hedging payments of $1.4 million ($0.25 per Bbl). Our average oil wellhead price increased $4.11 per Bbl in the third quarter of 2006 over the third quarter of 2005 as a result of increases in the overall market price for oil as reflected in the increase in the average NYMEX price from $63.19 per Bbl in the third quarter of 2005 to $70.48 per Bbl in the third quarter of 2006. Please read the discussion below regarding the widening of our oil wellhead price to average NYMEX price differential and its related adverse impact on oil revenues for the third quarter of 2006.

Our oil wellhead revenue was reduced by $7.1 million and $7.6 million in the third quarter of 2006 and 2005, respectively, for the net profits interests payments related to our CCA properties.

Natural gas revenues decreased $9.8 million from $42.0 million in the third quarter of 2005 to $32.2 million in the third quarter of 2006. The decrease is due primarily to lower realized average natural gas prices, which reduced natural gas revenues by approximately $9.7 million, as natural gas production volumes remained constant. The decrease in realized average natural gas prices consists of a $13.2 million decrease resulting from lower average natural gas wellhead prices and decreased hedging payments of $3.5 million ($0.64 per Mcf). Our average natural gas wellhead price decreased $2.41 per Mcf in the third quarter of 2006 over the third quarter of 2005. Although the average NYMEX price decreased $3.47 per Mcf over the same periods, a significant portion of our natural gas production is based on other indices that have recently traded at premiums to the NYMEX natural gas price.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of the average NYMEX prices for the three months ended September 30, 2006 and 2005. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Three months ended September 30,	
	2006	**2005**
Oil wellhead ($/Bbl)	$ 62.20	$ 58.09
Average NYMEX ($/Bbl)	$ 70.48	$ 63.19
Differential to NYMEX	$ (8.28)	$ (5.10)
Oil wellhead to NYMEX percentage	88%	92%
Natural gas wellhead ($/Mcf)	$ 6.06	$ 8.47
Average NYMEX ($/Mcf)	$ 6.17	$ 9.64
Differential to NYMEX	$ (0.11)	$ (1.17)
Natural gas wellhead to NYMEX percentage	98%	88%

As indicated above, our oil wellhead price as a percentage of the average NYMEX price decreased to 88 percent in the third quarter of 2006 from 92 percent in the third quarter of 2005. The widening of the differential is due to market conditions in the Rocky Mountain refining area, which has adversely affected the oil wellhead price we received on our CCA and Williston Basin production. Production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity in the Rocky Mountain area, created steep pricing discounts in the first quarter of 2006. These discounts narrowed in the second and third quarters of 2006, though they are still higher than our historical average. The decrease in the oil differential percentage in the third quarter of 2006 as compared to the third quarter of 2005 adversely impacted oil revenues by $5.8 million. As Rocky Mountain refiners have completed maintenance and increased their demand for crude oil, our oil wellhead price as a percentage of the average NYMEX price has improved from the first quarter 2006 level of 77 percent, but still remains wider than our historical average. We expect that our oil wellhead differentials will widen in the fourth quarter of 2006 as compared to the third quarter of 2006.

Our natural gas wellhead price as a percentage of the average NYMEX price was 98 percent for the third quarter of 2006, as compared to 88 percent for the third quarter of 2005. This favorable variance is due to our natural gas production in the North Louisiana Salt Basin and Crockett County, Texas, which is sold at Katy, Houston Ship Channel, and Henry Hub natural gas

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prices, which have recently been higher than the average front-month NYMEX natural gas price. The increase in the natural gas differential percentage favorably impacted natural gas revenues by $5.8 million in the third quarter of 2006 as compared with the third quarter of 2005.

Marketing activities. The following table summarizes our oil marketing activities for the three months ended September 30, 2006 (in thousands, except per BOE amounts):

Oil marketing revenues	$ 46,004
Oil marketing expenses	(48,001)
Oil marketing, net	$ (1,997)
Oil marketing revenues per BOE	$ 16.86
Oil marketing expenses per BOE	(17.60)
Oil marketing, net per BOE	$ (0.74)

We purchase third-party oil for aggregation and sale with our own equity production. These purchases are conducted for strategic purposes to assist us in marketing our production by decreasing our dependence on individual markets. These activities allow us to aggregate larger volumes, facilitate our efforts to maximize the prices we receive for production, provide for a greater allocation of future pipeline capacity in the event of curtailments, and enable us to reach other markets. We recognized $46.0 million in oil marketing revenues to third parties during the three months ended September 30, 2006, with corresponding oil marketing expenses of $48.0 million, for a net loss of $2.0 million, or $0.74 per BOE.

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Expenses. The following table summarizes our expenses for the three months ended September 30, 2006 and 2005:

	Three months ended September 30,		Increase / (Decrease)	
	2006	2005		
Expenses (in thousands):				
Production:				
Lease operations	$ 24,478	$ 18,410	*$ 6,068*	
Production, ad valorem, and severance taxes	13,560	12,526	*1,034*	
Total production expenses	38,038	30,936	*7,102*	*23%*
Other:				
Depletion, depreciation, and amortization	27,471	24,222	*3,249*	
Exploration	12,322	4,830	*7,492*	
General and administrative	6,250	5,064	*1,186*	
Oil marketing	48,001		*48,001*	
Derivative fair value loss (gain)	(33,363)	1,612	*(34,975)*	
Loss on early redemption of debt		19,477	*(19,477)*	
Other operating	976	2,520	*(1,544)*	
Total operating	99,695	88,661	*11,034*	*12%*
Interest	11,261	9,264	*1,997*	
Current and deferred income tax provision	25,069	9,373	*15,696*	
Total expenses	$ 136,025	$ 107,298	$ 28,727	*27%*
Expenses (per BOE):				
Production:				
Lease operations	$ 8.97	$ 7.09	*$ 1.88*	
Production, ad valorem, and severance taxes	4.97	4.83	*0.14*	
Total production expenses	13.94	11.92	*2.02*	*17%*
Other:				
Depletion, depreciation, and amortization	10.07	9.34	*0.73*	
Exploration	4.52	1.86	*2.66*	
General and administrative	2.29	1.95	*0.34*	
Derivative fair value loss (gain)	(12.23)	0.62	*(12.85)*	
Loss on early redemption of debt		7.51	*(7.51)*	
Other operating	0.36	0.97	*(0.61)*	
Total operating	18.95	34.17	*(15.22)*	*-45%*
Interest	4.13	3.57	*0.56*	

Current and deferred income tax provision		9.19		3.61		*5.58*	
Total expenses	$	32.27	$	41.35	$	(9.08)	*-22%*

Production expenses. Total production expenses increased $7.1 million from $30.9 million in the third quarter of 2005 to $38.0 million in the third quarter of 2006. This increase resulted from an increase in total production volumes, as well as a $2.02 increase in production expenses per BOE. Total production expenses per BOE increased by 17 percent while total oil and natural gas revenues per BOE decreased 2 percent due to an increase in the differential between the oil wellhead price we receive and the average NYMEX price in the third quarter of 2006 as compared to the third quarter of 2005. As a result of these changes, our production margin (defined as oil and natural gas revenues less production expenses) for the third quarter of 2006 decreased 8 percent to $34.33 per BOE as compared to $37.25 per BOE for the third quarter of 2005.

The production expense attributable to LOE increased $6.1 million from $18.4 million in the third quarter of 2005 to $24.5 million in the third quarter of 2006. The increase is due to higher production volumes, which contributed approximately $0.9 million of additional LOE, and an increase in the average per BOE rate, which contributed approximately $5.1 million of additional LOE. The increase in our average LOE per BOE rate of $1.88 was attributable to increases in prices paid to oilfield service companies and suppliers due to a current higher price environment, increased operational activity to maximize

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production, the operation of higher operating cost wells (which have offered acceptable rates of return due to increases in oil and natural gas prices), expensing HPAI costs associated with the Little Beaver Phase II program, and increased stock-based compensation expense attributable to equity instruments granted to employees under the 2000 Incentive Stock Plan (the Plan). Prior to the adoption of SFAS 123R, non-cash stock-based compensation expense was separately reported on the accompanying Consolidated Statements of Operations. Due to the adoption of SFAS 123R, non-cash stock-based compensation expense in all prior periods presented has been reclassified to allocate the amount to the same respective income statement lines as the employees salary, cash bonus, and benefits. As all full-time employees, including field personnel, are eligible for equity grants under the Plan, LOE, G&A expense, and exploration expense have been changed to reflect the new presentation. This change has resulted in additional LOE of $0.7 million in the third quarter of 2006, or $0.26 per BOE, as compared to $0.5 million in the third quarter of 2005, or $0.19 per BOE. The increase in non-cash stock-based compensation expense allocated to LOE is primarily due to new stock-based compensation awards granted to employees in 2006 and expensing of stock options beginning January 1, 2006 in accordance with SFAS 123R.

The production expense attributable to production, ad valorem, and severance taxes (production taxes) increased $1.0 million from $12.5 million in the third quarter of 2005 to $13.6 million in the third quarter of 2006. The increase is due to higher production volumes, which contributed approximately $0.6 million of additional production taxes, and an increase in the average per BOE rate, which contributed approximately $0.4 million of additional production taxes. As a percentage of oil and natural gas revenues (excluding the effects of hedges), production taxes remained constant at approximately 9 percent in the third quarter of 2006 and 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 taxes paid to taxing authorities.

Depletion, depreciation, and amortization (DD&A) expense. DD&A expense increased $3.2 million from $24.2 million in the third quarter of 2005 to $27.5 million in the third quarter of 2006 due to a higher per BOE rate and increased production volumes. The per BOE rate increased $0.73 from the third quarter of 2005 due to increased rig rates, increased oilfield services costs, and higher acquisition costs. These factors resulted in additional DD&A expense of approximately $2.0 million. The increase in production volumes resulted in approximately $1.2 million of additional DD&A expense.

Exploration expense. Exploration expense increased $7.5 million in the third quarter of 2006 as compared to the third quarter of 2005. In addition, impairment of unproved acreage increased $1.6 million from the third quarter of 2005 as we expanded our unproved acreage position and further defined our drilling success rates in certain areas. The following table details our exploration-related expenses for the third quarter of 2006 and 2005:

	Three months ended September 30, 2006	**2005**	***Increase / (Decrease)***
	(in thousands)		
Dry holes	$ 9,962	$ 3,604	*$ 6,358*
Geological and seismic	222	669	*(447)*
Delay rentals	175	169	*6*
Impairment of unproved acreage	1,963	388	*1,575*
Total	$ 12,322	$ 4,830	*$ 7,492*

G&A expense. G&A expense increased $1.2 million from $5.1 million in the third quarter of 2005 to $6.3 million in the third quarter of 2006. The overall increase, as well as the $0.34 increase in the per BOE rate, is primarily the result of increased corporate staffing to manage our larger asset base, increased personnel costs due to intense competition for human resources within the industry, and increased stock-based compensation expense attributable to equity instruments granted to employees under the Plan.

The previously discussed adoption of SFAS 123R and change in presentation of non-cash stock-based compensation expense resulted in additional G&A expense of $1.2 million in the third quarter of 2006, or $0.45 per BOE, as compared to $1.0 million in the third quarter of 2005, or $0.40 per BOE. The increase in non-cash stock-based compensation expense allocated to

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G&A expense is primarily due to new stock-based compensation awards granted to employees in 2006 and expensing of stock options beginning January 1, 2006 in accordance with SFAS 123R.

As of September 30, 2006, we had $12.8 million of total unrecognized compensation cost related to unvested, outstanding restricted stock, which is expected to be recognized over a weighted average period of 3.0 years. Additionally, we had $2.1 million of total unrecognized compensation cost related to unvested stock options as of September 30, 2006, which is expected to be recognized over a weighted average period of 1.9 years.

Derivative fair value loss (gain). During the third quarter of 2006, we recorded a $33.4 million derivative fair value gain as compared to a $1.6 million loss recorded in the third quarter of 2005. The 2006 derivative fair value gain represents net mark-to-market gains related to commodity derivatives not designated as hedges while the 2005 derivative fair value loss was primarily related to the ineffective portion of commodity derivatives which were designated as hedges.

The components of the derivative fair value loss (gain) reported in the third quarter of 2006 and 2005 are as follows:

	Three months ended September 30, 2006	2005	*Increase / (Decrease)*
	(in thousands)		
Designated cash flow hedges:			
Ineffectiveness Derivative commodity contracts	$	$ 2,212	*$ (2,212)*
Undesignated derivative contracts:			
Mark-to-market loss (gain):			
Commodity contracts	(34,280)	(573)	*(33,707)*
Settlements:			
Commodity contracts	917	(27)	*944*
Total derivative fair value loss (gain)	$ (33,363)	$ 1,612	*$ (34,975)*

To increase clarity in our financial statements by accounting for all contracts under the same method, we elected to discontinue hedge accounting prospectively for all of our remaining commodity derivatives beginning in July 2006. While this change has no effect on our cash flows, results of operations are affected by mark-to-market gains and losses, which fluctuate with the swings in oil and natural gas prices.

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 our 8 3/8% senior subordinated notes due 2012. We redeemed $150 million of 8 3/8% senior subordinated notes due 2012 with proceeds received from the issuance of $300 million of 6% senior subordinated notes due 2015.

Other operating expense. Other operating expense decreased $1.5 million from $2.5 million in the third quarter of 2005 to $1.0 million in the third quarter of 2006, primarily as a result of lower transportation costs.

Interest expense. Interest expense increased $2.0 million in the third quarter of 2006 as compared to the third quarter of 2005. The increase is primarily due to additional debt used to finance acquisitions and our capital program. We issued $150 million of 7 1/4% senior subordinated notes due 2017 in November 2005 and $300 million of 6% senior subordinated notes due 2015 in July 2005. We also redeemed $150 million of 8 3/8% senior subordinated notes due 2012 in August 2005. The weighted average interest rate, net of hedges, for the third quarter of 2006 was 6.9 percent as compared to 6.8 percent for the third quarter of 2005.

The following table illustrates the components of interest expense for the three months ended September 30, 2006 and 2005:

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	Three months ended September 30, 2006	2005	*Increase / (Decrease)*
		(in thousands)	
8 3/8% Notes	$	$ 1,570	*$ (1,570)*
6 1/4% Notes	2,422	2,344	*78*
6% Notes	4,624	3,937	*687*
7 1/4% Notes	2,745		*2,745*
Revolving credit facility	550	675	*(125)*
Other	920	738	*182*
Total	$ 11,261	$ 9,264	*$ 1,997*

Income taxes. Income tax expense for the third quarter of 2006 increased $15.7 million over the third quarter of 2005. This is due to higher pre-tax income and an increase in our effective tax rate. Our effective tax rate increased in the third quarter of 2006 to 37.3 percent from 31.0 percent in the third quarter of 2005 due to the absence of Section 43 income tax credits during the third quarter of 2006. The Section 43 Enhanced Oil Recovery credits available under Section 43 are fully phased out for the 2006 tax year due to high oil prices in 2005. Therefore, no credits were generated during the third quarter of 2006. We were able to reduce our income tax provision in the third quarter of 2005 by $1.2 million from the generation of Section 43 credits.

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Comparison of Nine Months Ended September 30, 2006 to Nine Months Ended September 30, 2005

Below is a comparison of our operations during the first nine months of 2006 with the first nine months of 2005.

Revenues and production. The following table illustrates the primary components of oil and natural gas revenues for the nine months ended September 30, 2006 and 2005, as well as each period s respective oil and natural gas volumes:

	Nine months ended September 30, 2006	Nine months ended September 30, 2005	*Increase / (Decrease)*	
	(in thousands, except per unit and per day amounts)			
Revenues:				
Oil wellhead	$ 306,833	$ 254,461	*$ 52,372*	
Oil hedges	(38,767)	(32,207)	*(6,560)*	
Total oil revenues	$ 268,066	$ 222,254	*$ 45,812*	*21%*
Natural gas wellhead	$ 115,948	$ 104,639	*$ 11,309*	
Natural gas hedges	(6,898)	(8,023)	*1,125*	
Total natural gas revenues	$ 109,050	$ 96,616	*$ 12,434*	*13%*
Combined wellhead	$ 422,781	$ 359,100	*$ 63,681*	
Combined hedges	(45,665)	(40,230)	*(5,435)*	

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Oil revenues increased $45.8 million from $222.3 million in the first nine months of 2005 to $268.1 million in the first nine months of 2006. The increase is due primarily to an increase in oil production volumes of 412 MBbls, which contributed approximately $20.6 million in additional oil revenues, and higher realized average oil prices, which contributed approximately $25.2 million in additional oil revenues. The increase in production volumes is the result of our development program and the integration of our acquisitions during the second half of 2005. The increase in realized average oil prices consists of a $31.8 million increase resulting from higher average oil wellhead prices, offset by increased hedging payments of $6.6 million ($0.72 per Bbl). Our average oil wellhead price increased $5.78 per Bbl in the first nine months of 2006 over the first nine months of 2005 as a result of increases in the overall market price for oil as reflected in the increase in the average NYMEX price from $55.40 per Bbl in the first nine months of 2005 to $68.22 per Bbl in the first nine months of 2006. Please read the discussion below regarding the widening of our oil wellhead price to average NYMEX price differential and its related adverse impact on oil revenues for the first nine months of 2006.

Our oil wellhead revenue was reduced by $19.2 million and $14.1 million in the first nine months of 2006 and 2005, respectively, for the net profits interests payments related to our CCA properties.

Natural gas revenues increased $12.4 million from $96.6 million in the first nine months of 2005 to $109.1 million in the first nine months of 2006. The increase is due primarily to increased natural gas production volumes of 2,681 MMcf, which contributed approximately $18.9 million in additional natural gas revenues, partially offset by lower realized average natural gas prices, which reduced natural gas revenues by approximately $6.4 million. The increase in production volumes is the result of our development program and the integration of our acquisitions during the second half of 2005. The decrease in realized average natural gas prices consists of a $7.6 million decrease resulting from lower average natural gas wellhead prices and decreased hedging payments of $1.1 million ($0.15 per Mcf). Our average natural gas wellhead price decreased $0.44 per Mcf in the first nine months of 2006 over the first nine months of 2005. Although the average NYMEX price decreased $0.78 per Mcf over the same periods, a significant portion of our natural gas production is based on other indices that have recently traded at premiums to the NYMEX natural gas price.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of the average NYMEX prices for the nine months ended September 30, 2006 and 2005. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Nine months ended September 30,	
	2006	**2005**
Oil wellhead ($/Bbl)	$ 55.85	$ 50.07
Average NYMEX ($/Bbl)	$ 68.22	$ 55.40
Differential to NYMEX	$ (12.37)	$ (5.33)
Oil wellhead to NYMEX percentage	82%	90%
Natural gas wellhead ($/Mcf)	$ 6.60	$ 7.04
Average NYMEX ($/Mcf)	$ 6.91	$ 7.69
Differential to NYMEX	$ (0.31)	$ (0.65)
Natural gas wellhead to NYMEX percentage	96%	92%

As indicated above, our oil wellhead price as a percentage of the average NYMEX price decreased to 82 percent in the first nine months of 2006 from 90 percent in the first nine months of 2005. The widening of the differential is due to market conditions in the Rocky Mountain refining area, which has adversely affected the oil wellhead price we received on our CCA and Williston Basin production. Production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity in the Rocky Mountain area, created steep pricing discounts in the first quarter of 2006. These discounts narrowed in the second and third quarters of 2006, though they are still higher than our historical average. The decrease in the oil differential percentage in the first nine months of 2006 as compared to the first nine months of 2005 adversely impacted oil revenues by $38.7 million. As Rocky Mountain refiners have recently completed maintenance and increased their demand for crude oil, our oil wellhead price as a percentage of the average NYMEX price has improved from the first quarter 2006 level of 77 percent, but still remains wider than our historical average. We expect that our oil wellhead differentials will widen in the fourth quarter of 2006 as compared to the third quarter of 2006.

Our natural gas wellhead price as a percentage of the average NYMEX price increased to 96 percent in the first nine months of 2006 from 92 percent in the first nine months of 2005. This favorable variance is due to our natural gas production in the North Louisiana Salt Basin and Crockett County, Texas, which is sold at Katy, Houston Ship Channel, and Henry Hub natural

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gas prices, which have recently been higher than the average front-month NYMEX natural gas price. The increase in the natural gas differential percentage favorably impacted natural gas revenues by $6.0 million in the first nine months of 2006 as compared with the first nine months of 2005.

Marketing activities. The following table summarizes our oil marketing activities for the nine months ended September 30, 2006 (in thousands, except per unit amounts):

Oil marketing revenues	$ 106,036
Oil marketing expenses	(105,661)
Oil marketing, net	$ 375
Oil marketing revenues per BOE	$ 12.59
Oil marketing expenses per BOE	(12.55)
Oil marketing, net per BOE	$ 0.04

We purchase third-party oil for aggregation and sale with our own equity production. These purchases are conducted for strategic purposes to assist us in marketing our production by decreasing our dependence on individual markets. These activities allow us to aggregate larger volumes, facilitate our efforts to maximize the prices we receive for production, provide for a greater allocation of future pipeline capacity in the event of curtailments, and enable us to reach other markets. We recognized $106.0 million in oil marketing revenues to third parties during the nine months ended September 30, 2006, with corresponding oil marketing expenses of $105.7 million, for a net gain of $0.4 million, or $0.04 per BOE.

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Expenses. The following table summarizes our expenses for the nine months ended September 30, 2006 and 2005:

	Nine months ended September 30, 2006	2005	*Increase / (Decrease)*	
Expenses (in thousands):				
Production:				
Lease operations	$ 70,332	$ 49,627	*$ 20,705*	
Production, ad valorem, and severance taxes	38,382	31,425	*6,957*	
Total production expenses	108,714	81,052	*27,662*	*34%*
Other:				
Depletion, depreciation, and amortization	82,479	59,943	*22,536*	
Exploration	18,347	11,238	*7,109*	
General and administrative	18,199	13,396	*4,803*	
Oil marketing	105,661		*105,661*	
Derivative fair value loss (gain)	(20,263)	5,713	*(25,976)*	
Loss on early redemption of debt		19,477	*(19,477)*	
Other operating	3,573	5,822	*(2,249)*	
Total operating	316,710	196,641	*120,069*	*61%*
Interest	33,766	23,671	*10,095*	
Current and deferred income tax provision	51,382	32,981	*18,401*	
Total expenses	$ 401,858	$ 253,293	$ 148,565	*59%*
Expenses (per BOE):				
Production:				
Lease operations	$ 8.35	$ 6.56	*$ 1.79*	
Production, ad valorem, and severance taxes	4.56	4.16	*0.40*	
Total production expenses	12.91	10.72	*2.19*	*20%*
Other:				
Depletion, depreciation, and amortization	9.80	7.93	*1.87*	
Exploration	2.18	1.49	*0.69*	
General and administrative	2.16	1.77	*0.39*	
Derivative fair value loss (gain)	(2.41)	0.75	*(3.16)*	
Loss on early redemption of debt		2.58	*(2.58)*	
Other operating	0.42	0.77	*(0.35)*	
Total operating	25.06	26.01	*(0.95)*	*-4%*
Interest	4.01	3.13	*0.88*	
Current and deferred income tax provision	6.10	4.36	*1.74*	

Total expenses	$ 35.17	$ 33.50	$ 1.67	*5%*

Production expenses. Total production expenses increased $27.7 million from $81.1 million in the first nine months of 2005 to $108.7 million in the first nine months of 2006. This increase resulted from an increase in total production volumes, as well as a $2.19 increase in production expenses per BOE. Total production expenses per BOE increased by 20 percent while total oil and natural gas revenues per BOE increased by 6 percent due to an increase in the differential between the oil wellhead price we receive and the average NYMEX price in the first nine months of 2006 as compared to the first nine months of 2005. As a result of these changes, our production margin (defined as oil and natural gas revenues less production expenses) for the first nine months of 2006 increased 1 percent to $31.88 per BOE as compared to $31.45 per BOE for the first nine months of 2005.

The production expense attributable to LOE increased $20.7 million from $49.6 million in the first nine months of 2005 to $70.3 million in the first nine months of 2006. The increase is due to higher production volumes, which contributed approximately $5.6 million of additional LOE, and an increase in the average per BOE rate, which contributed approximately $15.1 million of additional LOE. The increase in our average LOE per BOE rate of $1.79 was attributable to increases in prices

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paid to oilfield service companies and suppliers due to a current higher price environment, increased operational activity to maximize production, the operation of higher operating cost wells (which have offered acceptable rates of return due to increases in oil and natural gas prices), expensing HPAI costs associated with the Little Beaver Phase II program, and increased stock-based compensation expense attributable to equity instruments granted to employees under the Plan. The previously discussed adoption of SFAS 123R and change in presentation of non-cash stock-based compensation expense resulted in additional LOE of $1.7 million in the first nine months of 2006, or $0.20 per BOE, as compared to $1.1 million in the first nine months of 2005, or $0.15 per BOE. The increase in non-cash stock-based compensation expense allocated to LOE is primarily due to new stock-based compensation awards granted to employees in 2006 and expensing of stock options beginning January 1, 2006 in accordance with SFAS 123R.

The production expense attributable to production taxes increased $7.0 million from $31.4 million in the first nine months of 2005 to $38.4 million in the first nine months of 2006. The increase is due to higher production volumes, which contributed approximately $3.6 million of additional production taxes, and an increase in the average per BOE rate, which contributed approximately $3.4 million of additional production taxes. The increase in our average production taxes per BOE rate of $0.40 was attributable to higher oil and natural gas prices we received for our wellhead sales volumes. As a percentage of oil and natural gas revenues (excluding the effects of hedges), production taxes remained constant at approximately 9 percent in the first nine months of 2006 and 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 taxes paid to taxing authorities.

DD&A expense. DD&A expense increased $22.5 million from $59.9 million in the first nine months of 2005 to $82.5 million in the first nine months of 2006 due to a higher per BOE rate and increased production volumes. The per BOE rate increased $1.87 from the first nine months of 2005 due to increased rig rates, increased oilfield services costs, and higher acquisition costs. These factors resulted in additional DD&A expense of approximately $15.7 million. The increase in production volumes resulted in approximately $6.8 million of additional DD&A expense.

Exploration expense. Exploration expense increased $7.1 million in the first nine months of 2006 as compared to the first nine months of 2005. In addition, impairment of unproved acreage increased $2.5 million from the first nine months of 2005 as we expanded our unproved acreage position and further defined our drilling success rates in certain areas. The following table details our exploration-related expenses for the first nine months of 2006 and 2005:

	Nine months ended September 30,		***Increase /***
	2006	**2005**	***(Decrease)***
	(in thousands)		
Dry holes	$ 12,542	$ 6,935	*$ 5,607*
Geological and seismic	1,474	2,412	*(938)*
Delay rentals	530	545	*(15)*
Impairment of unproved acreage	3,801	1,346	*2,455*
Total	$ 18,347	$ 11,238	*$ 7,109*

G&A expense. G&A expense increased $4.8 million from $13.4 million in the first nine months of 2005 to $18.2 million in the first nine months of 2006. The overall increase, as well as the $0.39 increase in the per BOE rate, is primarily the result of increased corporate staffing to manage our larger asset base, increased personnel costs due to intense competition for human resources within the industry, and increased stock-based compensation expense attributable to equity instruments granted to employees under the Plan.

The previously discussed adoption of SFAS 123R and change in presentation of non-cash stock-based compensation expense resulted in additional G&A expense of $5.1 million in the first nine months of 2006, or $0.61 per BOE, as compared to $2.2 million in the first nine months of 2005, or $0.29 per BOE. The increase in non-cash stock-based compensation expense allocated to G&A expense is primarily due to new stock-based compensation awards granted to employees in 2006 and expensing of stock options beginning January 1, 2006 in accordance with SFAS 123R. G&A expense related to non-cash stock-based compensation expense in the first nine months of 2006 includes $2.1 million related to shares granted to retirement eligible employees. Restricted stock grants vest in full upon retirement, which results in non-cash stock-based compensation expense being fully recognized on the date of grant rather than over the vesting period for retirement eligible employees.

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Derivative fair value loss (gain). During the first nine months of 2006, we recorded a $20.3 million derivative fair value gain as compared to a $5.7 million loss recorded in the first nine months of 2005. The 2006 derivative fair value gain represents the net effect of the ineffective portion of the mark-to-market gains and losses on our derivative hedging instruments, prior to July 2006 as previously discussed, and net mark-to-market gains related to commodity derivatives not designated as hedges. The 2005 derivative fair value loss was primarily related to the ineffective portion of commodity derivatives which were designated as hedges.

The components of the derivative fair value loss (gain) reported in the first nine months of 2006 and 2005 are as follows:

	Nine months ended September 30, 2006	2005	*Increase / (Decrease)*
		(in thousands)	
Designated cash flow hedges:			
Ineffectiveness Derivative commodity contracts	$ 1,748	$ 6,878	*$ (5,130)*
Undesignated derivative contracts:			
Mark-to-market loss (gain):			
Interest rate swap		462	*(462)*
Commodity contracts	(20,819)	(707)	*(20,112)*
Settlements:			
Interest rate swap		(312)	*312*
Commodity contracts	(1,192)	(608)	*(584)*
Total derivative fair value loss (gain)	$ (20,263)	$ 5,713	*$ (25,976)*

As previously discussed, we discontinued hedge accounting for all of our derivative instruments in July 2006.

Loss on early redemption of debt. As previously discussed, in the third quarter of 2005, we recorded a one-time $19.5 million loss on early redemption of $150 million of 8 3/8% senior subordinated notes due 2012.

Other operating expense. Other operating expense decreased $2.2 million from $5.8 million in the first nine months of 2005 to $3.6 million in the first nine months of 2006, primarily due to lower transportation costs.

Interest expense. Interest expense increased $10.1 million in the first nine months of 2006 as compared to the first nine months of 2005. The increase is primarily due to additional debt used to finance acquisitions and our capital program. We issued $150 million of 7 1/4% senior subordinated notes due 2017 in November 2005 and $300 million of 6% senior subordinated notes due 2014 in July 2005. We also redeemed $150 million of 8 3/8% senior subordinated notes due 2012 in August 2005. The weighted average interest rate, net of hedges, for the first nine months of 2006 was 6.7 percent as compared to 7.4 percent for the first nine months of 2005.

The following table illustrates the components of interest expense for the nine months ended September 30, 2006 and 2005:

	Nine months ended September 30, 2006	2005	*Increase / (Decrease)*
		(in thousands)	
8 3/8% Notes	$	$ 7,851	*$ (7,851)*
6 1/4% Notes	7,262	7,031	*231*
6% Notes	13,795	3,937	*9,858*
7 1/4% Notes	8,238		*8,238*
Revolving credit facility	2,773	2,972	*(199)*

Other	1,698	1,880	*(182)*
Total	$ 33,766	$ 23,671	*$ 10,095*

Income taxes. Income tax expense for the first nine months of 2006 increased $18.4 million over the first nine months of 2005. This is due to higher pre-tax income and an increase in our effective tax rate. Our effective tax rate increased in the first nine months of 2006 to 38.4 percent from 33.2 percent in the first nine months of 2005 due to the absence of Section 43 income

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tax credits during the first nine months of 2006 and changes to the Texas franchise tax. The Enhanced Oil Recovery credits available under Section 43 are fully phased out for the 2006 tax year due to high oil prices in 2005. Therefore, no credits were generated during the nine months ended September 30, 2006. We were able to reduce our income tax provision in the first nine months of 2005 by $2.7 million from the generation of Section 43 credits. In addition, a recently enacted Texas franchise tax reform measure caused us to adjust our net deferred tax balances using the new higher marginal tax rate we expect to be effective when those deferred taxes become current. This resulted in a charge of $1.4 million during the nine months ended September 30, 2006.

Capital Resources

Our primary capital resources are as follows:

- Cash flows from operating activities;
- Cash flows from financing activities; and
- Current capitalization.

Cash flows from operating activities. Cash provided by operating activities increased $30.2 million from $204.2 million for the nine months ended September 30, 2005 to $234.4 million for the nine months ended September 30, 2006. Although total oil and natural gas revenues in the first nine months of 2006 increased $58.2 million, or 18 percent, from the first nine months of 2005, a widening in the differential between the wellhead price we received for our CCA and Williston Basin oil production and the average NYMEX price for oil in the first nine months of 2006 caused total oil and natural gas revenues per BOE in the first nine months of 2006 to increase only 6 percent from the first nine months of 2005. The increase in oil and natural gas revenues was partially offset by an increase of $14.4 million, or 7 percent, in total operating expenses (excluding oil marketing expenses) in the first nine months of 2006 from the first nine months of 2005, which resulted in a smaller increase in cash provided by operating activities.

Cash flows from financing activities. Our cash flows from financing activities consist primarily of proceeds from and payments on long-term debt and proceeds received from the issuance of common stock in April 2006. During the first nine months of 2006, we received net cash of $41.8 million from financing activities.

On April 4, 2006, we received net proceeds of approximately $127.1 million from a public offering of 4.0 million shares of our common stock. The net proceeds were used to repay outstanding balances under our revolving credit facility, invest in oil and natural gas activities, and to pay general corporate expenses.

We periodically draw on our revolving credit facility to fund acquisitions and other capital commitments. During the first nine months of 2006, using funds we received from our equity issuance, we repaid the balance of $80.0 million outstanding at December 31, 2005. We had no amounts outstanding at September 30, 2006.

During the first nine months of 2005, we received net cash of $94.3 million from financing activities. This consisted primarily of net proceeds from the issuance of $300 million of 6% senior subordinated notes due 2015 of $293.7 million, $165.9 million of which was used to redeem all of our 8 3/8% senior subordinated notes due 2014, and a net decrease in amounts outstanding under our revolving credit facility of $30.0 million.

Current capitalization. At September 30, 2006, we had total assets of $1.9 billion. Total capitalization as of September 30, 2006 was $1.4 billion, of which 57 percent was represented by stockholders equity and 43 percent by long-term debt. At December 31, 2005, we had total assets of $1.7 billion. Total capitalization as of December 31, 2005 was $1.2 billion, of which 45 percent was represented by stockholders equity and 55 percent by long-term debt. The percentages of our capitalization represented by stockholders equity and long-term debt could vary in the future if debt or equity is used to finance future capital projects or potential acquisitions.

Capital Commitments

Our primary needs for cash are as follows:

- Development, exploitation, and exploration of our existing oil and natural gas properties;
- Acquisitions of oil and natural gas properties and leasehold acreage costs;

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Other general property and equipment;

Funding of necessary working capital; and

Payment of contractual obligations.

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, 2006 and 2005:

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(in thousands)			
Development and exploitation	$ 63,499	$ 67,181	$ 159,394	$ 168,065
Exploration	27,289	16,359	65,922	44,762
High-pressure air injection	4,454	9,854	18,913	27,095
Total	$ 95,242	$ 93,394	$ 244,229	$ 239,922

Development and exploitation. 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 third quarter of 2006 included a total of 45 gross (13.7 net) successful wells and 4 gross (2.5 net) development dry holes. Our development and exploitation capital for the first nine months of 2006 included a total of 135 gross (52.1 net) successful wells and 4 gross (2.5 net) development dry holes.

We operated between 9 and 12 drilling rigs during the third quarter of 2006, including 4 rigs related to our West Texas joint development agreement. Higher working interests and generally elevated service costs have required additional capital for wells in our 2006 drilling program. As a result of these factors, our capital expenditures outpaced operating cash flow in 2006. In order to attain a better balance between investment and cash flow, we have opted to release a limited number of rigs, and instead plan to drill fewer yet higher-quality prospects during the remainder of 2006. Production attributable to some of these higher-quality prospects will not have an appreciable effect on results of operations for the remainder of 2006, since such wells typically take several months to bring online.

Exploration. Our expenditures for exploration investments primarily relate to drilling exploratory wells, seismic costs, delay rentals, and geological and geophysical costs. During the third quarter of 2006, our exploration capital was invested primarily in drilling extension and exploratory wells in the Mid-Continent area. In the third quarter of 2006, our exploration capital yielded 20 gross (4.1 net) exploratory wells that were productive and 4 gross (2.4 net) exploratory dry holes. During the nine months ended September 30, 2006, our exploration capital yielded 44 gross (11.2 net) exploratory wells that were productive and 11 gross (7.1 net) exploratory dry holes.

HPAI programs. In the Little Beaver area, our HPAI project continues to keep production relatively stable without drilling additional wells. Implementation of HPAI in Little Beaver Phases I and II was completed in the fourth quarter of 2004.

In the Pennel and Coral Creek areas of the CCA, we completed Phases I and II of the HPAI project in the fourth quarter of 2005, and we are seeing initial indications of response and expect to see more meaningful response toward the end of 2006. Implementation of Phase III at Pennel is currently underway.

Acquisitions and leasehold acreage costs. The following table summarizes our costs incurred (excluding asset retirement obligations) for oil and natural gas property acquisitions during the three and nine months ended September 30, 2006 and 2005:

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
		(in thousands)		
Acquisitions of proved properties	$ 263	$ 28,890	$ 4,315	$ 39,547
Leasehold acreage costs	6,629	3,502	18,494	10,224
Total	$ 6,892	$ 32,392	$ 22,809	$ 49,771

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Acquisitions. Our capital expenditures for proved oil and natural gas properties during the third quarter of 2006 totaled $0.3 million as compared to $28.9 million in the third quarter of 2005. The $28.9 million in the third quarter of 2005 was invested primarily in additional working interests in the ArkLaTx region and the Williston Basin. We do not budget for acquisitions.

Leasehold acreage costs. Our capital expenditures for leasehold acreage costs during the three months ended September 30, 2006 and 2005 totaled $6.6 million and $3.5 million, respectively. Undeveloped leasehold costs incurred in each period consists of costs for acreage spread over our various core areas.

Other general property and equipment. Our capital expenditures for other general property and equipment during the three months ended September 30, 2006 and 2005 totaled $0.9 million and $0.5 million, respectively. Capital expenditures for other general property and equipment include corporate leasehold improvements, computers, and various field equipment.

Funding of necessary working capital. At September 30, 2006, our working capital (defined as total current assets less total current liabilities) was negative $45.5 million, while at December 31, 2005 our working capital was negative $56.8 million, an improvement of $11.4 million. The improvement is primarily attributable to decreases in the NYMEX price of natural gas which favorably impacted the fair value of outstanding derivative contracts, net of deferred taxes, offset by the decrease in accounts receivable from sales of natural gas resulting from the lower price.

For the remainder of 2006, we expect working capital to remain negative. Negative working capital is expected mainly due to fair values of our derivative contracts, the settlements of which will be offset by cash flows from hedged production. We anticipate future cash reserves to be close to zero as we plan to use available cash to fund capital obligations and pay general corporate expenses. We do not plan to pay cash dividends in the foreseeable future. The overall 2006 market prices for oil and natural gas along with the impact of differentials between those market prices and the wellhead prices we receive on our production will be the largest variables driving the different components of working capital.

Higher working interests and generally elevated service costs have required additional capital for a given well in our 2006 drilling program. As a result of these factors, we increased oil and natural gas related budgeted capital expenditures from $320 million to approximately $360 million. 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 borrowings on our revolving credit facility.

Contractual obligations. The following table illustrates our contractual obligations and commercial commitments outstanding at September 30, 2006:

Contractual Obligations	Payments Due by Period				
and Commitments	Total	2006	2007 - 2008	2009 - 2010	Thereafter
			(in thousands)		
6 1/4% Notes (a)	$ 225,000	$ 4,687	$ 18,750	$ 18,750	$ 182,813
6% Notes (a)	462,000		36,000	36,000	390,000
7 1/4% Notes (a)	275,063	5,438	21,750	21,750	226,125
Revolving credit facility					
Derivative obligations (b)	98,672	9,711	82,030	6,931	
Development commitments (c)	204,516	64,630	128,611	11,275	
Operating leases (d)	14,649	438	4,022	4,199	5,990
Asset retirement obligations (e)	125,941	95	763	763	124,320
Total	$ 1,405,841	$ 84,999	$ 291,926	$ 99,668	$ 929,248

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

(b) Derivative obligations represent net liabilities for derivatives that were valued as of September 30, 2006. With the exception of $56.1 million of deferred premiums on derivative contracts, the ultimate settlement amounts of the remaining portions of our derivative obligations are unknown because they are subject to continuing market risk.

(c) Development commitments include authorized purchases for work in process of $39.7 million which is accrued at September 30, 2006, and future minimum payments for electricity, seismic data analysis, and drilling rig operations of $151.8 million. Also at September 30, 2006, we had $175.0 million of authorized purchases not placed to vendors (authorized AFEs) which were not accrued and are excluded from the above table, but are budgeted for and expected to be made unless circumstances change.

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

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

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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 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 natural gas prices. Realized oil and natural gas prices for the first nine months of 2006 were 6 percent higher as compared to the first nine months of 2005. These prices have historically fluctuated widely in response to changing market forces. For the first nine months of 2006, approximately 65 percent of our production was oil. As we previously discussed, our oil wellhead differentials during the first nine months of 2006 increased significantly from the first nine months of 2005, adversely impacting the amount of oil revenues we received on our oil production. To the extent oil and natural gas prices decline or we continue to experience significantly increased wellhead differentials, our earnings, cash flows from operations, and availability under our revolving credit facility may be adversely impacted. Prolonged periods of low oil and natural gas prices or sustained wider than historical wellhead differentials could cause us to not be in compliance with maintenance covenants under our revolving credit facility and thereby affect our liquidity. We believe that our internally generated cash flows and unused availability under our revolving credit facility are sufficient to fund our planned capital expenditures for the foreseeable future.

Revolving credit facility. Our principal source of short-term liquidity is our revolving credit facility, which matures on December 29, 2010. The revolving credit facility is with a bank syndicate comprised of Bank of America, N.A. and other lenders. The borrowing base is determined semi-annually and may be increased or decreased, up to a maximum of $750 million. The borrowing base as of September 30, 2006 was $550 million.

On September 30, 2006, we had no amounts outstanding and $523.3 million available to borrow under the revolving credit facility. On November 2, 2006, we had $2.0 million outstanding and $520.8 million available to borrow under the revolving credit facility.

Letters of credit. As of September 30, 2006, we had $26.7 million in letters of credit. As of November 2, 2006, we had $27.2 million of such outstanding letters of credit.

In prior periods, we have had letters of credit with some of our commodity derivative contract counterparties. At any point in time, we had hedge margin deposits and letters of credit equal to the amount by which the current mark-to-market liability of our commodity derivative contracts exceeded the margin maintenance thresholds we have negotiated with our counterparties. Once a margin threshold was reached, we were required to maintain cash reserves in an account with the counterparty or post letters of credit in lieu of cash to ensure future settlement were made pursuant to our contracts. These funds were released back to us as our mark-to-market liability decreases due to either a drop in the futures prices of oil and natural gas or the passage of time as settlements are made. During the third quarter of 2006, we negotiated with these counterparties to remove the letter of credit requirements as long as our senior notes maintain their current rating.

Contingencies

In order to facilitate ongoing sales of our oil production in the CCA, we ship a portion of our production in pipelines downstream and sell to purchasers at major U.S. market hubs. From time to time, shipping delays, purchaser stipulations, or other conditions 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 period of production on production volumes, oil and natural gas 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 the 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. While shipments on Platte Pipeline are currently oversubscribed and have been subject to apportionment since December 2005, we have been able to move our produced volumes through Platte Pipeline. In addition, shipments on Butte Pipeline were also apportioned in April 2006, but we have continued to

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move our produced volumes from the CCA to market. However, further restrictions on the available capacity to transport oil through these pipelines could have a material adverse effect on price received, production volumes, and oil and natural gas revenues.

Our oil wellhead price as a percentage of the average NYMEX price decreased to 82 percent in the first nine months of 2006 from 90 percent in the first nine months of 2005. The widening of the differential is due to market conditions in the Rocky Mountain area, which has adversely affected the wellhead price we received on our CCA and Williston Basin production. Production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity in the Rocky Mountain refining area during the first quarter of 2006, created deep pricing discounts. As Rocky Mountain refiners have completed maintenance and increased their demand for crude oil, the differential has narrowed from the first quarter 2006 level of 77 percent. However, future differentials are expected to remain wider than our historical average.

Critical Accounting Policies and Estimates

On January 1, 2006, we adopted the provisions of SFAS 123R. SFAS 123R is a revision of SFAS 123 and supersedes APB 25. SFAS 123R eliminates the option of using the intrinsic value method of accounting previously available, and requires companies to recognize in the financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. See Note 11 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for more information.

During July 2006, we elected to discontinue hedge accounting prospectively for all of our commodity derivatives which were previously accounted for as hedges. While this change will have no effect on our cash flows, future results of operations will be affected by mark-to-market gains and losses, which fluctuate with the swings in oil and natural gas prices. As of July 2006, all of our remaining derivative contracts accounted for as hedges were dedesignated. At the point of dedesignation, the gain (loss) to be amortized to revenue was established and is deferred in Accumulated Other Comprehensive Loss. We are recognizing prospective mark-to-market gains and losses in earnings rather than deferring such amounts in Accumulated Other Comprehensive Loss.

Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates in Encore s 2005 Annual Report on Form 10-K for more information.

New Accounting Pronouncements

The effects of new accounting pronouncements are discussed in Note 2 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements .

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The information included in Quantitative and Qualitative Disclosures about Market Risk in our 2005 Annual Report on Form 10-K is incorporated herein by reference. Such information includes a description of our potential exposure to market risks, including commodity price risk and interest rate risk. Our outstanding derivative contracts as of September 30, 2006 are discussed in Note 5 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements . As of September 30, 2006, the fair value of our open commodity derivative contracts was a net asset of $1.6 million. Based on our open commodity derivative positions at September 30, 2006, a $1.00 increase in the NYMEX prices for oil and natural gas would result in a decrease to our net derivative fair value asset of approximately $14.5 million, while a $1.00 decrease in the NYMEX prices for oil and natural gas would result in an increase to our net derivative fair value asset of approximately $16.8 million.

At September 30, 2006, we had total long-term debt of $593.6 million, which is recorded net of discount of $6.4 million. Of this amount, $150.0 million bears interest at a fixed rate of 6 1/4 percent, $300.0 million bears interest at a fixed rate of 6 percent, and $150.0 million bears interest at a fixed rate of 7 1/4 percent. At September 30, 2006, we had no amounts outstanding under our revolving credit facility, which is subject to floating market rates of interest that are linked to LIBOR.

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Item 4. Controls and Procedures

In accordance with the Securities Exchange Act of 1934 (the 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, 2006 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 SEC s rules and forms.

There has been no change in our internal control over financial reporting that occurred during the third quarter of 2006 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 1A. Risk Factors

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2005, which could materially affect our business, financial condition, and/or future results. The risks described in our Annual Report on Form 10-K are not the only risks we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition, and/or future results.

Item 6. Exhibits

Exhibits	
3.1	Second Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001, filed with the SEC on November 7, 2001).
3.1.2	Certificate of Amendment to Second Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to the Company s 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 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).
12.1	Statement showing computation of ratios of earnings to fixed charges.
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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ENCORE ACQUISITION COMPANY
SIGNATURE

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

Date: November 8, 2006	By: /s/ Robert C. Reeves
	Robert C. Reeves
	Senior Vice President, Chief Accounting Officer, and Controller

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