ENCORE ACQUISITION CO
Form 10-Q
August 08, 2008

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

(Mark One)

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2008

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from __________ to __________

Commission File Number: 001-16295

ENCORE ACQUISITION COMPANY

(Exact name of registrant as specified in its charter)

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

(817) 877-9955

(Registrant s telephone number, including area code)

Not applicable

(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

Number of shares of common stock, $0.01 par value, outstanding as of August 1, 2008	53,323,951

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain information included in this Quarterly Report on Form 10-Q (the Report) and other materials filed with the SEC, or in other written or oral statements made or to be made by us, other than statements of historical fact, are forward-looking statements as defined by the safe harbor provisions of the Private Securities Litigation Reform Act of

1995. These forward-looking statements give our current expectations or forecasts of future events. Forward-looking statements can be identified by the fact that they do not relate strictly to historical or current facts. These statements may include words such as may, will, could, anticipate, estimate, expect, project, intend, plan, beli potential, pursue, target, continue, and other words and terms of similar meaning. Readers are cautioned not to plac undue reliance on such forward-looking statements, which speak only as of the date of this Report. Our actual results may differ significantly from the results discussed in the forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, the matters discussed in Item 1A. Risk Factors in our 2007 Annual Report on Form 10-K and in our other filings with the SEC. If one or more of these risks or uncertainties materialize (or the consequences of such a development changes), or should underlying assumptions prove incorrect, actual outcomes may vary materially from those forecasted or expected. We undertake no responsibility to update forward-looking statements for changes related to these or any other factors that may occur subsequent to this filing for any reason.

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ENCORE ACQUISITION COMPANY
GLOSSARY

The following are abbreviations and definitions of certain terms used in this Report. The definitions of proved developed reserves, proved reserves, and proved undeveloped reserves have been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X.

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

Bbl/D. One Bbl per day.

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

BOE/D. One BOE per day.

Completion. The installation of permanent equipment for the production of oil or natural gas.

Council of Petroleum Accountants Societies (COPAS). A professional organization of oil and gas accountants that maintains consistency in accounting procedures and interpretations, including the procedures that are part of most joint operating agreements. These procedures establish a drilling rate and an overhead rate to reimburse the operator of a well for overhead costs, such as accounting and engineering.

Delay Rentals. Fees paid to the lessor of an oil and natural gas lease during the primary term of the lease prior to the commencement of production from a well.

Development Well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry Hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed LOE and production taxes.

Dry Gas. Natural gas comprised of over 90 percent methane and suitable for use by customers of local gas distribution companies.

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

ENP. Encore Energy Partners LP, a publicly traded Delaware limited partnership, together with its subsidiaries.

Exploratory Well. A well drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously producing oil or natural gas in another reservoir, or to extend a known reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which an entity owns a working interest.

Lease Operations Expense (LOE). All direct and allocated indirect costs of producing oil and natural gas after completion of drilling. Such costs include labor, superintendence, supplies, repairs, maintenance, and direct overhead charges.

LIBOR. London Interbank Offered Rate.

MBbl. One thousand Bbls.

MBOE. One thousand BOE.

Mcf. One thousand cubic feet, used in reference to natural gas.

Mcf/D. One Mcf per day.

MMcf. One million cubic feet, used in reference to natural gas.

Natural Gas Liquids (NGLs). The combination of ethane, propane, butane, and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

Net Acres or Net Wells. Gross acres or wells, as the case may be, multiplied by the working interest percentage owned by an entity.

Net Profits Interest (NPI). An interest that entitles the owner to a specified share of net profits from production of hydrocarbons.

NYMEX. New York Mercantile Exchange.

Oil. Crude oil, condensate, and NGLs.

Operator. The entity responsible for the exploration, exploitation, and production of an oil or natural gas well or lease.

Production Margin. Oil and natural gas revenues less LOE and production, ad valorem, and severance taxes.

Proved Developed Reserves. Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Proved Reserves. The estimated quantities of oil, natural gas, and NGLs that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved Undeveloped Reserves. Proved reserves that are expected to be recovered from new wells drilled to known reservoirs

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on acreage yet to be drilled for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells where a relatively major expenditure is required to establish production, including unrealized production response from enhanced recovery techniques that have been proved effective by actual tests in the area and in the same reservoir.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

SEC. The United States Securities and Exchange Commission.

Secondary Recovery. Enhanced recovery of oil or natural gas from a reservoir beyond the oil or natural gas that can be recovered by normal flowing and pumping operations. Secondary recovery techniques involve maintaining or enhancing reservoir pressure by injecting water, gas, or other substances into the formation. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are gas injection and waterflooding.

Successful Well. A well capable of producing oil and/or natural gas in commercial quantities.

Tertiary Recovery. An enhanced recovery operation that normally occurs after waterflooding in which chemicals or natural gases are used as the injectant.

Undeveloped Acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas regardless of whether such acreage contains proved reserves.

Waterflood. A secondary recovery operation in which water is injected into the producing formation in order to maintain reservoir pressure and force oil toward and into the producing wells.

Working Interest. An interest in an oil or natural gas lease that gives the owner the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the production and development costs.

Workover. Operations on a producing well to restore or increase production.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

ENCORE ACQUISITION COMPANY
CONSOLIDATED BALANCE SHEETS
(in thousands, except share and per share amounts)

	June 30, 2008 (unaudited)	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,594	$ 1,704
Accounts receivable, net of allowance for doubtful accounts of $6,045	185,054	134,880
Inventory	26,582	16,257
Derivatives	3,301	9,722
Deferred taxes	84,242	20,420
Other	4,882	5,527
Total current assets	305,655	188,510
Properties and equipment, at cost successful efforts method:		
Proved properties, including wells and related equipment	3,106,417	2,845,776
Unproved properties	85,757	63,352
Accumulated depletion, depreciation, and amortization	(586,900)	(489,004)
	2,605,274	2,420,124
Other property and equipment	22,357	21,750
Accumulated depreciation	(11,369)	(10,733)
	10,988	11,017
Goodwill	60,606	60,606
Derivatives	10,863	34,579
Long-term receivables	64,850	40,945
Other	29,040	28,780
Total assets	$ 3,087,276	$ 2,784,561
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 30,177	$ 21,548
Accrued liabilities:		
Lease operations expense	18,216	15,057

Development capital	61,025	48,359
Interest	12,078	12,795
Production, ad valorem, and severance taxes	42,712	24,694
Marketing	8,331	8,721
Derivatives	198,142	39,337
Oil and natural gas revenues payable	16,628	13,076
Other	27,512	21,143
Total current liabilities	414,821	204,730
Derivatives	133,318	47,091
Future abandonment cost, net of current portion	28,895	27,371
Deferred taxes	350,292	312,914
Long-term debt	1,141,519	1,120,236
Other	1,538	1,530
Total liabilities	2,070,383	1,713,872
Commitments and contingencies (see Note 16)		
Minority interest in consolidated partnership	101,034	122,534
Stockholders equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none issued and outstanding		
Common stock, $.01 par value, 144,000,000 shares authorized, 52,357,211 and 53,303,464 issued and outstanding, respectively	525	534
Additional paid-in capital	537,779	538,620
Treasury stock, at cost, none and 17,690 shares, respectively		(590)
Retained earnings	377,138	411,377
Accumulated other comprehensive income (loss)	417	(1,786)
Total stockholders equity	915,859	948,155
Total liabilities and stockholders equity	$ 3,087,276	$ 2,784,561

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

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

	Three months ended June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
Revenues:				
Oil	$ 286,924	$ 135,596	$ 507,458	$ 218,219
Natural gas	67,889	45,131	116,201	78,109
Marketing	2,521	8,916	6,577	23,857
Total revenues	357,334	189,643	630,236	320,185
Expenses:				
Production:				
Lease operations	40,697	37,552	81,047	68,072
Production, ad valorem, and severance taxes	35,043	19,232	62,495	31,747
Depletion, depreciation, and amortization	51,026	52,318	100,569	87,346
Exploration	11,593	3,415	17,081	14,936
General and administrative	11,559	6,188	21,246	13,548
Marketing	3,725	8,507	7,507	23,518
Derivative fair value loss	256,390	6,766	321,528	52,380
Other operating	3,226	4,751	5,732	7,316
Total expenses	413,259	138,729	617,205	298,863
Operating income (loss)	(55,925)	50,914	13,031	21,322
Other income (expenses):				
Interest	(16,785)	(27,820)	(36,545)	(44,107)
Other	686	601	1,537	1,032
Total other expenses	(16,099)	(27,219)	(35,008)	(43,075)
Income (loss) before income taxes and minority interest	(72,024)	23,695	(21,977)	(21,753)
Income tax benefit (provision)	21,322	(8,524)	2,589	7,496
Minority interest in loss of consolidated partnership	14,982		14,888	
Net income (loss)	$ (35,720)	$ 15,171	$ (4,500)	$ (14,257)

Net income (loss) per common share:				
Basic	$ (0.68)	$ 0.29	$ (0.09)	$ (0.27)
Diluted	$ (0.68)	$ 0.28	$ (0.09)	$ (0.27)
Weighted average common shares outstanding:				
Basic	52,344	53,143	52,571	53,111
Diluted	52,344	54,020	52,571	53,111

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

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ENCORE ACQUISITION COMPANY
CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY
(in thousands)
(unaudited)

	Issued Shares of Common Stock	Common Stock	Additional Paid-in Capital	Shares of Treasury Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders Equity
Balance at December 31, 2007	53,321	$ 534	$ 538,620	(18)	$ (590)	$ 411,377	$ (1,786)	$ 948,155
Exercise of stock options and vesting of restricted stock	256	3	1,325					1,328
Repurchase and retirement of common stock	(1,174)	(12)	(11,679)			(27,427)		(39,118)
Purchase of treasury stock				(28)	(954)			(954)
Cancellation of treasury stock	(46)		(465)	46	1,544	(1,079)		
Non-cash equity-based compensation			6,535					6,535
ENP distributions to holders of management incentive units						(1,233)		(1,233)
Adjustment to reflect gain on issuance of ENP common units			3,458					3,458
Other			(15)					(15)
Components of comprehensive loss:								
Net loss						(4,500)		(4,500)
Change in deferred hedge gain on interest rate swaps, net of tax of $253							417	417
							1,786	1,786

Amortization of deferred loss on commodity derivative contracts, net of tax of $1,071							
Total comprehensive loss							(2,297)
Balance at June 30, 2008	52,357	$ 525	$ 537,779	$	$ 377,138	$ 417	$ 915,859

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

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

	Six months ended June 30, 2008	Six months ended June 30, 2007
Cash flows from operating activities:		
Net loss	$ (4,500)	$ (14,257)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depletion, depreciation, and amortization	100,569	87,346
Non-cash exploration expense	15,545	13,870
Deferred taxes	(26,756)	(7,745)
Non-cash equity-based compensation expense	6,205	5,480
Non-cash derivative loss	300,370	65,038
Loss (gain) on disposition of assets	(79)	2,282
Minority interest in loss of consolidated partnership	(14,888)	
Other	6,619	2,589
Changes in operating assets and liabilities, net of effects from acquisitions:		
Accounts receivable	(47,301)	(42,735)
Current derivatives	(670)	(15,303)
Other current assets	(9,680)	(8,554)
Long-term derivatives	(1,196)	(19,828)
Other assets	(1,033)	(2,200)
Accounts payable	4,208	4,468
Other current liabilities	25,825	11,127
Other noncurrent liabilities	(923)	(253)
Net cash provided by operating activities	352,315	81,325
Cash flows from investing activities:		
Proceeds from disposition of assets	631	291,454
Purchases of other property and equipment	(1,622)	(1,614)
Acquisition of oil and natural gas properties	(49,280)	(779,576)
Development of oil and natural gas properties	(233,225)	(187,227)
Net advances to working interest partners	(22,907)	(24,158)
Net cash used in investing activities	(306,403)	(701,121)
Cash flows from financing activities:		
Repurchase of common stock	(39,118)	
Exercise of stock options and vesting of restricted stock, net of treasury stock purchases	374	497
Proceeds from long-term debt, net of issuance costs	618,339	1,120,019
Payments on long-term debt	(598,500)	(492,500)

ENP distributions to holders of management incentive units and public units		(11,168)		
Payment of commodity derivative contract premiums		(20,583)		(12,185)
Change in cash overdrafts		4,634		8,140
Net cash provided by (used in) financing activities		(46,022)		623,971
Increase (decrease) in cash and cash equivalents		(110)		4,175
Cash and cash equivalents, beginning of period		1,704		763
Cash and cash equivalents, end of period	$	1,594	$	4,938

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

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

Note 1. About EAC

EAC is engaged in the acquisition and development of oil and natural gas reserves from onshore fields in the United States. Since 1998, EAC has acquired producing properties with proven reserves and leasehold acreage and grown the production and proven reserves by drilling, exploring, reengineering or expanding existing waterflood projects, and applying tertiary recovery techniques. EAC s properties and oil and natural gas reserves are located in four core areas:

- the Cedar Creek Anticline (CCA) in the Williston Basin of Montana and North Dakota;
- the Permian Basin of West Texas and southeastern New Mexico;
- the Rockies, which includes non-CCA assets in the Williston, Big Horn, and Powder River Basins of Wyoming, Montana, and North Dakota, and the Paradox Basin of southeastern Utah; and
- the Mid-Continent area, which includes the Arkoma and Anadarko Basins of Oklahoma, the North Louisiana Salt Basin, and the East Texas Basin.

Note 2. Basis of Presentation

EAC s consolidated financial statements include the accounts of wholly owned and majority-owned subsidiaries. All material intercompany balances and transactions have been eliminated in consolidation.

In February 2007, EAC formed ENP to acquire, exploit, and develop oil and natural gas properties and to acquire, own, and operate related assets. In September 2007, ENP completed its initial public offering (IPO). As of June 30, 2008 and December 31, 2007, EAC owned approximately 66.7 percent and 58.0 percent, respectively, of ENP s common units, as well as all of the interests of Encore Energy Partners GP LLC (GP LLC), a Delaware limited liability company and ENP s general partner, which is an indirect wholly owned non-guarantor subsidiary of EAC. Considering the presumption of control of GP LLC in accordance with Emerging Issues Task Force Issue No. 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights* , the financial position, results of operations, and cash flows of ENP are consolidated with those of EAC. EAC elected to account for gains on ENP s issuance of common units as capital transactions as permitted by Staff Accounting Bulletin (SAB) Topic 5H, *Accounting for Sales of Stock by a Subsidiary* . See Note 18. ENP for additional discussion.

In the opinion of management, the accompanying unaudited consolidated financial statements include all adjustments necessary to present fairly, in all material respects, EAC s financial position as of June 30, 2008, results of operations for the three and six months ended June 30, 2008 and 2007, and cash flows for the six months ended June 30, 2008 and 2007. All adjustments are of a normal recurring nature. These interim results are not necessarily indicative of results for an entire year.

Certain amounts and disclosures have been condensed or omitted from these consolidated financial statements pursuant to the rules and regulations of the SEC. Therefore, these consolidated financial statements should be read in conjunction with the consolidated financial statements and related notes thereto included in EAC s 2007 Annual Report on Form 10-K.

Minority Interest

As presented in the accompanying Consolidated Balance Sheets, Minority interest in consolidated partnership as of June 30, 2008 and December 31, 2007 of $101.0 million and $122.5 million, respectively, represents third-party ownership interests in ENP. As presented in the accompanying Consolidated Statements of Operations, Minority interest in loss of consolidated partnership for the three and six months ended June 30, 2008 of $15.0 million and $14.9 million, respectively, represents the net loss of ENP attributable to third-party owners.

Reclassifications

Certain amounts in prior periods have been reclassified to conform to the current period presentation. In particular, certain amounts on the accompanying Consolidated Statements of Operations and Consolidated Statements of Cash Flows have been either combined or classified in more detail.

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

New Accounting Pronouncements

Statement of Financial Accounting Standards (SFAS) No. 157, Fair Value Measurements (SFAS 157)

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS 157, which standardizes the definition of fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures related to the use of fair value measures in financial statements. SFAS 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value, but does not require any new fair value measurements. SFAS 157 was prospectively effective for financial assets and liabilities for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. In February 2008, the FASB issued FASB Staff Position (FSP) 157-2, *Effective Date of FASB Statement No. 157* (FSP 157-2), which delayed the effective date of SFAS 157 for one year for nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). EAC elected a partial deferral of SFAS 157 for all instruments within the scope of FSP 157-2, including but not limited to, its asset retirement obligations and indefinite lived assets. EAC will continue to evaluate the impact of SFAS 157 on these instruments during the deferral period. The adoption of SFAS 157 on January 1, 2008, as it relates to financial assets and liabilities, did not have a material impact on EAC s results of operations or financial condition. See Note 7. Fair Values of Financial Assets and Liabilities for additional discussion.

SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FASB Statement No. 115 (SFAS 159)

In February 2007, the FASB issued SFAS 159, which permits entities to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis. SFAS 159 also allows entities an irrevocable option to measure eligible items at fair value at specified election dates, with resulting changes in fair value reported in earnings. SFAS 159 was effective for fiscal years beginning after November 15, 2007. EAC did not elect the fair value option for eligible instruments and therefore, the adoption of SFAS 159 on January 1, 2008 did not have an impact on EAC s results of operations or financial condition. In the future, EAC will assess the impact of electing the fair value option for any newly acquired eligible instruments. Electing the fair value option for such instruments could have a material impact on EAC s future results of operations or financial condition.

FSP Interpretation 39-1, Amendment of FASB Interpretation No. 39 (FSP FIN 39-1)

In April 2007, the FASB issued FSP FIN 39-1, which amends FASB Interpretation (FIN) No. 39, *Offsetting of Amounts Related to Certain Contracts* (FIN 39), to permit a reporting entity that is party to a master netting arrangement to offset the fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement in accordance with FIN 39. FSP FIN 39-1 was effective for fiscal years beginning after November 15, 2007. The adoption of FSP FIN 39-1 on January 1, 2008 did not have an impact on EAC s results of operations or financial condition.

SFAS No. 141 (revised 2007), Business Combinations (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, which replaces SFAS No. 141, *Business Combinations* . SFAS 141R establishes principles and requirements for the reporting entity in a business combination, including: (1) recognition and measurement in the financial statements of the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (2) recognition and measurement of goodwill acquired in the business combination or a gain from a bargain purchase; and (3) determination of the information to be disclosed to enable financial statement users to evaluate the nature and financial effects of the business combination. SFAS 141R is prospectively effective for business combinations consummated in fiscal years beginning on or after December 15, 2008 with early application prohibited. EAC is evaluating the impact SFAS 141R will have on its results of operations and financial condition and the reporting of future acquisitions in the consolidated financial statements.

SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment to ARB No. 51 (SFAS 160)

In December 2007, the FASB issued SFAS 160, which amends Accounting Research Bulletin No. 51, *Consolidated Financial Statements* to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the

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

deconsolidation of a subsidiary. SFAS 160 is effective for fiscal years beginning on or after December 15, 2008. SFAS 160 clarifies that a noncontrolling interest in a subsidiary, which is sometimes referred to as minority interest, is an ownership interest in the consolidated entity that should be reported as a component of equity in the consolidated financial statements. Among other requirements, SFAS 160 requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest and the disclosure of consolidated net income attributable to the parent and to the noncontrolling interest on the face of the consolidated statement of operations. EAC does not expect the adoption of SFAS 160 to have a material impact on its results of operations or financial condition.

SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133 (SFAS 161)

In March 2008, the FASB issued SFAS 161, which amends SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133), to require enhanced disclosures about (1) how and why an entity uses derivative instruments; (2) how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations; and (3) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS 161 is effective for fiscal years beginning on or after November 15, 2008, with early application encouraged. The adoption of SFAS 161 will require additional disclosures regarding EAC s derivative instruments; however, it will not impact EAC s results of operations or financial condition.

SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles (SFAS 162)

In May 2008, the FASB issued SFAS 162, which identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with GAAP. SFAS 162 moves the hierarchy of GAAP sources for nongovernmental entities from the auditing literature to the accounting literature. With some modifications and additions, the hierarchy from the American Institute of Certified Public Accountants Statement on Auditing Standards No. 69, *The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles* has been carried forward to SFAS 162. SFAS 162 is effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, *The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles* . The adoption of SFAS 162 will not impact EAC s results of operations or financial condition.

FSP No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP 03-6-1)

In June 2008, the FASB issued FSP 03-6-1, which addresses whether instruments granted in equity-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation for computing basic earnings per share (EPS) under the two-class method described in paragraphs 60 and 61 of SFAS No. 128, *Earnings per Share* . FSP 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years, with early application prohibited. FSP 03-6-1 requires all prior-period EPS data to be adjusted retrospectively (including interim financial statements, summaries of earnings, and selected financial data). EAC is currently evaluating the effect the adoption of FSP 03-6-1 will have on its EPS calculations.

Note 3. Acquisitions and Dispositions

Acquisitions

In January 2007, EAC entered into a purchase and sale agreement with certain subsidiaries of Anadarko Petroleum Corporation (Anadarko) to acquire 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 in April 2007. The Williston Basin acquisition was treated as a reverse like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended, (the Code) and I.R.S. Revenue Procedure 2000-37 with the Mid-Continent disposition discussed below. The total purchase price for the Williston Basin assets was approximately $392.1 million, including transaction costs of approximately $1.3 million.

Also in January 2007, EAC 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

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natural gas properties and related assets in the Gooseberry field in Park County, Wyoming. Prior to closing, EAC assigned the rights and duties under the purchase and sale agreement relating to the Elk Basin assets to Encore Energy Partners Operating LLC (OLLC), a Delaware limited liability company and wholly owned subsidiary of ENP, and the rights and duties under the purchase and sale agreement relating to the Gooseberry assets to Encore Operating, L.P. (Encore Operating), a Texas limited partnership and indirect wholly owned guarantor subsidiary of EAC. The closing of the Big Horn Basin acquisition occurred in March 2007. The total purchase price for the Big Horn Basin assets was approximately $393.6 million, including transaction costs of approximately $1.3 million.

EAC financed the acquisitions of the Gooseberry assets and Williston Basin assets through borrowings under its revolving credit facility. ENP financed the acquisition of the Elk Basin assets through a $93.7 million contribution from EAC, $120 million of borrowings under a subordinated credit agreement with EAP Operating, LLC, a Delaware limited liability company and direct wholly owned guarantor subsidiary of EAC, and borrowings under its revolving credit facility.

Dispositions

In June 2007, EAC completed the sale of certain oil and natural gas properties in the Mid-Continent area, and in July 2007, additional Mid-Continent properties that were subject to preferential rights were sold. EAC received total net proceeds of approximately $294.8 million, after deducting transaction costs of approximately $3.6 million, and recorded a loss on sale of approximately $7.4 million. The disposed properties included certain properties in the Anadarko and Arkoma Basins of Oklahoma. EAC retained material oil and natural gas interests in other properties in these basins and remains active in those areas. Proceeds from the Mid-Continent asset disposition were used to reduce outstanding borrowings under EAC s revolving credit facility.

Pro Formas

The following unaudited pro forma condensed financial data was derived from the historical financial statements of EAC and from the accounting records of Anadarko to give effect to the Big Horn Basin and Williston Basin asset acquisitions and the Mid-Continent asset disposition as if they had each occurred on January 1, 2007. The unaudited pro forma condensed financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Big Horn Basin and Williston Basin asset acquisitions and the Mid-Continent asset disposition taken place as of the date indicated and are not intended to be a projection of future results.

	Three months ended	Six months ended
	June 30, 2007	
	(in thousands, except per share amounts)	
Pro forma total revenues	$ 172,187	$ 327,766
Pro forma net income (loss)	$ 14,899	$ (15,739)
Pro forma net income (loss) per common share:		
Basic	$ 0.28	$ (0.30)
Diluted	$ 0.28	$ (0.30)

Note 4. Inventory

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

	June 30, 2008	December 31, 2007
	(in thousands)	
Materials and supplies	$ 12,020	$ 11,567
Oil in pipelines	14,562	4,690
Total inventory	$ 26,582	$ 16,257

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Note 5. Proved Properties

Amounts shown in the accompanying Consolidated Balance Sheets as Proved properties, including wells and related equipment consisted of the following as of the dates indicated:

	June 30, 2008	December 31, 2007
	(in thousands)	
Proved leasehold costs	$ 1,370,663	$ 1,346,516
Wells and related equipment Completed	1,590,353	1,408,512
Wells and related equipment In process	145,401	90,748
Total proved properties	$ 3,106,417	$ 2,845,776

Note 6. Derivative Financial Instruments

As of June 30, 2008, EAC had $58.1 million of deferred premiums payable of which $21.1 million was long-term and included in Derivatives in the non-current liabilities section of the accompanying Consolidated Balance Sheet and $37.0 million was current and included in Derivatives in the current liabilities section of the accompanying Consolidated Balance Sheet. The premiums relate to various oil and natural gas floor contracts and are payable on a monthly basis from July 2008 to January 2010. EAC recorded these premiums at their net present value at the time the contracts were entered into and accretes that value up to the eventual settlement price by recording interest expense each period.

Commodity Derivative Contracts Mark-to-Market Accounting

From time to time, EAC sells floors with a strike price below the strike price of the purchased floors in order to partially finance the premiums paid on the purchased floors. 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. As with EAC s other commodity derivative contracts, these are marked-to-market each quarter through Derivative fair value loss in the accompanying Consolidated Statements of Operations.

The following tables summarize EAC s open commodity derivative contracts as of June 30, 2008:

Oil Derivative Contracts

Period	Average Daily Floor Volume (Bbls)	Weighted Average Floor Price (per Bbl)	Average Daily Short Floor Volume (Bbls)	Weighted Average Short Floor Price (per Bbl)	Average Daily Cap Volume (Bbls)	Weighted Average Cap Price (per Bbl)	Average Daily Swap Volume (Bbls)	Weighted Average Swap Price (per Bbl)
July Dec. 2008								
	14,880	$83.36		$	2,440	$101.99	5,000	$91.56
	6,000	71.67			2,000	96.65		
	5,500	62.27						
	3,000	56.67	(4,000)	50.00				
2009								
	13,380	80.00			440	97.75	2,000	90.46
	2,250	74.11					3,000	89.22
			(5,000)	50.00			1,000	68.70
2010								

	880	80.00	440	93.80
	2,000	75.00	1,000	77.23
2011				
	1,880	80.00	1,440	95.41
	1,000	70.00		

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Natural Gas Derivative Contracts

Period	Average Daily Floor Volume (Mcf)	Weighted Average Floor Price (per Mcf)	Average Daily Short Floor Volume (Mcf)	Weighted Average Short Floor Price (per Mcf)	Average Daily Cap Volume (Mcf)	Weighted Average Cap Price (per Mcf)	Average Daily Swap Volume (Mcf)	Weighted Average Swap Price (per Mcf)
July Dec. 2008								
	6,300	$8.18		$	6,300	$9.52	5,000	$8.14
	11,300	7.38			7,500	8.35	5,000	7.47
	20,000	6.35						
2009								
	3,800	8.20			3,800	9.83		
	3,800	7.20						
2010								
	3,800	8.20			3,800	9.58		
	3,800	7.20						

Interest Rate Swaps

In the first quarter of 2008, as a result of the increase in debt levels, ENP entered into interest rate swaps whereby it swapped $100 million of floating rate debt on its revolving credit facility to a weighted average fixed rate of 3.06 percent and an expected margin of 1.25 percent. These interest rate swaps were designated as cash flow hedges. The following table summarizes ENP s open interest rate swaps as of June 30, 2008:

Term	Notional Amount (in thousands)	Fixed Rate	Floating Rate
July 2008-January 2011	$50,000	3.1610%	1-month LIBOR
July 2008-January 2011	25,000	2.9650%	1-month LIBOR
July 2008-January 2011	25,000	2.9613%	1-month LIBOR

During each of the three and six months ended June 30, 2008, settlements of interest rate swaps increased EAC s consolidated interest expense by approximately $0.1 million.

Current Period Impact

As a result of commodity derivative contracts that were previously designated as hedges, EAC recognized a pre-tax reduction in oil and natural gas revenues of approximately $1.4 million and $13.4 million during the three months ended June 30, 2008 and 2007, respectively, and $2.9 million and $26.8 million during the six months ended June 30, 2008 and 2007, respectively. EAC also recognized derivative fair value gains and losses related to (1) changes in the market value of derivative contracts, (2) settlements on commodity derivative contracts, and (3) premium amortization. The following table summarizes the components of derivative fair value loss for the periods indicated:

	Three months ended	Six months ended

	June 30,		June 30,	
	2008	2007	2008	2007
	(in thousands)			
Mark-to-market loss (gain) on derivative contracts	$ 220,586	$ (1,008)	$ 266,984	$ 46,437
Premium amortization	17,293	11,324	32,806	17,688
Settlements on commodity derivative contracts	18,511	(3,550)	21,738	(11,745)
Total derivative fair value loss	$ 256,390	$ 6,766	$ 321,528	$ 52,380

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Accumulated Other Comprehensive Income (AOCI)

At June 30, 2008, AOCI consisted entirely of deferred gains, net of tax, on ENP s interest rate swaps that are designated as hedges of $0.4 million. At December 31, 2007, AOCI consisted entirely of deferred losses, net of tax, on commodity derivative contracts that were previously designated as hedges of $1.8 million.

EAC expects to reclassify $0.1 million of deferred gains associated with ENP s interest rate swaps from AOCI to offset interest expense during the twelve months ending June 30, 2009. EAC also expects to reclassify $0.1 million of income taxes associated with ENP s interest rate swaps from AOCI to income tax benefit during the twelve months ending June 30, 2009.

Note 7. Fair Values of Financial Assets and Liabilities

As discussed in   Note 2. Basis of Presentation , EAC adopted SFAS 157 on January 1, 2008, as it relates to financial assets and liabilities. SFAS 157 requires enhanced disclosures about assets and liabilities carried at fair value. As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). EAC utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. EAC primarily applies the market and income approaches for recurring fair value measurements and utilizes the best available information. Accordingly, EAC utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. EAC has reviewed its recurring transactions and found that its markets and instruments are fairly liquid and has established that EAC is able to transact at the mid-point of the bid/ask spread. EAC is able to classify fair value balances based on the observability of those inputs.

SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy defined by SFAS 157 are as follows:

Level 1   Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2   Pricing inputs, other than quoted prices within Level 1, are observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace.

Level 3   Pricing inputs are unobservable as of the reporting date. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value.

The following table sets forth by level within the fair value hierarchy EAC s financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2008. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. EAC s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the financial assets and liabilities and their placement within the fair value hierarchy levels.

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		Fair Value Measurements at Reporting Date Using		
Description	June 30, 2008	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			(in thousands)	
Oil derivative contracts swaps	$ (159,105)	$	$ (159,105)	$
Oil derivative contracts floors and caps	(77,330)			(77,330)
Natural gas derivative contracts swaps	(8,730)		(8,730)	
Natural gas derivative contracts floors and caps	(15,378)			(15,378)
Interest rate swaps	1,350		1,350	
Total	$ (259,193)	$	$ (166,485)	$ (92,708)

The following table summarizes the changes in the fair value of EAC s Level 3 financial assets and liabilities for the six months ended June 30, 2008:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Oil Derivative Contracts	Natural Gas Derivative Contracts	
	Floors and Caps	Floors and Caps	Total
		(in thousands)	
Balance at January 1, 2008	$ 16,647	$ 7,081	$ 23,728
Total gains (losses):			
Included in earnings	(105,870)	(24,674)	(130,544)
Purchases, issuances, and settlements	11,893	2,215	14,108
Balance at June 30, 2008	$ (77,330)	$ (15,378)	$ (92,708)
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at the reporting date	$ (105,870)	$ (24,674)	$ (130,544)

Since EAC does not use hedge accounting for its commodity derivative contracts, all gains and losses on its Level 3 financial assets and liabilities are included in Derivative fair value loss in the accompanying Consolidated Statements of Operations. All fair values reflected in the table above and in the accompanying Consolidated Balance Sheet have been adjusted for non-performance risk. The adjustment to fair value related to non-performance risk as of June 30, 2008 was a reduction of the net liability value of approximately $3.3 million.

The following methods and assumptions were used to estimate the fair values of the financial assets and liabilities in the above tables that are accounted for at fair value on a recurring basis.

Level 2 Fair Value Measurements

Oil and natural gas derivative contracts swaps. Fair values were estimated using a combined income and market-based valuation methodology based upon forward commodity prices. Forward curves were obtained from independent pricing services reflecting broker market quotes.

Interest rate swaps. Fair values were estimated using a combined income and market-based valuation methodology based upon forward interest rate yield curves and credit. The curves were obtained from independent pricing services reflecting broker market quotes.

Level 3 Fair Value Measurements

Oil and natural gas derivative contracts floors and caps. Fair values were estimated using pricing models and discounted cash flow methodologies based on inputs that are not readily available in public markets.

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Note 8. Asset Retirement Obligations

EAC s asset retirement obligations relate to future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal. As of June 30, 2008 and December 31, 2007, EAC had $8.5 million and $6.7 million, respectively, held in escrow from which funds are released only for reimbursement of plugging and abandonment expenses on its Bell Creek properties, which is included in other long-term assets in the accompanying Consolidated Balance Sheets. The following table summarizes the changes in EAC s asset retirement obligations for the six months ended June 30, 2008 (in thousands):

Future abandonment liability at January 1, 2008	$ 28,079
Wells drilled	162
Acquisition of properties	81
Accretion of discount	667
Plugging and abandonment costs incurred	(891)
Revision of previous estimates	1,717
Future abandonment liability at June 30, 2008	$ 29,815

As of June 30, 2008, $28.9 million of EAC s asset retirement obligations was long-term and recorded in Future abandonment cost, net of current portion and $0.9 million was current and included in Other current liabilities on the accompanying Consolidated Balance Sheets.

Note 9. Long-Term Debt

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

	June 30, 2008	December 31, 2007
	(in thousands)	
Revolving credit facilities	$ 547,000	$ 526,000
6.25% Senior Subordinated Notes due April 15, 2014	150,000	150,000
6.0% Senior Subordinated Notes due July 15, 2015, net of unamortized discount of $4,204 and $4,440, respectively	295,796	295,560
7.25% Senior Subordinated Notes due December 1, 2017, net of unamortized discount of $1,277 and $1,324, respectively	148,723	148,676
Total	$ 1,141,519	$ 1,120,236

Encore Acquisition Company Senior Secured Credit Agreement

EAC is party to a five-year amended and restated credit agreement dated March 7, 2007 (as amended, the EAC Credit Agreement). Effective February 7, 2008, EAC amended the EAC Credit Agreement to, among other things, provide that certain negative covenants in the EAC Credit Agreement restricting hedge transactions do not apply to any oil and natural gas hedge transaction that is a floor or put transaction not requiring any future payments or delivery by EAC or any of its restricted subsidiaries. Effective May 22, 2008, EAC amended the EAC Credit Agreement to, among other things, increase the margins applicable to the ratio of total outstanding borrowings to borrowing base, as noted in the table below, and increase the borrowing base to $1.1 billion.

The following table represents the applicable margin for Eurodollar and base rate loans under the EAC Credit Agreement, as amended:

Ratio of Total Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans
Less than .50 to 1	1.250%	0.000%
Greater than or equal to .50 to 1 but less than .75 to 1	1.500%	0.250%
Greater than or equal to .75 to 1 but less than .90 to 1	1.750%	0.500%
Greater than or equal to .90 to 1	2.000%	0.750%

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The aggregate amount of the commitments of the lenders under the EAC Credit Agreement is $1.25 billion. Availability under the EAC Credit Agreement is subject to a borrowing base, which is redetermined semi-annually and upon requested special redeterminations. As of June 30, 2008, the borrowing base was $1.1 billion and there were $396 million of outstanding borrowings and $704 million of borrowing capacity under the EAC Credit Agreement. As of June 30, 2008, EAC was in compliance with all covenants of the EAC Credit Agreement.

Encore Energy Partners Operating LLC Credit Agreement

OLLC is a party to a five-year credit agreement dated March 7, 2007 (as amended, the OLLC Credit Agreement). The aggregate amount of the commitments of the lenders under the OLLC Credit Agreement is $300 million. Availability under the OLLC Credit Agreement is subject to a borrowing base, which is redetermined semi-annually and upon requested special redeterminations. As of June 30, 2008, the borrowing base was $240 million and there were $151 million of outstanding borrowings, $0.1 million of outstanding letters of credit, and $88.9 million of borrowing capacity under the OLLC Credit Agreement. As of June 30, 2008, OLLC was in compliance with all covenants of the OLLC Credit Agreement.

Note 10. Stockholders Equity

In December 2007, EAC announced that its Board of Directors (the Board) approved a share repurchase program authorizing EAC to repurchase up to $50 million of its common stock. As of June 30, 2008, EAC had repurchased and retired 1,174,691 shares of its outstanding common stock for approximately $39.1 million, or an average price of $33.30 per share, under the share repurchase program.

Note 11. Income Taxes

The components of EAC s income tax benefit were as follows for the periods indicated:

	Six months ended June 30, 2008	Six months ended June 30, 2007
	(in thousands)	
Federal:		
Current	$ (20,110)	$ (249)
Deferred	22,877	7,747
Total federal	2,767	7,498
State, net of federal benefit:		
Current	(4,057)	
Deferred	3,879	(2)
Total state	(178)	(2)
Income tax benefit	$ 2,589	$ 7,496

The following table reconciles EAC s income tax benefit with income tax at the Federal statutory rate for the periods indicated:

	Six months ended June 30, 2008	Six months ended June 30, 2007

	(in thousands)	
Loss before income taxes, net of minority interest	$ (7,089)	$ (21,753)
Income tax at the Federal statutory rate	$ 2,481	$ 7,614
State income taxes, net of federal benefit	165	519
Change in estimated future state tax rate		(542)
Nondeductible deferred compensation expense	20	
Permanent and other	(77)	(95)
Income tax benefit	$ 2,589	$ 7,496

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At June 30, 2008, EAC had net operating loss (NOL) carryforwards related to federal and state income taxes of $13.3 million, which are available to offset future regular taxable income, if any. At June 30, 2008, EAC also had alternative minimum tax (AMT) credits of $2.2 million, which are available to reduce future regular tax liabilities in excess of AMT. EAC believes it is more likely than not that the NOL carryforwards will offset future taxable income prior to their expiration. The AMT credits have no expiration. Therefore, a valuation allowance against these deferred tax assets is not considered necessary.

EAC has no tax positions that do not meet the highly certain positions threshold prescribed by FIN No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109* . As a result, no additional tax expense, interest, or penalties have been accrued. EAC includes interest assessed by taxing authorities in Interest expense and penalties related to income taxes in Other expense on its Consolidated Statements of Operations. For the six months ended June 30, 2008 and 2007, EAC recorded only a nominal amount of interest and penalties on certain tax positions.

Note 12. EPS

The following table reflects EAC s EPS computations for the periods indicated:

	Three months ended June 30,		Six months ended June 30,	
	2008 (c)	**2007**	**2008 (c)**	**2007**
	(in thousands, except per share data)			
Numerator:				
Net income (loss)	$ (35,720)	$ 15,171	$ (4,500)	$ (14,257)
Denominator:				
Denominator for basic EPS:				
Weighted average shares outstanding	52,344	53,143	52,571	53,111
Effect of dilutive options (a)		427		
Effect of dilutive restricted stock (b)		450		
Denominator for diluted EPS	52,344	54,020	52,571	53,111
Net income (loss) per common share:				
Basic	$ (0.68)	$ 0.29	$ (0.09)	$ (0.27)
Diluted	$ (0.68)	$ 0.28	$ (0.09)	$ (0.27)

(a) For the three months ended June 30, 2008 and 2007, options to purchase 1,524,107 and 98,562 shares of common stock, respectively, were outstanding but excluded from the diluted EPS calculations because their effect would have been antidilutive. For the six months ended June 30, 2008 and 2007, options to purchase 822,880 and 798,382 shares of common stock, respectively, were outstanding but excluded from the diluted EPS calculations because their effect would have been antidilutive.

(b) For the three months ended June 30, 2008 and 2007, 966,740 and 18,742 shares of restricted stock, respectively, were outstanding but excluded from the diluted EPS calculations because their effect would have been antidilutive. For the six months ended June 30, 2008 and 2007, 483,370 and 524,123 shares of restricted stock, respectively, were outstanding but excluded from the diluted EPS calculations because their effect would have been antidilutive.

(c) For the three and six months ended June 30, 2008, EAC considered the impact of the conversion of vested management incentive units held by certain executive officers of GP LLC. The conversion of the management incentive units into limited partner units of ENP would reduce EAC s share of ENP s earnings. For the three and six months ended June 30, 2008, the impact of this conversion was excluded from the diluted EPS calculations because their effect would have been antidilutive.

Note 13. Incentive Stock Plans

In May 2008, EAC s stockholders approved the 2008 Incentive Stock Plan (the 2008 Plan). No additional awards will be granted under EAC s 2000 Incentive Stock Plan (the 2000 Plan) and any previously granted awards currently outstanding under the 2000 Plan will remain outstanding in accordance with their terms. The purpose of the 2008 Plan is to attract, motivate, and retain selected employees of EAC and to provide EAC 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 EAC and its subsidiaries and affiliates are eligible to be granted awards under the 2008 Plan.
The total number of shares of common stock reserved for issuance pursuant to the 2008 Plan is 2,400,000. No more than 1,600,000 shares of EAC s common stock will be available for grants of full value stock awards, such as restricted stock or stock units. As of June 30, 2008, there were

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2,389,000 shares available for issuance under the 2008 Plan. Shares delivered or withheld for payment of the exercise price of an option, shares withheld for payment of tax withholding, shares subject to options or other awards that expire or are forfeited, and restricted shares that are forfeited will again become available for issuance under the 2008 Plan. The 2008 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 whose sole member is Jon S. Brumley, EAC s Chief Executive Officer and President. The Restricted Stock Award Committee may grant up to 25,000 shares of restricted stock on an annual basis to non-executive employees at its discretion.

The 2008 Plan contains the following individual limits:

- an employee may not be granted awards covering or relating to more than 300,000 shares of common stock during any calendar year;
- a non-employee director may not be granted awards covering or relating to more than 20,000 shares of common stock during 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 $5.0 million.

In May 2008, the Board approved certain amendments to the 2000 Plan to ensure compliance with Section 409A of the Code. In particular, the 2000 Plan was amended to allow for the exemption of options from the requirements of Section 409A of the Code by requiring that, upon a change-in-control, options granted or that vest on or after January 1, 2005 be valued at their fair market value as of the date they are cashed out, rather than the highest price per share paid in the 60 days prior to the change-in-control. The amendments to the 2000 Plan did not require stockholder approval under its terms, applicable laws, or the rules of the New York Stock Exchange.

All options have a strike price equal to the fair market value of EAC s common stock on the grant date, have a ten-year life, and vest over a three-year period. Restricted stock awards vest over varying periods from one to five years, subject to performance-based vesting for certain members of senior management.

The non-cash stock-based compensation expense recorded in the accompanying Consolidated Statements of Operations for the six months ended June 30, 2008 and 2007 was $4.1 million and $5.5 million, respectively. The income tax benefit of the non-cash stock-based compensation expense recorded in the accompanying Consolidated Statements of Operations for the six months ended June 30, 2008 and 2007 was $1.5 million and $2.0 million, respectively. During the six months ended June 30, 2008 and 2007, EAC also capitalized $1.0 million and $0.7 million, respectively, of non-cash stock-based compensation cost as a component of Properties and equipment in the accompanying Consolidated Balance Sheets. Non-cash stock-based compensation expense has been allocated to LOE and general and administrative (G&A) expense based on the allocation of the respective employees cash compensation.

See Note 18. ENP for a discussion of ENP s unit-based compensation plan.

Stock Options

The fair value of options granted during the six months ended June 30, 2008 and 2007 was estimated on the grant date using a Black-Scholes option valuation model based on the assumptions noted in the following table. The expected volatility was based on the historical volatility of EAC s common stock for a period of time commensurate with the expected term of the options. For options granted prior to January 1, 2008, EAC used the simplified method prescribed by SAB No. 107, *Valuation of Share-Based Payment Arrangements for Public Companies* 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. For options granted subsequent to December 31, 2007, EAC determined the expected life of the options based on an analysis of historical exercise and forfeiture behavior as well as expectations about future behavior. The risk-free interest rate is based on the U.S Treasury yield curve in effect at the grant date for a period of time commensurate with the expected term of the options.

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	Six months ended June 30, 2008	2007
Expected volatility	33.7%	35.7%
Expected dividend yield	0.0%	0.0%
Expected term (in years)	6.25	6.00
Risk-free interest rate	3.0%	4.8%

The following table summarizes the changes in EAC s outstanding options during the six months ended June 30, 2008:

	Number of Options	Weighted Average Strike Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (in thousands)
Outstanding at January 1, 2008	1,381,782	$16.03		
Granted	176,170	33.76		
Forfeited or expired	(12,300)	30.60		
Exercised	(21,545)	19.45		
Outstanding at June 30, 2008	1,524,107	17.91	5.6	$87,300
Exercisable at June 30, 2008	1,201,086	14.54	4.7	72,845

The weighted average fair value per share of options granted during the six months ended June 30, 2008 and 2007 was $13.15 and $11.16, respectively. The total intrinsic value of options exercised during the six months ended June 30, 2008 and 2007 was $0.6 million and $0.8 million, respectively. During the six months ended June 30, 2008 and 2007, EAC received proceeds from the exercise of stock options of $0.4 million and $0.8 million, respectively, and realized tax benefits related to stock options of $0.2 million and $0.3 million, respectively. At June 30, 2008, EAC had $2.0 million of total unrecognized compensation cost related to unvested stock options, which is expected to be recognized over a weighted average period of 2.3 years.

Restricted Stock

During the six months ended June 30, 2008 and 2007, EAC recognized expense related to restricted stock of $3.4 million and $4.5 million, respectively, and recognized tax benefits related to restricted stock of $1.3 million and $1.7 million, respectively. The following table summarizes the changes in the number of EAC s unvested restricted stock awards and their related weighted average grant date fair value for the six months ended June 30, 2008:

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2008	918,338	$27.07
Granted	314,086	37.02
Vested	(235,086)	26.37

Forfeited	(30,598)	29.14
Outstanding at June 30, 2008	966,740	30.29

As of June 30, 2008, there were 899,501 shares of unvested restricted stock the vesting of which is dependent only on the passage of time and continued employment, 241,515 shares of which were granted during 2008. Additionally, as of June 30, 2008, there were 67,239 shares of unvested restricted stock the vesting of which is dependent not only on the passage of time and continued employment, but on the achievement of certain performance measures, all of which were granted during 2008.

As of June 30, 2008, EAC had $12.7 million of total unrecognized compensation cost related to unvested restricted stock, which is expected to be recognized over a weighted average period of 3.1 years. None of EAC s unvested restricted stock is subject to variable accounting. During the six months ended June 30, 2008 and 2007, there were 235,086 shares and 118,273 shares, respectively, of restricted stock that vested for which employees elected to satisfy minimum tax withholding obligations

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS   Continued
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related thereto by directing EAC to withhold 28,193 shares and 5,545 shares of common stock, respectively. EAC accounts for these shares as treasury stock until they are formally retired and have been reflected as such in the accompanying consolidated financial statements.

Note 14. Comprehensive Income (Loss)

The components of EAC s comprehensive income (loss), net of tax, were as follows for the periods indicated:

	Three months ended June 30,		Six months ended June 30,	
	2008	**2007**	**2008**	**2007**
	(in thousands)			
Net income (loss)	$ (35,720)	$ 15,171	$ (4,500)	$ (14,257)
Amortization of deferred loss on commodity derivative contracts	907	8,373	1,786	16,554
Change in deferred hedge gain on interest rate swaps	1,588		417	
Comprehensive income (loss)	$ (33,225)	$ 23,544	$ (2,297)	$ 2,297

Note 15. Financial Statements of Subsidiary Guarantors

In February 2007, EAC formed certain non-guarantor subsidiaries in connection with the formation of ENP. See Note 18. ENP for additional discussion of ENP s formation and other matters. As of June 30, 2008 and December 31, 2007, certain of EAC s wholly owned subsidiaries were subsidiary guarantors of EAC s senior subordinated notes. The subsidiary guarantees are full and unconditional, and joint and several. The subsidiary guarantors may, without restriction, transfer funds to EAC in the form of cash dividends, loans, and advances. In accordance with SEC rules, EAC has prepared condensed consolidating financial statements in order to quantify the financial position, results of operations, and cash flows of the subsidiary guarantors. The following Condensed Consolidating Balance Sheets as of June 30, 2008 and December 31, 2007, Condensed Consolidating Statements of Operations and Comprehensive Income (Loss) for the three and six months ended June 30, 2008 and 2007, and Condensed Consolidating Statements of Cash Flows for the six months ended June 30, 2008 and 2007 present consolidating financial information for Encore Acquisition Company (the Parent) on a stand alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries. As of June 30, 2008, EAC s guarantor subsidiaries were:

EAP Properties, Inc.;

EAP Operating, LLC;

Encore Operating; and

Encore Operating Louisiana, LLC.

As of June 30, 2008, EAC s non-guarantor subsidiaries were:

ENP;

OLLC;

Encore Partners GP Holdings LLC;

Encore Partners LP Holdings LLC;

GP LLC; and

Encore Clear Fork Pipeline LLC.

All intercompany investments in, loans due to/from, subsidiary equity, and revenues and expenses between the Parent, guarantor subsidiaries, and non-guarantor subsidiaries are shown prior to consolidation with the Parent and then eliminated to arrive at consolidated totals per the accompanying consolidated financial statements of EAC.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING BALANCE SHEET
June 30, 2008
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
ASSETS					
Current assets:					
Cash and cash equivalents	$ 413	$ 264	$ 917	$	$ 1,594
Other current assets	85,441	187,815	33,151	(2,346)	304,061
Total current assets	85,854	188,079	34,068	(2,346)	305,655
Properties and equipment, at cost successful efforts method:					
Proved properties, including wells and related equipment		2,588,934	517,483		3,106,417
Unproved properties		85,508	249		85,757
Accumulated depletion, depreciation, and amortization		(505,434)	(81,466)		(586,900)
		2,169,008	436,266		2,605,274
Other property and equipment, net		10,410	578		10,988
Other assets, net	14,212	136,696	14,451		165,359
Investment in subsidiaries	2,179,710	(64,695)		(2,115,015)	
Total assets	$ 2,279,776	$ 2,439,498	$ 485,363	$ (2,117,361)	$ 3,087,276
LIABILITIES AND STOCKHOLDERS EQUITY					
Current liabilities	$ 23,138	$ 346,011	$ 48,018	$ (2,346)	$ 414,821
Deferred taxes	350,260		32		350,292
Long-term debt	990,519		151,000		1,141,519
Other liabilities		86,766	76,985		163,751
Total liabilities	1,363,917	432,777	276,035	(2,346)	2,070,383

Commitments and contingencies (see Note 16)					
Minority interest in consolidated partnership			101,034		101,034
Total stockholders equity	915,859	2,006,721	108,294	(2,115,015)	915,859
Total liabilities and stockholders equity	$ 2,279,776	$ 2,439,498	$ 485,363	$ (2,117,361)	$ 3,087,276

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING BALANCE SHEET
December 31, 2007
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
ASSETS					
Current assets:					
Cash and cash equivalents	$ 1	$ 1,700	$ 3	$	$ 1,704
Other current assets	535,221	437,852	21,053	(807,320)	186,806
Total current assets	535,222	439,552	21,056	(807,320)	188,510
Properties and equipment, at cost successful efforts method:					
Proved properties, including wells and related equipment		2,467,606	378,170		2,845,776
Unproved properties		63,352			63,352
Accumulated depletion, depreciation, and amortization		(451,343)	(37,661)		(489,004)
		2,079,615	340,509		2,420,124
Other property and equipment, net		10,610	407		11,017
Other assets, net	14,899	121,904	28,107		164,910
Investment in subsidiaries	2,090,471	20,611		(2,111,082)	
Total assets	$ 2,640,592	$ 2,672,292	$ 390,079	$ (2,918,402)	$ 2,784,561
LIABILITIES AND STOCKHOLDERS EQUITY					
Current liabilities	$ 306,787	$ 687,351	$ 17,885	$ (807,293)	$ 204,730
Deferred taxes	312,914				312,914
Long-term debt	1,072,736		47,500		1,120,236
Other liabilities		49,461	26,531		75,992
Total liabilities	1,692,437	736,812	91,916	(807,293)	1,713,872

Commitments and contingencies (see Note 16)					
Minority interest in consolidated partnership			122,534		122,534
Total stockholders equity	948,155	1,935,480	175,629	(2,111,109)	948,155
Total liabilities and stockholders equity	$ 2,640,592	$ 2,672,292	$ 390,079	$ (2,918,402)	$ 2,784,561

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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 June 30, 2008
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 239,783	$ 47,141	$	$ 286,924
Natural gas		56,081	11,808		67,889
Marketing		1,618	903		2,521
Total revenues		297,482	59,852		357,334
Expenses:					
Production:					
Lease operations		33,775	6,922		40,697
Production, ad valorem, and severance taxes		29,261	5,782		35,043
Depletion, depreciation, and amortization		41,811	9,215		51,026
Exploration		11,555	38		11,593
General and administrative	3,911	5,830	2,933	(1,115)	11,559
Marketing		2,116	1,609		3,725
Derivative fair value loss		179,962	76,428		256,390
Other operating	42	2,853	331		3,226
Total expenses	3,953	307,163	103,258	(1,115)	413,259
Operating loss	(3,953)	(9,681)	(43,406)	1,115	(55,925)
Other income (expenses):					
Interest	(14,876)		(1,909)		(16,785)
Equity loss from subsidiaries	(38,923)	(15,800)		54,723	
Other	(85)	1,821	65	(1,115)	686
Total other expenses	(53,884)	(13,979)	(1,844)	53,608	(16,099)
Loss before income taxes and minority interest	(57,837)	(23,660)	(45,250)	54,723	(72,024)
Income tax benefit (provision)	21,151	(81)	252		21,322
Minority interest in loss of consolidated partnership				14,982	14,982

Net loss	(36,686)		(23,741)		(44,998)		69,705		(35,720)
Amortization of deferred loss on commodity derivative contracts, net of tax	(522)		1,429						907
Change in deferred hedge gain on interest rate swaps, net of tax	(647)				2,235				1,588
Comprehensive loss	$ (37,855)	$	(22,312)	$	(42,763)	$	69,705	$	(33,225)

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended June 30, 2007
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 119,508	$ 16,088	$	$ 135,596
Natural gas		44,950	181		45,131
Marketing		5,302	3,614		8,916
Total revenues		169,760	19,883		189,643
Expenses:					
Production:					
Lease operations		34,202	3,350		37,552
Production, ad valorem, and severance taxes		17,139	2,093		19,232
Depletion, depreciation, and amortization		44,924	7,394		52,318
Exploration		3,415			3,415
General and administrative	13	5,552	623		6,188
Marketing		5,232	3,275		8,507
Derivative fair value loss		3,952	2,814		6,766
Other operating	42	4,550	159		4,751
Total expenses	55	118,966	19,708		138,729
Operating income (loss)	(55)	50,794	175		50,914
Other income (expenses):					
Interest	(10,219)	(18,599)	(5,342)	6,340	(27,820)
Equity income (loss) from subsidiaries	30,773			(30,773)	
Other	3,196	3,718	27	(6,340)	601
Total other income (expenses)	23,750	(14,881)	(5,315)	(30,773)	(27,219)
Income (loss) before income taxes	23,695	35,913	(5,140)	(30,773)	23,695
Income tax provision	(8,524)				(8,524)

Net income (loss)	15,171	35,913	(5,140)	(30,773)	15,171
Amortization of deferred loss on commodity derivative contracts, net of tax	(5,024)	13,397			8,373
Comprehensive income (loss)	$ 10,147	$ 49,310	$ (5,140)	$ (30,773)	$ 23,544

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2008
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 423,122	$ 84,336	$	$ 507,458
Natural gas		97,391	18,810		116,201
Marketing		2,815	3,762		6,577
Total revenues		523,328	106,908		630,236
Expenses:					
Production:					
Lease operations		68,067	12,980		81,047
Production, ad valorem, and severance taxes		51,915	10,580		62,495
Depletion, depreciation, and amortization		82,234	18,335		100,569
Exploration		17,014	67		17,081
General and administrative	6,945	10,580	5,855	(2,134)	21,246
Marketing		3,505	4,002		7,507
Derivative fair value loss		229,513	92,015		321,528
Other operating	83	4,967	682		5,732
Total expenses	7,028	467,795	144,516	(2,134)	617,205
Operating income (loss)	(7,028)	55,533	(37,608)	2,134	13,031
Other income (expenses):					
Interest	(32,996)		(3,549)		(36,545)
Equity income (loss) from subsidiaries	31,832	(13,840)		(17,992)	
Other	(48)	3,637	82	(2,134)	1,537
Total other expenses	(1,212)	(10,203)	(3,467)	(20,126)	(35,008)
Income (loss) before income taxes and minority interest	(8,240)	45,330	(41,075)	(17,992)	(21,977)
Income tax benefit (provision)	2,508	(81)	162		2,589

Minority interest in loss of consolidated partnership				14,888	14,888
Net income (loss)	(5,732)	45,249	(40,913)	(3,104)	(4,500)
Amortization of deferred loss on commodity derivative contracts, net of tax	(1,071)	2,857			1,786
Change in deferred hedge gain on interest rate swaps, net of tax	(250)		667		417
Comprehensive income (loss)	$ (7,053)	$ 48,106	$ (40,246)	$ (3,104)	$ (2,297)

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2007
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 197,888	$ 20,331	$	$ 218,219
Natural gas		77,779	330		78,109
Marketing		19,005	4,852		23,857
Total revenues		294,672	25,513		320,185
Expenses:					
Production:					
Lease operations		63,754	4,318		68,072
Production, ad valorem, and severance taxes		29,017	2,730		31,747
Depletion, depreciation, and amortization		77,445	9,901		87,346
Exploration		14,936			14,936
General and administrative	37	12,700	811		13,548
Marketing		19,163	4,355		23,518
Derivative fair value loss		45,883	6,497		52,380
Other operating	83	7,050	183		7,316
Total expenses	120	269,948	28,795		298,863
Operating income (loss)	(120)	24,724	(3,282)		21,322
Other income (expenses):					
Interest	(41,304)	(3,641)	(6,444)	7,282	(44,107)
Equity income (loss) from subsidiaries	16,046			(16,046)	
Other	3,625	4,662	27	(7,282)	1,032
Total other income (expenses)	(21,633)	1,021	(6,417)	(16,046)	(43,075)
Income (loss) before income taxes	(21,753)	25,745	(9,699)	(16,046)	(21,753)
Income tax benefit	7,496				7,496

Net income (loss)	(14,257)	25,745	(9,699)	(16,046)	(14,257)
Amortization of deferred loss on commodity derivative contracts, net of tax	(10,240)	26,794			16,554
Comprehensive income (loss)	$ (24,497)	$ 52,539	$ (9,699)	$ (16,046)	$ 2,297

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
For the Six Months Ended June 30, 2008
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Cash flows from operating activities:					
Net cash provided by (used in) operating activities	$ (15,147)	$ 303,826	$ 63,636	$	$ 352,315
Cash flows from investing activities:					
Acquisition of oil and natural gas properties		(49,199)	(81)		(49,280)
Development of oil and natural gas properties		(221,175)	(12,050)		(233,225)
Investments in subsidiaries	128,148			(128,148)	
Other		(23,681)	(217)		(23,898)
Net cash provided by (used in) investing activities	128,148	(294,055)	(12,348)	(128,148)	(306,403)
Cash flows from financing activities:					
Repurchase of common stock	(39,118)				(39,118)
Proceeds from long-term debt, net of issuance costs	455,029		163,310		618,339
Payments on long-term debt	(538,500)		(60,000)		(598,500)
Net equity distributions		(3,121)	(125,027)	128,148	
Other	10,000	(8,086)	(28,657)		(26,743)
Net cash used in financing activities	(112,589)	(11,207)	(50,374)	128,148	(46,022)
Increase (decrease) in cash and cash equivalents	412	(1,436)	914		(110)
Cash and cash equivalents, beginning of period	1	1,700	3		1,704
Cash and cash equivalents, end of period	$ 413	$ 264	$ 917	$	$ 1,594

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
For the Six Months Ended June 30, 2007
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Cash flows from operating activities:					
Net cash provided by operating activities	$	$ 79,732	$ 1,593	$	$ 81,325
Cash flows from investing activities:					
Proceeds from disposition of assets		291,454			291,454
Acquisition of oil and natural gas properties		(452,361)	(327,215)		(779,576)
Development of oil and natural gas properties		(187,227)			(187,227)
Intercompany loans	(120,000)	(120,000)		240,000	
Investments in subsidiaries	(379,542)			379,542	
Other		(25,701)	(71)		(25,772)
Net cash used in investing activities	(499,542)	(493,835)	(327,286)	619,542	(701,121)
Cash flows from financing activities:					
Proceeds from long-term debt, net of issuance costs	991,136	120,000	248,883	(240,000)	1,120,019
Payments on long-term debt	(477,000)		(15,500)		(492,500)
Net equity contributions		285,884	93,658	(379,542)	
Other	(14,594)	11,046			(3,548)
Net cash provided by financing activities	499,542	416,930	327,041	(619,542)	623,971
Increase in cash and cash equivalents		2,827	1,348		4,175
Cash and cash equivalents, beginning of period		763			763
Cash and cash equivalents, end of period	$	$ 3,590	$ 1,348	$	$ 4,938

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
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Note 16. Commitments and Contingencies

Litigation

EAC 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 EAC s results of operations or financial position.

ExxonMobil

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

EAC will earn the right to participate in all fields by drilling a total of 24 commitment wells by the end of 2008. During the commitment phase, ExxonMobil will have the option to receive non-recourse advanced funds from EAC 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 EAC s monthly receipt of 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 EAC has fulfilled its obligations under the commitment phase, it will be entitled to a 30 percent working interest in future drilling locations. EAC will have the right to propose and drill wells for as long as it is engaged in continuous drilling operations.

During the six months ended June 30, 2008 and 2007, EAC advanced $27.6 million and $26.4 million, respectively, to ExxonMobil for its portion of capital related to drilling commitment wells. At June 30, 2008, EAC had a net receivable from ExxonMobil of $75.6 million, of which $12.2 million was included in Accounts receivable, net and $63.4 million was included in Long-term receivables on the accompanying Consolidated Balance Sheet based on when EAC expects repayment. At December 31, 2007, EAC had a net receivable from ExxonMobil of $51.7 million, of which $12.3 million was included in Accounts receivable, net and $39.4 million was included in Long-term receivables on the accompanying Consolidated Balance Sheet. As of June 30, 2008, EAC had only one re-entry well to drill in order to fulfill its commitment under the joint development agreement at a minimum cost of $1.0 million.

Note 17. Related Party Transactions

During the six months ended June 30, 2007, EAC paid approximately $1.1 million to affiliates of Exterran Holdings, Inc., the successor of Hanover Compressor Company (Hanover) for compressors and field compression services. Mr. I. Jon Brumley, EAC s Chairman of the Board, served as a director of Hanover until August 2007.

During the six months ended June 30, 2008 and 2007, EAC received approximately $89.3 million and $18.7 million, respectively, from affiliates of Tesoro Corporation (Tesoro) related to gross production sold from wells operated by Encore Operating. Mr. John V. Genova, a member of the Board, served as an employee of Tesoro until May 2008.

See Note 18. ENP for a discussion of related party transactions with ENP.

Note 18. ENP

Administrative Services Agreement

In connection with the closing of ENP s IPO, EAC entered into an amended and restated administrative services agreement (the Administrative Services Agreement) with ENP, GP LLC, OLLC, and Encore Operating, whereby Encore Operating performs administrative services for ENP, such as accounting, corporate development, finance, land, legal, and engineering. In addition, Encore Operating provides all personnel and any facilities, goods, and equipment necessary to perform these services and not otherwise provided by ENP. Initially, Encore Operating received an administrative fee of $1.75 per BOE of ENP s production for such services and reimbursement of actual third-party expenses incurred on ENP s behalf. The administrative fee

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

increases by the same percentage as the COPAS overhead charges discussed below. Effective April 1, 2008, the administrative fee increased to $1.88 per BOE.

In addition, Encore Operating is entitled to retain any COPAS overhead charges associated with drilling and operating wells that would otherwise be paid by non-operating interest owners to the operator of a well. Most joint operating agreements provide for an annual increase or decrease in the COPAS overhead rate based on the change in average weekly earnings as measured by an index published by the United States Department of Labor, Bureau of Labor Statistics. The COPAS overhead cost is charged to all non-operating interest owners under a joint operating agreement each month.

ENP also reimburses EAC for any additional state income, franchise, or similar tax paid by EAC resulting from the inclusion of ENP and its subsidiaries in consolidated tax returns with EAC and its subsidiaries as required by applicable law. The amount of any such reimbursement is limited to the tax that ENP and its subsidiaries would have paid had it not been included in a combined group with EAC.

ENP does not have any employees. The employees supporting ENP s operations are employees of EAC or its subsidiaries. Accordingly, EAC recognizes all employee-related expenses and liabilities in its consolidated financial statements. Encore Operating has substantial discretion in determining which third-party expenses to incur on ENP s behalf. ENP also pays its share of expenses that are directly chargeable to wells under joint operating agreements. Encore Operating is not liable to ENP for its performance of, or failure to perform, services under the Administrative Services Agreement unless its acts or omissions constitute gross negligence or willful misconduct.

Purchase and Investment Agreement

In December 2007, OLLC entered into a purchase and investment agreement with Encore Operating, whereby OLLC acquired certain oil and natural gas properties and related assets in the Permian and Williston Basins from Encore Operating. The transaction closed in February 2008, but was effective as of January 1, 2008.

The consideration for the acquisition consisted of approximately $125.3 million in cash, including post-closing adjustments, and 6,884,776 common units representing limited partner interests in ENP. ENP funded the cash portion of the purchase price through borrowings under the OLLC Credit Agreement. EAC used the proceeds from the sale to reduce outstanding borrowings under the EAC Credit Agreement.

Long-Term Incentive Plan

In September 2007, GP LLC approved a long-term incentive plan (the ENP Plan), which provides for the granting of options, restricted units, phantom units, unit appreciation rights, distribution equivalent rights, other unit-based awards, and unit awards. All employees, consultants, and directors of EAC, GP LLC, and any of their subsidiaries and affiliates who perform services for ENP are eligible to be granted awards under the ENP Plan. The total number of shares of common units reserved for issuance pursuant to the ENP Plan is 1,150,000. As of June 30, 2008, there were 1,125,000 units available for issuance under the ENP Plan. The ENP Plan is administered by the board of directors of GP LLC or a committee thereof, referred to as the plan administrator.

In October 2007, ENP issued 20,000 phantom units to members of GP LLC s board of directors pursuant to the ENP Plan. In February 2008, ENP issued 5,000 phantom units to a new member of GP LLC s board of directors pursuant to the ENP Plan. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit or, at the discretion of the plan administrator, cash equivalent to the value of a common unit. These phantom units are classified as liability awards. Accordingly, ENP determines the fair value of these awards at the end of each reporting period, based on the closing price of its common units, and recognizes the current portion of the liability as a component of Other current liabilities and the long-term portion of the liability as a component of Other noncurrent liabilities in the accompanying Consolidated Balance Sheets. As of June 30, 2008 and December 31, 2007, the total liability was approximately $232,000 and $31,000, respectively. For liability awards, the fair value of the award, which determines the measurement of the liability on the balance sheet, is remeasured each reporting period until the award is settled. Changes in the fair value of the liability award from period to period are recorded as increases or decreases in compensation expense, over the remaining service period. The phantom units vest in four equal installments on October 29, 2008, 2009, 2010, and 2011. The holders of phantom units are also entitled to receive distribution equivalent rights prior to vesting, which entitle them to receive cash equal to the amount of any cash distributions made by ENP

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with respect to a common unit during the period the right is outstanding. During the three and six months ended June 30, 2008, ENP recognized non-cash unit-based compensation expense of approximately $128,000 and $200,000, respectively, for the phantom units, which is included in General and administrative expense in the accompanying Consolidated Statements of Operations.

To satisfy common unit awards under the ENP Plan, ENP may issue new common units, acquire common units in the open market, or use common units owned by EAC and its subsidiaries. There have been no additional issuances or forfeitures of awards under the ENP Plan.

Management Incentive Units (MIUs)

In May 2007, the board of directors of GP LLC issued 550,000 MIUs to certain executive officers of GP LLC. MIUs are a limited partner interest in ENP that entitles the holder to quarterly distributions to the extent paid to ENP s common unitholders and to increasing distributions upon the achievement of 10 percent compounding increases in ENP s distribution rate to common unitholders. MIUs are convertible into ENP common units upon the occurrence of certain events and to increasing conversion rates upon the achievement of 10 percent compounding increases in ENP s distribution rate to common unitholders. MIUs are subject to a maximum limit on the aggregate number of common units issuable to, and the aggregate distributions payable to, holders of MIUs as follows:

- the holders of MIUs are not entitled to receive, in the aggregate, common units upon conversion of the MIUs that exceed a maximum limit of 5.1 percent of ENP s then-outstanding units; and
- the holders of MIUs are not entitled to receive, in the aggregate, distributions of ENP s available cash in an amount that exceeds a maximum limit of 5.1 percent of all such distributions to all unitholders at the time of any such distribution.

The holders of MIUs do not have voting rights with respect to the MIUs.

The MIUs vest in three equal installments. The first installment vested upon the closing of the IPO, and the subsequent vestings will occur in September 2008 and 2009. For the three and six months ended June 30, 2008, ENP recognized total non-cash unit-based compensation expense for the MIUs of $1.1 million and $2.1 million, respectively, which is included in General and administrative expense in the accompanying Consolidated Statements of Operations. As of June 30, 2008, ENP had $2.6 million of total unrecognized compensation cost related to unvested MIUs, which is expected to be recognized over a weighted average period of 0.5 years. For the third quarter of 2008, the expense will be approximately $1.1 million, and for the fourth quarter of 2008 through the third quarter of 2009, the expense will be approximately $0.4 million per quarter. There have been no additional issuances or forfeitures of MIUs.

Distributions

In January 2008, ENP announced a cash distribution for the fourth quarter of 2007 to unitholders of record as of the close of business on February 6, 2008 at a rate of $0.3875 per unit. Approximately $9.8 million was paid on February 14, 2008, $5.6 million of which was paid to EAC and its subsidiaries and had no impact on EAC s consolidated cash.

In May 2008, ENP announced a cash distribution for the first quarter of 2008 to unitholders of record as of the close of business on May 9, 2008 at a rate of $0.5755 per unit. Approximately $19.3 million was paid on May 15, 2008, $12.3 million of which was paid to EAC and its subsidiaries and had no impact on EAC s consolidated cash.

Note 19. Segment Information

EAC operates in only one industry: the oil and natural gas exploration and production industry in the United States. However, EAC is organizationally structured along two reportable segments: EAC Standalone and ENP. EAC s segments are components of its business for which separate financial information related to operating and development costs are available and regularly evaluated by the chief operating decision maker in deciding how to allocate capital resources to projects and in assessing performance. The accounting policies used in the generation of segment financial statements are the same as those described in Note 2. Summary of Significant Accounting Policies in EAC s 2007 Annual Report on Form 10-K. Prior to ENP s IPO in September 2007, segment reporting was not applicable to EAC.

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The following tables provide EAC s operating segment information required by SFAS No. 131, *Disclosure about Segments of an Enterprise and Related Information* .

	For the Three Months Ended June 30, 2008			
	EAC Standalone	ENP	Eliminations	Consolidated Total
	(in thousands)			
Revenues:				
Oil	$ 239,783	$ 47,141	$	$ 286,924
Natural gas	56,081	11,808		67,889
Marketing	1,618	903		2,521
Total revenues	297,482	59,852		357,334
Expenses:				
Production:				
Lease operations	33,775	6,922		40,697
Production, ad valorem, and severance taxes	29,261	5,782		35,043
Depletion, depreciation, and amortization	41,811	9,215		51,026
Exploration	11,555	38		11,593
General and administrative	9,755	2,933	(1,129)	11,559
Marketing	2,116	1,609		3,725
Derivative fair value loss	179,962	76,428		256,390
Other operating	2,895	331		3,226
Total expenses	311,130	103,258	(1,129)	413,259
Operating loss	(13,648)	(43,406)	1,129	(55,925)
Other income (expenses):				
Interest	(14,876)	(1,909)		(16,785)
Other	1,750	65	(1,129)	686
Total other expenses	(13,126)	(1,844)	(1,129)	(16,099)
Loss before income taxes and minority interest	(26,774)	(45,250)		(72,024)
Income tax benefit	21,070	252		21,322
Minority interest in loss of consolidated partnership	14,982			14,982
Net income (loss)	9,278	(44,998)		(35,720)

Amortization of deferred loss on commodity derivative contracts, net of tax		907						907
Change in deferred hedge gain on interest rate swaps, net of tax		(967)		2,552				1,585
Comprehensive income (loss)	$	9,218	$	(42,446)	$		$	(33,228)
Segment assets (as of June 30, 2008)	$	2,602,438	$	485,072	$	(234)	$	3,087,276

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	For the Six Months Ended June 30, 2008			
	EAC Standalone	ENP	Eliminations	Consolidated Total
	(in thousands)			
Revenues:				
Oil	$ 423,122	$ 84,336	$	$ 507,458
Natural gas	97,391	18,810		116,201
Marketing	2,815	3,762		6,577
Total revenues	523,328	106,908		630,236
Expenses:				
Production:				
Lease operations	68,067	12,980		81,047
Production, ad valorem, and severance taxes	51,915	10,580		62,495
Depletion, depreciation, and amortization	82,234	18,335		100,569
Exploration	17,014	67		17,081
General and administrative	17,525	5,855	(2,134)	21,246
Marketing	3,505	4,002		7,507
Derivative fair value loss	229,513	92,015		321,528
Other operating	5,050	682		5,732
Total expenses	474,823	144,516	(2,134)	617,205
Operating income (loss)	48,505	(37,608)	2,134	13,031
Other income (expenses):				
Interest	(32,996)	(3,549)		(36,545)
Other	3,589	82	(2,134)	1,537
Total other expenses	(29,407)	(3,467)	(2,134)	(35,008)
Income (loss) before income taxes and minority interest	19,098	(41,075)		(21,977)
Income tax benefit	2,427	162		2,589
Minority interest in loss of consolidated partnership	14,888			14,888
Net income (loss)	36,413	(40,913)		(4,500)
	1,786			1,786

Amortization of deferred loss on commodity derivative contracts, net of tax				
Change in deferred hedge gain on interest rate swaps, net of tax	(567)	984		417
Comprehensive income (loss)	$ 37,632	$ (39,929)	$	$ (2,297)

Note 20. Subsequent Events

In July 2008, the Board approved a retention plan for all of EAC s current employees, excluding the Chairman of the Board and Chief Executive Officer, providing for the payment of eight months of base salary or base rate of pay, as applicable, in August 2009, subject to continued employment.

On August 4, 2008, ENP announced a cash distribution for the second quarter of 2008 to unitholders of record as of the close of business on August 11, 2008 at a rate of $0.6881 per unit. Approximately $23.1 million is expected to be paid on or about August 14, 2008, $14.7 million of which is expected to be paid to EAC and its subsidiaries and will have no impact on EAC s consolidated cash.

Subsequent to June 30, 2008, EAC drilled the final commitment well under its joint development agreement with ExxonMobil.

Subsequent to June 30, 2008, EAC entered into additional oil derivative contracts. The following table summarizes EAC s open oil derivative contracts as of August 5, 2008:

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Period	Average Daily Floor Volume (Bbls)	Weighted Average Floor Price (per Bbl)	Average Daily Short Floor Volume (Bbls)	Weighted Average Short Floor Price (per Bbl)	Average Daily Cap Volume (Bbls)	Weighted Average Cap Price (per Bbl)	Average Daily Swap Volume (Bbls)	Weighted Average Swap Price (per Bbl)
Aug. Dec. 2008								
	14,880	$ 83.36		$	2,440	$101.99	5,000	$91.56
	6,000	71.67			2,000	96.65		
	5,500	62.27						
	3,000	56.67	(4,000)	50.00				
2009								
	8,500	110.00			440	97.75	2,000	90.46
	8,880	80.00					3,000	89.22
	2,250	74.11	(5,000)	50.00			1,000	68.70
2010								
	880	80.00			440	93.80		
	2,000	75.00			1,000	77.23		
2011								
	1,880	80.00			1,440	95.41		
	1,000	70.00						

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

The following discussion and analysis contains forward-looking statements, which give our current expectations or forecasts of future events. Actual results could differ materially from those stated in the forward-looking statements due to many factors, including, but not limited to, those set forth under Item 1A. Risk Factors in our 2007 Annual Report on Form 10-K. The following discussion and analysis 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 2007 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:

- Second Quarter 2008 Highlights
- Results of Operations
  - Comparison of Quarter Ended June 30, 2008 to Quarter Ended June 30, 2007
  - Comparison of Six Months Ended June 30, 2008 to Six Months Ended June 30, 2007
- Capital Commitments, Capital Resources, and Liquidity
- Critical Accounting Policies and Estimates
- New Accounting Pronouncements

In May 2008, we announced that our Board authorized our management team to explore strategic alternatives to further enhance shareholder value, including, but not limited to, a sale or merger. Our Board has since decided that a sale or merger is not currently in the best interest of our shareholders.

Second Quarter 2008 Highlights

Our financial and operating results for the second quarter of 2008 included the following:

- Our oil and natural gas revenues increased 96 percent to $354.8 million as compared to $180.7 million in the second quarter of 2007 as a result of higher average realized prices.
- Our average realized oil price increased 125 percent to $116.64 per Bbl as compared to $51.92 per Bbl in the second quarter of 2007. Our average realized natural gas price increased 71 percent to $11.12 per Mcf as compared to $6.52 per Mcf in the second quarter of 2007.
- We invested $166.8 million in oil and natural gas activities. Of this amount, we invested $142.4 million in development, exploitation, and exploration activities, which yielded 60 gross (21.0 net) successful wells, and $24.4 million related to acquisitions.
- Our production margin (defined as oil and natural gas revenues less production expenses) increased 125 percent to $279.1 million as compared to $123.9 million in the second quarter of 2007. Total oil and natural gas revenues per BOE increased by 113 percent while total production expenses per BOE increased by only 44 percent. On a per BOE basis, our production margin increased 144 percent to $80.25 per BOE as compared to $32.91 per BOE for the second quarter of 2007.

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Results of Operations

Comparison of Quarter Ended June 30, 2008 to Quarter Ended June 30, 2007

Oil and natural gas revenues. The following table illustrates the components of oil and natural gas revenues for the periods indicated, as well as each period s respective production volumes and average prices:

	Three months ended June 30,		Increase / (Decrease)	
	2008	2007	$	%
Revenues (in thousands):				
Oil wellhead	$ 288,352	$ 146,420	*$ 141,932*	
Oil commodity derivative contracts	(1,428)	(10,824)	*9,396*	
Total oil revenues	$ 286,924	$ 135,596	*$ 151,328*	*112%*
Natural gas wellhead	$ 67,889	$ 47,704	*$ 20,185*	
Natural gas commodity derivative contracts		(2,573)	*2,573*	
Total natural gas revenues	$ 67,889	$ 45,131	*$ 22,758*	*50%*
Combined wellhead	$ 356,241	$ 194,124	*$ 162,117*	
Combined commodity derivative contracts	(1,428)	(13,397)	*11,969*	
Total combined oil and natural gas revenues	$ 354,813	$ 180,727	*$ 174,086*	*96%*
Average realized prices:				
Oil wellhead ($/Bbl)	$ 117.22	$ 56.07	*$ 61.15*	
Oil commodity derivative contracts ($/Bbl)	(0.58)	(4.15)	*3.57*	
Total oil revenues ($/Bbl)	$ 116.64	$ 51.92	*$ 64.72*	*125%*
Natural gas wellhead ($/Mcf)	$ 11.12	$ 6.89	*$ 4.23*	
Natural gas commodity derivative contracts ($/Mcf)		(0.37)	*0.37*	
Total natural gas revenues ($/Mcf)	$ 11.12	$ 6.52	*$ 4.60*	*71%*
Combined wellhead ($/BOE)	$ 102.44	$ 51.55	*$ 50.89*	
Combined commodity derivative contracts ($/BOE)	(0.41)	(3.56)	*3.15*	
Total combined oil and natural gas revenues ($/BOE)	$ 102.03	$ 47.99	*$ 54.04*	*113%*
Total production volumes:				
Oil (MBbls)	2,460	2,611	*(151)*	*-6%*

Natural gas (MMcf)	6,105	6,927	*(822)*	*-12%*
Combined (MBOE)	3,477	3,766	*(289)*	*-8%*
Average daily production volumes:				
Oil (Bbls/D)	27,032	28,696	*(1,664)*	*-6%*
Natural gas (Mcf/D)	67,090	76,123	*(9,033)*	*-12%*
Combined (BOE/D)	38,214	41,384	*(3,170)*	*-8%*
Average NYMEX prices:				
Oil (per Bbl)	$ 124.30	$ 65.06	*$ 59.24*	*91%*
Natural gas (per Mcf)	$ 10.94	$ 7.55	*$ 3.39*	*45%*

Oil revenues increased 112 percent from $135.6 million in the second quarter of 2007 to $286.9 million in the second quarter of 2008 as a result of an increase in our average realized oil price, partially offset by a decrease in oil production volumes of 151 MBbls, which reduced oil revenues by approximately $8.5 million. The decrease in oil production volumes was primarily the result of a large snow storm in Montana that temporarily disrupted the electrical supply to our wells in the CCA and a 25 percent curtailment of shipments due to pipeline problems by the operator of a natural gas liquids pipeline we use to move liquids from a West Texas natural gas processing plant to the Gulf Coast.

Our average realized oil price increased $64.72 per Bbl as a result of an increase in our wellhead price and a decrease in the effects of commodity derivative contracts that were previously designated as hedges. Our higher average oil wellhead price increased oil revenues by approximately $150.4 million, or $61.15 per Bbl, and the decrease in the effects of commodity

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derivative contracts that were previously designated as hedges increased oil revenues by approximately $9.4 million, or $3.57 per Bbl. Our average oil wellhead price increased as a result of increases in the overall market price for oil, as reflected in the increase in the average NYMEX price from $65.06 per Bbl in the second quarter of 2007 to $124.30 per Bbl in the second quarter of 2008.

Our oil wellhead revenue was reduced by $18.3 million and $6.1 million in the second quarter of 2008 and 2007, respectively, for NPI payments related to our CCA properties.

Natural gas revenues increased 50 percent from $45.1 million in the second quarter of 2007 to $67.9 million in the second quarter of 2008 as a result of an increase in our average realized natural gas price, partially offset by a decrease in production volumes of 822 MMcf, which reduced natural gas revenues by approximately $5.7 million. The decrease in natural gas production volumes was primarily the result of our Mid-Continent asset disposition in June 2007 and an unscheduled third-party natural gas processing plant shutdown in New Mexico.

Our average realized natural gas price increased $4.60 per Mcf as a result of an increase in our wellhead price and a decrease in the effects of commodity derivative contracts that were previously designated as hedges. Our higher average natural gas wellhead price increased natural gas revenues by approximately $25.8 million, or $4.23 per Mcf, and the decrease in the effects of commodity derivative contracts that were previously designated as hedges increased natural gas revenues by approximately $2.6 million, or $0.37 per Mcf. Our average natural gas wellhead price increased as a result of increases in the overall market price for natural gas, as reflected in the increase in the average NYMEX price from $7.55 per Mcf in the second quarter of 2007 to $10.94 per Mcf in the second quarter of 2008.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices for the periods indicated. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Three months ended June 30,	
	2008	2007
Oil wellhead ($/Bbl)	$117.22	$56.07
Average NYMEX ($/Bbl)	$124.30	$65.06
Differential to NYMEX	$ (7.08)	$ (8.99)
Oil wellhead to NYMEX percentage	94%	86%
Natural gas wellhead ($/Mcf)	$ 11.12	$ 6.89
Average NYMEX ($/Mcf)	$ 10.94	$ 7.55
Differential to NYMEX	$ 0.18	$ (0.66)
Natural gas wellhead to NYMEX percentage	102%	91%

Our oil wellhead price as a percentage of the average NYMEX price improved to 94 percent in the second quarter of 2008 as compared to 86 percent in the second quarter of 2007. The differential improved because of term contracts based on a fixed differential of NYMEX and the subsequent strength of West Texas Intermediate, continued strong demand, and the relatively high price of oil sold into the Clearbrook, Minnesota market. We expect our oil wellhead differentials to begin widening in the third quarter of 2008 as compared to the second quarter of 2008, which is historically common.

Our natural gas wellhead price as a percentage of the average NYMEX price improved to 102 percent in the second quarter of 2008 as compared to 91 percent in the second quarter of 2007. Certain of our natural gas marketing contracts determine the price that we are paid based on the value of the dry gas sold plus a portion of the value of liquids extracted. Since title of the natural gas sold under these contracts passes at the inlet of the processing plant, we report inlet volumes of natural gas in Mcf as production. From the second quarter of 2007 to the second quarter of 2008, the price of NGLs increased at a much faster pace than did the price of natural gas. As a result, the price we were paid per Mcf for natural gas sold under certain contracts increased to a level above NYMEX. This resulted in our overall natural gas differential to NYMEX swinging from a negative in the second quarter of 2007 to a slight positive in the second quarter of 2008. We expect our natural gas wellhead differentials to remain approximately constant or to widen slightly in the third quarter of 2008 as compared to the second quarter of 2008.

Marketing revenues and expenses. In 2007, we discontinued purchasing oil from third party companies as market conditions changed and pipeline space was gained. Implementing this change allowed us to focus on the marketing of our own oil production, leveraging newly gained pipeline space, and delivering oil to various newly developed markets in an effort to maximize the value of the oil at the wellhead.

In March 2007, ENP acquired a natural gas pipeline from Anadarko as part of the Big Horn Basin asset acquisition. Natural gas volumes are purchased from numerous gas producers at the inlet to the pipeline and resold downstream to various local and

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off-system markets. Marketing expenses in the second quarter of 2008 include pipeline tariffs, storage, truck facility fees, and tank bottom costs used to support the sale of equity crude, the revenues of which are included in our oil revenues instead of marketing revenues.

The following table summarizes our marketing activities for the periods indicated:

	Three months ended June 30,		***Increase / (Decrease)***	
	2008	**2007**	***$***	***%***
	($ in thousands, except per BOE amounts)			
Marketing revenues	$ 2,521	$ 8,916	*$ (6,395)*	*-72%*
Marketing expenses	(3,725)	(8,507)	*4,782*	*-56%*
Marketing gain (loss)	$ (1,204)	$ 409	*$ (1,613)*	*-394%*
Marketing revenues per BOE	$ 0.72	$ 2.37	*$ (1.65)*	*-70%*
Marketing expenses per BOE	(1.07)	(2.26)	*1.19*	*-53%*
Marketing gain (loss) per BOE	$ (0.35)	$ 0.11	*$ (0.46)*	*-418%*

Expenses. The following table summarizes our expenses, excluding marketing expenses shown above, for the periods indicated:

	Three months ended June 30,		***Increase / (Decrease)***	
	2008	**2007**	***$***	***%***
Expenses (in thousands):				
Production:				
Lease operations	$ 40,697	$ 37,552	*$ 3,145*	
Production, ad valorem, and severance taxes	35,043	19,232	*15,811*	
Total production expenses	75,740	56,784	*18,956*	*33%*
Other:				
Depletion, depreciation, and amortization	51,026	52,318	*(1,292)*	
Exploration	11,593	3,415	*8,178*	
General and administrative	11,559	6,188	*5,371*	
Derivative fair value loss	256,390	6,766	*249,624*	
Other operating	3,226	4,751	*(1,525)*	
Total operating	409,534	130,222	*279,312*	*214%*
Interest	16,785	27,820	*(11,035)*	
Income tax provision (benefit)	(21,322)	8,524	*(29,846)*	
Total expenses	$ 404,997	$ 166,566	*$ 238,431*	*143%*
Expenses (per BOE):				
Production:				

Lease operations	$ 11.70	$ 9.97	*$ 1.73*	
Production, ad valorem, and severance taxes	10.08	5.11	*4.97*	
Total production expenses	21.78	15.08	*6.70*	*44%*
Other:				
Depletion, depreciation, and amortization	14.67	13.89	*0.78*	
Exploration	3.33	0.91	*2.42*	
General and administrative	3.32	1.64	*1.68*	
Derivative fair value loss	73.73	1.80	*71.93*	
Other operating	0.93	1.26	*(0.33)*	
Total operating	117.76	34.58	*83.18*	*241%*
Interest	4.83	7.39	*(2.56)*	
Income tax provision (benefit)	(6.13)	2.26	*(8.39)*	
Total expenses	$ 116.46	$ 44.23	*$ 72.23*	*163%*

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Production expenses. Total production expenses increased 33 percent from $56.8 million in the second quarter of 2007 to $75.7 million in the second quarter of 2008 as a result of a $6.70 increase in the per BOE rate, partially offset by an eight percent decrease in total production volumes.

Production expense attributable to LOE increased $3.1 million from $37.6 million in the second quarter of 2007 to $40.7 million in the second quarter of 2008 as a result of a $1.73 increase in the per BOE rate, which contributed approximately $6.0 million of additional LOE, partially offset by a decrease in production volumes, which reduced LOE by approximately $2.9 million. The increase in our LOE per BOE rate was attributable to:

- increases in prices paid to oilfield service companies and suppliers;
- increased operational activity to maximize production; and
- higher compensation levels for engineers and other technical professionals.

In May 2008, our Board approved a retention plan for all of our current employees, excluding members of our strategic team, providing for the payment of four months of base salary or base rate of pay, as applicable, upon the completion of the strategic alternatives process, subject to continued employment. We expect to pay this bonus in August 2008. In July 2008, our Board approved a separate retention plan for all of our current employees, excluding our Chairman and Chief Executive Officer, providing for the payment of eight months of base salary or base rate of pay, as applicable, in August 2009, subject to continued employment. We expect our LOE for the third quarter of 2008 to increase by approximately $1.12 per BOE for the bonuses to be paid in August 2008 and by approximately $0.47 per BOE for the bonuses to be paid in August 2009.

Production expense attributable to production, ad valorem, and severance taxes (production taxes) increased $15.8 million from $19.2 million in the second quarter of 2007 to $35.0 million in the second quarter of 2008 primarily due to higher wellhead revenues. As a percentage of oil and natural gas wellhead revenues, production taxes remained relatively constant at 9.8 percent in the second quarter of 2008 as compared to 9.9 percent in the second quarter of 2007.

Depletion, depreciation, and amortization (DD&A) expense. DD&A expense decreased $1.3 million from $52.3 million in the second quarter of 2007 to $51.0 million in the second quarter of 2008 as a result a decrease in production volumes, which reduced DD&A expense by approximately $4.0 million, partially offset by a $0.78 increase in the per BOE rate, which contributed approximately $2.7 million of additional DD&A expense. The increase in our average DD&A per BOE rate was attributable to the higher cost basis of the properties associated with our Williston Basin asset acquisition in April 2007, and higher costs incurred resulting from increases in rig rates, oilfield services costs, and acquisition costs.

Exploration expense. Exploration expense increased $8.2 million from $3.4 million in the second quarter of 2007 to $11.6 million in the second quarter of 2008. During the second quarter of 2008, we expensed 2 exploratory dry holes totaling $6.6 million. During the second quarter of 2007, we recognized $0.5 million of carryover expense related to exploratory wells that were determined to be dry holes in the first quarter of 2007. Impairment of unproved acreage through the normal course of evaluation increased $1.6 million from $2.6 million in the second quarter of 2007 to $4.2 million in the second quarter of 2008, as we continue to expand our acreage positions in certain areas and refine our estimated success rates. The following table illustrates the components of exploration expenses for the periods indicated:

	Three months ended June 30, 2008	Three months ended June 30, 2007	*Increase / (Decrease)*
	(in thousands)		
Dry holes	$ 6,612	$ 539	*$ 6,073*
Geological and seismic	455	94	*361*
Delay rentals	357	163	*194*

Impairment of unproved acreage	4,169	2,619	*1,550*
Total	$ 11,593	$ 3,415	*$ 8,178*

G&A expense. G&A expense increased $5.4 million from $6.2 million in the second quarter of 2007 to $11.6 million in the second quarter of 2008 primarily due to:

- an increase in non-cash equity-based compensation expense of $0.8 million;
- increased staffing to manage our larger asset base;
- $0.5 million of ENP public entity expenses;
- higher activity levels; and
- increased personnel costs due to intense competition for human resources within the industry.

In connection with the aforementioned retention bonuses, we expect our G&A for the third quarter of 2008 to increase by approximately $0.69 per BOE for the bonuses to be paid in August 2008 and by approximately $0.31 per BOE for the bonuses to be paid in August 2009.

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Derivative fair value loss. In the second quarter of 2008, we recorded a $256.4 million derivative fair value loss as compared to a loss of $6.8 million in the second quarter of 2007, the components of which were as follows:

	Three months ended June 30, 2008	2007	*Increase / (Decrease)*
	(in thousands)		
Mark-to-market loss (gain) on derivative contracts	$ 220,586	$ (1,008)	*$ 221,594*
Premium amortization	17,293	11,324	*5,969*
Settlements on commodity derivative contracts	18,511	(3,550)	*22,061*
Total derivative fair value loss	$ 256,390	$ 6,766	*$ 249,624*

Interest expense. Interest expense decreased $11.0 million from $27.8 million in the second quarter of 2007 to $16.8 million in the second quarter of 2008, primarily due to (1) the use of net proceeds from our Mid-Continent asset disposition and ENP s IPO to reduce outstanding borrowings on our revolving credit facilities and (2) a reduction in LIBOR. The weighted average interest rate for all long-term debt was 5.4 percent for the second quarter of 2008 as compared to 7.0 percent for the second quarter of 2007.

The following table illustrates the components of interest expense for the periods indicated:

	Three months ended June 30, 2008	2007	*Increase / (Decrease)*
	(in thousands)		
6.25% Notes	$ 2,431	$ 2,425	*$ 6*
6.0% Notes	4,636	4,627	*9*
7.25% Notes	2,749	2,747	*2*
Revolving credit facilities	7,215	17,396	*(10,181)*
Other	(246)	625	*(871)*
Total	$ 16,785	$ 27,820	*$ (11,035)*

Minority interest. As of June 30, 2008, public unitholders owned approximately 31.1 percent of ENP s common units. We include ENP s results of operations in our consolidated financial statements and show the public ownership as minority interest. Minority interest in the loss of ENP was approximately $15.0 million for the second quarter of 2008.

Income taxes. In the second quarter of 2008, we recorded an income tax benefit of $21.3 million as compared to an income tax provision of $8.5 million in the second quarter of 2007. In the second quarter of 2008, we had a loss before income taxes, net of minority interest, of $57.0 million as compared to income before income taxes of $23.7 million in the second quarter of 2007. Our effective tax rate increased to 37.4 percent in the second quarter of 2008 as compared to 36.0 percent in the second quarter of 2007, primarily due to a permanent rate adjustment for Section 199 production activities deduction that will not reverse in future periods.

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Comparison of Six Months Ended June 30, 2008 to Six Months Ended June 30, 2007

Oil and natural gas revenues. The following table illustrates the components of oil and natural gas revenues for the periods indicated, as well as each period s respective production volumes and average prices:

	Six months ended June 30,		Increase / (Decrease)	
	2008	2007	$	%
Revenues (in thousands):				
Oil wellhead	$ 510,315	$ 239,867	*$ 270,448*	
Oil commodity derivative contracts	(2,857)	(21,648)	*18,791*	
Total oil revenues	$ 507,458	$ 218,219	*$ 289,239*	*133%*
Natural gas wellhead	$ 116,201	$ 83,255	*$ 32,946*	
Natural gas commodity derivative contracts		(5,146)	*5,146*	
Total natural gas revenues	$ 116,201	$ 78,109	*$ 38,092*	*49%*
Combined wellhead	$ 626,516	$ 323,122	*$ 303,394*	
Combined commodity derivative contracts	(2,857)	(26,794)	*23,937*	
Total combined oil and natural gas revenues	$ 623,659	$ 296,328	*$ 327,331*	*110%*
Average realized prices:				
Oil wellhead ($/Bbl)	$ 102.81	$ 53.10	*$ 49.71*	
Oil commodity derivative contracts ($/Bbl)	(0.58)	(4.79)	*4.21*	
Total oil revenues ($/Bbl)	$ 102.23	$ 48.31	*$ 53.92*	*112%*
Natural gas wellhead ($/Mcf)	$ 9.73	$ 6.39	*$ 3.34*	
Natural gas commodity derivative contracts ($/Mcf)		(0.39)	*0.39*	
Total natural gas revenues ($/Mcf)	$ 9.73	$ 6.00	*$ 3.73*	*62%*
Combined wellhead ($/BOE)	$ 90.10	$ 48.30	*$ 41.80*	
Combined commodity derivative contracts ($/BOE)	(0.41)	(4.01)	*3.60*	
Total combined oil and natural gas revenues ($/BOE)	$ 89.69	$ 44.29	*$ 45.40*	*103%*
Total production volumes:				
Oil (MBbls)	4,964	4,517	*447*	*10%*

Natural gas (MMcf)	11,937	13,036	*(1,099)*	*-8%*
Combined (MBOE)	6,953	6,690	*263*	*4%*
Average daily production volumes:				
Oil (Bbls/D)	27,274	24,957	*2,317*	*9%*
Natural gas (Mcf/D)	65,586	72,022	*(6,436)*	*-9%*
Combined (BOE/D)	38,205	36,961	*1,244*	*3%*
Average NYMEX prices:				
Oil (per Bbl)	$ 111.02	$ 61.70	*$ 49.32*	*80%*
Natural gas (per Mcf)	$ 9.48	$ 7.16	*$ 2.32*	*32%*

Oil revenues increased 133 percent from $218.2 million in the first six months of 2007 to $507.5 million in the first six months of 2008 as a result of an increase in oil production volumes of 447 MBbls, which contributed approximately $23.7 million in additional oil revenues, and an increase in our average realized oil price. The increase in oil production volumes was primarily the result of our Big Horn Basin asset acquisition in March 2007, our Williston Basin asset acquisition in April 2007, and our development programs.

Our average realized oil price increased $53.92 per Bbl as a result of an increase in our wellhead price and a decrease in the effects of commodity derivative contracts that were previously designated as hedges. Our higher average oil wellhead price increased oil revenues by approximately $246.7 million, or $49.71 per Bbl, and the decrease in the effects of commodity derivative contracts that were previously designated as hedges increased oil revenues by approximately $18.8 million, or $4.21 per Bbl. Our average oil wellhead price increased as a result of increases in the overall market price for oil, as reflected in the increase in the average NYMEX price from $61.70 per Bbl in the first six months of 2007 to $111.02 per Bbl in the first six months of 2008.

Our oil wellhead revenue was reduced by $31.2 million and $10.2 million in the first six months of 2008 and 2007, respectively, for NPI payments related to our CCA properties.

Natural gas revenues increased 49 percent from $78.1 million for the first six months of 2007 to $116.2 million for the first six months of 2008 as a result of an increase in our average realized natural gas price, partially offset by a decrease in production volumes of 1,099 MMcf, which reduced natural gas revenues by approximately $7.0 million. The decrease in natural gas production volumes was primarily the result of our Mid-Continent asset disposition in June 2007 and an unscheduled third-party natural gas processing plant shutdown in New Mexico.

Our average realized natural gas price increased $3.73 per Mcf as a result of an increase in our wellhead price and a decrease in the effects of commodity derivative contracts that were previously designated as hedges. Our higher average natural gas wellhead price increased natural gas revenues by approximately $40.0 million, or $3.34 per Mcf, and the decrease in the effects of commodity derivative contracts that were previously designated as hedges increased natural gas revenues by approximately $5.1 million, or $0.39 per Mcf. Our average natural gas wellhead price increased as a result of increases in the overall market price for natural gas, as reflected in the increase in the average NYMEX price from $7.16 per Mcf in the first six months of 2007 to $9.48 per Mcf in the first six months of 2008.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices for the periods indicated. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Six months ended June 30,	
	2008	**2007**
Oil wellhead ($/Bbl)	$102.81	$53.10
Average NYMEX ($/Bbl)	$111.02	$61.70
Differential to NYMEX	$ (8.21)	$ (8.60)
Oil wellhead to NYMEX percentage	93%	86%
Natural gas wellhead ($/Mcf)	$ 9.73	$ 6.39
Average NYMEX ($/Mcf)	$ 9.48	$ 7.16
Differential to NYMEX	$ 0.25	$ (0.77)
Natural gas wellhead to NYMEX percentage	103%	89%

Our oil wellhead price as a percentage of the average NYMEX price improved to 93 percent for the first six months of 2008 as compared to 86 percent for the first six months of 2007. The differential improved because of term contracts based on a fixed differential of NYMEX and the subsequent strength of West Texas Intermediate, continued strong demand, and the relatively high price of oil sold into the Clearbrook, Minnesota market.

Our natural gas wellhead price as a percentage of the average NYMEX price improved to 103 percent for the first six months of 2008 as compared to 89 percent for the first six months of 2007. Certain of our natural gas marketing contracts determine the price that we are paid based on the value of the dry gas sold plus a portion of the value of liquids extracted. Since title of the natural gas sold under these contracts passes at the inlet of the processing plant, we report inlet volumes of natural gas in Mcf as production. From the first half of 2007 to the first half of 2008, the price of NGLs increased at a much faster pace than did the price of natural gas. As a result, the price we were paid per Mcf for natural gas sold under certain contracts increased to a level above NYMEX. This resulted in our overall natural gas differential to NYMEX swinging from a negative in the first half of 2007 to a slight positive in the first half of 2008.

Marketing revenues and expenses. In 2007, we discontinued purchasing oil from third party companies as market conditions changed and pipeline space was gained. Implementing this change allowed us to focus on the marketing of our own oil production, leveraging newly gained pipeline space, and delivering oil to various newly developed markets in an effort to maximize the value of the oil at the wellhead.

In March 2007, ENP acquired a natural gas pipeline from Anadarko as part of the Big Horn Basin asset acquisition. Natural gas volumes are purchased from numerous gas producers at the inlet to the pipeline and resold downstream to various local and off-system markets. Marketing expenses in 2008 include pipeline tariffs, storage, truck facility fees, and tank bottom costs used to support the sale of equity crude, the revenues of which are included in our oil revenues instead of marketing revenues.

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The following table summarizes our marketing activities for the periods indicated:

	Six months ended June 30, 2008	Six months ended June 30, 2007	Increase / (Decrease) $	Increase / (Decrease) %
	($ in thousands, except per BOE amounts)			
Marketing revenues	$ 6,577	$ 23,857	$ (17,280)	-72%
Marketing expenses	(7,507)	(23,518)	16,011	-68%
Marketing gain (loss)	$ (930)	$ 339	$ (1,269)	-374%
Marketing revenues per BOE	$ 0.95	$ 3.57	$ (2.62)	-73%
Marketing expenses per BOE	(1.08)	(3.52)	2.44	-69%
Marketing gain (loss) per BOE	$ (0.13)	$ 0.05	$ (0.18)	-360%

Expenses. The following table summarizes our expenses, excluding marketing expenses shown above, for the periods indicated:

	Six months ended June 30, 2008	Six months ended June 30, 2007	Increase / (Decrease) $	Increase / (Decrease) %
Expenses (in thousands):				
Production:				
Lease operations	$ 81,047	$ 68,072	$ 12,975	
Production, ad valorem, and severance taxes	62,495	31,747	30,748	
Total production expenses	143,542	99,819	43,723	44%
Other:				
Depletion, depreciation, and amortization	100,569	87,346	13,223	
Exploration	17,081	14,936	2,145	
General and administrative	21,246	13,548	7,698	
Derivative fair value loss	321,528	52,380	269,148	
Other operating	5,732	7,316	(1,584)	
Total operating	609,698	275,345	334,353	121%
Interest	36,545	44,107	(7,562)	
Income tax benefit	(2,589)	(7,496)	4,907	
Total expenses	$ 643,654	$ 311,956	$ 331,698	106%
Expenses (per BOE):				
Production:				
Lease operations	$ 11.66	$ 10.18	$ 1.48	
Production, ad valorem, and severance taxes	8.99	4.75	4.24	

Total production expenses	20.65	14.93	*5.72*	*38%*
Other:				
Depletion, depreciation, and amortization	14.46	13.06	*1.40*	
Exploration	2.46	2.23	*0.23*	
General and administrative	3.06	2.03	*1.03*	
Derivative fair value loss	46.24	7.83	*38.41*	
Other operating	0.82	1.09	*(0.27)*	
Total operating	87.69	41.17	*46.52*	*113%*
Interest	5.26	6.59	*(1.33)*	
Income tax benefit	(0.37)	(1.12)	*0.75*	
Total expenses	$ 92.58	$ 46.64	*$ 45.94*	*98%*

Production expenses. Total production expenses increased 44 percent from $99.8 million in the first six months of 2007 to $143.5 million in the first six months of 2008 as a result of a four percent increase in total production volumes and a $5.72 increase in the per BOE rate.

Production expense attributable to LOE increased $13.0 million from $68.1 million in the first six months of 2007 to $81.0 million in the first six months of 2008 as a result of an increase in production volumes, which contributed approximately $2.7 million of additional LOE, and a $1.48 increase in the per BOE rate, which contributed approximately $10.3 million of

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additional LOE. The increase in our LOE per BOE rate was attributable to:

- increases in prices paid to oilfield service companies and suppliers;
- increased operational activity to maximize production; and
- higher compensation levels for engineers and other technical professionals.

Production expense attributable to production taxes increased $30.7 million from $31.7 million in the first six months of 2007 to $62.5 million in the first six months of 2008 primarily due to higher wellhead revenues. As a percentage of oil and natural gas wellhead revenues, production taxes remained relatively constant at 10.0 percent in the first six months of 2008 as compared to 9.8 percent in the first six months of 2007.

DD&A expense. DD&A expense increased $13.2 million from $87.3 million in the first six months of 2007 to $100.6 million in the first six months of 2008 as a result of a $1.40 increase in the per BOE rate, which contributed approximately $9.8 million of additional DD&A expense, and an increase in production volumes, which contributed approximately $3.4 million of additional DD&A expense. The increase in our average DD&A per BOE rate was attributable to the higher cost basis of the properties associated with our Big Horn Basin asset acquisition in March 2007 and our Williston Basin asset acquisition in April 2007, and higher costs incurred resulting from increases in rig rates, oilfield services costs, and acquisition costs.

Exploration expense. Exploration expense increased $2.1 million from $14.9 million in the first six months of 2007 to $17.1 million in the first six months of 2008. During the first six months of 2008, we expensed 4 exploratory dry holes totaling $7.2 million. During the first six months of 2007, we expensed 3 exploratory dry holes totaling $9.0 million. Impairment of unproved acreage through the normal course of evaluation increased $3.5 million from $4.9 million in the first six months of 2007 to $8.3 million in the first six months of 2008, as we continued to expand our acreage positions in certain areas and refine our estimated success rates. The following table illustrates the components of exploration expenses for the periods indicated:

	Six months ended June 30, 2008	Six months ended June 30, 2007	*Increase / (Decrease)*
	(in thousands)		
Dry holes	$ 7,234	$ 9,020	*$ (1,786)*
Geological and seismic	833	725	*108*
Delay rentals	703	341	*362*
Impairment of unproved acreage	8,311	4,850	*3,461*
Total	$ 17,081	$ 14,936	*$ 2,145*

G&A expense. G&A expense increased $7.7 million from $13.5 million in the first six months of 2007 to $21.2 million in the first six months of 2008 primarily due to:

- an increase in non-cash equity-based compensation expense of $0.5 million;
- increased staffing to manage our larger asset base;
- $1.2 million of ENP public entity expenses;
- higher activity levels; and
- increased personnel costs due to intense competition for human resources within the industry.

Derivative fair value loss. In the first six months of 2008, we recorded a $321.5 million derivative fair value loss as compared to a loss of $52.4 million in the first six months of 2007, the components of which were as follows:

	Six months ended June 30,		***Increase / (Decrease)***
	2008	**2007**	
	(in thousands)		
Mark-to-market loss on derivative contracts	$ 266,984	$ 46,437	*$ 220,547*
Premium amortization	32,806	17,688	*15,118*
Settlements on commodity derivative contracts	21,738	(11,745)	*33,483*
Total derivative fair value loss	$ 321,528	$ 52,380	$ 269,148

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Interest expense. Interest expense decreased $7.6 million from $44.1 million in the first six months of 2007 to $36.5 million in the first six months of 2008, primarily due to (1) the use of net proceeds from our Mid-Continent asset disposition and ENP s IPO to reduce outstanding borrowings on our revolving credit facilities and (2) a reduction in LIBOR. The weighted average interest rate for all long-term debt was 5.9 percent for the first six months of 2008 as compared to 7.0 percent for the first six months of 2007.

The following table illustrates the components of interest expense for the periods indicated:

	Six months ended June 30,		Increase /
	2008	2007	(Decrease)
	(in thousands)		
6.25% Notes	$ 4,861	$ 4,850	*$ 11*
6.0% Notes	9,271	9,255	*16*
7.25% Notes	5,497	5,493	*4*
Revolving credit facilities	15,605	23,022	*(7,417)*
Other	1,311	1,487	*(176)*
Total	$ 36,545	$ 44,107	*$ (7,562)*

Minority interest. Minority interest in the loss of ENP was approximately $14.9 million for the first six months of 2008.

Income taxes. In the first six months of 2008, we recorded an income tax benefit of $2.6 million as compared to $7.5 million in the first six months of 2007. In the first six months of 2008, we had a loss before income taxes, net of minority interest, of $7.1 million as compared to $21.8 million in the first six months of 2007. Our effective tax rate increased to 36.5 percent for the first six months of 2008 as compared to 34.5 percent for the first six months of 2007, primarily due to a permanent rate adjustment for Section 199 production activities deduction that will not reverse in future periods.

Capital Commitments, Capital Resources, and Liquidity

Capital commitments. Our primary needs for cash are:

Development, exploitation, and exploration of oil and natural gas properties;

Acquisitions of oil and natural gas properties;

Funding of necessary working capital; and

Contractual obligations.

Development, exploitation, and exploration of oil and natural gas properties. The following table summarizes our costs incurred (excluding asset retirement obligations) related to development, exploitation, and exploration activities for the periods indicated:

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
	(in thousands)			
Development and exploitation	$ 76,876	$ 75,019	$ 134,248	$ 138,517
Exploration	65,431	19,005	109,257	50,223
Total	$ 142,307	$ 94,024	$ 243,505	$ 188,740

Our development and exploitation expenditures primarily relate to drilling development and infill wells, workovers of existing wells, and field related facilities. Our development and exploitation capital for the second quarter of 2008 yielded 35 gross (13.5 net) successful wells and 2 gross (0.5 net) dry holes. Our development and exploitation capital for the first six months of 2008 yielded 83 gross (25.1 net) successful wells and 3 gross (1.4 net) dry holes.

Our exploration expenditures primarily relate to drilling exploratory wells, seismic costs, delay rentals, and geological and geophysical costs. Our exploration capital for the second quarter of 2008 yielded 25 gross (7.5 net) successful wells and 2 gross (2 net) dry holes. Our exploration capital for the first six months of 2008 yielded 51 gross (13.7 net) successful wells and 4 gross (2.5 net) dry holes.

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Acquisitions of oil and natural gas properties and leasehold acreage. The following table summarizes our costs incurred (excluding asset retirement obligations) related to oil and natural gas property acquisitions for the periods indicated:

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
	(in thousands)			
Acquisitions of proved property	$ 5,687	$ 365,909	$ 20,468	$ 761,885
Acquisitions of leasehold acreage	18,642	20,528	34,641	23,783
Total	$ 24,329	$ 386,437	$ 55,109	$ 785,668

In March 2007, Encore Operating and OLLC acquired oil and natural gas properties in the Big Horn Basin, including properties in the Elk Basin and the Gooseberry fields for approximately $393.3 million. In April 2007, we acquired oil and natural gas properties in the Williston Basin for approximately $393.7 million.

During the three and six months ended June 30, 2008, our capital expenditures for leasehold acreage totaled $18.6 million and $34.6 million, respectively, all of which related to the acquisition of unproved acreage in various areas. During the three and six months ended June 30, 2007, our capital expenditures for leasehold acreage totaled $20.5 million and $23.8 million, respectively. Of these amounts, $16.1 million related to the Williston Basin asset acquisition and the remainder related to the acquisition of unproved acreage in various areas.

Funding of necessary working capital. As of June 30, 2008 and December 31, 2007, our working capital (defined as total current assets less total current liabilities) was negative $109.2 million and negative $16.2 million, respectively. The decrease was primarily attributable to an increase in commodity prices, which negatively impacted the fair value of our outstanding derivative contracts, partially offset by an increase in accounts receivable as a result of increased oil and natural gas revenues.

For the remainder of 2008, we expect working capital to remain negative, primarily due to the fair values of our commodity derivative contracts and deferred commodity derivative contract premiums. We anticipate cash reserves to be close to zero because we intend to use any excess cash to fund capital obligations and reduce outstanding borrowings and related interest expense under our revolving credit facility. However, we have significant availability under our revolving credit facility to fund our obligations as they become due. We do not plan to pay cash dividends in the foreseeable future. Our production volumes, commodity prices, and differentials for oil and natural gas will be the largest variables affecting working capital. Our operating cash flow is determined in large part by production volumes and commodity prices. Assuming relatively stable commodity prices and constant or increasing production volumes, our operating cash flow should remain positive for the remainder of 2008.

The Board approved a capital budget of $445 million for 2008. 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 and borrowings under our revolving credit facility.

Off-balance sheet arrangements. We have no investments in unconsolidated entities or persons that could materially affect our liquidity or availability of capital resources. Other than those described below under Contractual obligations and undrawn letters of credit related to our revolving credit facilities, we do not have any off-balance sheet arrangements that are material to our financial position or results of operations.

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Contractual obligations. The following table illustrates our contractual obligations and commitments at June 30, 2008:

		Payments Due by Period			
Contractual Obligations and Commitments	**Total**	**Six Months Ending December 31, 2008**	**Years Ending December 31, 2009 - 2010**	**Years Ending December 31, 2011 - 2012**	**Thereafter**
			(in thousands)		
6.25% Notes (a)	$ 206,250	$ 4,687	$ 18,750	$ 18,750	$ 164,063
6.0% Notes (a)	435,000	9,000	36,000	36,000	354,000
7.25% Notes (a)	253,313	5,438	21,750	21,750	204,375
Revolving credit facilities (a)	625,393	10,690	42,760	571,943	
Commodity derivative contracts (b)	329,233	116,723	193,288	19,222	
Interest rate swaps	106	106			
Development commitments (c)	104,587	55,623	48,964		
Operating leases and commitments (d)	19,251	1,943	6,727	6,642	3,939
Asset retirement obligations (e)	154,758	336	1,344	1,344	151,734
Total	$ 2,127,891	$ 204,546	$ 369,583	$ 675,651	$ 878,111

(a) Amounts include principal and projected interest payments. Please read Note 9 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our long-term debt.

(b) Represents our net liabilities for commodity derivative contracts. With the exception of $58.1 million of deferred premiums on commodity derivative contracts, the ultimate settlement amounts of our commodity derivative contracts are unknown because they are subject to continuing market risk. Please read "Item 3. Quantitative and Qualitative Disclosures about Market Risk" and Notes 6 and 7 of Notes to Consolidated Financial Statements included in "Item 1. Financial Statements" for additional information regarding our commodity derivative contracts.

(c) Development commitments include: authorized purchases for work in process of $79.1 million; future minimum payments for drilling rig operations of $24.5 million; and $1.0 million for minimum capital obligations associated with the remaining one commitment wells to be drilled under our joint development agreement with ExxonMobil. Also at June 30, 2008, we had approximately $232.5 million of authorized purchases not placed with 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 $15.6 million and future minimum payments for other operating commitments of $3.6 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 end of field life. Please read Note 8 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 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. Alternative transportation routes and markets have been developed by moving a portion of the crude oil production through the Enbridge Pipeline to the Clearbrook, Minnesota hub. In addition, we have identified new markets to the west 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 the Platte Pipeline to Wood River, Illinois as well as other pipelines connected to the Guernsey, Wyoming area. While shipments on the Platte Pipeline are currently oversubscribed and have been subject to apportionment since December 2005, we were allocated sufficient pipeline capacity to move our equity crude oil production effective January 1, 2007. Enbridge Pipeline North Dakota completed an expansion of their pipeline in January 2008. The expansion has provided a small degree of stability to oil differentials by effectively moving the total Rockies area pipeline takeaway closer to a balancing point with increasing production volumes. In spite of the increase in capacity, the Enbridge Pipeline North Dakota continues to run at capacity and is scheduled to complete an additional expansion by the beginning of 2010. 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 begin widening, which is historically common, in the third quarter of 2008 as compared to the $7.08 per Bbl differential we realized in the second quarter of 2008. 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 affected this differential. Natural gas differentials are expected to remain approximately constant or to slightly widen in the third quarter of 2008 as compared to the

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$0.18 per Mcf differential we realized in the second quarter of 2008. We cannot accurately predict future crude oil and natural gas differentials. 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.

Capital resources

Cash flows from operating activities. Cash provided by operating activities increased $271.0 million from $81.3 million for the first six months of 2007 to $352.3 million for the first six months of 2008, primarily due to an increase in our production margin, partially offset by increased settlements on our commodity derivative contracts as a result of increases in oil and natural gas prices and an increase in accounts receivable as a result of increased oil and natural gas sales.

Cash flows from investing activities. Cash used in investing activities decreased $394.7 million from $701.1 million in the first six months of 2007 to $306.4 million in the first six months of 2008, primarily due to a $730.3 million decrease in amounts paid for the acquisition of oil and natural gas properties, partially offset by a $290.8 million decrease in proceeds from the disposition of assets. In March 2007, Encore Operating and OLLC paid approximately $393.3 million in conjunction with the Big Horn Basin asset acquisition and in April 2007, we paid approximately $393.7 million in conjunction with the Williston Basin asset acquisition. In June 2007, we completed the sale of certain oil and natural gas properties in the Mid-Continent for net proceeds of approximately $293.6 million. During the first six months of 2008, we advanced $22.9 million (net of collections) to ExxonMobil for their portion of costs incurred drilling the commitment wells under the joint development agreement as compared to $24.2 million in the first six months of 2007.

Cash flows from financing activities. Our cash flows from financing activities consist primarily of proceeds from and payments on long-term debt. We periodically draw on our revolving credit facility to fund acquisitions and other capital commitments.

During the first six months of 2008, we used net cash of $46.0 million in financing activities. During the first six months of 2008, we had net borrowings on our revolving credit facilities of $19.8 million, which resulted in an increase in outstanding borrowings under our revolving credit facilities from $526 million at December 31, 2007 to $547 million at June 30, 2008.

In December 2007, we announced that the Board approved a share repurchase program authorizing us to repurchase up to $50 million of our common stock. As of June 30, 2008, we had repurchased and retired 1,174,691 shares of our outstanding common stock for approximately $39.1 million, or an average price of $33.30 per share, under the share repurchase program.

During the first six months of 2007, we received net cash of $624.0 million from financing activities, including net borrowings on our revolving credit facilities of $627.5 million, most of which was used to finance the Big Horn Basin and Williston Basin asset acquisitions.

Liquidity. Our primary sources of liquidity are internally generated cash flows and the borrowing capacity under our revolving credit facility. 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 acquisitions or maintain our financial flexibility.

Internally generated cash flows. Our internally generated cash flows, results of operations, and financing for our operations are largely dependent on oil and natural gas prices. During the first six months of 2008, our average realized oil and natural gas prices increased by approximately 112 percent and 62 percent, respectively, as compared to the first six months of 2007. Realized oil and natural gas prices fluctuate widely in response to changing market forces. For the first six months of 2008, approximately 71 percent of our production was oil. As we previously discussed, our oil and natural gas wellhead differentials during the first six months of 2008 improved as compared to the first six months of 2007, favorably impacting the prices we received for our production. To the extent oil and natural gas prices decline or we experience a significant widening of our wellhead differentials, our earnings, cash flows from operations, and availability under our revolving credit facility may be adversely impacted. Prolonged periods of lower oil and natural gas prices or sustained wider wellhead differentials could cause us to not be in compliance with financial covenants under our revolving credit facility and thereby affect our liquidity.

We believe that our internally generated cash flows and availability under our revolving credit facility will be sufficient to fund our planned capital expenditures for the foreseeable future.

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Revolving credit facilities. Our principal source of short-term liquidity is our revolving credit facility.

Encore Acquisition Company Senior Secured Credit Agreement

In March 2007, we entered into a five-year amended and restated credit agreement (as amended, the EAC Credit Agreement) with a bank syndicate including Bank of America, N.A. and other lenders. Effective February 7, 2008, we amended the EAC Credit Agreement to, among other things, provide that certain negative covenants in the EAC Credit Agreement restricting hedge transactions do not apply to any oil and natural gas hedge transaction that is a floor or put transaction not requiring any future payments or delivery by us or any of our restricted subsidiaries. Effective May 22, 2008, we amended the EAC Credit Agreement to, among other things, increase the margins applicable to the ratio of total outstanding borrowings to borrowing base, as noted in the table below, and increase the borrowing base to $1.1 billion. The EAC Credit Agreement provides for revolving credit loans to be made to us from time to time and letters of credit to be issued from time to time for our account or any of our restricted subsidiaries.

The aggregate amount of the commitments of the lenders under the EAC Credit Agreement is $1.25 billion. Availability under the EAC Credit Agreement is subject to a borrowing base, which is redetermined semi-annually and upon requested special redeterminations. As of June 30, 2008, the borrowing base was $1.1 billion.

Our obligations under the EAC Credit Agreement are secured by a first-priority security interest in our restricted subsidiaries proved oil and natural gas reserves and in our equity interests in our restricted subsidiaries. In addition, our obligations under the EAC Credit Agreement are guaranteed by our restricted subsidiaries.

Loans under the EAC Credit Agreement are subject to varying rates of interest based on (1) the total amount outstanding in relation to the borrowing base and (2) 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 Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans
Less than .50 to 1	1.250%	0.000%
Greater than or equal to .50 to 1 but less than .75 to 1	1.500%	0.250%
Greater than or equal to .75 to 1 but less than .90 to 1	1.750%	0.500%
Greater than or equal to .90 to 1	2.000%	0.750%

The Eurodollar rate for any interest period (either one, two, three, or six months, as selected by us) 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 (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate and (2) the federal funds effective rate plus 0.5 percent.

Any outstanding letters of credit reduce the availability under the EAC Credit Agreement. Borrowings under the EAC Credit Agreement may be repaid from time to time without penalty.

The EAC 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 our and our 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, or 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 we maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0; and

a requirement that we maintain a ratio of consolidated EBITDA (as defined in the EAC Credit Agreement) to the sum of

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consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0.

The EAC 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 EAC Credit Agreement to be immediately due and payable.

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

Ratio of Total Outstanding Borrowings to Borrowing Base	Commitment Fee Percentage
Less than .50 to 1	0.250%
Greater than or equal to .50 to 1 but less than .75 to 1	0.300%
Greater than or equal to .75 to 1	0.375%

On June 30, 2008, there were $396 million of outstanding borrowings and $704 million of borrowing capacity under the EAC Credit Agreement. On August 1, 2008, there were $460 million of outstanding borrowings and $640 million of borrowing capacity under the EAC Credit Agreement.

Encore Energy Partners Operating LLC Credit Agreement

OLLC is a party to a five-year credit agreement dated March 7, 2007 (as amended, the OLLC Credit Agreement) with a bank syndicate including Bank of America, N.A. and other lenders. On August 22, 2007, OLLC amended its credit agreement to revise certain financial covenants. The OLLC Credit Agreement provides for revolving credit loans to be made to OLLC from time to time and letters of credit to be issued from time to time for the account of OLLC or any of its restricted subsidiaries.

The aggregate amount of the commitments of the lenders under the OLLC Credit Agreement is $300 million. Availability under the OLLC Credit Agreement is subject to a borrowing base, which is redetermined semi-annually and upon requested special redeterminations. As of June 30, 2008, the borrowing base was $240 million.

OLLC s obligations under the OLLC Credit Agreement are secured by a first-priority security interest in OLLC s proved oil and natural gas reserves and in OLLC s equity interests in its restricted subsidiaries. In addition, OLLC s obligations under the OLLC Credit Agreement are guaranteed by ENP and OLLC s restricted subsidiaries. We consolidate the debt of ENP with that of our own; however, obligations under the OLLC Credit Agreement are non-recourse to us and our restricted subsidiaries.

Loans under the OLLC Credit Agreement are subject to varying rates of interest based on (1) the total amount outstanding in relation to the borrowing base and (2) 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 Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans
Less than .50 to 1	1.000%	0.000%
Greater than or equal to .50 to 1 but less than .75 to 1	1.250%	0.000%
Greater than or equal to .75 to 1 but less than .90 to 1	1.500%	0.250%
Greater than or equal to .90 to 1	1.750%	0.500%

The Eurodollar rate for any interest period (either one, two, three, or six months, as selected by us) 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 (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate and (2) the federal funds effective rate plus 0.5 percent.

Any outstanding letters of credit reduce the availability under the OLLC Credit Agreement. Borrowings under the OLLC Credit Agreement may be repaid from time to time without penalty.

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

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against purchasing or redeeming capital stock, or prepaying indebtedness, subject to permitted exceptions;
- a restriction on creating liens on the assets of ENP, OLLC 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, or 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 OLLC maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0;
- a requirement that OLLC maintain a ratio of consolidated EBITDA (as defined in the OLLC Credit Agreement) to the sum of consolidated net interest expense plus letter of credit fees of not less than 1.5 to 1.0;
- a requirement that OLLC maintain a ratio of consolidated EBITDA (as defined in the OLLC Credit Agreement) to consolidated senior interest expense of not less than 2.5 to 1.0; and
- a requirement that OLLC maintain a ratio of consolidated funded debt (excluding certain related party debt) to consolidated adjusted EBITDA (as defined in the OLLC Credit Agreement) of not more than 3.5 to 1.0.

The OLLC 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 OLLC Credit Agreement to be immediately due and payable.

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

Ratio of Total Outstanding Borrowings to Borrowing Base	Commitment Fee Percentage
Less than .50 to 1	0.250%
Greater than or equal to .50 to 1 but less than .75 to 1	0.300%
Greater than or equal to .75 to 1	0.375%

On June 30, 2008, there were $151 million of outstanding borrowings, approximately $0.1 million of outstanding letters of credit, and $88.9 million of borrowing capacity under the OLLC Credit Agreement. On August 1, 2008, there were $140 million of outstanding borrowings, approximately $0.1 million of outstanding letters of credit, and $99.9 million of borrowing capacity under the OLLC Credit Agreement.

Please read Note 9 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our long-term debt.

Debt covenants. At June 30, 2008, we and ENP were in compliance with all debt covenants.

Current capitalization. At June 30, 2008, we had total assets of $3.1 billion and total capitalization of $2.1 billion, of which 45 percent was represented by stockholders equity and 55 percent by long-term debt. At December 31, 2007, we had total assets of $2.8 billion and total capitalization of $2.1 billion, of which 46 percent was represented by stockholders equity and 54 percent by long-term debt. The percentages of our capitalization represented by stockholders equity and long-term debt could vary in the future if debt or equity is used to finance capital projects or acquisitions.

Critical Accounting Policies and Estimates

Please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates in our 2007 Annual Report on Form 10-K for additional information regarding our critical accounting policies and estimates.

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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 2007 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 commodity derivative contracts as of June 30, 2008 are discussed in Notes 6 and 7 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements. As of June 30, 2008, the fair market value of our oil and natural gas commodity derivative contracts was a net liability of approximately $236.4 million and $24.1 million, respectively. Based on our open commodity derivative positions at June 30, 2008, a $1.00 increase in the respective NYMEX prices for oil and natural gas would increase our net derivative fair value liability by approximately $11.8 million, while a $1.00 decrease in the respective NYMEX prices for oil and natural gas would decrease our net derivative fair value liability by approximately $11.8 million. These amounts exclude deferred premiums of $58.1 million that are not subject to changes in commodity prices.

Interest Rate Sensitivity

At June 30, 2008, we had total long-term debt of $1.1 billion, net of discount of $5.5 million. Of this amount, $150 million bears interest at a fixed rate of 6.25 percent, $300 million bears interest at a fixed rate of 6.0 percent, and $150 million bears interest at a fixed rate of 7.25 percent. The remaining long-term debt balance of $547 million consists of outstanding borrowings on 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 $5.5 million of interest expense per year on our revolving credit facilities, and if LIBOR decreased one percent, we would incur $5.5 million less. Additionally, if LIBOR increased one percent, we estimate the fair value of our fixed rate debt at June 30, 2008 would decrease from approximately $684.1 million to approximately $642.6 million, and if LIBOR decreased one percent, we estimate the fair value would increase to approximately $729.1 million.

ENP s outstanding interest rate swaps as of June 30, 2008 are discussed in Notes 6 and 7 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements. As of June 30, 2008, the unrealized gain on interest rate swaps was approximately $0.4 million and is included in AOCI in our Consolidated Balance Sheet. As of June 30, 2008, the fair market value of ENP s interest rate swaps was a net asset of approximately $1.4 million. If LIBOR increased one percent, we estimate the fair value of ENP s interest rate swaps at June 30, 2008 would increase to approximately $3.8 million, and if LIBOR decreased one percent, we estimate the fair value would decrease to a net liability of approximately $1.2 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 June 30, 2008. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2008 to ensure 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 and that information required to be disclosed is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

There were no changes in our internal control over financial reporting during the second quarter of 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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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 our results of operations or financial position.

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 2007 Annual Report on Form 10-K, which could materially affect our business, financial condition, and/or future results. The risks described in our 2007 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 may also 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

In December 2007, we announced that the Board approved a share repurchase program authorizing us to repurchase up to $50 million of our common stock. The following table summarizes purchases of our common stock during the second quarter of 2008:

Month	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs
April		$		
May		$		
June		$		
Total		$		$ 10,881,107

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

Our annual meeting of stockholders was held on May 6, 2008. The items submitted to stockholders for vote were (1) the election of eight nominees to serve as directors until our next annual meeting, (2) the approval of the 2008 Incentive Stock Plan, and (3) the ratification of Ernst & Young LLP as our independent registered public accounting firm for 2008. Notice of the meeting and proxy information was distributed to stockholders prior to the meeting in accordance with law. There were no solicitations in opposition to the nominees. Out of a total of 53,181,112 shares of our common stock outstanding and entitled to vote at the meeting, 48,998,748 shares (92.1 percent) were present in person or by proxy.

Election of Directors

The Board recommended that our stockholders elect all eight nominees to serve as our directors until our next annual meeting. The vote tabulation with respect to each nominee to the Board was as follows:

NOMINEE	FOR	WITHHELD
I. Jon Brumley	48,107,197	891,551
Jon S. Brumley	48,211,258	787,490
John A. Bailey	48,174,763	823,985

Martin C. Bowen	44,932,990	4,065,758
Ted Collins, Jr.	44,847,682	4,151,066
Ted A. Gardner	48,174,773	823,975
John V. Genova	48,174,773	823,975
James A. Winne III	44,807,182	4,191,566

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Approval of the 2008 Incentive Stock Plan

The Board recommended that our stockholders approve the 2008 Incentive Stock Plan. The vote tabulation with respect to the approval of the 2008 Incentive Stock Plan was as follows:

FOR	AGAINST	ABSTAIN
39,528,616	5,249,991	353,689

Appointment of Independent Registered Public Accounting Firm

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

FOR	AGAINST	ABSTAIN
48,598,081	53,587	347,080

Item 5. Other Information

In July 2008, our Board approved a retention plan for all of our current employees, excluding our Chairman of the Board and Chief Executive Officer, providing for the payment of eight months of base salary or base rate of pay, as applicable, in August 2009, subject to continued employment.

Item 6. Exhibits

Exhibits	
3.1	Second Amended and Restated Certificate of Incorporation of Encore Acquisition Company (incorporated by reference from EAC s Quarterly Report on Form 10-Q for the 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 Encore Acquisition Company (incorporated by reference from EAC s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, filed with the SEC on May 5, 2005).
3.2	Second Amended and Restated Bylaws of Encore Acquisition Company (incorporated by reference from EAC s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, filed with the SEC on November 7, 2001).
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).
99.1*	Statement showing computation of ratios of earnings (loss) to fixed charges.
99.2*	Second Amendment to Amended and Restated Credit Agreement, dated as of May 22, 2008, by and among Encore Acquisition Company, Encore Operating, L.P., Bank of America, N.A., as administrative agent and L/C Issuer, and the lenders party thereto.

* Filed herewith.

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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: August 8, 2008

/s/ Andrea Hunter
Andrea Hunter
Vice President, Controller, and Principal
Accounting Officer