BRADY CORP
Form 8-K
October 20, 2003

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K
CURRENT REPORT

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): October 20, 2003

Commission File Number 1-14959

BRADY CORPORATION
(Exact name of registrant as specified in its charter)

Wisconsin	39-0971239
(State of Incorporation)	(IRS Employer Identification No.)

6555 West Good Hope Road
Milwaukee, Wisconsin 53223
(Address of Principal Executive Offices and Zip Code)

(414) 358-6600
(Registrant's Telephone Number)

Item 5. OTHER EVENTS AND REGULATION FD DISCLOSURE.

On October 20, 2003, Brady Corporation (the "Company") issued a press release announcing that David W. Schroeder, Senior Vice President and Chief Financial Officer, has decided to leave the Company to pursue other interests. Mr. Schroeder plans to remain in his current role until a successor is named and throughout an appropriate transition period, but no later than May 2004.

A copy of the press release is attached as Exhibit 99.1.

Item 7. FINANCIAL STATEMENTS AND EXHIBITS

(c) Exhibits:

The following Exhibits are filed with this Current Report on Form 8-K:

Exhibit No.

99.1 Press Release dated October 20, 2003.

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 hereunto duly authorized.

BRADY CORPORATION
(Registrant)

Date: October 20, 2003

/s/ Frank M. Jaehnert

Frank M. Jaehnert
President and Chief Executive Officer

Exhibit Index

Exhibit No.	Description
99.1	Press Release dated October 20, 2003.

$ 3,000 $36.75 $(21,695)

Jan. - June 2008
18,500 62.84 (4,000) 50.00 1,000 58.59 10,340
July - Dec. 2008
14,500 63.62 (4,000) 50.00 11,790
Jan. - Dec. 2009
6,000 68.83 (5,000) 50.00 1,000 68.70 13,226

$13,661

Natural Gas Derivative Instruments

Period	**Daily Floor Volume (Mcf)**	**Average Floor Price (per Mcf)**	**Daily Short Floor Volume (Mcf)**	**Average Short Floor Price (per Mcf)**	**Daily Swap Volume (Mcf)**	**Average Swap Price (per Mcf)**	**Asset (Liability) Fair Market Value (in thousands)**
Apr. - June 2007	32,500	$ 6.74		$	10,000	$ 4.99	$ (1,039)
July - Dec. 2007	34,500	6.83					(2,579)
Jan. - Dec. 2008	22,000	6.52					4,100
Jan. - Dec. 2009	2,000	8.20					944

$	1,426

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 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/D in 2008 and 5,000 Bbls/D in 2009. As with the Company s other derivative contracts, these are marked-to-market each quarter through Derivative fair value (gain) loss 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.

Commodity Contracts Current Period Impact

As a result of derivative transactions for oil and natural gas, the Company recognized a pre-tax reduction in oil and natural gas revenues of approximately $13.4 million and $16.5 million during the three months ended March 31, 2007 and 2006, respectively. The Company also recognized 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 certain other commodity derivatives that were never designated as hedges, (iii) settlements on derivative contracts not designated as hedges, and (iv) ineffectiveness of derivative contracts designated as hedges prior to July 2006. The following table summarizes the components of derivative fair value loss for the three months ended March 31, 2007 and 2006:

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	Three months ended March 31,	
	2007	2006
	(in thousands)	
Ineffectiveness on designated cash flow hedges	$	$ 2,839
Mark-to-market loss on commodity contracts not designated as hedges	40,214	1,093
Settlements on commodity contracts	5,400	(1,626)
Total derivative fair value loss	$ 45,614	$ 2,306

Commodity Contracts   Future Period Impact

At March 31, 2007 and December 31, 2006, AOCL consisted entirely of deferred losses on commodity derivatives, net of tax, of $27.1 million and $35.3 million, respectively.

During the twelve months ending March 31, 2008, the Company expects to reclassify $40.9 million of deferred losses associated with its dedesignated commodity contracts from AOCL to oil and natural gas revenues. The remaining pretax amount of AOCL will be reclassified to oil and natural gas revenues by the end of 2008. The Company also expects to reclassify approximately $15.1 million of net deferred tax assets from AOCL to income tax benefit on the Company s Consolidated Statements of Operations during the next twelve months.

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 include a market risk premium in its risk estimates as the effect would not be material. As of March 31, 2007, the Company had $5.1 million held in an escrow account from which funds are released only for reimbursement of plugging and abandonment expenses on Encore s Bell Creek property. This amount is included in Other assets in the accompanying Consolidated Balance Sheet. The following table summarizes the changes in the Company s future abandonment liability, the long-term portion of which is recorded in Future abandonment cost on the accompanying Consolidated Balance Sheets, for the first quarter of 2007:

Future abandonment liability at January 1, 2007	$ 19,841
Wells drilled	32
Accretion expense	219
Plugging and abandonment costs incurred	(49)
Acquisition of properties	9,636
Future abandonment liability at March 31, 2007	$ 29,679

Note 7. Debt

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

	March 31, 2007	December 31, 2006
	(in thousands)	
Revolving credit facilities	$ 607,973	$ 68,000
6 1/4% Notes	150,000	150,000

6% Notes, net of unamortized discount of $4,781 and $4,892, respectively	295,219	295,108
7 1/4% Notes, net of unamortized discount of $1,390 and $1,412, respectively	148,610	148,588
Total	$ 1,201,802	$ 661,696

Revolving Credit Facilities

Encore Acquisition Company Senior Secured Credit Agreement

On March 7, 2007, Encore entered into a five-year amended and restated credit agreement (the Encore Credit Agreement) with Bank of America, N.A., as administrative agent and letter of credit issuer, Fortis Capital Corp., and Wachovia Bank, N.A.,

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as co-syndication agents, BNP Paribas and Calyon New York Branch, as co-documentation agents, Banc of America Securities LLC, as sole lead arranger and sole book manager, and other lenders. The Encore Credit Agreement amended and restated Encore s Amended and Restated Credit Agreement dated as of August 19, 2004, as amended. The Company incurred approximately $6.6 million of debt issuance costs related to the Encore Credit Agreement, which is being amortized to interest expense over the remaining term.

The Encore Credit Agreement provides for revolving credit loans to be made to Encore from time to time and letters of credit to be issued from time to time for the account of Encore or any of its restricted subsidiaries. The aggregate amount of the commitments of the lenders under the Encore Credit Agreement is $1.25 billion. Availability under the Encore Credit Agreement is subject to a borrowing base. The initial borrowing base was $650 million, which automatically increased to $950 million upon the closing of Encore s acquisition of certain properties located in the Williston Basin of Montana and North Dakota. Please see Note 16. Subsequent Events below for a discussion of the Williston Basin acquisition. The borrowing base is redetermined semi-annually and upon requested special redeterminations.

The Encore Credit Agreement matures on March 7, 2012. Encore s obligations under the Encore Credit Agreement are secured by a first-priority security interest in Encore s and its restricted subsidiaries proved oil and natural gas reserves and in the equity interests of Encore s restricted subsidiaries. In addition, Encore s obligations under the Encore Credit Agreement are guaranteed by its restricted subsidiaries.

Loans under the Encore Credit Agreement are subject to varying rates of interest based on (i) the total amount outstanding under the credit agreement in relation to the borrowing base and (ii) whether the loan is a Eurodollar loan or a base rate loan. Eurodollar loans bear interest at the Eurodollar rate plus the applicable margin indicated in the following table, and base rate loans bear interest at the base rate plus the applicable margin indicated in the following table:

Ratio of Total Outstandings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans
Less than .50 to 1	1.000%	0.000%
From .50 to 1 but less than .75 to 1	1.250%	0.000%
From .75 to 1 but less than .90 to 1	1.500%	0.250%
Greater than .90 to 1	1.750%	0.500%

The Eurodollar rate for any interest period (either one, two, three or six months, as selected by Encore) is the rate per year equal to LIBOR, as published by Reuters or another source designated by Bank of America, N.A., for deposits in dollars for a similar interest period. The base rate is calculated as the higher of (i) the annual rate of interest announced by Bank of America, N.A. as its prime rate and (ii) the federal funds effective rate plus 0.5 percent.

As of March 31, 2007, the aggregate principal amount of loans outstanding under the Encore Credit Agreement was $488.9 million and the aggregate face amount of outstanding letters of credit was $20 million, all of which related to the ExxonMobil joint development agreement. Any outstanding letters of credit reduce the availability under the Encore Credit Agreement. Borrowings under the Encore Credit Agreement may be repaid from time to time without penalty.

The Encore Credit Agreement contains covenants that include, among others:

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against paying dividends or making distributions, purchasing, or redeeming capital stock or prepaying indebtedness, subject to permitted exceptions;

a restriction on creating liens on Encore s and its restricted subsidiaries assets, subject to permitted exceptions;

restrictions on merging and selling assets outside the ordinary course of business;

restrictions on use of proceeds, investments, transactions with affiliates, change of principal business;

a provision limiting oil and natural gas hedging transactions (other than puts) to a volume not exceeding 75 percent of anticipated production from proved producing reserves;

a requirement that Encore maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0; and

a requirement that Encore maintain a ratio of consolidated EBITDA (as defined in the Encore Credit Agreement) to the sum of consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0.

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The Encore Credit Agreement contains customary events of default. If an event of default occurs and is continuing, lenders with a majority of the aggregate commitments may require Bank of America, N.A. to declare all amounts outstanding under the Encore Credit Agreement to be immediately due and payable.

Encore incurs a commitment fee on the unused portion of the Encore Credit Agreement determined based on the ratio of amounts outstanding under the Encore Credit Agreement to the borrowing base in effect on such date. The following table summarizes the calculation of the commitment fee under the Encore Credit Agreement:

Ratio of Total Outstandings to Borrowing Base	Commitment Fee Percentage
Less than .50 to 1	0.250%
From .50 to 1 but less than .75 to 1	0.300%
From .75 to 1 but less than .90 to 1	0.375%
Greater than .90 to 1	0.375%

Encore Energy Partners Operating LLC Credit Agreement

On March 7, 2007, EEPO entered into a five-year credit agreement (the EEPO Credit Agreement) with Bank of America, N.A., as administrative agent and letter of credit issuer, and Banc of America Securities LLC, as sole lead arranger and sole book manager, and other lenders. The EEPO Credit Agreement provides for revolving credit loans to be made to EEPO from time to time and letters of credit to be issued from time to time for the account of EEPO or any of its restricted subsidiaries. The Company incurred approximately $1.6 million of debt issuance costs related to the EEPO Credit Agreement, which is being amortized to interest expense over the remaining term.

The aggregate amount of the commitments of the lenders under the EEPO Credit Agreement is $300 million. Availability under the EEPO Credit Agreement is subject to a borrowing base, provided that EEPO has the option of borrowing up to $10 million in excess of the borrowing base for a certain period of time following the closing date. The initial borrowing base is $115 million. The borrowing base is redetermined semi-annually and upon requested special redeterminations.

The EEPO Credit Agreement matures on March 7, 2012. EEPO s obligations under the EEPO Credit Agreement are secured by a first-priority security interest in EEPO s and its restricted subsidiaries proved oil and natural gas reserves and in the equity interests of EEPO and its restricted subsidiaries. In addition, EEPO s obligations under the EEPO Credit Agreement are guaranteed by its direct parent, Encore Energy Partners LP, a Delaware limited partnership (the Partnership), and EEPO s restricted subsidiaries. Obligations under the EEPO Credit Agreement are non-recourse to Encore and its restricted subsidiaries.

Loans under the EEPO Credit Agreement are subject to varying rates of interest based on (i) the total amount outstanding under the credit agreement in relation to the borrowing base and (ii) whether the loan is a Eurodollar loan or a base rate loan. Eurodollar loans bear interest at the Eurodollar rate plus the applicable margin indicated in the following table, and base rate loans bear interest at the base rate plus the applicable margin indicated in the following table:

Ratio of Total Outstandings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans
Less than .50 to 1	1.000%	0.000%
From .50 to 1 but less than .75 to 1	1.250%	0.000%
From .75 to 1 but less than .90 to 1	1.500%	0.250%
Greater than .90 to 1	1.750%	0.500%

The Eurodollar rate for any interest period (either one, two, three or six months, as selected by Encore) is the rate per year equal to LIBOR, as published by Reuters or another source designated by Bank of America, N.A., for deposits in dollars for a similar interest period. The base rate is calculated as the higher of (i) the annual rate of interest announced by Bank of America, N.A. as its prime rate and (ii) the federal funds effective rate plus 0.5 percent.

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As of March 31, 2007, the aggregate principal amount of loans outstanding under the EEPO Credit Agreement was $119.1 million and there were no outstanding letters of credit. Any outstanding letters of credit reduce the availability under the EEPO Credit Agreement. Borrowings under the EEPO Credit Agreement may be repaid from time to time without penalty.

The EEPO Credit Agreement contains covenants that include, among others:

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against paying dividends or making distributions prior to the IPO Effective Date (as defined in the EEPO Credit Agreement), purchasing or redeeming capital stock or prepaying indebtedness, subject to permitted exceptions;
- a restriction on creating liens on the assets of the Partnership, EEPO and its restricted subsidiaries, subject to permitted exceptions;
- restrictions on merging and selling assets outside the ordinary course of business;
- restrictions on use of proceeds, investments, transactions with affiliates, change of principal business;
- a provision limiting oil and natural gas hedging transactions (other than puts) to a volume not exceeding 75 percent of anticipated production from proved producing reserves;
- a requirement that EEPO maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0;
- a requirement that EEPO maintain a ratio of consolidated EBITDA (as defined in the EEPO Credit Agreement) to the sum of consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0; and
- a requirement that EEPO maintain a ratio of consolidated funded debt (excluding certain related party debt) to consolidated adjusted EBITDA (as defined in the EEPO Credit Agreement) of credit fees of not more than 3.5 to 1.0.

The EEPO Credit Agreement contains customary events of default. If an event of default occurs and is continuing, lenders with a majority of the aggregate commitments may require Bank of America, N.A. to declare all amounts outstanding under the EEPO Credit Agreement to be immediately due and payable.

EEPO incurs a commitment fee on the unused portion of the EEPO Credit Agreement determined based on the ratio of amounts outstanding under the EEPO Credit Agreement to the borrowing base in effect on such date. The following table summarizes the calculation of the commitment fee under the EEPO Credit Agreement:

Ratio of Total Outstandings to Borrowing Base	Commitment Fee Percentage
Less than .50 to 1	0.250%
From .50 to 1 but less than .75 to 1	0.300%
From .75 to 1 but less than .90 to 1	0.375%
Greater than .90 to 1	0.375%

Note 8. Income Taxes

The components of the income tax benefit (provision) were as follows for the three months ended March 31, 2007 and 2006:

	Three months ended March 31, 2007	Three months ended March 31, 2006
	(in thousands)	
Federal:		
Current	$ 120	$ (112)
Deferred	15,750	(10,353)
Total federal	15,870	(10,465)
State, net of federal benefit/expense:		
Current		(170)
Deferred	149	(609)
Total state	149	(779)
Income tax benefit (provision)	$ 16,019	$ (11,244)

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The following table reconciles income tax benefit (provision) with income tax at the Federal statutory rate for the three months ended March 31, 2007 and 2006:

	Three months ended March 31, 2007	Three months ended March 31, 2006
	(in thousands)	
Income (loss) before income taxes	$ (45,448)	$ 29,180
Tax at statutory rate	$ 15,907	$ (10,213)
State income taxes, net of federal benefit/expense	1,124	(781)
Change in estimated future tax rate	(972)	
Permanent and other	(40)	(250)
Income tax benefit (provision)	$ 16,019	$ (11,244)

On January 1, 2007, the Company adopted the provisions of FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes (SFAS 109). FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Subject to statutory exceptions that allow for a possible extension of the assessment period, the Company is no longer subject to U.S. federal, state, and local income tax examinations for years prior to 2003.

The Company has performed its evaluation of tax positions and has determined that the adoption of FIN 48 did not have a material impact on the Company s financial condition, results of operations, or cash flows. This evaluation is a review of the appropriate recognition threshold for each tax position recognized in the Company s financial statements. The evaluation included, but was not limited to: (1) a review of documentation of tax positions taken on previous returns including an assessment of whether the Company followed industry practice or the applicable requirements under the tax code, (2) a review of open tax returns (on a jurisdiction by jurisdiction basis) as well as supporting documentation used to support those tax returns, (3) a review of the results of past tax examinations, (4) a review of whether tax returns have been filed in all appropriate jurisdictions, (5) a review of existing permanent and temporary differences, and (6) consideration of any tax planning strategies that may have been used to support realization of deferred tax assets. Based on this evaluation the Company did not identify any tax positions that did not meet the highly certain positions threshold. As a result no additional tax expense, interest, or penalties have been accrued as a result of the review.

The Company includes interest assessed by the taxing authorities in Interest expense and penalties related to income taxes in Other expense on the Consolidated Statements of Operations. For the three months ended March 31, 2007 and 2006, the Company recorded only a nominal amount of interest and penalties on certain tax positions.

Note 9. Earnings Per Share (EPS)

The following table reflects EPS data for the three months ended March 31, 2007 and 2006:

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	Three months ended March 31,			
	2007		2006	
	(in thousands, except per share data)			
Numerator:				
Net income (loss)	$	(29,429)	$	17,936
Denominator:				
Denominator for basic EPS:				
Weighted average shares outstanding		53,077		48,797
Effect of dilutive options and diluted restricted stock (a)				975
Denominator for diluted EPS		53,077		49,772
Net income (loss) per common share:				
Basic	$	(0.55)	$	0.37
Diluted	$	(0.55)	$	0.36

(a) Options to purchase 1,498,202 shares of common stock were outstanding but not included in the above calculation of EPS for the first quarter of 2007 because their effect would be antidilutive. There were no antidilutive options during the first quarter of 2006.

Note 10. 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 provide 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 March 31, 2007, there were 832,118 shares available for issuance under the Plan. Shares delivered or withheld for payment of the exercise price of an option, shares withheld for payment of tax withholding, or shares subject to options or other awards which expire or are terminated and restricted shares that are forfeited will again become available for issuance 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 Board also has a Restricted Stock Award Committee having Jon S. Brumley, the Company s Chief Executive Officer and President, as its sole member. The Restricted Stock Award Committee may grant certain awards of restricted stock to non-executive employees at its discretion.

The Plan contains the following individual limits:

- an employee may not be granted awards covering or relating to more than 225,000 shares of common stock in any calendar year;

- a non-employee director may not be granted awards covering or relating to more than 15,000 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.

All options that have been granted under the Plan have a strike price equal to the fair market value of the Company s 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.

The compensation cost related to the Plan that has been recorded in the accompanying Consolidated Statements of Operations for the three months ended March 31, 2007 and 2006 was $3.1 million and $3.7 million, respectively. The income tax benefit related to the Plan that has been recorded in the accompanying Consolidated Statements of Operations for the three months ended March 31, 2007 and 2006 was $1.1 million and $1.3 million, respectively. During the three months ended March 31, 2007 and 2006, the Company also capitalized $0.3 million and $0.2 million, respectively, of non-cash stock-based compensation cost as a component of Properties and equipment in the accompanying Consolidated Balance Sheets. Non-cash

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stock-based compensation expense has been allocated to lease operations expense, general and administrative 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 three months ended March 31, 2007 and 2006 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 the historical volatility of the Company s stock for a period of time commensurate with the expected term of the award. For options granted in the three months ended March 31, 2007 and 2006, the Company used the simplified method prescribed by SEC Staff Accounting Bulletin No. 107 to estimate the expected term of the options, which is calculated as the average midpoint between each vesting date and the life of the option. 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.

	Three months ended March 31,	
	2007	**2006**
Expected volatility	35.7%	42.8%
Expected dividend yield	0.0%	0.0%
Expected term (in years)	6.0	6.0
Risk-free interest rate	4.8%	4.6%

The following table summarizes the changes in the number of outstanding options and their related weighted average strike prices during the first quarter of 2007:

	Number of Options	**Weighted Average Strike Price**	**Weighted Average Remaining Contractual Term**	**Aggregate Intrinsic Value** (in thousands)
Outstanding at January 1, 2007	1,337,118	$ 14.44		
Granted	200,059	25.73		
Forfeited	(9,262)	29.33		
Exercised	(29,713)	13.38		
Outstanding at March 31, 2007	1,498,202	15.88	6.3	$ 13,642
Exercisable at March 31, 2007	1,193,792	13.11	5.5	13,587

The weighted average fair value per share of individual options granted during the three months ended March 31, 2007 and 2006 was $11.16 and $14.96, respectively. The total intrinsic value of options exercised during the three months ended March 31, 2007 and 2006 was $0.3 million and $0.4 million, respectively. During each of the three months ended March 31, 2007 and 2006, the Company received proceeds from the exercise of stock options of $0.4 million. During the three months ended March 31, 2007 and 2006, the Company realized related tax benefits of $0.2 million and $0.1 million, respectively. At March 31, 2007, the Company had $3.3 million of total unrecognized compensation cost related to unvested stock options, which is expected to be recognized over a weighted average period of 2.5 years.

Restricted Stock

During the three months ended March 31, 2007 and 2006, the Company recognized expense related to restricted stock of $2.6 million and $3.3 million, respectively. During the three months ended March 31, 2007 and 2006, the Company realized tax benefits related to restricted stock of $1.0 million and $1.2 million, respectively. During the first quarter of 2006, the Company did not realize any tax benefits as no shares vested during that period. A summary of the status of the Company s unvested restricted stock outstanding as of March 31, 2007, and changes during the three months then ended, is presented below:

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	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2007	828,619	$ 26.17
Granted	312,133	25.73
Vested	(83,668)	26.67
Forfeited	(27,581)	26.02
Outstanding at March 31, 2007	1,029,503	26.00

As of March 31, 2007, there were 854,313 shares of unvested restricted stock outstanding, dependent only on the passage of time and continued employment for vesting. Of this amount, 136,943 shares were granted during the first quarter of 2007. Additionally, as of March 31, 2007, there were 175,190 shares of unvested restricted stock outstanding that not only depend on the passage of time and continued employment, but on certain performance measures for vesting, all of which were granted during the first quarter of 2007.

As of March 31, 2007, there was $16.4 million of total unrecognized compensation cost related to unvested, outstanding restricted stock, which is expected to be recognized over a weighted average period of 3.2 years. During the first quarter of 2007, there were 83,668 shares of restricted stock that vested. Employees elected to satisfy minimum tax withholding obligations related to these shares by allowing the Company to withhold 15,743 shares. These shares are treated as treasury stock by the Company until the shares are formally retired and have been reflected as such in the accompanying Consolidated Balance Sheets and Statements of Cash Flows. There were no shares of restricted stock that vested during the first quarter of 2006.

Note 11. Comprehensive Income (Loss)

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

	Three months ended March 31, 2007	2006
	(in thousands)	
Net income (loss)	$ (29,429)	$ 17,936
Amortization of deferred loss on commodity derivatives	8,181	8,250
Amortization of deferred gain on interest rate swap		(14)
Comprehensive income (loss)	$ (21,248)	$ 26,172

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

Note 12. Financial Statements of Subsidiary Guarantors

Effective February 2007, the Company formed certain non-guarantor in anticipation of forming a master limited partnership (MLP). See Note 15. MLP for additional discussion. As of March 31, 2007, certain of the Company s wholly owned subsidiaries were subsidiary guarantors of the Company s outstanding notes. The subsidiary guarantees are full and unconditional, and joint and several. The subsidiary guarantors may, without restriction, transfer funds to the Company in the form of cash dividends, loans, and advances. In accordance with SEC rules, the Company has prepared Consolidating Condensed Financial Statements in order to quantify the assets and results of operations of the subsidiary guarantors. The following Consolidating Condensed Balance Sheet as of March 31, 2007, Consolidating Condensed Statement of Operations and Comprehensive Income for the three months ended March 31, 2007, and Consolidating Condensed Statement of Cash Flows for the three months ended March 31, 2007 present consolidating financial information for Encore Acquisition Company on a stand alone, unconsolidated basis and its combined guarantor and combined non-guarantor subsidiaries. The guarantor subsidiaries are EAP Energy, Inc., EAP Properties Inc., EAP Operating Inc., EAP Energy Services, L.P., Encore Operating, L.P., and Encore Operating Louisiana, LLC and the non-guarantor subsidiaries are EEPO, Encore Partners GP LLC, and Encore Energy Partners LP. All intercompany investments in, loans

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due to/from, subsidiary equity, income and expenses between Encore Acquisition Company (Parent), the guarantor subsidiaries, and non-guarantor subsidiaries are shown prior to final consolidation with the Parent then eliminated to arrive at consolidated totals per the Consolidated Financial Statements of Encore Acquisition Company. Prior to February 2007, all of the Company s subsidiaries were subsidiary guarantors of the Company s outstanding senior notes. Therefore, comparative condensed consolidating financial statements are not presented for the first quarter of 2006.

CONDENSED CONSOLIDATING BALANCE SHEET
March 31, 2007
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
ASSETS					
Current assets:					
Cash and cash equivalents	$	$ 106	$ 520	$	$ 626
Other current assets	22,408	113,800	9,248	(1,452)	144,004
Total current assets	22,408	113,906	9,768	(1,452)	144,630
Properties and equipment, at cost successful efforts method:					
Proved properties, including wells and related equipment		2,185,346	340,218		2,525,564
Unproved properties		47,007			47,007
Accumulated depletion, depreciation, and amortization		(396,386)	(2,507)		(398,893)
		1,835,967	337,711		2,173,678
Other property and equipment, net		10,359			10,359
Other assets, net	133,997	295,277	8,841	(240,942)	197,173
Investment in subsidiaries	2,006,162			(2,006,162)	
Total assets	$ 2,162,567	$ 2,255,509	$ 356,320	$ (2,248,556)	$ 2,525,840
LIABILITIES AND STOCKHOLDERS EQUITY					
Current liabilities	$ 12,149	$ 171,780	$ 8,605	$ (1,452)	$ 191,082
Deferred taxes	268,700				268,700
Long-term debt	1,082,686	120,471	239,587	(240,942)	1,201,802
Other liabilities		55,598	9,626		65,224

Total liabilities	1,363,535	347,849	257,818	(242,394)	1,726,808
Commitments and contingencies (see Note 13)					
Total stockholders equity	799,032	1,907,660	98,502	(2,006,162)	799,032
Total liabilities and stockholders equity	$ 2,162,567	$ 2,255,509	$ 356,320	$ (2,248,556)	$ 2,525,840

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS AND COMPREHENSIVE LOSS
For the Three Months Ended March 31, 2007
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 78,380	$ 4,243	$	$ 82,623
Natural gas		32,829	149		32,978
Marketing		13,703	1,238		14,941
Total revenues		124,912	5,630		130,542
Expenses:					
Production:					
Lease operations		29,552	968		30,520
Production, ad valorem, and severance taxes		11,878	637		12,515
Depletion, depreciation, and amortization		32,521	2,507		35,028
Exploration		11,521			11,521
General and administrative	24	7,148	188		7,360
Marketing		13,931	1,080		15,011
Derivative fair value loss		41,931	3,683		45,614
Other operating	41	2,500	24		2,565
Total expenses	65	150,982	9,087		160,134
Operating loss	(65)	(26,070)	(3,457)		(29,592)
Other income (expenses):					
Interest	(15,656)	(471)	(1,102)	942	(16,287)
Equity (income) loss from subsidiary	(30,156)			30,156	
Other	429	944		(942)	431
Total other income (expenses)	(43,383)	473	(1,102)	30,156	(15,856)
Loss before income taxes	(45,448)	(25,597)	(4,559)	30,156	(45,448)
Income tax benefit	16,019				16,019

Net loss	(29,429)	(25,597)	(4,559)	30,156	(29,429)
Amortization of deferred hedge losses, net of tax	8,181				8,181
Comprehensive loss	$ (21,248)	$ (25,597)	$ (4,559)	$ 30,156	$ (21,248)

Income taxes in the accompanying Condensed Consolidating Statement of Operations and Comprehensive Loss has been shown as an expense of the parent as the Company files a consolidated return and all the non-guarantor subsidiaries are disregarded entities for income tax purposes. Additionally, the Company s net current deferred tax asset and net long-term deferred tax liability have been included in the balance sheet of the Parent in the Condensed Consolidating Balance Sheet.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
For the Three Months Ended March 31, 2007
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Cash flows from operating activities:					
Net cash provided by (used in) operating activities	$	$ 17,339	$ (2,280)	$	$ 15,059
Cash flows from investing activities:					
Proceeds from disposition of assets		1,214			1,214
Acquisition of oil and natural gas properties	(41,000)	(69,210)	(328,358)		(438,568)
Development of oil and natural gas properties		(101,924)			(101,924)
Intercompany loans	(120,000)	(120,000)		240,000	
Investments in subsidiaries	(251,694)			251,694	
Other		(13,988)			(13,988)
Net cash used in investing activities	(412,694)	(303,908)	(328,358)	491,694	(553,266)
Cash flows from financing activities:					
Exercise of stock options and vesting of restricted stock, net	60				60
Proceeds from long-term debt	487,500	120,000	247,500	(240,000)	615,000
Payments on long-term debt	(66,644)		(8,383)		(75,027)
Debt issuance cost	(6,605)		(1,617)		(8,222)
Equity contributions		158,036	93,658	(251,694)	
Other	(1,617)	7,876			6,259
Net cash provided by financing activities	412,694	285,912	331,158	(491,694)	538,070
Increase (decrease) in cash and cash equivalents		(657)	520		(137)
Cash and cash equivalents, beginning of period		763			763

Cash and cash equivalents, end of period	$		$	106	$	520	$	$	626

Note 13. Commitments and Contingencies

Litigation

The Company is a party to ongoing legal proceedings in the ordinary course of business. Management does not believe the result of these proceedings will have a material adverse effect on the Company.

ExxonMobil

In March 2006, Encore entered into a joint development agreement with ExxonMobil Corporation (ExxonMobil) to develop legacy natural gas fields in West Texas. Under the terms of the agreement, Encore will have the opportunity to develop approximately 100,000 gross acres. Encore will earn 30 percent of ExxonMobil s working interest and 22.5 percent of ExxonMobil s net revenue interest in each well drilled. Encore will operate each well during the drilling and completion phase, after which ExxonMobil will assume operational control of the well.

Encore will earn the right to participate in all fields by drilling a total of 24 commitment wells. During the commitment phase, ExxonMobil will have the option to receive non-recourse advanced funds from Encore attributable to ExxonMobil s 70 percent working interest in each commitment well. Once a commitment well is producing, ExxonMobil will repay 95 percent of the advanced funds plus accrued interest assessed on the unpaid balance through Encore s monthly receipt of future proceeds of oil and natural gas sales. As an alternative to receiving advanced funds during the commitment phase, ExxonMobil can elect to pay their share of capital costs for each well. After Encore has fulfilled its obligations under the commitment phase, Encore will be entitled to a 30 percent working interest in future drilling locations. Encore will have the right to propose and drill wells for as long as Encore is engaged in continuous drilling operations.

During the first quarter of 2007 and the year ended December 31, 2006, we advanced $13.8 million and $22.4 million, respectively, to ExxonMobil for their portion of capital related to drilling commitment wells, of which $34.5 million and $21.0 million remained outstanding at March 31, 2007 and December 31, 2006, respectively. At March 31, 2007, $2.5 million is included in Accounts receivable and $32.0 million is included in Other assets on the accompanying Consolidated Balance

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)

Sheets based on when Encore expects repayment. At December 31, 2006, $3.0 million is included in Accounts receivable and $18.0 million is included in Other assets on the accompanying Consolidated Balance Sheets. As of March 31, 2007, Encore had 8 additional wells to drill in order to fulfill its drilling obligation under the joint development agreement.

Note 14. Related Party Transactions

The Company paid $0.6 million and $0.4 million to affiliates of Hanover Compressor Company (Hanover) during the three months ended March 31, 2007 and 2006, respectively, for compressors and field compression services. Mr. I. Jon Brumley, the Company s Chairman of the Board, also serves as a director of Hanover.

The Company paid $0.2 million and $0.1 million to affiliates of Kinder Morgan, Inc. (Kinder Morgan) during the three months ended March 31, 2007 and 2006, respectively, for its portion of production costs of certain non-operated wells. Mr. Ted A. Gardner, a member of the Board, also serves as a director of Kinder Morgan.

Note 15. MLP

On January 17, 2007, the Company announced an intention to form an MLP that will engage in an initial public offering of common units representing limited partner interests. The MLP was formed on February 13, 2007 and owns certain oil and gas properties and related assets in the Big Horn Basin of Wyoming and Montana. At the time of the initial public offering, the Company plans to contribute to the MLP certain of its legacy oil and gas properties in the Permian Basin of West Texas. Any sale of securities in the MLP would be registered under the Securities Act of 1933, and such units would only be offered and sold by means of a prospectus. This Report does not constitute an offer to sell or the solicitation of any offer to buy any securities of the MLP, and there will not be any sale of any such securities in any state in which such offer, solicitation, or sale would be unlawful prior to registration or qualification under the securities laws of such state.

Note 16. Subsequent Events

Williston Basin

On January 23, 2007, the Company entered into a purchase and sale agreement with certain subsidiaries of Anadarko to acquire certain oil and natural gas properties and related assets in the Williston Basin of Montana and North Dakota. The closing of the Williston Basin acquisition occurred on April 11, 2007. Prior to closing, Encore assigned all of its rights and duties under the purchase and sale agreement to Encore Operating, L.P., which further assigned all of its rights and duties under the purchase and sale agreement to Encore Exchange, LLC, a Delaware limited liability company unaffiliated with Encore or Encore Operating, L.P. (Encore Exchange). The Company plans to consolidate Encore Exchange under FASB Interpretation 46(R), Consolidation of Variable Interest Entities.

The Williston Basin acquisition has been structured so as to qualify as the first step of a reverse like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended, and I.R.S. Revenue Procedure 2000-37. The Williston Basin assets were acquired by Encore Exchange as an exchange accommodation titleholder. Encore Exchange will hold the assets pursuant to a qualified exchange accommodation agreement until the second step of the like-kind exchange is completed. In the interim, Encore Operating, L.P. will operate the Williston Basin assets pursuant to a management agreement with Encore Exchange.

The purchase price for the Williston Basin assets was approximately $392.5 million. In connection with the like-kind exchange described above, Encore (through Encore Operating, L.P.) loaned an amount equal to the purchase price to Encore Exchange. Encore financed the Williston Basin acquisition through borrowings under its credit facilities.

Upon closing, the borrowing base on the Encore Credit Agreement automatically increased to $950 million. The borrowing base was increased again on May 7, 2007 up to $985 million.

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ENCORE ACQUISITION COMPANY

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, 2006. 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 2006 Annual Report on Form 10-K.

Introduction

In this management s discussion and analysis of financial condition and results of operations, the following will be discussed and analyzed:

- Recent Developments
- First Quarter 2007 Highlights
- Results of Operations
  - Comparison of Quarter Ended March 31, 2007 to Quarter Ended March 31, 2006
- Capital Resources
- Capital Commitments
- Liquidity
- Contingencies
- Critical Accounting Policies and Estimates
- New Accounting Pronouncements

Recent Developments

Big Horn Acquisition

On January 16, 2007, we entered into a purchase and sale agreement with certain subsidiaries of Anadarko to acquire oil and natural gas properties and related assets in the Big Horn Basin of Wyoming and Montana, which included oil and natural gas properties and related assets in or near the Elk Basin field in Park County, Wyoming and Carbon County, Montana and oil and natural gas properties and related assets in the Gooseberry field in Park County, Wyoming. The closing of the Big Horn Basin acquisition occurred on March 7, 2007. Prior to closing, we assigned the rights and duties under the purchase and sale agreement relating to the Elk Basin assets to EEPO and the rights and duties under the purchase and sale agreement relating to the Gooseberry assets to Encore Operating, L.P. At closing, EEPO paid the sellers approximately $328.4 million for the Elk Basin assets and Encore Operating, L.P. paid the sellers approximately $63.7 million for the Gooseberry assets.

The Big Horn Basin properties currently produce approximately 4,350 BOE/D net. In connection with the acquisition, we purchased put contracts on 2,500 Bbls/D at $65.00 per Bbl for the remainder of 2007 and all of 2008, put contracts for 1,000 Bbls/D at $63.00 per Bbl for 2009, and swap contracts for 1,000 Bbls/D for 2009 at $68.70 per Bbl.

Williston Basin Acquisition

On January 23, 2007, we entered into a purchase and sale agreement with certain subsidiaries of Anadarko to acquire certain oil and natural gas properties and related assets in the Williston Basin of Montana and North Dakota. The closing of the Williston Basin acquisition occurred on April 11, 2007. Prior to closing, we assigned all of our rights and duties under the purchase and sale agreement to Encore Operating, L.P., which further assigned all of its rights and duties under the purchase and sale agreement to Encore Exchange. The purchase price for the Williston

Basin Assets was approximately $392.5 million.

The Williston Basin properties currently produce approximately 5,000 BOE/D net, will be 85 percent operated by us and will complement our existing Rockies oil portfolio. In connection with the acquisition, we purchased put contracts on approximately 80 percent of the acquisition s expected production volumes with an average strike price of $57.50 per Bbl for the remainder of 2007 and all of 2008.

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ENCORE ACQUISITION COMPANY

MLP

On January 17, 2007, we announced our intention to form a MLP that will engage in an initial public offering of common units representing limited partner interests. The MLP was formed on February 13, 2007 and owns certain oil and natural gas properties and related assets in the Big Horn Basin of Wyoming and Montana. At the time of the initial public offering, the Company plans to contribute to the MLP certain of its legacy oil and gas properties in the Permian Basin of West Texas. Any sale of common units of the MLP would be registered under the Securities Act of 1933, and such common units would only be offered and sold by means of a prospectus. This Report does not constitute an offer to sell or the solicitation of any offer to buy any securities of the MLP, and there will not be any sale of any such securities in any state in which such offer, solicitation, or sale would be unlawful prior to registration or qualification under the securities laws of such state.

First Quarter 2007 Highlights

Our financial and operating results for first quarter of 2007 included the following:

During the first quarter of 2007, our oil and natural gas revenues were $115.6 million. This represents a two percent increase over the $113.6 million of oil and natural gas revenues reported in the first quarter of 2006 despite a softer commodity market price environment overall.

We were able to post higher oil and natural gas revenues as our realized average oil price for the first quarter of 2007, including the effects of hedging, increased $2.54 per Bbl to $43.35 per Bbl as compared to $40.81 per Bbl in the first quarter of 2006. Our realized average natural gas price for the first quarter of 2007, including the effects of hedging, decreased $0.75 per Mcf to $5.40 per Mcf as compared to $6.15 per Mcf in the first quarter of 2006.

Our revenues increased during a period when the average NYMEX price fell, as our oil wellhead differential to the average NYMEX price improved in the first quarter of 2007 as compared to the fourth quarter of 2006. The narrowing of our oil wellhead differential was due to improving market conditions in the northern Rockies, as well as additional markets into which we can move our oil for sales, which has positively affected the wellhead price we received on our CCA and Williston Basin properties.

Production volumes for the first quarter of 2007 increased to 32,489 BOE/D as compared to 32,033 BOE/D for the first quarter of 2006. The rise in production volumes was attributable to our Big Horn Basin acquisition. Oil represented 65 percent of our total production volumes in the first quarter of 2007 and 2006.

During the first quarter of 2007, we generated cash flows from operating activities of $15.1 million. This represents a 72 percent decrease from the $54.7 million of cash flows from operating activities we reported for the first quarter of 2006. The decrease was primarily due to a $32.8 million increase in our net derivative liabilities and a $6.1 million decrease in our production margin.

We reported a net loss of $29.4 million, or $0.55 per diluted share, in the first quarter of 2007, as compared to net income of $17.9 million, or $0.36 per diluted share, for the first quarter of 2006. The decrease in net income was primarily due to a pretax increase in derivative fair value loss of $43.3 million and exploration costs of $11.5 million.

We invested $493.9 million in oil and natural gas activities during the first quarter of 2007 (excluding related asset retirement obligations of $9.7 million). Of this amount, we invested $94.7 million in development, exploitation, HPAI expansion, and exploration activities, which yielded 65 gross (29.7 net) productive wells, and $399.2 million in acquisitions, primarily related to the Big Horn Basin acquisition. We operated between ten and twelve drilling rigs during the first quarter of 2007, including five to six rigs related to our West Texas joint development agreement.

On March 7, 2007, we entered into an amended and restated five-year senior secured credit facility with an initial borrowing base of $650 million, which increased to $950 million upon the closing of the Williston Basin acquisition. Also on March 7, 2007, one of our subsidiaries entered into a five-year senior secured credit facility with an initial borrowing base of $115 million and a $10 million overadvance feature.

On March 7, 2007, we closed the aforementioned Big Horn Basin acquisition, and on April 11, 2007, we closed the aforementioned Williston Basin acquisition.

Results of Operations

Comparison of Quarter Ended March 31, 2007 to Quarter Ended March 31, 2006

Below is a comparison of our operations during the first quarter of 2007 with the first quarter of 2006.

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ENCORE ACQUISITION COMPANY

Oil and natural gas revenues and production. The following table illustrates the primary components of oil and natural gas revenues for the three months ended March 31, 2007 and 2006, as well as each quarter s respective oil and natural gas production volumes:

	Three months ended March 31,		*Increase / (Decrease)*	
	2007	**2006**		
	(in thousands, except per unit and per day amounts)			
Revenues:				
Oil wellhead	$ 93,447	$ 88,108	*$ 5,339*	
Oil hedges	(10,824)	(11,993)	*1,169*	
Total oil revenues	$ 82,623	$ 76,115	*$ 6,508*	*9%*
Natural gas wellhead	$ 35,551	$ 42,046	*$ (6,495)*	
Natural gas hedges	(2,573)	(4,516)	*1,943*	
Total natural gas revenues	$ 32,978	$ 37,530	*$ (4,552)*	*-12%*
Combined wellhead	$ 128,998	$ 130,154	*$ (1,156)*	
Combined hedges	(13,397)	(16,509)	*3,112*	
Total combined oil and natural gas revenues	$ 115,601	$ 113,645	*$ 1,956*	*2%*
Revenues ($/Unit):				
Oil wellhead	$ 49.03	$ 47.24	*$ 1.79*	
Oil hedges	(5.68)	(6.43)	*0.75*	
Total oil revenues	$ 43.35	$ 40.81	*$ 2.54*	*6%*
Natural gas wellhead	$ 5.82	$ 6.89	*$ (1.07)*	
Natural gas hedges	(0.42)	(0.74)	*0.32*	
Total natural gas revenues	$ 5.40	$ 6.15	*$ (0.75)*	*-12%*
Combined wellhead	$ 44.11	$ 45.15	*$ (1.04)*	
Combined hedges	(4.58)	(5.73)	*1.15*	
Total combined oil and natural gas revenues	$ 39.53	$ 39.42	*$ 0.11*	*0%*
Total production volumes:				

Oil (Bbls)	1,906	1,865	*41*	*2%*
Natural gas (Mcf)	6,109	6,107	*2*	*0%*
Combined (BOE)	2,924	2,883	*41*	*1%*
Daily production volumes:				
Oil (Bbls/D)	21,177	20,723	*454*	*2%*
Natural gas (Mcf/D)	67,876	67,860	*16*	*0%*
Combined (BOE/D)	32,489	32,033	*456*	*1%*
Average NYMEX prices:				
Oil (per Bbl)	$ 58.27	$ 63.48	*$ (5.21)*	*-8%*
Natural gas (per Mcf)	$ 7.17	$ 7.91	*$ (0.74)*	*-9%*

Oil revenues increased $6.5 million from $76.1 million in the first quarter of 2006 to $82.6 million in the first quarter of 2007. The increase is primarily due to higher realized average oil prices, which contributed approximately $4.6 million in additional oil revenues, and an increase in oil production volumes of 41 MBbls, which contributed approximately $1.9 million in additional oil revenues. Our realized average oil price increased as our wellhead price increased, coupled with a decrease in hedging costs included in oil revenues. Our higher average oil wellhead price resulted in $3.4 million of additional oil revenues, or $1.79 per Bbl, and hedging costs decreased $1.2 million, or $0.75 per Bbl. Our average oil wellhead price increased $1.79 per Bbl in the first quarter of 2007 over the first quarter of 2006 as a result of the narrowing of our oil wellhead price to average NYMEX price differential. Please read the discussion below regarding our oil wellhead price to average NYMEX price differential. Revenues from the Big Horn Basin acquisition are included in the first quarter 2007 results from March 7, 2007.

Our oil wellhead revenue was reduced by $4.1 million and $5.6 million in the three months ended March 31, 2007 and 2006, respectively, for the net profits interests payments related to our CCA properties.

ENCORE ACQUISITION COMPANY

Natural gas revenues decreased $4.6 million from $37.5 million in the first quarter of 2006 to $33.0 million in the first quarter of 2007. The decrease is primarily due to lower realized average natural gas prices as production was relatively unchanged. Our realized average natural gas price decreased as our natural gas wellhead price decreased, which had a negative $6.5 million impact on natural gas revenues, or $1.07 per Mcf. This decrease was partially offset by decreased hedging costs of $1.9 million, or $0.32 per Mcf. Our average natural gas wellhead price decreased $1.07 per Mcf in the first quarter of 2007 over the first quarter of 2006 as a result of decreases in the overall market price for natural gas, which was reflected in the decrease in the average NYMEX price from $7.91 per Mcf in the first quarter of 2006 to $7.17 per Mcf in the first quarter of 2007.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices for the three months ended March 31, 2007 and 2006. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Three months ended March 31,	
	2007	**2006**
Oil wellhead ($/Bbl)	$ 49.03	$ 47.24
Average NYMEX ($/Bbl)	$ 58.27	$ 63.48
Differential to NYMEX	$ (9.24)	$ (16.24)
Oil wellhead to NYMEX percentage	84%	74%
Natural gas wellhead ($/Mcf)	$ 5.82	$ 6.89
Average NYMEX ($/Mcf)	$ 7.17	$ 7.91
Differential to NYMEX	$ (1.35)	$ (1.02)
Natural gas wellhead to NYMEX percentage	81%	87%

In the first quarter of 2007, our oil wellhead price as a percentage of the average NYMEX price increased to 84%. The differential was due to market conditions in the Rocky Mountain refining area, which has adversely affected the oil wellhead price we receive 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 but have since tightened in the first quarter of 2007. The tighter oil differential in the first quarter of 2007 as compared to the first quarter of 2006 favorably impacted oil revenues by $13.3 million. We expect that our oil wellhead differentials may improve slightly in the second quarter of 2007 as compared to the first quarter of 2007.

In the first quarter of 2007, our natural gas wellhead price as a percentage of the average NYMEX price fell six percent. The differential widened because the price received for natural gas in CCA did not correlate well with NYMEX during the quarter due to market conditions in the Rockies. The increase in the natural gas differential percentage in the first quarter of 2007 as compared with the first quarter of 2006 negatively impacted natural gas revenues by $2.0 million.

Marketing revenues and expenses. In 2006, we began purchasing third-party oil Bbls from a counterparty other than to whom the Bbls were sold for aggregation and sale with our own equity production in various markets. These purchases are 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.

In March 2007, we acquired a gas pipeline from Anadarko as part of the Big Horn Basin acquisition for which natural gas volumes are purchased from one counterparty at the inlet to the pipeline and sold to another counterparty at the end of pipeline.

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ENCORE ACQUISITION COMPANY

The following table summarizes our marketing activities for the three months ended March 31, 2007 and 2006:

	Three months ended March 31, 2007	2006
	(in thousands, except per BOE amounts)	
Marketing revenues	$ 14,941	$ 34,316
Marketing expenses	(15,011)	(32,746)
Marketing, net	$ (70)	$ 1,570
Marketing revenues per BOE	$ 5.11	$ 11.90
Marketing expenses per BOE	(5.13)	(11.36)
Marketing, net per BOE	$ (0.02)	$ 0.54

Expenses. The following table summarizes our expenses for the three months ended March 31, 2007 and 2006:

	Three months ended March 31, 2007	2006	*Increase / (Decrease)*	
Expenses (in thousands):				
Production:				
Lease operations	$ 30,520	$ 22,736	*$ 7,784*	
Production, ad valorem, and severance taxes	12,515	12,242	*273*	
Total production expenses	43,035	34,978	*8,057*	*23%*
Other:				
Depletion, depreciation, and amortization	35,028	27,020	*8,008*	
Exploration	11,521	2,009	*9,512*	
General and administrative	7,360	6,528	*832*	
Derivative fair value loss	45,614	2,306	*43,308*	
Other operating	2,565	1,528	*1,037*	
Total operating	145,123	74,369	*70,754*	*95%*
Interest	16,287	11,787	*4,500*	
Income tax provision (benefit)	(16,019)	11,244	*(27,263)*	
Total expenses	$ 145,391	$ 97,400	*$ 47,991*	*49%*

Expenses (per BOE):

Production:				
Lease operations	$ 10.44	$ 7.89	*$ 2.55*	
Production, ad valorem, and severance taxes	4.28	4.25	*0.03*	
Total production expenses	14.72	12.14	*2.58*	*21%*
Other:				
Depletion, depreciation, and amortization	11.98	9.37	*2.61*	
Exploration	3.94	0.70	*3.24*	
General and administrative	2.52	2.26	*0.26*	
Derivative fair value loss	15.60	0.80	*14.80*	
Other operating	0.88	0.53	*0.35*	
Total operating	49.64	25.80	*23.84*	*92%*
Interest	5.57	4.09	*1.48*	
Income tax provision (benefit)	(5.48)	3.90	*(9.38)*	
Total expenses	$ 49.73	$ 33.79	*$ 15.94*	*47%*

Production expenses. Total production expenses increased $8.1 million from $35.0 million in the first quarter of 2006 to $43.0 million in the first quarter of 2007. This increase resulted from an increase in total production volumes, as well as a $2.58 increase in production expenses per BOE. Total production expenses per BOE increased by 21 percent while total oil and natural gas revenues per BOE remained relatively constant. As a result, our production margin (defined as oil and natural gas

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revenues less production expenses) for the first quarter of 2007 decreased by eight percent ($6.1 million) as compared to the first quarter of 2006. On a per BOE basis, our production margin decreased nine percent to $24.81 per BOE as compared to $27.28 per BOE for the first quarter of 2006.

The production expense attributable to LOE increased $7.8 million from $22.7 million in the first quarter of 2006 to $30.5 million in the first quarter of 2007, primarily as a result of an increase in the average per BOE rate, which gave rise to approximately $7.5 million of additional LOE. Production volumes also increased slightly, which contributed approximately $0.3 million of additional LOE. The increase in our average LOE per BOE rate of $2.55 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 production;

HPAI expensed at the CCA;

higher than expected operating costs in the Anadarko Basin and Arkoma Basin of Oklahoma and the North Louisiana Salt Basin; and

higher salary levels for engineers and other technical professionals.

The production expense attributable to production, ad valorem, and severance taxes (production taxes) increased $0.3 million from $12.2 million in the first quarter of 2006 to $12.5 million in the first quarter of 2007. The increase is due to higher wellhead revenues. As a percentage of oil and natural gas revenues (excluding the effects of hedges), production taxes were up slightly to 9.7 percent in the first quarter of 2007 as compared to 9.4 percent in the first quarter of 2006. 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 $8.0 million from $27.0 million in the first quarter of 2006 to $35.0 million in the first quarter of 2007 due to a higher per BOE rate and increased production volumes. The per BOE rate in the first quarter of 2007 increased $1.58 as compared to the first quarter of 2006 due to development of proved undeveloped reserves and higher finding, development, and acquisition costs. The higher finding, development, and acquisition costs were a result of increases in rig rates, oilfield services costs, and acquisition costs. These factors resulted in additional DD&A expense of approximately $7.6 million. The increase in production volumes resulted in approximately $0.4 million of additional DD&A expense.

Exploration expense. Exploration expense increased $9.5 million in the first quarter of 2007 as compared to the first quarter of 2006. During the first quarter of 2007, we expensed 3 exploratory dry holes totaling $8.5 million. During the first quarter of 2006, we expensed 2 exploratory dry holes totaling $0.6 million. In addition, impairment of unproved acreage in the first quarter of 2007 increased $1.5 million as compared to the first quarter of 2006 as we added additional leasehold costs and refined our estimated success rate in certain areas. The following table details our exploration-related expenses for the three months ended March 31, 2007 and 2006:

	Three months ended March 31,		***Increase /***
	2007	**2006**	***(Decrease)***
		(in thousands)	
Dry holes	$ 8,480	$ 581	*$ 7,899*
Geological and seismic	631	438	*193*
Delay rentals	178	213	*(35)*
Impairment of unproved acreage	2,232	777	*1,455*

Total	$ 11,521	$ 2,009	*$ 9,512*

G&A expense. G&A expense increased $0.8 million from $6.5 million in the first quarter of 2006 to $7.4 million in the first quarter of 2007. The overall increase, as well as the $0.26 increase in the per BOE rate, is primarily the result of increased staffing to manage our larger asset base, higher activity levels, and increased personnel costs due to intense competition for human resources within the industry.

Derivative fair value loss. 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.

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During the first quarter of 2007, we recorded a $45.6 million derivative fair value loss as compared to $2.3 million in the first quarter of 2006. The components of the derivative fair value loss reported in the three months ended March 31, 2007 and 2006 are as follows:

	Three months ended March 31, 2007	2006	Increase / (Decrease)
		(in thousands)	
Ineffectiveness on designated cash flow hedges	$	$ 2,839	*$ (2,839)*
Mark-to-market loss on undesignated derivative contracts	40,214	1,093	*39,121*
Settlements on commodity contracts	5,400	(1,626)	*7,026*
Total derivative fair value loss	$ 45,614	$ 2,306	*$ 43,308*

Other operating expense. Other operating expense increased $1.0 million from $1.5 million in the first quarter of 2006 to $2.6 million in the first quarter of 2007. The increase is primarily due to an increase in third-party transportation costs attributable to moving our CCA production into markets outside the immediate area of the production.

Interest expense. Interest expense increased $4.5 million in the first quarter of 2007 as compared to the first quarter of 2006. The increase is primarily due to additional debt used to finance the Big Horn Basin acquisition and our capital program. The weighted average interest rate for all long-term debt for the first quarter of 2007 was 6.9 percent as compared to 6.7 percent for the first quarter of 2006.

The following table illustrates the components of interest expense for the three months ended March 31, 2007 and 2006:

	Three months ended March 31, 2007	2006	Increase / (Decrease)
		(in thousands)	
6 1/4% Notes	$ 2,425	$ 2,344	*$ 81*
6% Notes	4,627	4,437	*190*
7 1/4% Notes	2,746	2,718	*28*
Revolving credit facilities	5,675	1,362	*4,313*
Other	814	926	*(112)*
Total	$ 16,287	$ 11,787	*$ 4,500*

Income taxes. During the first quarter of 2007, we recorded an income tax benefit of $16.0 million as compared to an income tax provision of $11.2 million in the first quarter of 2006. This is due to a pre-tax loss in the first quarter of 2007 as compared to pre-tax income in the first quarter of 2006. Our estimated annual effective tax rate decreased in the first quarter of 2007 to 37.5 percent from 38.5 percent in the first quarter of 2006 (before significant effect items) due to a change in prior apportioned state net deferred tax liabilities. Asset acquisitions in the first quarter of 2007 resulted in deferred tax expense to revalue state net deferred tax liabilities as a result of a larger apportionment future taxable income to states with higher tax rates. The expense related to the state net deferred liability adjustment reduced the benefit resulting from the quarter s pre-tax loss. Our estimated annual effective rate was 37.5 percent and our calculated effective rate was 35.3 percent for the current quarter.

On January 1, 2007, we adopted the provisions of FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with SFAS 109. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. We have performed its evaluation of tax positions and have determined that the adoption of FIN 48 did not have a material impact on our financial condition, results of operations, or cash flows.

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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 decreased $39.6 million from $54.7 million for the first quarter of 2006 to $15.1 million for the first quarter of 2007. The decrease was primarily due to a $32.8 million increase in our net derivative liabilities and a $6.1 million decrease in our production margin.

Cash flows from financing activities. Our cash flows from financing activities consist primarily of proceeds from and payments on long-term debt and net proceeds received from the sale of additional common stock. During the first quarter of 2007, we received net cash of $538.1 million from financing activities. During the first quarter of 2007, we had net borrowings on our revolving credit facilities of $540.0 million.

We periodically draw on our revolving credit facilities to fund acquisitions and other capital commitments. Historically, we have repaid large balances on our revolving credit facilities with proceeds from the issuance of senior subordinated notes in order to extend the maturity date of the debt and fix the interest rate. Our total borrowings less repayments on our revolving credit facilities, as described above, resulted in a net increase in outstanding borrowings under our revolving credit facilities of $540.0 million from $68 million at December 31, 2006 to $608.0 million at March 31, 2007, primarily due to borrowings used to finance the Big Horn Basin acquisition.

During the first quarter of 2006, we received net cash of $15.3 million from financing activities. This consisted primarily of a net increase in amounts outstanding under our revolving credit facilities of $19 million.

Current capitalization. At March 31, 2007, we had total assets of $2.5 billion and total capitalization was $2.0 billion, of which 40 percent was represented by stockholders equity and 60 percent by long-term debt. At December 31, 2006, we had total assets of $2.0 billion and total capitalization was $1.5 billion, of which 55 percent was represented by stockholders equity and 45 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 is used to finance future capital projects or potential acquisitions.

Capital Commitments

Our primary needs for cash are as follows:

Cash flows from investing activities including:

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

- Acquisitions of oil and natural gas properties and leasehold acreage;

Funding of necessary working capital; and

Payment of contractual obligations.

Cash flows from investing activities. Cash used in investing activities increased $482.8 million from $70.5 million in the first quarter of 2006 to $553.3 million in the first quarter of 2007. The increase was primarily due to a $430.9 million increase in amounts paid for the acquisition of oil and natural gas properties, primarily due to the Big Horn acquisition and a $41 million deposit on the Williston Basin acquisition, and a $41.6 million increase in development of oil and natural gas properties.

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 months ended March 31, 2007 and 2006:

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	Three months ended March 31,	
	2007	2006
	(in thousands)	
Development and exploitation	$ 62,182	$ 22,869
Exploration	31,218	31,740
HPAI	1,316	6,581
Total	$ 94,716	$ 61,190

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. Our development and exploitation capital for the first quarter of 2007 included a total of 44 gross (22.5 net) successful wells and 1 gross (0.5 net) development dry holes.

We currently have twelve operated rigs drilling on the onshore continental United States with four rigs in Mid-Continent, three rigs in the Northern region, and five rigs in West Texas.

Exploration. Our expenditures for exploration investments primarily relate to drilling exploratory wells, seismic costs, delay rentals, and geological and geophysical costs. In the first quarter of 2007, our exploration capital yielded 21 gross (7.2 net) successful wells and 3 gross (1.5 net) exploratory dry holes.

HPAI programs. During the three months ended March 31, 2007 and 2006, we invested $1.3 million and $6.6 million on the HPAI programs in the Pennel, Coral Creek, and Little Beaver units of the CCA.

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 months ended March 31, 2007 and 2006:

	Three months ended March 31,	
	2007	2006
	(in thousands)	
Acquisitions of proved property	$ 395,976	$ 507
Acquisitions of leasehold acreage	3,255	7,182
Total	$ 399,231	$ 7,689

2007 Acquisitions. On March 7, 2007, we acquired oil and natural gas properties in the Big Horn Basin for a purchase price of approximately $393.1 million, including $1.0 million of transaction costs.

Leasehold acreage costs. Our capital expenditures for leasehold acreage during the three months ended March 31, 2007 and 2006 totaled $3.3 million and $7.2 million, respectively, related to the acquisition of unproved acreage in various areas.

Funding of necessary working capital. At March 31, 2007, our working capital (defined as total current assets less total current liabilities) was negative $46.5 million while at December 31, 2006 our working capital was negative $40.7 million, a deterioration of $5.7 million. The deterioration is primarily attributable to increases in NYMEX prices, which negatively impacted the fair value of outstanding derivative contracts, net of deferred taxes.

For the remainder of 2007, 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 the hedged production, and deferred hedge premiums. We anticipate cash reserves to be close to zero because we intend to use any excess cash to fund capital obligations and pay down any outstanding borrowings under our revolving credit facilities. We do not plan to pay cash dividends in the foreseeable future. The overall 2007 commodity prices and our related differentials for oil and natural gas will be the largest variables affecting working capital. Our operating cash flow is determined in large part by commodity prices. Assuming moderate to high commodity prices, our operating cash flow should remain positive in 2007.

The Board has approved a capital budget of approximately $350 million for 2007. 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 under our revolving credit facilities.

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Contractual obligations. The following table illustrates our contractual obligations and commercial commitments outstanding at March 31, 2007:

Contractual Obligations and Commitments	Payments Due by Period Total	2007	2008 - 2009	2010 - 2011	Thereafter
	(in thousands)				
6 1/4% Notes (a)	$ 220,313	$ 9,375	$ 18,750	$ 18,750	$ 173,438
6% Notes (a)	453,000	9,000	36,000	36,000	372,000
7 1/4% Notes (a)	269,625	10,875	21,750	21,750	215,250
Revolving credit facilities (a)	827,687	33,516	89,375	89,375	615,421
Derivative obligations (b)	89,171	53,246	35,070	855	
Development commitments (c)	173,981	103,703	70,278		
Operating leases and commitments (d)	15,746	1,932	5,348	4,569	3,897
Asset retirement obligations (e)	177,251	738	1,969	1,969	172,575
Total	$ 2,226,774	$ 222,385	$ 278,540	$ 173,268	$ 1,552,581

(a) Amounts included in the table above include both principal and projected interest payments. Please read Note 7 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our long-term debt.

(b) Derivative obligations represent net liabilities for derivatives that were valued as of March 31, 2007. With the exception of $56.7 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. Please read Item 3. Quantitative and Qualitative Disclosures about Market Risk and Note 5 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our derivative obligations.

(c) Development commitments include: authorized purchases for work in process of $35.3 million which is accrued at March 31, 2007;

future minimum payments for drilling rig operations of $130.7 million; and $8.0 million for minimum capital obligations associated with the remaining eight commitment wells to be drilled under the ExxonMobil joint development agreement. Also at March 31, 2007, we had $152.0 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 and commitments include: office space and equipment obligations that have non-cancelable lease terms in excess of one year of

$13.9 million and future minimum payments for other operating commitments of $1.9 million.

(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. Please read Note 6 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our asset retirement obligations.

Other contingencies and commitments. 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 reported production volumes, oil and natural gas revenues, and costs as measured on a unit-of-production basis.

The marketing of our CCA oil production is mainly dependent on transportation through the Bridger, Poplar, and Butte pipelines to markets in the Guernsey, Wyoming area. Recently, alternative transportation routes and markets have been developed by moving a portion of the crude oil production through Enbridge to the Clearbrook, Minnesota hub. In addition, new markets to the west have been identified and a portion of our crude oil is being moved that direction through the Rocky Mountain Pipeline. 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 subject to apportionment since December 2005, we were allocated transportation effective January 1, 2007. However, further restrictions on available capacity to transport oil through any of the above mentioned pipelines, or any other pipelines, or any refinery upsets could have a material adverse effect on our production volumes and the prices we receive for our production.

We expect the differential between the NYMEX price of crude oil and the wellhead price we receive to slightly improve in the second quarter of 2007 as compared to the first quarter of 2007. In recent years, production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity from the Rocky Mountain area, have gradually widened this differential. We cannot accurately predict crude oil differentials. Natural gas differentials are expected to remain approximately constant in the second quarter of 2007 as compared to the first quarter of 2007. Increases in the differential between the NYMEX price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial position, and cash flows.

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Liquidity

Cash on hand, internally generated cash flows, and the borrowing capacity under our revolving credit facilities 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 quarter of 2007 remained constant as compared to the first quarter of 2006. These prices have historically fluctuated widely in response to changing market forces. For the first quarter of 2007, approximately 65 percent of our production was oil. As we previously discussed, our oil wellhead differentials during the first quarter of 2007 tightened significantly from the first quarter of 2006, favorably impacting the amount of oil revenues we received on our oil production. To the extent oil and natural gas prices decline or we experience significant widening of our wellhead differentials, our earnings, cash flows from operations, and availability under our revolving credit facilities 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 financial covenants under our revolving credit facilities and thereby affect our liquidity. We believe that our internally generated cash flows and unused availability under our revolving credit facilities are sufficient to fund our planned capital expenditures for the foreseeable future.

Revolving credit facilities. Our principal source of short-term liquidity is our revolving credit facilities, which mature on March 7, 2012.

On March 7, 2007, we entered into the Encore Credit Agreement with a bank syndicate comprised of Bank of America, N.A. and other lenders. The Encore Credit Agreement amended and restated our Amended and Restated Credit Agreement dated as of August 19, 2004, as amended. The borrowing base is redetermined semi-annually and upon requested special redeterminations and may be increased or decreased, up to a maximum of $1.25 billion. The borrowing base on March 31, 2007 was $650 million, but increased automatically to $950 million on April 11, 2007 when the Williston Basin acquisition closed, and was increased an additional $35 million on May 7, 2007 up to $985 million. Please read Note 7 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding the Encore Credit Agreement.

Also on March 7, 2007, EEPO entered into the EEPO Credit Agreement with a bank syndicate comprised of Bank of America, N.A. and other lenders. The EEPO Credit Agreement provides for revolving credit loans to be made to EEPO from time to time and letters of credit to be issued from time to time for the account of EEPO or any of its restricted subsidiaries. The borrowing base is redetermined semi-annually and upon requested special redeterminations and may be increased or decreased, up to a maximum of $300 million. The borrowing base on March 31, 2007 was $115 million. Please read Note 7 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding the EEPO Credit Agreement.

On March 31, 2007, we had $608.0 million outstanding and $137.0 million available to borrow under the revolving credit facilities. On May 4, 2007, we had $974.5 million outstanding and $90.5 million available to borrow under the revolving credit facilities.

Debt covenants. At March 31, 2007, we were in compliance with all of our debt covenants.

Letters of credit. As of March 31, 2007, we had $20 million in letters of credit all of which relates to the ExxonMobil joint development agreement. As of May 4, 2007, we had $20 million of such outstanding letters of credit all of which relates to the ExxonMobil joint development agreement.

Critical Accounting Policies and Estimates

On January 1, 2007, we adopted the provisions of FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with SFAS 109. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. See Note 8 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for more information.

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Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates in our 2006 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 2006 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.

Commodity Price Sensitivity

Our outstanding derivative contracts as of March 31, 2007 are discussed in Note 5 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements. As of March 31, 2007, the fair market value of our oil derivative contracts was a net $13.7 million asset and the fair market value of our natural gas derivative contracts was a net $1.4 million asset. Based on our open commodity derivative positions at March 31, 2007, a $1.00 per Bbl and $1.00 per Mcf increase in the NYMEX prices for oil and natural gas would result in a decrease to our net derivative fair value asset of approximately $10.4 million, while a $1.00 decrease in the respective NYMEX prices for oil and natural gas would result in an increase to our net derivative fair value asset of approximately $13.6 million.

Interest Rate Sensitivity

At March 31, 2007, we had total long-term debt of $1.2 billion, which is recorded net of discount of $6.2 million. Of this amount, $150 million bears interest at a fixed rate of 6 1/4 percent, $300 million bears interest at a fixed rate of 6 percent, and $150 million bears interest at a fixed rate of 7 1/4 percent. The remaining outstanding long-term debt balance of $608.0 million is under our revolving credit facilities and is subject to floating market rates of interest that are linked to LIBOR.

At this level of floating rate debt, if LIBOR increased one percent, we would incur an additional $6.1 million of interest expense per year, and if the rate decreased one percent, we would incur $6.1 million less. Additionally, if LIBOR increased one percent, we estimate the fair value of our fixed rate debt at March 31, 2007 would decrease from $553.0 million to $518.8 million, and if the rate decreased one percent, we estimate the fair value would increase to $590.3 million.

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 March 31, 2007 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 were no changes in our internal control over financial reporting that occurred during the first quarter of 2007 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ENCORE ACQUISITION COMPANY
PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We are a party to ongoing legal proceedings in the ordinary course of business. Management does not believe the result of these legal proceedings will have a material adverse effect on us.

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, 2006, 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, or results of operations.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities

The following table summarizes purchases of our common stock during the first quarter of 2007:

Month	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs
January		$		NA
February (a)	15,743	$ 24.87		NA
March		$		NA
Total	15,743	$ 24.87		NA

(a) We do not have a formal common stock repurchase program. During the first quarter of 2007, certain employees surrendered shares of common stock to pay income tax withholding obligations in conjunction with vesting of restricted shares.

Item 6. Exhibits

Exhibits

2.1	Purchase and Sale Agreement dated January 16, 2007 among Clear Fork Pipeline Company, Howell Petroleum Corporation, Kerr-McGee Oil & Gas Onshore LP, and the Company (incorporated by reference to Exhibit 2.1 to the Company s Current Report on Form 8-K filed with the SEC on January 17, 2007).
2.2	Purchase and Sale Agreement dated January 23, 2007 among Howell Petroleum Corporation, Kerr-McGee Oil & Gas Onshore LP, and the Company (incorporated by reference to Exhibit 2.1 to the Company s Current Report on Form 8-K filed with the SEC on January 25, 2007).
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).
10.1	Credit Agreement dated as of March 7, 2007 by and among Encore Acquisition Company, Encore Operating, L.P., Bank of America, N.A., as administrative agent and L/C Issuer, Fortis Capital Corp. and Wachovia Bank, N.A., as co-syndication agents, BNP Paribas and Calyon New York Branch, as co-documentation agents, Banc of America

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	Securities LLC, as sole lead arranger and sole book manager, and other lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed with the SEC on March 13, 2007).
10.2	Credit Agreement dated as of March 7, 2007 by and among Encore Energy Partners Operating LLC, Encore Energy Partners LP, Bank of America, N.A., as administrative agent and L/C Issuer, Banc of America Securities LLC, as sole lead arranger and sole book manager, and other lenders (incorporated by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed with the SEC on March 13, 2007).
10.3*+	Form of Restricted Stock Award Executive.
10.4*+	Form of Stock Option Agreement Nonqualified.
10.5*+	Form of Stock Option Agreement Incentive.
12.1*	Statement showing computation of ratios of earnings (loss) 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).

* Filed herewith.

\+ Management contract or compensatory plan, contract, or arrangement.

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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.

ENCORE ACQUISITION COMPANY

Date: May 10, 2007

/s/ Robert C. Reeves

Robert C. Reeves
Senior Vice President, Chief Financial
Officer, and Treasurer