ENCORE ACQUISITION CO
Form 10-Q
November 02, 2009

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

(Mark One)

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

For the quarterly period ended September 30, 2009

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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes o 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.

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

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 October 27, 2009	55,541,823

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain information included in this Quarterly Report on Form 10-Q (the Report) and our other materials filed with the United States Securities and Exchange Commission (SEC), or in other written or oral statements made or to be made by us, other than statements of historical fact, are forward-looking statements as defined by the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. These forward-looking statements give our current expectations or forecasts of future events. 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, believe, should, predict, potential, pursue, target, cont terms of similar meaning. You are cautioned not to place 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 and elsewhere in our 2008 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 summarized from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X.

ASC. FASB Accounting Standards Codification.

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 nine 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 hydrocarbons.

Council of Petroleum Accountants Societies (COPAS). A professional organization of petroleum 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 or Unsuccessful Well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production costs.

EAC. Encore Acquisition Company, a publicly traded 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 hydrocarbons in an unproved area, to find a new reservoir in a field previously producing hydrocarbons in another reservoir, or to extend a known reservoir.

FASB. Financial Accounting Standards Board.

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.

GAAP. Accounting principles generally accepted in the United States.

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

Lease Operating Expense (LOE). All direct and allocated indirect costs of producing hydrocarbons after the completion of drilling and before the commencement of production. 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 Production. Production owned by an entity less royalties, net profits interests, and production due others.

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

NYMEX. New York Mercantile Exchange.

Oil. Crude oil, condensate, and NGLs.

Operator. The entity responsible for the exploration, development, and production of a well or lease.

Production Margin. Wellhead revenues less production costs.

Production Taxes. Production expense attributable to production, ad valorem, and severance taxes.

Productive Well or Successful Well. A well capable of producing hydrocarbons in commercial quantities, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.

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 hydrocarbons that geological and engineering data demonstrate with reasonable certainty are recoverable in future periods from known reservoirs under existing economic and operating conditions.

Proved Undeveloped Reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage 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 for recompletion. Includes unrealized production response from enhanced recovery techniques that have been proved effective by actual tests in the area and in the same reservoir.

Recompletion. The completion for production from an existing wellbore in another formation from that in which the well has been previously completed.

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

Royalty. An interest in an oil and natural gas lease that gives the owner the right to receive a portion of the production from the leased acreage (or of the proceeds from the sale thereof), but does not require the owner to pay any portion of the production or development costs on the leased acreage. Royalties may be either landowner s royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

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. Involves maintaining or enhancing reservoir pressure by injecting water, gas, or other substances into the formation in order to displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are gas injection and waterflooding.

SFAS. Statement of Financial Accounting Standards.

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

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 hydrocarbons 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 par value amounts)

	September 30, 2009 (unaudited)	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 6,683	$ 2,039
Accounts receivable, net of allowance for doubtful accounts of $434 and $381, respectively	104,980	117,995
Current portion of long-term receivables	8,325	11,070
Inventory	24,593	24,798
Derivatives	51,974	349,344
Income taxes	9,801	29,445
Other	7,310	6,239
Total current assets	213,666	540,930
Properties and equipment, at cost successful efforts method:		
Proved properties, including wells and related equipment	4,146,881	3,538,459
Unproved properties	104,931	124,339
Accumulated depletion, depreciation, and amortization	(985,349)	(771,564)
	3,266,463	2,891,234
Other property and equipment	28,598	25,192
Accumulated depreciation	(16,100)	(12,753)
	12,498	12,439
Goodwill	60,606	60,606
Derivatives	47,694	38,497
Long-term receivables, net of allowance for doubtful accounts of $13,725 and $7,643, respectively	53,454	60,915
Other	59,433	28,574
Total assets	$ 3,713,814	$ 3,633,195
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 10,412	$ 10,017

Accrued liabilities:				
Lease operating		18,115		19,108
Development capital		48,266		79,435
Interest		21,839		11,808
Production, ad valorem, and severance taxes		34,475		25,133
Compensation		9,434		16,216
Derivatives		37,238		63,476
Oil and natural gas revenues payable		16,658		10,821
Deferred taxes		63,968		105,768
Other		15,202		10,470
Total current liabilities		275,607		352,252
Derivatives		39,370		8,922
Future abandonment cost, net of current portion		51,664		48,058
Deferred taxes		431,075		416,915
Long-term debt		1,243,496		1,319,811
Other		3,837		3,989
Total liabilities		2,045,049		2,149,947
Commitments and contingencies (see Note 15)				
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, 54,621,701 and 51,551,937 issued and outstanding, respectively		546		516
Additional paid-in capital		666,386		525,763
Treasury stock, at cost, none and 4,753 shares, respectively				(101)
Retained earnings		728,299		789,698
Accumulated other comprehensive loss		(1,184)		(1,748)
Total EAC stockholders equity		1,394,047		1,314,128
Noncontrolling interest		274,718		169,120
Total equity		1,668,765		1,483,248
Total liabilities and equity	$	3,713,814	$	3,633,195

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

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

	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
Revenues:				
Oil	$ 152,949	$ 268,543	$ 374,915	$ 776,001
Natural gas	32,168	66,772	86,908	182,973
Marketing	887	2,163	2,008	8,740
Total revenues	186,004	337,478	463,831	967,714
Expenses:				
Production:				
Lease operating	38,141	48,966	122,817	130,013
Production, ad valorem, and severance taxes	19,222	33,350	48,074	95,845
Depletion, depreciation, and amortization	72,627	58,545	217,361	159,114
Impairment of long-lived assets		26,292		26,292
Exploration	16,668	13,381	43,801	30,462
General and administrative	13,270	15,303	40,743	36,549
Marketing	358	1,855	1,612	9,362
Derivative fair value loss (gain)	(13,256)	(239,435)	(741)	82,093
Other operating	8,241	4,073	29,419	9,805
Total expenses	155,271	(37,670)	503,086	579,535
Operating income (loss)	30,733	375,148	(39,255)	388,179
Other income (expenses):				
Interest	(21,920)	(18,124)	(57,009)	(54,669)
Other	600	1,553	1,811	3,090
Total other expenses	(21,320)	(16,571)	(55,198)	(51,579)
Income (loss) before income taxes	9,413	358,577	(94,453)	336,600
Income tax benefit (provision)	(11,189)	(121,184)	25,254	(118,595)
Consolidated net income (loss)	(1,776)	237,393	(69,199)	218,005
Less: net loss (income) attributable to noncontrolling interest	(3,223)	(31,086)	9,669	(16,198)

Net income (loss) attributable to EAC stockholders	$ (4,999)	$ 206,307	$ (59,530)	$ 201,807
Net income (loss) per common share:				
Basic	$ (0.10)	$ 3.88	$ (1.15)	$ 3.78
Diluted	$ (0.10)	$ 3.77	$ (1.15)	$ 3.67
Weighted average common shares outstanding:				
Basic	52,349	52,258	51,964	52,466
Diluted	52,349	52,979	51,964	53,134

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

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ENCORE ACQUISITION COMPANY

CONSOLIDATED STATEMENT OF EQUITY AND COMPREHENSIVE LOSS
(in thousands)
(unaudited)

	EAC Stockholders								
	Issued Shares of Common Stock	**Common Stock**	**Additional Paid-in Capital**	**Shares of Treasury Stock**	**Treasury Stock**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Noncontrolling Interest**	**Total Equity**
Balance at December 31, 2008	51,557	$ 516	$ 525,763	(5)	$ (101)	$ 789,698	$ (1,748)	$ 169,120	$ 1,483,248
Exercise of stock options and vesting of restricted stock	430	3	37						40
Net proceeds from issuance of common stock	2,750	27	100,663						100,690
Purchase of treasury stock				(111)	(2,961)				(2,961)
Cancellation of treasury stock	(116)		(1,193)	116	3,062	(1,869)			
Non-cash equity-based compensation			11,308					117	11,425
ENP cash distributions to noncontrolling interest								(24,629)	(24,629)
Net proceeds from ENP issuance of common units								169,945	169,945
Adjustment to reflect gain on ENP issuance of common units			29,691					(29,691)	
Other			117						117
Components of comprehensive loss:									
Consolidated net loss						(59,530)		(9,669)	(69,199)
Change in deferred hedge							564	(475)	89

loss on interest rate swaps, net of tax of $256								
Total comprehensive loss								(69,110)
Balance at September 30, 2009	54,621	$ 546	$ 666,386	$	$ 728,299	$ (1,184)	$ 274,718	$ 1,668,765

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

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

	Nine months ended September 30,	
	2009	2008
Cash flows from operating activities:		
Consolidated net income (loss)	$ (69,199)	$ 218,005
Adjustments to reconcile consolidated net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, and amortization	217,361	159,114
Impairment of long-lived assets		26,292
Non-cash exploration expense	42,374	27,699
Deferred taxes	(25,903)	109,653
Non-cash equity-based compensation expense	9,761	9,963
Non-cash derivative loss	105,757	38,203
Loss (gain) on disposition of assets	26	(691)
Other	17,992	7,349
Changes in operating assets and liabilities, net of effects from acquisitions:		
Accounts receivable	37,719	(31,135)
Current derivatives	256,261	(12,196)
Other current assets	12,565	(30,745)
Long-term derivatives		(7,028)
Other assets	(413)	(2,094)
Accounts payable	5,511	(2,476)
Other current liabilities	24,563	20,581
Other noncurrent liabilities	(1,222)	(1,507)
Net cash provided by operating activities	633,153	528,987
Cash flows from investing activities:		
Proceeds from disposition of assets	5,205	1,230
Purchases of other property and equipment	(3,576)	(2,416)
Acquisition of oil and natural gas properties	(423,959)	(116,767)
Development of oil and natural gas properties	(293,443)	(384,864)
Net collections from (advances to) working interest partners	5,457	(33,277)
Net cash used in investing activities	(710,316)	(536,094)
Cash flows from financing activities:		
Repurchase and retirement of common stock		(50,000)
Exercise of stock options and vesting of restricted stock, net of treasury stock purchases	(2,921)	799
Proceeds from long-term debt, net of issuance costs	590,090	1,070,238
Payments on long-term debt	(676,000)	(974,500)

Proceeds from EAC issuance of common stock, net of offering costs		100,690		
ENP cash distributions to noncontrolling interest		(24,629)		(19,525)
Proceeds from ENP issuance of common units, net of offering costs		170,149		
Payments of deferred commodity derivative contract premiums		(70,456)		(30,822)
Change in cash overdrafts		(5,116)		13,040
Net cash provided by financing activities		81,807		9,230
Increase in cash and cash equivalents		4,644		2,123
Cash and cash equivalents, beginning of period		2,039		1,704
Cash and cash equivalents, end of period	$	6,683	$	3,827

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. Description of Business

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 in Montana and North Dakota;
- the Permian Basin in West Texas and southeastern New Mexico;
- the Rockies, which includes non-CCA assets in the Williston, Big Horn, and Powder River Basins in Wyoming, Montana, and North Dakota, and the Paradox Basin in southeastern Utah; and
- the Mid-Continent area, which includes the Arkoma and Anadarko Basins in Arkansas and 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 its wholly owned and majority-owned subsidiaries. All material intercompany balances and transactions have been eliminated in consolidation.

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 September 30, 2009, results of operations for the three and nine months ended September 30, 2009 and 2008, and cash flows for the nine months ended September 30, 2009 and 2008. 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 notes thereto included in EAC s 2008 Annual Report on Form 10-K.

Noncontrolling Interest

As of September 30, 2009 and December 31, 2008, EAC owned approximately 46 percent and 63 percent, respectively, of ENP s common units. EAC also owns 100 percent of Encore Energy Partners GP LLC (GP LLC), a Delaware limited liability company and indirect wholly owned non-guarantor subsidiary of EAC, which is ENP s general partner. Considering the presumption of control of GP LLC in accordance with Emerging Issues Task Force (EITF) 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* (ASC 810-20), the financial position, results of operations, and cash flows of ENP are fully consolidated with those of EAC.

As presented in the accompanying Consolidated Balance Sheets, Noncontrolling interest as of September 30, 2009 and December 31, 2008 of approximately $274.7 million and $169.1 million, respectively, represents third-party partnership interests in ENP. As presented in the accompanying Consolidated Statements of Operations, Net income attributable to noncontrolling interest for the three months ended September 30, 2009 of approximately $3.2 million, Net loss attributable to noncontrolling interest for the nine months ended September 30, 2009 of approximately $9.7 million, and Net income attributable to noncontrolling interest for the three and nine months ended September 30, 2008 of approximately $31.1 million and $16.2 million, respectively, represents the net income or loss of ENP attributable to third-party partners.

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

The following table summarizes the effects of changes in EAC s partnership interest in ENP on EAC s equity for the periods indicated:

	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
	(in thousands)			
Net income (loss) attributable to EAC stockholders	$ (4,999)	$ 206,307	$ (59,530)	$ 201,807
Transfer from (to) noncontrolling interest:				
Increase in EAC s paid-in capital for ENP s issuance of 283,700 common units in connection with acquisition of net profits interest in certain Crockett County properties				3,458
Increase in EAC s paid-in capital for ENP s issuance of 2,760,000 common units in public offering			9,312	
Increase in EAC s paid-in capital for ENP s issuance of 9,430,000 common units in public offering	20,379		20,379	
Net transfer from noncontrolling interest	20,379		29,691	3,458
Change from net income (loss) attributable to EAC stockholders and transfers from (to) noncontrolling interest	$ 15,380	$ 206,307	$ (29,839)	$ 205,265

Supplemental Disclosures of Non-cash Investing and Financing Activities

The following table sets forth supplemental disclosures of non-cash investing and financing activities for the periods indicated:

	Nine months ended September 30,	
	2009	2008
	(in thousands)	
Non-cash investing and financing activities:		
Deferred premiums on commodity derivative contracts	$ 44,907	$ 53,387
ENP s issuance of common units in connection with acquisition of net profits interest in certain Crockett County properties		5,748

Allowance for Doubtful Accounts

During the three and nine months ended September 30, 2009, EAC recorded an allowance for doubtful accounts of approximately $2.4 million and $7.1 million, respectively, primarily related to balances due from ExxonMobil Corporation (ExxonMobil) in connection with EAC s joint development agreement, which are included in Other operating expense in the accompanying Consolidated Statements of Operations. The following table summarizes the changes in the allowance for doubtful accounts for the nine months ended September 30, 2009 (in thousands):

Allowance for doubtful accounts at January 1, 2009	$ 8,024
Bad debt expense	7,116
Write off	(981)

Allowance for doubtful accounts at September 30, 2009	$ 14,159

As of September 30, 2009, $0.4 million of EAC s allowance for doubtful accounts was current and $13.7 million was long-term.

Reclassifications

Certain amounts in prior periods have been reclassified to conform to the current period presentation. In particular, certain amounts in the Consolidated Financial Statements have been either combined or classified in more detail.

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

FASB Launches Accounting Standards Codification

In June 2009, the FASB issued SFAS No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles* (SFAS 168 or ASC 105-10). SFAS 168 (ASC 105-10) establishes the Codification as the sole source of authoritative accounting principles recognized by the FASB to be applied by all nongovernmental entities in the preparation of financial statements in conformity with GAAP. SFAS 168 (ASC 105-10) was prospectively effective for financial statements issued for fiscal years ending on or after September 15, 2009, and interim periods within those fiscal years. The adoption of SFAS 168 (ASC 105-10) on July 1, 2009 did not impact EAC s results of operations or financial condition.

Following the Codification, the FASB will not issue new standards in the form of Statements, FASB Staff Positions (FSP), or EITF Abstracts. Instead, it will issue Accounting Standards Updates (ASU), which will serve to update the Codification, provide background information about the guidance, and provide the basis for conclusions on the changes to the Codification.

The Codification did not change GAAP; however, it did change the way GAAP is organized and presented. As a result, these changes impact how companies, including EAC, reference GAAP in their financial statements and in their significant accounting policies. EAC implemented the Codification in this Report by providing references to the Codification topics alongside references to the corresponding standards.

New Accounting Pronouncements

FSP No. FAS 157-2, Effective Date of FASB Statement No. 157 (FSP FAS 157-2 or ASC 820.10)

In February 2008, the FASB issued FSP FAS 157-2, which delayed the effective date of SFAS No. 157, *Fair Value Measurements* (SFAS 157 or ASC 820-10) 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 (ASC 820-10) for all instruments within the scope of FSP FAS 157-2 (ASC 820-10), including, but not limited to, its asset retirement obligations and indefinite lived assets. FSP FAS 157-2 (ASC 820-10) was prospectively effective for financial statements issued for fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. The adoption of FSP FAS 157-2 (ASC 820-10) on January 1, 2009 did not have a material impact on EAC s results of operations or financial condition. Please read Note 6. Fair Value Measurements for additional discussion.

SFAS No. 141 (revised 2007), Business Combinations (SFAS 141R or ASC 805)

In December 2007, the FASB issued SFAS 141R, which replaces SFAS No. 141, *Business Combinations* (ASC 805). SFAS 141R (ASC 805) establishes principles and requirements for the acquiror 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. In April 2009, the FASB issued FSP No. FAS 141(R)-1, *Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arises from Contingencies* (FSP FAS 141R-1 or ASC 805), which amends and clarifies SFAS 141R (ASC 805) to address application issues, including: (1) initial recognition and measurement; (2) subsequent measurement and accounting; and (3) disclosure of assets and liabilities arising from contingencies in a business combination. SFAS 141R (ASC 805) and FSP FAS 141R-1 (ASC 805) were prospectively effective for business combinations consummated in fiscal years beginning on or after December 15, 2008. The adoption of SFAS 141R (ASC 805) and FSP FAS 141R-1 (ASC 805) on January 1, 2009 did not impact EAC s results of operations or financial condition. However, the application of SFAS 141R (ASC 805) and FSP FAS 141R-1 (ASC 805) to future acquisitions could impact EAC s results of operations and financial condition and the reporting of acquisitions in the consolidated financial statements.

SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment to ARB No. 51 (SFAS 160 or ASC 810-10-65-1)

In December 2007, the FASB issued SFAS 160 (ASC 810-10-65-1), which amends Accounting Research Bulletin No. 51, *Consolidated Financial Statements* (ASC 810-10, 860-10-60-1, 850-10-60, 970-810-25-1, 958-810-60, and 505-10), to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS 160 (ASC 810-10-65-1) was prospectively effective for financial statements issued for fiscal years beginning on or after December 15,

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2008, except for the presentation and disclosure requirements which were retrospectively effective. SFAS 160 (ASC 810-10-65-1) clarifies that a noncontrolling interest in a subsidiary, which was often 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 (ASC 810-10-65-1) requires consolidated net income to be reported for the amounts attributable to both the parent and the noncontrolling interest on the face of the consolidated statement of operations and gains or losses on a subsidiaries issuance of equity to be accounted for as capital transactions. The adoption of SFAS 160 (ASC 810-10-65-1) on January 1, 2009 did not have a material impact on EAC s results of operations or financial condition; however, it did impact the presentation of noncontrolling interest in the accompanying Consolidated Financial Statements.

SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133 (SFAS 161 or ASC 815-10-65-1)

In March 2008, the FASB issued SFAS 161 (ASC 815-10-65-1), which amends SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133 or ASC 815), to require enhanced disclosures, including: (1) how and why an entity uses derivative instruments; (2) how derivative instruments and related hedged items are accounted for under SFAS 133 (ASC 815) 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 (ASC 815-10-65-1) was prospectively effective for financial statements issued for fiscal years beginning on or after November 15, 2008, and interim periods within those fiscal years. The adoption of SFAS 161 (ASC 815-10-65-1) on January 1, 2009 required additional disclosures regarding EAC s derivative instruments; however, it did not impact EAC s results of operations or financial condition. Please read Note 6. Fair Value Measurements for additional discussion.

FSP No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1 or ASC 260-10)

In June 2008, the FASB issued FSP EITF 03-6-1 (ASC 260-10), 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 prescribed by SFAS No. 128, *Earnings per Share* (SFAS 128 or ASC 260-10). FSP EITF 03-6-1 (ASC 260-10) was retroactively effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. The adoption of FSP EITF 03-6-1 (ASC 260-10) on January 1, 2009 did not have a material impact on EAC s EPS calculations. In the accompanying Consolidated Financial Statements, periods prior to the adoption of FSP EITF 03-6-1 (ASC 260-10) have been restated to calculate EPS in accordance with this pronouncement. Please read Note 11. Earnings Per Share for additional discussion.

SEC Release No. 33-8995, Modernization of Oil and Gas Reporting (Release 33-8995)

In December 2008, the SEC issued Release 33-8995, which amends oil and natural gas reporting requirements under Regulations S-K and S-X. Release 33-8995 also adds a section to Regulation S-K (Subpart 1200) to codify the revised disclosure requirements in Securities Act Industry Guide 2, which is being phased out. Release 33-8995 permits the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. Release 33-8995 will also allow companies to disclose their probable and possible reserves to investors at the company s option. In addition, the new disclosure requirements require companies to: (1) report the independence and qualifications of its reserves preparer or auditor; (2) file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit; and (3) report oil and gas reserves using an average price based upon the prior 12-month period rather than a year-end price, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. Release 33-8995 is prospectively effective for financial statements issued for fiscal years ending on or after December 31, 2009. EAC is evaluating the impact Release 33-8995 will have on its financial condition, results of operations, and disclosures.

FSP No. FAS 107-1 and APB 28-1, Disclosure of Fair Value of Financial Instruments in Interim Statements (FSP FAS 107-1 and APB 28-1 or ASC 825-10-65-1)

In April 2009, the FASB issued FSP FAS 107-1 and APB 28-1 (ASC 825-10-65-1), which requires that disclosures concerning the fair value of financial instruments be presented in interim as well as annual financial statements. FSP FAS 107-1 and APB 28-1 (ASC 825-10-65-1) was prospectively effective for financial statements issued for interim periods ending after June 15, 2009. The adoption of FSP FAS 107-1 and APB 28-1 (ASC 825-10-65-1) on June 30, 2009 required additional disclosures regarding EAC s

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financial instruments; however, it did not impact EAC s results of operations or financial condition. Please read Note 6. Fair Value Measurements for additional discussion.

SFAS No. 165, Subsequent Events (SFAS 165 or ASC 855-10)

In June 2009, the FASB issued SFAS 165 (ASC 855-10) to establish general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or available to be issued. In particular, SFAS 165 (ASC 855-10) sets forth: (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. SFAS 165 (ASC 855-10) was prospectively effective for financial statements issued for interim or annual periods ending after June 15, 2009. The adoption of SFAS 165 (ASC 855-10) on June 30, 2009 did not impact EAC s results of operations or financial condition.

ASU No. 2009-05, Fair Value Measurement and Disclosure: Measuring Liabilities at Fair Value (ASU 2009-05 or ASC 820-10)

In August 2009, the FASB issued ASU 2009-05 (ASC 820-10) to provide clarification on measuring liabilities at fair value when a quoted price in an active market is not available. In particular, ASU 2009-05 specifies that a valuation technique should be applied that uses either the quote of the liability when traded as an asset, the quoted prices for similar liabilities when traded as assets, or another valuation technique consistent with existing fair value measurement guidance. ASU 2009-05 (ASC 820-10) is prospectively effective for financial statements issued for interim or annual periods ending after October 1, 2009. The adoption of ASU 2009-05 (ASC 820-10) on December 31, 2009 will not impact EAC s results of operations or financial condition.

Note 3. Acquisitions

Acquisitions from EXCO

In August 2009, Encore Operating acquired certain oil and natural gas properties and related assets in the Mid-Continent and East Texas from EXCO Resources, Inc. (together with its affiliates, EXCO) for approximately $357.0 million in cash, substantially all of which are proved producing. The operations of these properties have been included with those of EAC from the date of acquisition forward. EAC financed the acquisitions through borrowings under its revolving credit facilities and proceeds from the issuance of ENP common units to the public. A portion of the properties acquired in the EXCO acquisition and the sale of properties to ENP in August 2009, as discussed in Note 17. ENP, qualified as a like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended, and I.R.S. Revenue Procedure 2000-37.

CO2 Supply Agreement

In July 2009, EAC acquired contract rights for $24 million in cash, which procures a CO2 supply to be used for a tertiary oil recovery project in EAC s Bell Creek Field. The initial term of the contract is 15 years. The contract is classified as an intangible asset and is included in Other assets in the accompanying Consolidated Balance Sheet as of September 30, 2009.

Note 4. Inventory

Inventory includes 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. Inventory consisted of the following as of the dates indicated:

	September 30, 2009	December 31, 2008

	(in thousands)	
Materials and supplies	$ 17,592	$ 15,933
Oil in pipelines	7,001	8,865
Total inventory	$ 24,593	$ 24,798

During the three and nine months ended September 30, 2009, EAC recorded a lower of cost or market adjustment of approximately $0.7 million and $6.5 million, respectively, to the carrying value of pipe and other tubular inventory whose market value had declined below cost, which are included in Other operating expense in the accompanying Consolidated Statements of Operations.

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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:

	September 30, 2009	December 31, 2008
	(in thousands)	
Proved leasehold costs	$ 1,775,500	$ 1,421,859
Wells and related equipment Completed	2,336,717	1,943,275
Wells and related equipment In process	34,664	173,325
Total proved properties	$ 4,146,881	$ 3,538,459

EAC follows FSP No. 19-1 *Accounting for Suspended Well Costs* (FSP 19-1 or ASC 932), which permits the continued capitalization of exploratory well costs beyond one year if the well found a sufficient quantity of reserves to justify its completion as a producing well or the entity is making sufficient progress towards assessing the reserves and the economic and operating viability of the project. The following table reflects the net changes in capitalized exploratory well costs during the periods indicated, and does not include amounts that were capitalized and subsequently expensed in the same period.

	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
	(in thousands)	
Beginning balance	$ 28,948	$ 18,220
Additions to capitalized exploratory well costs pending the determination of proved reserves	1,456	4,588
Reclassification to proved property and equipment based on the determination of proved reserves	(20,201)	(15,054)
Capitalized exploratory well costs charged to expense	(5,614)	(3,165)
Total	$ 4,589	$ 4,589

The following table provides an aging, as of the dates indicated, of capitalized exploratory well costs and the number of projects for which exploratory well costs have been capitalized for a period greater than one year:

	September 30, 2009	December 31, 2008
	(in thousands, except project counts)	
Capitalized exploratory well costs that have been suspended:		
One year or less	$ 2,755	$ 18,220

More than one year	1,834	
Total	$ 4,589	$ 18,220
Number of projects with exploratory well costs that have been suspended for a period of greater than one year	1	0

The following table provides an aging of gross capitalized costs of exploration projects with exploratory well costs which have been suspended for more than one year as of September 30, 2009:

	Total	**2009**	**2008**
		(in thousands)	
Tuscaloosa Marine Shale	$1,834	$1,834	$

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Note 6. Fair Value Measurements

The following table sets forth EAC s book value and estimated fair value of financial instruments as of the dates indicated:

	September 30, 2009		December 31, 2008	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Assets:				
Cash and cash equivalents	$ 6,683	$ 6,683	$ 2,039	$ 2,039
Accounts receivable, net	104,980	104,980	117,995	117,995
Plugging bond	862	1,059	824	1,202
Bell Creek escrow	9,260	9,260	9,229	9,241
Commodity derivative contracts	99,668	99,668	387,841	387,841
Long-term receivables, net	61,779	61,779	71,986	71,986
Liabilities:				
Accounts payable	10,412	10,412	10,017	10,017
6.25% Senior Subordinated Notes	150,000	140,250	150,000	101,250
6.0% Senior Subordinated Notes	296,421	276,000	296,040	194,250
9.5% Senior Subordinated Notes	208,228	234,000		
7.25% Senior Subordinated Notes	148,847	140,250	148,771	94,500
Revolving credit facilities	440,000	440,000	725,000	725,000
Commodity derivative contracts	29,230	29,230	229	229
Deferred premiums on commodity derivative contracts	43,228	43,228	67,610	67,610
Interest rate swaps	4,150	4,150	4,559	4,559

The book values of cash and cash equivalents, accounts receivable, net, and accounts payable approximate fair value due to the short-term nature of these instruments. The book value of long-term receivables, net, approximates fair value as it is net of amounts deemed to be uncollectible and bears interest at market rates. The plugging bond and Bell Creek escrow are included in Other assets in the accompanying Consolidated Balance Sheets and are classified as held to maturity and therefore, are recorded at amortized cost, which was less than fair value. The fair values of the plugging bond, Bell Creek escrow, and senior subordinated notes were determined using open market quotes. The difference between book value and fair value of the senior subordinated notes represents the premium or discount on that date. The book value of the revolving credit facilities approximates fair value as the interest rate is variable. EAC s and ENP s credit risk have not changed materially from the date the revolving credit facilities were entered into. Commodity derivative contracts and interest rate swaps are marked-to-market each period and are thus stated at fair value in the accompanying Consolidated Balance Sheets. Deferred premiums on commodity derivative contracts were recorded at their net present value at the time the contracts were entered into and EAC accretes that value to the eventual settlement price by recording interest expense each period.

Derivative Policy

EAC uses various financial instruments for non-trading purposes to manage and reduce price volatility and other market risks associated with its oil and natural gas production. These arrangements are structured to reduce EAC s exposure to commodity price decreases, but they can also limit the benefit EAC might otherwise receive from commodity price increases. EAC s risk management activity is generally accomplished through over-the-counter derivative contracts with large financial institutions. EAC also uses derivative instruments in the form of interest rate swaps, which hedge risk related to interest rate fluctuation.

EAC applies the provisions of SFAS 133 (ASC 815), which requires each derivative instrument to be recorded in the balance sheet at fair value. If a derivative has not been designated as a hedge or does not otherwise qualify for hedge accounting, it must be

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adjusted to fair value through earnings. However, if a derivative qualifies for hedge accounting, depending on the nature of the hedge, the effective portion of changes in fair value can be recognized in accumulated other comprehensive income or loss until such time as the hedged item is recognized in earnings. In order to qualify for cash flow hedge accounting, the cash flows from the hedging instrument must be highly effective in offsetting changes in cash flows of the hedged item. In addition, all hedging relationships must be designated, documented, and reassessed periodically.

EAC has elected to designate its outstanding interest rate swaps as cash flow hedges. The effective portion of the mark-to-market gain or loss on these derivative instruments is recorded in Accumulated other comprehensive loss on the accompanying Consolidated Balance Sheets and reclassified into earnings in the same period in which the hedged transaction affects earnings. Any ineffective portion of the mark-to-market gain or loss is recognized in earnings and included in Derivative fair value loss (gain) in the accompanying Consolidated Statements of Operations.

EAC has not elected to designate its current portfolio of commodity derivative contracts as hedges. Therefore, changes in fair value of these derivative instruments are recognized in earnings and included in Derivative fair value loss (gain) in the accompanying Consolidated Statements of Operations.

Commodity Derivative Contracts

EAC manages commodity price risk with swap contracts, put contracts, collars, and floor spreads. Swap contracts provide a fixed price for a notional amount of sales volumes. Put contracts provide a fixed floor price on a notional amount of sales volumes while allowing full price participation if the relevant index price closes above the floor price. Collars provide a floor price on a notional amount of sales volumes while allowing some additional price participation if the relevant index price closes above the floor price.

From time to time, EAC enters into floor spreads. In a floor spread, EAC purchases puts at a specified price (a purchased put) and also sells a put at a lower price (a short put). This strategy enables EAC to achieve some downside protection for a portion of its production, while funding the cost of such protection by selling a put at a lower price. If the price of the commodity falls below the strike price of the purchased put, then EAC has protection against commodity price decreases for the covered production down to the strike price of the short put. At commodity prices below the strike price of the short put, the benefit from the purchased put is generally offset by the expense associated with the short put. For example, in 2007, EAC purchased oil put options for 2,000 Bbls/D in 2010 at $65 per Bbl. As NYMEX prices increased in 2008, EAC wished to protect downside price exposure at the higher price. In order to do this, EAC purchased oil put options for 2,000 Bbls/D in 2010 at $75 per Bbl and simultaneously sold oil put options for 2,000 Bbls/D in 2010 at $65 per Bbl. Thus, after these transactions were completed, EAC had purchased two oil put options for 2,000 Bbls/D in 2010 (one at $65 per Bbl and one at $75 per Bbl) and sold one oil put option for 2,000 Bbls/D in 2010 at $65 per Bbl. However, the net effect resulted in EAC owning one oil put option for 2,000 Bbls/D at $75 per Bbl. In the following tables, the purchased floor component of these floor spreads are shown net and included with EAC s other floor contracts.

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The following tables summarize EAC s open commodity derivative contracts as of September 30, 2009:

Oil Derivative Contracts

Period	Average Daily Floor Volume (Bbls)	Weighted Average 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)	Asset Fair Market Value (in thousands)
Oct. - Dec. 2009 (a)							$ 10,941
	3,130	$ 110.00	440	$ 97.75	1,000	$ 68.70	
2010							16,086
	880	80.00	2,940	90.57			
	5,500	73.47	3,000	74.13	3,885	77.79	
	8,385	62.83	500	65.60	1,750	64.08	
	1,000	56.00			1,000	59.70	
2011							27,767
	1,880	80.00	1,440	95.41	325	80.00	
	2,500	70.00			1,060	78.42	
	4,385	65.00			250	69.65	
2012							4,628
	750	70.00	500	82.05	835	81.19	
	2,135	65.00	250	79.25	1,300	76.54	
							$ 59,422

(a) In addition, ENP has a floor contract for 1,000 Bbls/D at $63.00 per Bbl and a short floor contract for 1,000 Bbls/D at $65.00 per Bbl.

Natural Gas Derivative Contracts

Average Daily	Weighted Average	Average Daily	Weighted Average	Average Daily	Weighted Average	Asset (Liability)

Period	Floor Volume (Mcf)	Floor Price (per Mcf)	Cap Volume (Mcf)	Cap Price (per Mcf)	Swap Volume (Mcf)	Swap Price (per Mcf)	Fair Market Value (in thousands)
Oct. - Dec. 2009							$ 4,829
	3,800	$ 8.20	3,800	$ 9.83		$	
	3,800	7.20	5,000	7.45			
	6,800	6.57	15,000	6.63			
	15,000	5.64					
Jan. - June 2010							4,434
	3,800	8.20	3,800	9.58	25,452	6.46	
	4,698	7.26			20,550	5.23	
July - Dec. 2010							3,005
	3,800	8.20	3,800	9.58			
	4,698	7.26	10,000	6.25	25,452	6.46	
	10,000	5.13			550	5.86	
2011							212
	3,398	6.31			27,952	6.48	
					550	5.86	
2012							(1,463)
	898	6.76			25,452	6.47	
					550	5.86	
							$ 11,017

As of September 30, 2009, EAC had $43.2 million of deferred premiums payable, of which $26.0 million was long-term and included in Derivatives in the non-current liabilities section of the accompanying Consolidated Balance Sheet and $17.2 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 October 2009 to January 2013.

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Counterparty Risk. At September 30, 2009, EAC had committed 10 percent or greater (in terms of fair market value) of either its oil or natural gas derivative contracts to the following counterparties:

Counterparty	Percentage of Oil Derivative Contracts Committed	Percentage of Natural Gas Derivative Contracts Committed
BNP Paribas	33%	23%
Calyon	15%	43%
JP Morgan	14%	6%
RBC	17%	2%
Wachovia Bank	14%	26%

In order to mitigate the credit risk of financial instruments, EAC enters into master netting agreements with significant counterparties. The master netting agreement is a standardized, bilateral contract between a given counterparty and EAC. Instead of treating each derivative financial transaction between the counterparty and EAC separately, the master netting agreement enables the counterparty and EAC to aggregate all financial trades and treat them as a single agreement. This arrangement benefits EAC in three ways: (1) the netting of the value of all trades reduces the likelihood of counterparties requiring daily collateral posting by EAC; (2) default by a counterparty under one financial trade can trigger rights to terminate all financial trades with such counterparty; and (3) netting of settlement amounts reduces EAC s credit exposure to a given counterparty in the event of close-out. EAC s accounting policy is to not offset fair value amounts for derivative instruments.

Interest Rate Swaps

ENP uses derivative instruments in the form of interest rate swaps, which hedge risk related to interest rate fluctuation, whereby it converts the interest due on certain floating rate debt under its revolving credit facility to a weighted average fixed rate. The following table summarizes ENP s open interest rate swaps as of September 30, 2009, all of which were entered into with Bank of America, N.A.:

Term	Notional Amount (in thousands)	Fixed Rate	Floating Rate
Oct. 2009 - Jan. 2011	$ 50,000	3.1610%	1-month LIBOR
Oct. 2009 - Jan. 2011	25,000	2.9650%	1-month LIBOR
Oct. 2009 - Jan. 2011	25,000	2.9613%	1-month LIBOR
Oct. 2009 - Mar. 2012	50,000	2.4200%	1-month LIBOR

The actual gains or losses ENP will realize from its interest rate swaps may vary significantly from the deferred loss recorded in Accumulated other comprehensive loss in the accompanying Consolidated Balance Sheet due to the fluctuation of interest rates.

Current Period Impact

EAC recognizes derivative fair value gains and losses related to: (1) ineffectiveness on derivative contracts designated as hedges; (2) changes in the fair market value of derivative contracts not designated as hedges; (3) settlements on derivative contracts not designated as hedges; and (4) premium amortization. The following table summarizes the components of Derivative fair value loss (gain) for the periods indicated:

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	Three months ended September 30, 2009	Three months ended September 30, 2008	Nine months ended September 30, 2009	Nine months ended September 30, 2008
	(in thousands)			
Ineffectiveness	$ 18	$ (6)	$ (16)	$ (349)
Mark-to-market loss (gain)	576	(276,932)	281,569	(11,884)
Premium amortization	6,838	14,773	91,557	47,579
Settlements	(20,688)	22,730	(373,851)	46,747
Total derivative fair value loss (gain)	$ (13,256)	$ (239,435)	$ (741)	$ 82,093

In March 2009, EAC elected to monetize certain of its 2009 oil derivative contracts and received proceeds of approximately $190.4 million from these settlements, which were used to reduce outstanding borrowings under EAC s revolving credit facility.

Accumulated Other Comprehensive Loss

At September 30, 2009 and December 31, 2008, Accumulated other comprehensive loss on the accompanying Consolidated Balance Sheet consisted entirely of deferred losses, net of tax, on ENP s interest rate swaps of $1.2 million and $1.7 million, respectively. During the twelve months ending September 30, 2010, EAC expects to reclassify $3.5 million of deferred losses associated with ENP s interest rate swaps from accumulated other comprehensive loss to interest expense.

Tabular Disclosures of Fair Value Measurements

The following table summarizes the fair value of EAC s derivative contracts as of the dates indicated (in thousands):

	Asset Derivatives				Liability Derivatives			
	September 30, 2009		December 31, 2008		September 30, 2009		December 31, 2008	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives not designated as hedging instruments under SFAS 133 (ASC 815)								
Commodity derivative contracts	Derivatives - current	$ 51,974	Derivatives - current	$ 349,344	Derivatives - current	$ 16,532	Derivatives - current	$
Commodity derivative contracts	Derivatives - noncurrent	47,694	Derivatives - noncurrent	38,497	Derivatives - noncurrent	12,698	Derivatives - noncurrent	229

Total derivatives not designated as hedging instruments under SFAS 133 (ASC 815)		$ 99,668		$ 387,841		$ 29,230		$ 229
Derivatives designated as hedging instruments under SFAS 133 (ASC 815)								
Interest rate swaps	Derivatives - current	$	Derivatives - current	$	Derivatives - current	$ 3,470	Derivatives - current	$ 1,297
Interest rate swaps	Derivatives - noncurrent		Derivatives - noncurrent		Derivatives - noncurrent	680	Derivatives-noncurrent	3,262
Total derivatives designated as hedging instruments under SFAS 133 (ASC 815)		$		$		$ 4,150		$ 4,559
Total derivatives		$ 99,668		$ 387,841		$ 33,380		$ 4,788

The following table summarizes the effect of derivative instruments not designated as hedges under SFAS 133 (ASC 815) on the Consolidated Statements of Operations for the periods indicated (in thousands):

		Amount of Loss (Gain) Recognized In Income			
		Three Months Ended September 30,		**Nine Months Ended September 30,**	
Derivatives Not Designated as Hedges Under SFAS 133 (ASC 815)	**Location of Loss Recognized In Income**	**2009**	**2008**	**2009**	**2008**
Commodity derivative contracts	Derivative fair value loss (gain)	$ (13,274)	$ (239,429)	$ (725)	$ 82,442

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The following tables summarize the effect of derivative instruments designated as hedges under SFAS 133 (ASC 815) on the Consolidated Statements of Operations for the periods indicated (in thousands):

Derivatives Designated as Hedges Under SFAS 133 (ASC 815)	Amount of Loss Recognized in Accumulated OCI (Effective Portion) Three months ended September 30, 2009	2008	Location of Loss (Gain) Reclassified from Accumulated OCI into Income (Effective Portion)	Amount of Loss Reclassified from Accumulated OCI into Income (Effective Portion) Three months ended September 30, 2009	2008	Location of Loss (Gain) Recognized in Income as Ineffective	Amount of Loss (Gain) Recognized In Income as Ineffective Three months ended September 30, 2009	2008
Interest rate swaps	$ 725	$ 381	Interest expense	$ 983	$ 117	Derivative fair value loss (gain)	$ 18	$ (6)

Derivatives Designated as Hedges Under SFAS 133 (ASC 815)	Amount of Loss Recognized in Accumulated OCI (Effective Portion) Nine months ended September 30, 2009	2008	Location of Loss (Gain) Reclassified from Accumulated OCI into Income (Effective Portion)	Amount of Loss Reclassified from Accumulated OCI into Income (Effective Portion) Nine months ended September 30, 2009	2008	Location of Gain Recognized in Income as Ineffective	Amount of Gain Recognized In Income as Ineffective Nine months ended September 30, 2009	2008
Interest rate swaps	$ 2,214	$ 1,142	Interest expense	$ 2,786	$ 224	Derivative fair value gain	$ 16	$ 349
Commodity derivative contracts			Oil and natural gas revenues		2,857			
Total	$ 2,214	$ 1,142		$ 2,786	$ 3,081		$ 16	$ 349

Fair Value Hierarchy

As discussed in Note 2. Basis of Presentation, EAC adopted FSP FAS 157-2 (ASC 820-10) on January 1, 2009 and SFAS 157 (ASC 820-10) on January 1, 2008. SFAS 157 (ASC 820-10) establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The three levels of the fair value hierarchy defined by SFAS 157

(ASC 820-10) are as follows:

Level 1 Unadjusted quoted prices are available in active markets for identical assets or liabilities.

Level 2 Pricing inputs, other than quoted prices within Level 1, that are either directly or indirectly observable.

Level 3 Pricing inputs that are unobservable requiring the use of valuation methodologies that result in management s best estimate of fair value.

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. The following methods and assumptions were used to estimate the fair values of EAC s assets and liabilities that are accounted for at fair value on a recurring basis:

Level 2 Fair values of oil and natural gas swaps were estimated using a combined income-based and market-based valuation methodology based upon forward commodity price curves obtained from independent pricing services reflecting broker market quotes. Fair values of interest rate swaps were estimated using a combined income-based and market-based valuation methodology based upon credit ratings and forward interest rate yield curves obtained from independent pricing services reflecting broker market quotes.

Level 3 EAC s oil and natural gas calls, puts, and short puts are average value options, which are not exchange-traded contracts. Settlement is determined by the average underlying price over a predetermined period of time. EAC uses both observable and unobservable inputs in a Black-Scholes valuation model to determine fair value. Accordingly, these derivative instruments are classified within the Level 3 valuation hierarchy. The observable inputs of EAC s valuation model include: (1) current market and contractual prices for the underlying instruments; (2) quoted forward prices for oil and natural gas; and (3) interest rates, such as a LIBOR curve for a term similar to the commodity derivative contract. The unobservable input of EAC s valuation model is volatility. The implied volatilities for EAC s calls, puts, and short puts with comparable strike prices are based on the settlement values from certain exchange-traded contracts. The implied volatilities for calls, puts, and short puts where there are no exchange-traded contracts with the same strike price are extrapolated from exchange-traded implied volatilities by an independent party.

EAC adjusts the valuations from the valuation model for nonperformance risk, using management s estimate of the counterparty s credit quality for asset positions and EAC s credit quality for liability positions. EAC uses the multiple sources of third-party credit data in determining counterparty nonperformance risk, including credit default swaps. EAC considers the impact of netting and offset

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provisions in the agreements on counterparty credit risk, including whether the position with the counterparty is a net asset or net liability. There have been no changes in the valuation techniques used to measure the fair value of EAC s oil and natural gas calls, puts, or short puts during 2009.

The following table sets forth EAC s assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2009:

		Fair Value Measurements at Reporting Date Using		
Description	Asset (Liability) at September 30, 2009	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	$ (7,860)	$	$ (7,860)	$
Oil derivative contracts floors and caps	67,282			67,282
Natural gas derivative contracts swaps	(387)		(387)	
Natural gas derivative contracts floors and caps	11,404			11,404
Interest rate swaps	(4,150)		(4,150)	
Total	$ 66,289	$	$ (12,397)	$ 78,686

The following table summarizes the changes in the fair value of EAC s Level 3 assets and liabilities for the nine months ended September 30, 2009:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Oil Derivative Contracts - Floors and Caps	Natural Gas Derivative Contracts - Floors and Caps	Total
	(in thousands)		
Balance at January 1, 2009	$ 337,335	$ 12,741	$ 350,076
Total gains (losses):			
Included in earnings	30,329	20,882	51,211
Purchases, issuances, and settlements	(300,382)	(22,219)	(322,601)

Balance at September 30, 2009	$ 67,282	$ 11,404	$ 78,686
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	$ 30,329	$ 20,882	$ 51,211

Since EAC does not use hedge accounting for its commodity derivative contracts, all gains and losses on its Level 3 assets and liabilities are included in Derivative fair value loss (gain) in the accompanying Consolidated Statements of Operations.

All fair values have been adjusted for nonperformance risk resulting in a reduction of the net commodity derivative asset of approximately $0.5 million as of September 30, 2009. For commodity derivative contracts which are in an asset position, EAC uses the counterparty s credit default swap rating. For commodity derivative contracts which are in a liability position, EAC uses the average credit default swap rating of its peer companies as EAC does not have its own credit default swap rating.

EAC s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the nonfinancial assets and liabilities and their placement within the fair value hierarchy levels. The following methods and assumptions were used to estimate the fair values of EAC s assets and liabilities that are accounted for at fair value on a nonrecurring basis:

Level 3 Fair values of asset retirement obligations are determined using discounted cash flow methodologies based on inputs, such as plugging costs and reserve lives, which are not readily available in public markets. See Note 7. Asset Retirement Obligations for additional discussion of EAC s asset retirement obligations.

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The following table sets forth EAC s assets and liabilities that were measured at fair value on a nonrecurring basis as of September 30, 2009:

		Fair Value Measurements Using			
Description	**Liability at September 30, 2009**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total Gains (Losses)**
			(in thousands)		
Asset retirement obligations	$3,775	$	$	$ 3,775	$

Note 7. Asset Retirement Obligations

Asset retirement obligations relate to future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal. The following table summarizes the changes in EAC s asset retirement obligations for the nine months ended September 30, 2009 (in thousands):

Future abandonment liability at January 1, 2009	$ 49,569
Wells drilled	283
Acquisition of properties	3,492
Disposition of properties	(220)
Accretion of discount	1,761
Plugging and abandonment costs incurred	(1,223)
Revision of previous estimates	49
Future abandonment liability at September 30, 2009	$ 53,711

As of September 30, 2009, $51.7 million of EAC s asset retirement obligations were long-term and recorded in Future abandonment cost, net of current portion and $2.0 million were current and included in Other current liabilities in the accompanying Consolidated Balance Sheets. Approximately $4.7 million of the future abandonment liability represents the estimated cost for decommissioning ENP s Elk Basin natural gas processing plant.

As of September 30, 2009 and December 31, 2008, EAC held $9.3 million and $9.2 million, respectively, in escrow, which is to be released only for reimbursement of actual plugging and abandonment costs incurred on its Bell Creek properties. These amounts are included in Other assets in the accompanying Consolidated Balance Sheets.

Note 8. Long-Term Debt

Long-term debt consisted of the following as of the dates indicated:

	Maturity Date	**September 30, 2009**	**December 31, 2008**
		(in thousands)	
Revolving credit facilities	3/7/2012	$ 440,000	$ 725,000
6.25% Senior Subordinated Notes	4/15/2014	150,000	150,000

6.0% Senior Subordinated Notes, net of unamortized discount of $3,579 and $3,960, respectively	7/15/2015	296,421	296,040
9.5% Senior Subordinated Notes, net of unamortized discount of $16,772 and zero, respectively	5/1/2016	208,228	
7.25% Senior Subordinated Notes, net of unamortized discount of $1,153 and $1,229, respectively	12/1/2017	148,847	148,771
Total		$ 1,243,496	$ 1,319,811

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Encore Acquisition Company Credit Agreement

EAC is a party to a five-year amended and restated credit agreement dated March 7, 2007 (as amended, the EAC Credit Agreement). The EAC Credit Agreement matures on March 7, 2012. Effective March 10, 2009, EAC amended the EAC Credit Agreement to, among other things, increase the interest rate margins and commitment fees applicable to loans made under the EAC Credit Agreement. The EAC Credit Agreement provides for revolving credit loans to be made to EAC from time to time and letters of credit to be issued from time to time for the account of EAC or any of its 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. In March 2009, the borrowing base of the EAC Credit Agreement was reaffirmed at $1.1 billion before a reduction of $200 million solely as a result of the monetization of certain of EAC s 2009 oil derivative contracts during the first quarter of 2009. In April 2009, the borrowing base of the EAC Credit Agreement was reduced by $75 million as a result of EAC s issuance of senior subordinated notes. As of September 30, 2009, the borrowing base was $825 million and there were $180 million of outstanding borrowings, $0.3 million of outstanding letters of credit, and $644.7 million of borrowing capacity under the EAC Credit Agreement.

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

Ratio of Outstanding Borrowings to Borrowing Base	Commitment Fee Percentage
Less than .90 to 1	0.375%
Greater than or equal to .90 to 1	0.500%

Obligations under the EAC Credit Agreement are secured by a first-priority security interest in substantially all of EAC s restricted subsidiaries proved oil and natural gas reserves and in EAC s equity interests in its restricted subsidiaries. In addition, obligations under the EAC Credit Agreement are guaranteed by EAC s restricted subsidiaries.

Loans under the EAC Credit Agreement are subject to varying rates of interest based on (1) outstanding borrowings in relation to the borrowing base and (2) whether the loan is a Eurodollar loan or a base rate loan. Eurodollar loans under the EAC Credit Agreement bear interest at the Eurodollar rate plus the applicable margin indicated in the following table, and base rate loans under the EAC Credit Agreement bear interest at the base rate plus the applicable margin indicated in the following table:

Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans
Less than .50 to 1	1.750%	0.500%
Greater than or equal to .50 to 1 but less than .75 to 1	2.000%	0.750%
Greater than or equal to .75 to 1 but less than .90 to 1	2.250%	1.000%
Greater than or equal to .90 to 1	2.500%	1.250%

The Eurodollar rate for any interest period (either one, two, three, or six months, as selected by EAC) is the rate equal to the British Bankers Association LIBOR for deposits in dollars for a similar interest period. The Base Rate is calculated as the highest of: (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate ; (2) the federal funds effective rate plus 0.5 percent; or (3) except during a LIBOR Unavailability Period, the

Eurodollar rate (for dollar deposits for a one-month term) for such day plus 1.0 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 including, among others, the following:

- 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;

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- a restriction on creating liens on the assets of EAC 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 EAC maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0; and
- a requirement that EAC maintain a ratio of consolidated EBITDA to the sum of consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0.

As of September 30, 2009, EAC was in compliance with all covenants of the EAC Credit Agreement.

The EAC Credit Agreement contains customary events of default including, among others, the following:

- failure to pay principal on any loan when due;
- failure to pay accrued interest on any loan or fees when due and such failure continues for more than three days;
- failure to observe or perform covenants and agreements contained in the EAC Credit Agreement, subject in some cases to a 30-day grace period after discovery or notice of such failure;
- failure to make a payment when due on any other debt in a principal amount equal to or greater than $15 million or any other event or condition occurs which results in the acceleration of such debt or entitles the holder of such debt to accelerate the maturity of such debt;
- the commencement of liquidation, reorganization, or similar proceedings with respect to EAC or any guarantor under bankruptcy or insolvency law, or the failure of EAC or any guarantor generally to pay its debts as they become due;
- the entry of one or more judgments in excess of $15 million (to the extent not covered by insurance) and such judgment(s) remain unsatisfied and unstayed for 30 days;
- the occurrence of certain ERISA events involving an amount in excess of $15 million;
- there cease to exist liens covering at least 80 percent of the borrowing base properties; or
- the occurrence of a change in control.

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.

Encore Energy Partners Operating LLC Credit Agreement

Encore Energy Partners Operating LLC (OLLC), a Delaware limited liability company and wholly owned subsidiary of ENP, is a party to a five-year credit agreement dated March 7, 2007 (as amended, the OLLC Credit

Agreement). The OLLC Credit Agreement matures on March 7, 2012. Effective March 10, 2009, OLLC amended the OLLC Credit Agreement to, among other things, increase the interest rate margins and commitment fees applicable to loans made under the OLLC Credit Agreement. Effective August 11, 2009, OLLC amended the OLLC Credit Agreement to, among other things, (1) increase the borrowing base from $240 million to $375 million, (2) increase the aggregate commitments of the lenders from $300 million to $475 million, and (3) increase the interest rate margins and commitment fees applicable to loans made under the OLLC Credit Agreement. 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 $475 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 September 30, 2009, the borrowing base was $375 million and there were $260 million of outstanding borrowings and $115 million of borrowing capacity under the OLLC Credit Agreement.

OLLC incurs a commitment fee of 0.5 percent on the unused portion of the OLLC Credit Agreement.

Obligations under the OLLC Credit Agreement are secured by a first-priority security interest in substantially all of OLLC s proved oil and natural gas reserves and in the equity interests of OLLC and its restricted subsidiaries. In addition, Obligations under

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the OLLC Credit Agreement are guaranteed by ENP and OLLC s restricted subsidiaries. Obligations under the OLLC Credit Agreement are non-recourse to EAC and its restricted subsidiaries.

Loans under the OLLC Credit Agreement are subject to varying rates of interest based on (1) amount outstanding in relation to the borrowing base and (2) whether the loan is a Eurodollar loan or a base rate loan. Eurodollar loans under the OLLC Credit Agreement bear interest at the Eurodollar rate plus the applicable margin indicated in the following table, and base rate loans under the OLLC Credit Agreement bear interest at the base rate plus the applicable margin indicated in the following table:

Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans
Less than .50 to 1	2.250%	1.250%
Greater than or equal to .50 to 1 but less than .75 to 1	2.500%	1.500%
Greater than or equal to .75 to 1 but less than .90 to 1	2.750%	1.750%
Greater than or equal to .90 to 1	3.000%	2.000%

The Eurodollar rate for any interest period (either one, two, three, or six months, as selected by ENP) is the rate equal to the British Bankers Association LIBOR for deposits in dollars for a similar interest period. The Base Rate is calculated as the highest of: (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate ; (2) the federal funds effective rate plus 0.5 percent; or (3) except during a LIBOR Unavailability Period, the Eurodollar rate (for dollar deposits for a one-month term) for such day plus 1.0 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.

The OLLC Credit Agreement contains covenants including, among others, the following:

- 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 OLLC s 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 ENP and OLLC maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0;
- a requirement that ENP and OLLC maintain a ratio of consolidated EBITDA to the sum of consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0; and

- a requirement that ENP and OLLC maintain a ratio of consolidated funded debt to consolidated adjusted EBITDA of not more than 3.5 to 1.0.

As of September 30, 2009, ENP and OLLC were in compliance with all covenants of the OLLC Credit Agreement.

The OLLC Credit Agreement contains customary events of default including, among others, the following:

- failure to pay principal on any loan when due;
- failure to pay accrued interest on any loan or fees when due and such failure continues for more than three days;
- failure to observe or perform covenants and agreements contained in the OLLC Credit Agreement, subject in some cases to a 30-day grace period after discovery or notice of such failure;
- failure to make a payment when due on any other debt in a principal amount equal to or greater than $3 million or any other event or condition occurs which results in the acceleration of such debt or entitles the holder of such debt to accelerate the maturity of such debt;
- the commencement of liquidation, reorganization, or similar proceedings with respect to OLLC or any guarantor under bankruptcy or insolvency law, or the failure of OLLC or any guarantor generally to pay its debts as they become due;

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the entry of one or more judgments in excess of $3 million (to the extent not covered by insurance) and such judgment(s) remain unsatisfied and unstayed for 30 days;

the occurrence of certain ERISA events involving an amount in excess of $3 million;

there cease to exist liens covering at least 80 percent of the borrowing base properties; or

the occurrence of a change in control.

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.

9.50% Senior Subordinated Notes due 2016 (the 9.5% Notes)

In April 2009, EAC issued $225 million of its 9.5% Notes at 92.228 percent of par value. EAC used the net proceeds of approximately $202.5 million, after deducting the underwriters discounts and commissions of $4.5 million, in the aggregate, and offering expenses of approximately $0.6 million. EAC used the net proceeds to reduce outstanding borrowings under the EAC Credit Agreement. Interest on the 9.5% Notes is due semi-annually on May 1 and November 1, beginning November 1, 2009. The 9.5% Notes mature on May 1, 2016.

Note 9. Stockholders Equity

Stock Repurchase Program

In October 2008, EAC announced that its Board of Directors (the Board) approved a share repurchase program authorizing EAC to repurchase up to $40 million of its common stock. As of September 30, 2009, EAC had repurchased and retired 620,265 shares of its outstanding common stock for approximately $17.2 million, or an average price of $27.68 per share, under the share repurchase program. During the three and nine months ended September 30, 2009, EAC did not repurchase any shares of its outstanding common stock under the share repurchase program. As of September 30, 2009, approximately $22.8 million of EAC s common stock remained authorized for repurchase.

Stock Option Exercises and Restricted Stock Vestings

During the three and nine months ended September 30, 2009, certain employees exercised 1,621 options and 23,105 options, respectively, for which EAC received proceeds of approximately $49 thousand and $0.5 million, respectively. During the nine months ended September 30, 2009, certain employees elected to satisfy minimum tax withholding obligations in conjunction with the vesting of restricted stock by directing EAC to withhold 111,819 shares of common stock, which are accounted for as treasury stock until they are formally retired.

Issuance of EAC Common Stock

In September 2009, EAC issued 2,750,000 shares of common stock under its shelf registration statement at a price to the public of $37.40 per common share. EAC used the net proceeds of approximately $100.7 million, after deducting the underwriters discounts and commissions of $2.0 million, in the aggregate, and offering costs of approximately $0.1 million, to reduce outstanding borrowings under the EAC Credit Facility.

Issuance of ENP Common Units

In May 2009, ENP issued 2,760,000 common units at a price to the public of $15.60 per common unit. As a result, EAC s partnership percentage of ENP s common units decreased from approximately 63 percent to approximately 58 percent. Additionally, EAC increased Noncontrolling interest and Additional paid-in capital on the accompanying Consolidated Balance Sheets by $31.2 million and $9.3 million, respectively, to recognize the net proceeds from the issuance of ENP s common units.

In July 2009, ENP issued 9,430,000 common units under its shelf registration statement at a price to the public of $14.30 per common unit. As a result, EAC s partnership percentage of ENP s common units decreased from approximately 58 percent to its current partnership of approximately 46 percent. Additionally, EAC increased Noncontrolling interest and Additional paid-in capital on the accompanying Consolidated Balance Sheets by

$109.0 million and $20.4 million, respectively, to recognize the net proceeds from the issuance of ENP s common units.

The following table summarizes EAC s change of ownership of ENP since December 31, 2008:

	Common Units Owned			EAC % of Common	GP Units Owned	EAC % of All
Date	**EAC**	**Others**	**Total**	**Units**	**by EAC**	**Units**
12/31/2008	20,924,055	12,153,555	33,077,610	63.3%	504,851	63.8%
Equity Offering		2,760,000	2,760,000			
5/22/2009	20,924,055	14,913,555	35,837,610	58.4%	504,851	59.0%
Equity Offering		9,430,000	9,430,000			
7/22/2009	20,924,055	24,343,555	45,267,610	46.2%	504,851	46.8%

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Note 10. Income Taxes

The components of income tax benefit (provision) were as follows for the periods indicated:

	Nine months ended September 30, 2009	Nine months ended September 30, 2008
	(in thousands)	
Federal:		
Current	$ 2,683	$ (6,693)
Deferred	25,117	(104,436)
Total federal	27,800	(111,129)
State, net of federal benefit:		
Current	(3,332)	(2,249)
Deferred	786	(5,217)
Total state	(2,546)	(7,466)
Income tax benefit (provision)	$ 25,254	$ (118,595)

The following table reconciles income tax benefit (provision) with income tax at the Federal statutory rate for the periods indicated:

	Nine months ended September 30, 2009	Nine months ended September 30, 2008
	(in thousands)	
Income (loss) before income taxes	$ (94,453)	$ 336,600
Income taxes at the Federal statutory rate	$ 33,059	$ (117,810)
State income taxes, net of federal benefit	(2,546)	(7,466)
Tax on income attributable to noncontrolling interest	(3,384)	5,669
2008 provision to return adjustment	(1,735)	872
Permanent and other	(140)	140
Income tax benefit (provision)	$ 25,254	$ (118,595)

As of September 30, 2009 and December 31, 2008, all of EAC s tax positions met the more-likely-than-not threshold prescribed by FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109* (ASC 740, 805-740, and 835-10). 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. During the nine months ended September 30, 2009 and 2008, EAC recorded only a nominal amount of interest and penalties on certain tax positions.

Note 11. Earnings Per Share

As discussed in Note 2. Basis of Presentation, EAC adopted FSP EITF 03-6-1 (ASC 260-10) on January 1, 2009, and all periods prior to adoption have been restated to calculate EPS in accordance with this pronouncement. Under the two-class method of calculating EPS, earnings are allocated to participating securities as if all earnings for the period had been distributed. A participating security is any security that contains nonforfeitable rights to dividends or dividend equivalents paid to common stockholders. For purposes of calculating EPS, unvested restricted stock awards are considered participating securities. EPS is calculated by dividing the common stockholders interest in net income (loss), after deducting the interests of participating securities, by the weighted average shares outstanding. The adoption of EITF 03-6-1 (ASC 260-10) reduced EAC s basic EPS by $0.07 for the three and nine months ended September 30, 2008 and reduced EAC s diluted EPS by $0.03 for the three and nine months ended September 30, 2008.

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The following table reflects the allocation of net income (loss) to EAC s common stockholders and EPS computations for the periods indicated:

	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
	(in thousands, except per share amounts)			
Basic Earnings Per Share				
Numerator:				
Undistributed net income (loss) attributable to EAC	$ (4,999)	$ 206,307	$ (59,530)	$ 201,807
Participation rights of unvested restricted stock in undistributed earnings (a)		(3,737)		(3,642)
Basic undistributed net income (loss) attributable to EAC common shares	$ (4,999)	$ 202,570	$ (59,530)	$ 198,165
Denominator:				
Basic weighted average shares outstanding	52,349	52,258	51,964	52,466
Basic EPS attributable to EAC common shares	$ (0.10)	$ 3.88	$ (1.15)	$ 3.78
Diluted Earnings Per Share				
Numerator:				
Basic undistributed net income (loss) attributable to EAC common shares	$ (4,999)	$ 206,307	$ (59,530)	$ 201,807
Participation rights of unvested restricted stock in undistributed earnings (a)		(3,631)		(3,535)
Incremental noncontrolling interest from assumed conversion of ENP MIUs		(3,143)		(3,461)
Basic undistributed net income (loss) attributable to EAC common shares	$ (4,999)	$ 199,533	$ (59,530)	$ 194,811
Denominator:				
Basic weighted average shares outstanding	52,349	52,258	51,964	52,466
Effect of dilutive options (b)		721		668
Diluted weighted average shares outstanding	52,349	52,979	51,964	53,134
Diluted EPS attributable to EAC common shares	$ (0.10)	$ 3.77	$ (1.15)	$ 3.67

(a) Unvested restricted stock

has no contractual obligation to absorb losses of EAC. Therefore, for the three and nine months ended September 30, 2009, 923,122 shares of restricted stock were outstanding but excluded from the EPS calculations because their effect would have been antidilutive. Please read Note 12. Incentive Stock Plans for additional discussion of restricted stock.

(b) For the three and nine months ended September 30, 2009, options to purchase 1,730,762 shares of common stock were outstanding but excluded from the EPS calculations because their effect would have been antidilutive. Please read Note 12. Incentive Stock Plans for additional discussion of stock options.

Note 12. 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 outstanding awards granted 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 stockholder 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 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 Special Stock Award Committee whose sole member is Jon S. Brumley, EAC s Chief Executive Officer and President. The Special 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 total number of shares of EAC s common stock reserved for issuance pursuant to the 2008 Plan is 2,400,000, of which 1,600,000 are available for grants of full value stock awards, such as restricted stock or stock units. As of September 30, 2009, there were 1,715,900 shares available for issuance under the 2008 Plan, of which 1,181,143 are available for grants of full value stock awards. 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 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;

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ENCORE ACQUISITION COMPANY
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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 grant date fair value in excess of $5.0 million.

During the nine months ended September 30, 2009 and 2008, EAC recorded non-cash stock-based compensation expense related to its incentive stock plans of $9.5 million and $6.5 million, respectively, which was allocated to LOE and general and administrative expense in the accompanying Consolidated Statements of Operations based on the allocation of the respective employees cash compensation. During the nine months ended September 30, 2009 and 2008, EAC also capitalized $1.8 million and $1.7 million, respectively, of non-cash stock-based compensation expense related to its incentive stock plans as a component of Proved properties in the accompanying Consolidated Balance Sheets. During the nine months ended September 30, 2009 and 2008, EAC recognized income tax benefits related to its incentive stock plans of $3.5 million and $2.4 million, respectively.

Please read Note 17. ENP for a discussion of ENP s unit-based compensation plans.

Stock Options

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. The fair value of options granted during the nine months ended September 30, 2009 and 2008 was estimated on the grant date using a Black-Scholes option valuation model based on the following assumptions:

	Nine months ended September 30,	
	2009	**2008**
Expected volatility	51.9%	33.7%
Expected dividend yield	0.0%	0.0%
Expected term (in years)	6.25	6.25
Risk-free interest rate	2.1%	3.0%
Weighted-average fair value per share	$ 15.81	$ 13.15

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. EAC determined the expected term 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.

The following table summarizes the changes in EAC s outstanding options for the nine months ended September 30, 2009:

	Number of Options	Weighted Average Strike Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (in thousands)
Outstanding at January 1, 2009	1,497,413	$ 18.02		
Granted	269,417	30.55		
Forfeited or expired	(12,963)	30.91		
Exercised	(23,105)	20.17		

Outstanding at September 30, 2009	1,730,762	19.85	5.1	$30,377
Exercisable at September 30, 2009	1,298,056	16.23	3.9	27,477

The total intrinsic value of options exercised during the nine months ended September 30, 2009 and 2008 was $0.3 million and $1.6 million, respectively. During the nine months ended September 30, 2009 and 2008, EAC received proceeds from the exercise of stock options of $0.5 million and $0.5 million, respectively. During the nine months ended September 30, 2009 and 2008, EAC recognized income tax benefits related to stock options of $38 thousand and $0.5 million, respectively. At September 30, 2009, EAC had $2.4 million of total unrecognized compensation cost related to unvested stock options, which is expected to be recognized over a weighted average period of 2.1 years.

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
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Restricted Stock

Restricted stock awards vest over varying periods from one to five years, subject to performance-based vesting for certain members of senior management. During the nine months ended September 30, 2009, EAC recognized expense related to restricted stock of $7.3 million and recognized an income tax provision related to the vesting of restricted stock of $0.4 million. During the nine months ended September 30, 2008, EAC recognized expense related to restricted stock of $5.5 million and recognized an income tax benefit related to the vesting of restricted stock of $0.8 million. The following table summarizes the changes in EAC s unvested restricted stock awards for the nine months ended September 30, 2009:

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2009	938,407	$ 30.67
Granted	412,449	30.52
Vested	(408,478)	29.25
Forfeited	(19,256)	30.26
Outstanding at June 30, 2009	923,122	31.20

As of September 30, 2009, there were 704,102 shares of unvested restricted stock, 188,837 shares of which were granted during 2009, in which the vesting is dependent only on the passage of time and continued employment. Additionally, as of September 30, 2009, there were 219,020 shares of unvested restricted stock, all of which were granted during 2009, in which the vesting is dependent not only on the passage of time and continued employment, but also on the achievement of certain performance measures.

None of EAC s unvested restricted stock awards are subject to variable accounting. During the nine months ended September 30, 2009 and 2008, there were 408,478 shares and 235,086 shares, respectively, of restricted stock that vested for which certain employees elected to satisfy minimum tax withholding obligations related thereto by directing EAC to withhold 111,819 shares and 28,193 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. The total fair value of restricted stock that vested during the nine months ended September 30, 2009 and 2008 was $11.0 million and $8.2 million, respectively. As of September 30, 2009, EAC had $10.6 million of total unrecognized compensation cost related to unvested restricted stock, which is expected to be recognized over a weighted average period of 2.9 years.

Note 13. Comprehensive Income (Loss)

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

	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
	(in thousands)			
Consolidated net income (loss)	$ (1,776)	$ 237,393	$ (69,199)	$ 218,005
Amortization of deferred loss on commodity derivative contracts				1,786
Change in deferred hedge loss on interest rate swaps	(343)	(264)	89	153

Consolidated comprehensive income (loss)	(2,119)	237,129	(69,110)	219,944
Less: comprehensive loss (income) attributable to noncontrolling interest	(2,630)	(30,901)	10,144	(16,330)
Comprehensive income (loss) attributable to EAC stockholders	$ (4,749)	$ 206,228	$ (58,966)	$ 203,614

Note 14. Financial Statements of Subsidiary Guarantors

Certain of EAC s wholly owned subsidiaries are 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. The following Condensed Consolidating Balance Sheets as of September 30, 2009 and December 31, 2008, Condensed Consolidating Statements of Operations and Comprehensive Income (Loss) for the three and nine

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months ended September 30, 2009 and 2008, and Condensed Consolidating Statements of Cash Flows for the nine months ended September 30, 2009 and 2008 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 September 30, 2009, EAC s guarantor subsidiaries were:

EAP Properties, Inc.;

EAP Operating, LLC;

Encore Operating, L.P.;

Encore Operating Louisiana, LLC;

Greencore Pipeline Company LLC;

Green Rock LLC; and

Belle Aire LLC.

As of September 30, 2009, EAC s non-guarantor subsidiaries were:

ENP;

OLLC;

GP LLC;

Encore Partners GP Holdings LLC;

Encore Partners LP Holdings LLC;

Encore Energy Partners Finance Corporation; and

Encore Clear Fork Pipeline LLC.

All intercompany investments in, loans due to/from, subsidiary equity, 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. Prior period amounts have not been adjusted for ENP s acquisitions from EAC. Please read Note 17. ENP for a discussion of transactions with ENP.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING BALANCE SHEET
September 30, 2009
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
ASSETS					
Current assets:					
Cash and cash equivalents	$	$ 3,246	$ 3,437	$	$ 6,683
Other current assets	9,522	150,710	51,369	(4,618)	206,983
Total current assets	9,522	153,956	54,806	(4,618)	213,666
Properties and equipment, at cost successful efforts method:					
Proved properties, including wells and related equipment		3,295,370	851,511		4,146,881
Unproved properties		104,870	61		104,931
Accumulated depletion, depreciation, and amortization		(787,211)	(198,138)		(985,349)
		2,613,029	653,434		3,266,463
Other property and equipment, net		12,087	411		12,498
Other assets, net	15,462	166,180	39,551	(6)	221,187
Investment in subsidiaries	2,869,292	(3,473)		(2,865,819)	
Total assets	$ 2,894,276	$ 2,941,779	$ 748,202	$ (2,870,443)	$ 3,713,814
LIABILITIES AND EQUITY					
Current liabilities	$ 85,661	$ 160,997	$ 33,567	$ (4,618)	$ 275,607
Deferred taxes	431,072	9		(6)	431,075
Long-term debt	983,496		260,000		1,243,496
Other liabilities		76,238	18,633		94,871
Total liabilities	1,500,229	237,244	312,200	(4,624)	2,045,049

Commitments and contingencies (see Note 15)					
Total equity	1,394,047	2,704,535	436,002	(2,865,819)	1,668,765
Total liabilities and equity	$ 2,894,276	$ 2,941,779	$ 748,202	$ (2,870,443)	$ 3,713,814

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING BALANCE SHEET
December 31, 2008
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
ASSETS					
Current assets:					
Cash and cash equivalents	$ 607	$ 813	$ 619	$	$ 2,039
Other current assets	29,004	421,392	90,797	(2,302)	538,891
Total current assets	29,611	422,205	91,416	(2,302)	540,930
Properties and equipment, at cost successful efforts method:					
Proved properties, including wells and related equipment		3,016,937	521,522		3,538,459
Unproved properties		124,272	67		124,339
Accumulated depletion, depreciation, and amortization		(670,991)	(100,573)		(771,564)
		2,470,218	421,016		2,891,234
Other property and equipment, net		11,877	562		12,439
Other assets, net	12,846	129,482	46,264		188,592
Investment in subsidiaries	2,976,208	(12,865)		(2,963,343)	
Total assets	$ 3,018,665	$ 3,020,917	$ 559,258	$ (2,965,645)	$ 3,633,195
LIABILITIES AND EQUITY					
Current liabilities	$ 118,089	$ 215,640	$ 20,825	$ (2,302)	$ 352,252
Deferred taxes	416,637		278		416,915
Long-term debt	1,169,811		150,000		1,319,811
Other liabilities		48,000	12,969		60,969
Total liabilities	1,704,537	263,640	184,072	(2,302)	2,149,947

Commitments and contingencies (see Note 15)					
Total equity	1,314,128	2,757,277	375,186	(2,963,343)	1,483,248
Total liabilities and equity	$ 3,018,665	$ 3,020,917	$ 559,258	$ (2,965,645)	$ 3,633,195

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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 September 30, 2009
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 117,669	$ 35,280	$	$ 152,949
Natural gas		26,518	5,650		32,168
Marketing		785	102		887
Total revenues		144,972	41,032		186,004
Expenses:					
Production:					
Lease operating		29,124	9,017		38,141
Production, ad valorem, and severance taxes		14,529	4,693		19,222
Depletion, depreciation, and amortization		58,169	14,458		72,627
Exploration		13,634	3,034		16,668
General and administrative	3,881	8,011	2,912	(1,534)	13,270
Marketing		304	54		358
Derivative fair value gain		(8,434)	(4,822)		(13,256)
Other operating	48	6,890	1,303		8,241
Total expenses	3,929	122,227	30,649	(1,534)	155,271
Operating income (loss)	(3,929)	22,745	10,383	1,534	30,733
Other income (expenses):					
Interest	(18,936)		(2,984)		(21,920)
Equity income from subsidiaries	29,184	2,162		(31,346)	
Other	(91)	2,202	23	(1,534)	600
Total other expenses	10,157	4,364	(2,961)	(32,880)	(21,320)
Income (loss) before income taxes	6,228	27,109	7,422	(31,346)	9,413
Income tax benefit (provision)	(11,228)	1	38		(11,189)

Consolidated net income (loss)		(5,000)		27,110		7,460		(31,346)		(1,776)
Change in deferred hedge loss on interest rate swaps, net of tax		(37)				(306)				(343)
Consolidated comprehensive income (loss)	$	(5,037)	$	27,110	$	7,154	$	(31,346)	$	(2,119)

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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 224,101	$ 44,442	$	$ 268,543
Natural gas		56,956	9,816		66,772
Marketing		718	1,445		2,163
Total revenues		281,775	55,703		337,478
Expenses:					
Production:					
Lease operating		40,124	8,842		48,966
Production, ad valorem, and severance taxes		27,609	5,741		33,350
Depletion, depreciation, and amortization		49,481	9,064		58,545
Impairment of long-lived assets		26,292			26,292
Exploration		13,335	46		13,381
General and administrative	4,723	9,050	2,600	(1,070)	15,303
Marketing		539	1,316		1,855
Derivative fair value gain		(168,992)	(70,443)		(239,435)
Other operating	41	3,688	344		4,073
Total expenses	4,764	1,126	(42,490)	(1,070)	(37,670)
Operating income (loss)	(4,764)	280,649	98,193	1,070	375,148
Other income (expenses):					
Interest	(16,357)		(1,767)		(18,124)
Equity income from subsidiaries	347,114	32,564		(379,678)	
Other	78	2,535	10	(1,070)	1,553
Total other income (expenses)	330,835	35,099	(1,757)	(380,748)	(16,571)
Income before income taxes	326,071	315,748	96,436	(379,678)	358,577
Income tax benefit (provision)	(120,943)	81	(322)		(121,184)

Consolidated net income	205,128	315,829	96,114	(379,678)	237,393
Change in deferred hedge gain on interest rate swaps, net of tax	150		(414)		(264)
Consolidated comprehensive income	$ 205,278	$ 315,829	$ 95,700	$ (379,678)	$ 237,129

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS AND COMPREHENSIVE LOSS
For the Nine Months Ended September 30, 2009
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 286,482	$ 88,433	$	$ 374,915
Natural gas		71,765	15,143		86,908
Marketing		1,627	381		2,008
Total revenues		359,874	103,957		463,831
Expenses:					
Production:					
Lease operating		91,697	31,120		122,817
Production, ad valorem, and severance taxes		36,488	11,586		48,074
Depletion, depreciation, and amortization		173,677	43,684		217,361
Exploration		40,727	3,074		43,801
General and administrative	13,595	21,860	9,138	(3,850)	40,743
Marketing		1,367	245		1,612
Derivative fair value loss (gain)		(22,452)	21,711		(741)
Other operating	131	26,558	2,730		29,419
Total expenses	13,726	369,922	123,288	(3,850)	503,086
Operating loss	(13,726)	(10,048)	(19,331)	3,850	(39,255)
Other income (expenses):					
Interest	(49,458)		(7,551)		(57,009)
Equity loss from subsidiaries	(21,460)	(8,845)		30,305	
Other	(187)	5,819	29	(3,850)	1,811
Total other expenses	(71,105)	(3,026)	(7,522)	26,455	(55,198)
Loss before income taxes	(84,831)	(13,074)	(26,853)	30,305	(94,453)
Income tax benefit (provision)	25,299	118	(163)		25,254
Consolidated net loss	(59,532)	(12,956)	(27,016)	30,305	(69,199)

Change in deferred hedge loss on interest rate swaps, net of tax	(253)		342		89
Consolidated comprehensive loss	$ (59,785)	$ (12,956)	$ (26,674)	$ 30,305	$ (69,110)

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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 647,223	$ 128,778	$	$ 776,001
Natural gas		154,347	28,626		182,973
Marketing		3,533	5,207		8,740
Total revenues		805,103	162,611		967,714
Expenses:					
Production:					
Lease operating		108,191	21,822		130,013
Production, ad valorem, and severance taxes		79,524	16,321		95,845
Depletion, depreciation, and amortization		131,715	27,399		159,114
Impairment of long-lived assets		26,292			26,292
Exploration		30,349	113		30,462
General and administrative	11,668	19,630	8,455	(3,204)	36,549
Marketing		4,044	5,318		9,362
Derivative fair value loss		60,521	21,572		82,093
Other operating	124	8,655	1,026		9,805
Total expenses	11,792	468,921	102,026	(3,204)	579,535
Operating income (loss)	(11,792)	336,182	60,585	3,204	388,179
Other income (expenses):					
Interest	(49,353)		(5,316)		(54,669)
Equity income from subsidiaries	378,946	18,724		(397,670)	
Other	30	6,172	92	(3,204)	3,090
Total other income (expenses)	329,623	24,896	(5,224)	(400,874)	(51,579)
Income before income taxes	317,831	361,078	55,361	(397,670)	336,600
Income tax provision	(118,435)		(160)		(118,595)

Consolidated net income	199,396	361,078	55,201	(397,670)	218,005
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	(103)		256		153
Consolidated comprehensive income	$ 198,222	$ 363,935	$ 55,457	$ (397,670)	$ 219,944

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
For the Nine Months Ended September 30, 2009
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Cash flows from operating activities:					
Net cash provided by (used in) operating activities	$ (42,913)	$ 583,522	$ 92,544	$	$ 633,153
Cash flows from investing activities:					
Acquisition of oil and natural gas properties		(391,975)	(31,984)		(423,959)
Development of oil and natural gas properties		(286,113)	(7,330)		(293,443)
Investments in subsidiaries	122,389			(122,389)	
Other		7,086			7,086
Net cash provided by (used in) investing activities	122,389	(671,002)	(39,314)	(122,389)	(710,316)
Cash flows from financing activities:					
Proceeds from long-term debt, net of issuance costs	387,029		203,061		590,090
Payments on long-term debt	(580,000)		(96,000)		(676,000)
Proceeds from issuance of common stock, net of offering costs	100,690				100,690
Proceeds from ENP issuance of common units, net of offering costs			170,149		170,149
Net equity contributions (distributions)		147,600	(269,989)	122,389	
Other	12,198	(57,687)	(57,633)		(103,122)
Net cash provided by (used in) financing activities	(80,083)	89,913	(50,412)	122,389	81,807
Increase (decrease) in cash and cash equivalents	(607)	2,433	2,818		4,644

Cash and cash equivalents, beginning of period	607	813	619		2,039
Cash and cash equivalents, end of period	$	$ 3,246	$ 3,437	$	$ 6,683

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
For the Nine Months Ended September 30, 2008
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Cash flows from operating activities:					
Net cash provided by operating activities	$ 289,310	$ 141,580	$ 98,097	$	$ 528,987
Cash flows from investing activities:					
Acquisition of oil and natural gas properties		(116,679)	(88)		(116,767)
Development of oil and natural gas properties		(369,396)	(15,468)		(384,864)
Investments in subsidiaries	(259,105)			259,105	
Other		(34,161)	(302)		(34,463)
Net cash used in investing activities	(259,105)	(520,236)	(15,858)	259,105	(536,094)
Cash flows from financing activities:					
Repurchase of common stock	(50,000)				(50,000)
Proceeds from long-term debt, net of issuance costs	864,969		205,269		1,070,238
Payments on long-term debt	(861,500)		(113,000)		(974,500)
Net equity contributions (distributions)		383,823	(124,718)	(259,105)	
Other	17,303	(4,175)	(49,636)		(36,508)
Net cash provided by (used in) financing activities	(29,228)	379,648	(82,085)	(259,105)	9,230
Increase in cash and cash equivalents	977	992	154		2,123
Cash and cash equivalents, beginning of period	1	1,700	3		1,704
	$ 978	$ 2,692	$ 157	$	$ 3,827

Cash and cash equivalents, end of period

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ENCORE ACQUISITION COMPANY
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Note 15. Commitments and Contingencies

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 business, financial condition, results of operations, or liquidity.

Additionally, EAC has contractual obligations related to future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal, long-term debt, derivative contracts, capital and operating leases, and development commitments. Please read Capital Commitments, Capital Resources, and Liquidity Capital commitments Contractual obligations included in Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations of this Report for a description of EAC s contractual obligations as of September 30, 2009.

Note 16. Related Party Transactions

During the nine months ended September 30, 2008, EAC received approximately $132.3 million, from affiliates of Tesoro Corporation (Tesoro) related to gross oil and gas production sold from wells operated by Encore Operating, L.P. (Encore Operating), a Texas limited partnership and indirect wholly owned subsidiary of EAC. Mr. John V. Genova, a member of the Board, served as an employee of Tesoro until May 2008.

Please read Note 17. ENP for a discussion of transactions with ENP.

Note 17. ENP

Administrative Services Agreement

ENP does not have any employees. The employees supporting ENP s operations are employees of EAC. Encore Operating performs administrative services for ENP, such as accounting, corporate development, finance, land, legal, and engineering, pursuant to an administrative services agreement. In addition, Encore Operating provides all personnel, facilities, goods, and equipment necessary to perform these services which are not otherwise provided for by ENP. 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.

Encore Operating initially received an administrative fee of $1.75 per BOE of ENP s production for such services. From April 1, 2008 to March 31, 2009, the administration fee was $1.88 per BOE of ENP s production. Effective April 1, 2009, the administrative fee increased to $2.02 per BOE of ENP s production. ENP also reimburses Encore Operating for actual third-party expenses incurred on ENP s behalf. Encore Operating has substantial discretion in determining which third-party expenses to incur on ENP s behalf. 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.

The administrative fee will increase in the following circumstances:

- beginning on the first day of April in each year by an amount equal to the product of the then-current administrative fee multiplied by the COPAS Wage Index Adjustment for that year;
- if ENP or one of its subsidiaries acquires additional assets, Encore Operating may propose an increase in its administrative fee that covers the provision of services for such additional assets; however, such proposal must be approved by the board of directors of GP LLC upon the recommendation of its conflicts committee; and
- otherwise as agreed upon by Encore Operating and GP LLC, with the approval of the conflicts committee of the board of directors of GP LLC.

ENP reimburses EAC for any state income, franchise, or similar tax incurred 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 incurred had they not been included in a combined group with EAC.

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Sales of Assets to ENP

In August 2009, Encore Operating sold certain oil and natural gas properties and related assets in the Big Horn Basin in Wyoming, the Permian Basin in West Texas and New Mexico, and the Williston Basin in Montana and North Dakota (the Rockies and Permian Basin Assets) to ENP for approximately $186.8 million in cash, which ENP financed through borrowings under the OLLC Credit Agreement and proceeds from the issuance of ENP common units to the public. EAC used the proceeds from the sale of properties to fund a portion of the purchase price of its acquisitions from EXCO.

In June 2009, Encore Operating sold certain oil and natural gas producing properties and related assets in the Williston Basin in North Dakota and Montana (the Williston Basin Assets) to ENP for approximately $25.2 million in cash, which ENP financed through borrowings under the OLLC Credit Agreement and proceeds from the issuance of ENP common units to the public. EAC used the proceeds from the sale of the properties to reduce outstanding borrowings under the EAC Credit Agreement.

In January 2009, Encore Operating sold certain oil and natural gas producing properties and related assets in the Arkoma Basin in Arkansas and royalty interest properties primarily in Oklahoma, as well as 10,300 unleased mineral acres (the Arkoma Basin Assets), to ENP for approximately $46.4 million in cash, which ENP financed through borrowings under the OLLC Credit Agreement. EAC used the proceeds from the sale of the properties to reduce outstanding borrowings under the EAC Credit Agreement.

In February 2008, Encore Operating sold certain oil and natural gas properties and related assets in the Permian Basin in West Texas and in the Williston Basin in North Dakota to ENP for approximately $125.0 million in cash and 6,884,776 ENP common units. In determining the total purchase price, the common units were valued at $125.0 million. However, no accounting value was ascribed to the common units as the cash consideration exceeded Encore Operating s carrying value of the properties. ENP financed the cash portion of the purchase price through borrowings under the OLLC Credit Agreement. EAC used the proceeds from the sale of the properties to reduce outstanding borrowings under the EAC Credit Agreement.

Shelf Registration Statement on Form S-3

In November 2008, ENP s shelf registration statement on Form S-3 was declared effective by the SEC. Under the shelf registration statement, ENP may offer common units, senior debt, or subordinated debt in one or more offerings with a total initial offering price of up to $1 billion.

Public Offerings of Common Units

In July 2009, ENP issued 9,430,000 common units under its shelf registration statement at a price to the public of $14.30 per common unit. ENP used the net proceeds of approximately $129.2 million, after deducting the underwriters discounts and commissions of $5.4 million, in the aggregate, and offering costs of $0.2 million, to fund a portion of the purchase price of the Rockies and Permian Basin Assets.

In May 2009, ENP issued 2,760,000 common units under its shelf registration statement at a price to the public of $15.60 per common unit. ENP used the net proceeds of approximately $40.9 million, after deducting the underwriters discounts and commissions of $1.9 million, in the aggregate, and offering costs of approximately $0.2 million, to fund the acquisition of certain natural gas producing properties in the Vinegarone Field in Val Verde County, Texas (the Vinegarone Assets) from an independent energy company for approximately $27.5 million, and a portion of the purchase price of the Williston Basin Assets.

Long-Term Incentive Plan

In September 2007, the board of directors of GP LLC adopted the Encore Energy Partners GP LLC 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 ENP Plan is administered by the board of directors of GP LLC or a committee thereof, referred to as the plan administrator. To satisfy common unit awards under the ENP

Plan, ENP may issue common units, acquire common units in the open market, or use common units owned by EAC and its affiliates.

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The total number of common units reserved for issuance pursuant to the ENP Plan is 1,150,000. As of September 30, 2009, there were 1,100,000 common units available for issuance under the ENP Plan.

Phantom Units. Each October, ENP issues 5,000 phantom units to each 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. ENP intends to settle the phantom units at vesting by issuing common units to the grantee; therefore, these phantom units are classified as equity instruments. Phantom units vest equally over a four-year period. The holders of phantom units are also entitled to distribution equivalent rights prior to vesting, which entitle them to receive cash equal to the amount of any cash distributions paid by ENP with respect to a common unit during the period the right is outstanding. During the nine months ended September 30, 2009 and 2008, ENP recognized non-cash unit-based compensation expense related to phantom units of approximately $0.3 million and $0.2 million, respectively, which is included in General and administrative expense in the accompanying Consolidated Statements of Operations.

The following table summarizes the changes in ENP s unvested phantom units for the nine months ended September 30, 2009:

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2009	43,750	$18.67
Granted		
Vested		
Forfeited		
Outstanding at September 30, 2009	43,750	18.67

As of September 30, 2009, ENP had $0.4 million of total unrecognized compensation cost related to unvested phantom units, which is expected to be recognized over a weighted average period of 1.9 years.

Management Incentive Units

In May 2007, the board of directors of GP LLC issued 550,000 management incentive units to certain executive officers of GP LLC. During the fourth quarter of 2008, the management incentive units became convertible into ENP common units, at the option of the holder, at a ratio of one management incentive unit to approximately 3.1186 ENP common units, and all 550,000 management incentive units were converted into 1,715,205 ENP common units.

During the three and nine months ended September 30, 2008, ENP recognized non-cash unit-based compensation expense related to management incentive units of $1.1 million and $3.2 million, respectively, which is included in General and administrative expense in the accompanying Consolidated Statements of Operations. There have been no additional issuances of management incentive units.

Distributions

During the three and nine months ended September 30, 2009, ENP paid cash distributions of approximately $23.5 million and $57.1 million, respectively, of which $11.0 million and $32.4 million, respectively, was paid to EAC and its subsidiaries and had no impact on EAC s consolidated cash. During the three and nine months ended September 30, 2008, ENP paid cash distributions of approximately $23.1 million and $52.3 million, respectively, of which $14.7 million and $32.7 million, respectively, was paid to EAC and its subsidiaries and had no impact on EAC s consolidated cash.

During the three and nine months ended September 30, 2008, ENP paid cash distributions of approximately $1.2 million and $2.4 million, respectively, to certain executive officers of GP LLC, who serve in the same capacities for EAC, based on their ownership of management incentive units.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
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Note 18. 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 is 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 to Notes to the Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Date of EAC s 2008 Annual Report on Form 10-K.

The following tables provide EAC s operating segment information required by SFAS No. 131, *Disclosure about Segments of an Enterprise and Related Information* (ASC 280-10). The prior period financial information of ENP in the following tables was recast to include the financial results of the Rockies and Permian Basin Assets, the Arkoma Basin Assets, and the Williston Basin Assets.

	For the Three Months Ended September 30, 2009			
	EAC Standalone	ENP	Eliminations	Consolidated Total
	(in thousands)			
Revenues:				
Oil	$ 117,669	$ 35,280	$	$ 152,949
Natural gas	26,518	5,650		32,168
Marketing	785	102		887
Total revenues	144,972	41,032		186,004
Expenses:				
Production:				
Lease operating	29,124	9,017		38,141
Production, ad valorem, and severance taxes	14,529	4,693		19,222
Depletion, depreciation, and amortization	58,169	14,458		72,627
Exploration	13,634	3,034		16,668
General and administrative	11,892	2,912	(1,534)	13,270
Marketing	304	54		358
Derivative fair value gain	(8,434)	(4,822)		(13,256)
Other operating	6,938	1,303		8,241
Total expenses	126,156	30,649	(1,534)	155,271
Operating income	18,816	10,383	1,534	30,733
Other income (expenses):				
Interest	(18,936)	(2,984)		(21,920)
Other	2,111	23	(1,534)	600

Total other expenses	(16,825)	(2,961)	(1,534)	(21,320)
Income before income taxes	1,991	7,422		9,413
Income tax benefit (provision)	(11,227)	38		(11,189)
Consolidated net income (loss)	(9,236)	7,460		(1,776)
Change in deferred hedge loss on interest rate swaps, net of tax	(37)	(306)		(343)
Consolidated comprehensive income (loss)	$ (9,273)	$ 7,154	$	$ (2,119)

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	For the Three Months Ended September 30, 2008			
	EAC Standalone	ENP	Eliminations	Consolidated Total
	(in thousands)			
Revenues:				
Oil	$ 201,322	$ 67,221	$	$ 268,543
Natural gas	51,328	15,444		66,772
Marketing	718	1,445		2,163
Total revenues	253,368	84,110		337,478
Expenses:				
Production:				
Lease operating	35,999	12,967		48,966
Production, ad valorem, and severance taxes	25,140	8,210		33,350
Depletion, depreciation, and amortization	44,725	13,820		58,545
Impairment of long-lived assets	26,292			26,292
Exploration	13,334	47		13,381
General and administrative	12,601	3,772	(1,070)	15,303
Marketing	539	1,316		1,855
Derivative fair value gain	(168,992)	(70,443)		(239,435)
Other operating	3,633	440		4,073
Total expenses	(6,729)	(29,871)	(1,070)	(37,670)
Operating income	260,097	113,981	1,070	375,148
Other income (expenses):				
Interest	(16,357)	(1,767)		(18,124)
Other	2,613	10	(1,070)	1,553
Total other expenses	(13,744)	(1,757)	(1,070)	(16,571)
Income before income taxes	246,353	112,224		358,577
Income tax provision	(120,852)	(332)		(121,184)
Consolidated net income	125,501	111,892		237,393
Change in deferred hedge gain on interest rate swaps, net of tax	333	(597)		(264)

Consolidated comprehensive income	$ 125,834	$ 111,295	$	$ 237,129

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	For the Nine Months Ended September 30, 2009			
	EAC Standalone	ENP	Eliminations	Consolidated Total
	(in thousands)			
Revenues:				
Oil	$ 286,482	$ 88,433	$	$ 374,915
Natural gas	71,765	15,143		86,908
Marketing	1,627	381		2,008
Total revenues	359,874	103,957		463,831
Expenses:				
Production:				
Lease operating	91,697	31,120		122,817
Production, ad valorem, and severance taxes	36,488	11,586		48,074
Depletion, depreciation, and amortization	173,677	43,684		217,361
Exploration	40,727	3,074		43,801
General and administrative	35,458	9,135	(3,850)	40,743
Marketing	1,367	245		1,612
Derivative fair value loss (gain)	(22,452)	21,711		(741)
Other operating	26,689	2,730		29,419
Total expenses	383,651	123,285	(3,850)	503,086
Operating loss	(23,777)	(19,328)	3,850	(39,255)
Other income (expenses):				
Interest	(49,458)	(7,551)		(57,009)
Other	5,632	29	(3,850)	1,811
Total other expenses	(43,826)	(7,522)	(3,850)	(55,198)
Loss before income taxes	(67,603)	(26,850)		(94,453)
Income tax benefit (provision)	25,417	(163)		25,254
Consolidated net loss	(42,186)	(27,013)		(69,199)
Change in deferred hedge loss on interest rate swaps, net of tax	(253)	342		89
Consolidated comprehensive loss	$ (42,439)	$ (26,671)	$	$ (69,110)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
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	For the Nine Months Ended September 30, 2008			
	EAC Standalone	ENP	Eliminations	Consolidated Total
	(in thousands)			
Revenues:				
Oil	$ 578,414	$ 197,587	$	$ 776,001
Natural gas	137,563	45,410		182,973
Marketing	3,533	5,207		8,740
Total revenues	719,510	248,204		967,714
Expenses:				
Production:				
Lease operating	95,944	34,069		130,013
Production, ad valorem, and severance taxes	72,134	23,711		95,845
Depletion, depreciation, and amortization	116,618	42,496		159,114
Impairment of long-lived assets	26,292			26,292
Exploration	30,347	115		30,462
General and administrative	27,854	11,899	(3,204)	36,549
Marketing	4,044	5,318		9,362
Derivative fair value loss	60,521	21,572		82,093
Other operating	8,511	1,294		9,805
Total expenses	442,265	140,474	(3,204)	579,535
Operating income	277,245	107,730	3,204	388,179
Other income (expenses):				
Interest	(49,353)	(5,316)		(54,669)
Other	6,202	92	(3,204)	3,090
Total other expenses	(43,151)	(5,224)	(3,204)	(51,579)
Income before income taxes	234,094	102,506		336,600
Income tax provision	(118,401)	(194)		(118,595)
Consolidated net income	115,693	102,312		218,005
Amortization of deferred loss on commodity derivative contracts, net of tax	1,786			1,786

Change in deferred hedge gain on interest rate swaps, net of tax	(234)	387		153
Consolidated comprehensive income	$ 117,245	$ 102,699	$	$ 219,944

The following table provides EAC s balance sheet segment information as of the dates indicated:

	September 30, 2009	December 31, 2008
	(in thousands)	
Segment assets:		
EAC Standalone	$ 2,967,971	$ 2,823,778
ENP	748,202	813,313
Eliminations	(2,359)	(3,896)
Total consolidated assets	$ 3,713,814	$ 3,633,195
Segment liabilities:		
EAC Standalone	$ 1,735,108	$ 1,961,453
ENP	312,200	193,962
Eliminations	(2,259)	(5,468)
Total consolidated liabilities	$ 2,045,049	$ 2,149,947

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Note 19. Subsequent Events

Subsequent events were evaluated through November 2, 2009, which is the date the financial statements were issued.

On October 26, 2009, the board of directors of GP LLC declared an ENP cash distribution for the third quarter of 2009 to unitholders of record as of the close of business on November 9, 2009 at a rate of $0.5375 per unit. Approximately $24.6 million is expected to be paid to unitholders on or about November 13, 2009.

On October 26, 2009, ENP issued 25,000 phantom units to members of GP LLC s board of directors pursuant to the ENP Plan. The phantom units vest in four equal installments beginning on the first anniversary of the date of grant.

On November 1, 2009, EAC announced that it had entered into a definitive merger agreement with Denbury Resources Inc. (Denbury) pursuant to which Denbury will acquire EAC in a transaction valued at approximately $4.5 billion, including the assumption of debt and the value of the minority interest in ENP. Under the definitive agreement, EAC stockholders will receive $50.00 per share for each share of EAC common stock, comprised of $15.00 in cash and $35.00 in Denbury common stock subject to both an election feature and a collar mechanism on the stock portion of the consideration. Completion of the transaction is subject to the approval of both Denbury and EAC stockholders, regulatory approvals, and other conditions.

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ENCORE ACQUISITION COMPANY

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 discussed in the forward-looking statements due to many factors, including, but not limited to, those set forth under Item 1A. Risk Factors and elsewhere in our 2008 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 2008 Annual Report on Form 10-K.

Introduction

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

- Third Quarter 2009 Highlights
- Results of Operations
  - o Comparison of Quarter Ended September 30, 2009 to Quarter Ended September 30, 2008
  - o Comparison of Nine Months Ended September 30, 2009 to Nine Months Ended September 30, 2008
- Capital Commitments, Capital Resources, and Liquidity
- Critical Accounting Policies and Estimates
- New Accounting Pronouncements

Third Quarter 2009 Highlights

Our financial and operating results for the third quarter of 2009 included the following:

- Our average daily production volumes increased nine percent to 43,225 BOE/D as compared to 39,617 BOE/D in the third quarter of 2008. Oil represented 64 percent of our total production volumes as compared to 68 percent in the third quarter of 2008.
- In September 2009, we issued 2,750,000 shares of our common stock at a price to the public of $37.40 per common share. The net proceeds of approximately $100.7 million were used to reduce outstanding borrowings under our revolving credit facility.
- In August, we purchased certain oil and natural gas properties and related assets in the Mid-Continent and East Texas from EXCO for approximately $357.0 million in cash (including a deposit of $37.5 million made in June 2009).
- In August, we sold the Rockies and Permian Basin Assets to ENP for approximately $186.8 million in cash.
- In July, ENP issued 9,430,000 common units under its shelf registration statement at a price to the public of $14.30 per common unit. The net proceeds of approximately $129.1 million were used to fund a portion of the purchase price of the Rockies and Permian Basin Assets.
- We invested $411.5 million in oil and natural gas activities (excluding $3.5 million of asset retirement obligations), of which $42.7 million was invested in development, exploitation, and exploration activities, yielding 22 gross (7.7 net) productive wells, and $368.8 million was invested in acquisitions, primarily related to our EXCO asset acquisition.

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Results of Operations

Comparison of Quarter Ended September 30, 2009 to Quarter Ended September 30, 2008

Revenues. The following table provides the components of our revenues for the periods indicated, as well as each period s respective production volumes and average prices:

	Three months ended September 30, 2009	Three months ended September 30, 2008	Increase / (Decrease) $	Increase / (Decrease) %
Revenues (in thousands):				
Oil wellhead	$ 152,949	$ 268,543	*$ (115,594)*	*-43%*
Natural gas wellhead	32,168	66,772	*(34,604)*	*-52%*
Total combined oil and natural gas revenues	185,117	335,315	*(150,198)*	*-45%*
Marketing	887	2,163	*(1,276)*	*-59%*
Total revenues	$ 186,004	$ 337,478	$ (151,474)	*-45%*
Average realized prices:				
Oil ($/Bbl)	$ 60.45	$ 108.21	*$ (47.76)*	*-44%*
Natural gas ($/Mcf)	$ 3.71	$ 9.57	*$ (5.86)*	*-61%*
Total combined oil and natural gas revenues ($/BOE)	$ 46.55	$ 92.00	*$ (45.45)*	*-49%*
Total production volumes:				
Oil (MBbls)	2,530	2,482	*48*	*2%*
Natural gas (MMcf)	8,681	6,978	*1,703*	*24%*
Combined (MBOE)	3,977	3,645	*332*	*9%*
Average daily production volumes:				
Oil (Bbls/D)	27,500	26,975	*525*	*2%*
Natural gas (Mcf/D)	94,353	75,847	*18,506*	*24%*
Combined (BOE/D)	43,225	39,617	*3,608*	*9%*
Average NYMEX prices:				
Oil (per Bbl)	$ 68.24	$ 118.67	*$ (50.43)*	*-42%*
Natural gas (per Mcf)	$ 3.40	$ 10.27	*$ (6.87)*	*-67%*

Oil revenues decreased 43 percent from $268.5 million in the third quarter of 2008 to $152.9 million in the third quarter of 2009 as a result of a $47.76 per Bbl decrease in our average realized oil price, partially offset by a 48 MBbls increase in our oil production volumes. Our lower average realized oil price decreased oil revenues by approximately $120.8 million and was primarily due to a lower average NYMEX price, which decreased from $118.67 per Bbl in the third quarter of 2008 to $68.24 per Bbl in the third quarter of 2009. Our higher oil production volumes increased oil revenues by approximately $5.2 million and was primarily due to our acquisitions of properties from EXCO in August 2009.

In the third quarter of 2009 and 2008, our average daily production volumes were decreased by 1,654 BOE/D and 1,535 BOE/D, respectively, for net profits interests related to our CCA properties, which reduced our oil wellhead revenues by approximately $8.8 million and $18.5 million, respectively.

Natural gas revenues decreased 52 percent from $66.8 million in the third quarter of 2008 to $32.2 million in the third quarter of 2009 as a result of a $5.86 per Mcf decrease in our average realized natural gas price, partially offset by a 1,703 MMcf increase in our natural gas production volumes. Our lower average realized natural gas price decreased natural gas revenues by approximately $50.9 million and was primarily due to a lower average NYMEX price, which decreased from $10.27 per Mcf in the third quarter of 2008 to $3.40 per Mcf in the third quarter of 2009. Our higher natural gas production increased natural gas revenues by approximately $16.3 million and was primarily due to our acquisitions of properties from EXCO in August 2009.

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

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	Three months ended September 30,	
	2009	**2008**
Average realized oil price ($/Bbl)	$ 60.45	$ 108.21
Average NYMEX ($/Bbl)	$ 68.24	$ 118.67
Differential to NYMEX	$ (7.79)	$ (10.46)
Average realized oil price to NYMEX percentage	89%	91%
Average realized natural gas price ($/Mcf)	$ 3.71	$ 9.57
Average NYMEX ($/Mcf)	$ 3.40	$ 10.27
Differential to NYMEX	$ 0.31	$ (0.70)
Average realized natural gas price to NYMEX percentage	109%	93%

Our average oil wellhead price as a percentage of the average NYMEX price was 89 percent in the third quarter of 2009 as compared to 91 percent in the third quarter of 2008.

Our average natural gas wellhead price as a percentage of the average NYMEX price was 109 percent in the third quarter of 2009 as compared to 93 percent in the third quarter of 2008. 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. In the third quarter of 2009, the natural gas index prices related to our West Texas, East Texas, and Rocky Mountains natural gas contracts all improved in their relationship to NYMEX narrowing the average differential. As a result of the incremental NGLs value and the narrower differentials, the price we were paid per Mcf for natural gas sold under certain contracts during the third quarter of 2009 increased to a level above NYMEX.

Marketing revenues decreased 59 percent from $2.2 million in the third quarter of 2008 to $0.9 million in the third quarter of 2009 primarily as a result of a reduction in natural gas throughput in our Wildhorse pipeline and the decrease in natural gas prices. Natural gas volumes are purchased from numerous gas producers at the inlet of the pipeline and resold downstream to various local and off-system markets.

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Expenses. The following table provides the components of our expenses for the periods indicated:

	Three months ended September 30,		Increase / (Decrease)	
	2009	2008	$	%
Expenses (in thousands):				
Production:				
Lease operating	$ 38,141	$ 48,966	$ (10,825)	
Production, ad valorem, and severance taxes	19,222	33,350	(14,128)	
Total production expenses	57,363	82,316	(24,953)	-30%
Other:				
Depletion, depreciation, and amortization	72,627	58,545	14,082	
Impairment of long-lived assets		26,292	(26,292)	
Exploration	16,668	13,381	3,287	
General and administrative	13,270	15,303	(2,033)	
Marketing	358	1,855	(1,497)	
Derivative fair value gain	(13,256)	(239,435)	226,179	
Other operating	8,241	4,073	4,168	
Total operating expenses	155,271	(37,670)	192,941	-512%
Interest	21,920	18,124	3,796	
Income tax provision	11,189	121,184	(109,995)	
Total expenses	$ 188,380	$ 101,638	$ 86,742	85%
Expenses (per BOE):				
Production:				
Lease operating	$ 9.59	$ 13.43	$ (3.84)	
Production, ad valorem, and severance taxes	4.83	9.15	(4.32)	
Total production expenses	14.42	22.58	(8.16)	-36%
Other:				
Depletion, depreciation, and amortization	18.26	16.06	2.20	
Impairment of long-lived assets		7.21	(7.21)	
Exploration	4.19	3.67	0.52	
General and administrative	3.34	4.20	(0.86)	
Marketing	0.09	0.51	(0.42)	
Derivative fair value gain	(3.33)	(65.69)	62.36	
Other operating	2.07	1.12	0.95	
Total operating expenses	39.04	(10.34)	49.38	-478%
Interest	5.51	4.97	0.54	
Income tax provision	2.81	33.25	(30.44)	
Total expenses	$ 47.36	$ 27.88	$ 19.48	70%

Production expenses. Total production expenses decreased 30 percent from $82.3 million in the third quarter of 2008 to $57.4 million in the third quarter of 2009. Our production margin decreased 50 percent from $253.0 million in the third quarter of 2008 to $127.8 million in the third quarter of 2009. Total oil and natural gas wellhead revenues per BOE decreased by 49 percent and total production expenses per BOE decreased by 36 percent. On a per BOE basis, our production margin decreased 54 percent to $32.13 per BOE in the third quarter of 2009 as compared to $69.42 per BOE in the third quarter of 2008.

Production expense attributable to LOE decreased $10.8 million from $49.0 million in the third quarter of 2008 to $38.1 million in the third quarter of 2009 as a result of a $3.84 decrease in the per BOE rate, partially offset by higher production volumes. Our lower average LOE per BOE rate decreased LOE by approximately $15.3 million and was primarily due to decreases in natural gas prices resulting in lower electricity costs and gas plant fuel costs, lower prices paid to oilfield service companies and suppliers, and retention bonuses paid in August 2008 related to our 2008 strategic alternatives process. Our higher production volumes increased LOE by approximately $4.5 million.

Production expense attributable to production taxes decreased $14.1 million from $33.4 million in the third quarter of 2008 to $19.2 million in the third quarter of 2009 primarily due to lower wellhead revenues, which exclude the effects of commodity derivative contracts. As a percentage of wellhead revenues, production taxes increased to 10.4 percent in the third quarter of 2009 as

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compared to 9.9 percent in the third quarter of 2008 primarily due to higher ad valorem taxes, which are based on production volumes as opposed to a percentage of wellhead revenues.

Depletion, depreciation, and amortization expense (DD&A). DD&A expense increased $14.1 million from $58.5 million in the third quarter of 2008 to $72.6 million in the third quarter of 2009 as a result of a $2.20 increase in the per BOE rate and higher production volumes. Our higher average DD&A per BOE rate increased DD&A expense by approximately $8.7 million and was primarily due to the decrease in our proved reserves as a result of lower average commodity prices, partially offset by reserves added through our EXCO asset acquisition. Our higher production volumes increased DD&A expense by approximately $5.3 million.

Impairment of long-lived assets. During the third quarter of 2008, circumstances indicated that the carrying value of the two wells we drilled in the Tuscaloosa Marine Shale may not be recoverable. We compared the assets carrying value to the undiscounted expected future net cash flows, which indicated a need for an impairment charge. We then compared the net book value of the impaired assets to their estimated discounted value, which resulted in a write-down of the value of proved oil and natural gas properties of $26.3 million. Fair value was determined using estimates of future production volumes and estimates of future prices we might receive for these volumes, discounted to a present value.

Exploration expense. Exploration expense increased $3.3 million from $13.4 million in the third quarter of 2008 to $16.7 million in the third quarter of 2009. During the third quarter of 2009, we expensed 1.6 net exploratory dry holes totaling $9.8 million. During the third quarter of 2008, we expensed 1.3 net exploratory dry holes totaling $7.2 million. Impairment of unproved acreage increased $1.4 million from $5.0 million in the third quarter of 2008 to $6.4 million in the third quarter of 2009, primarily due to our larger unproved property base, as well as the impairment of certain acreage through the normal course of evaluation. The following table provides the components of exploration expense for the periods indicated:

	Three months ended September 30, 2009	Three months ended September 30, 2008	*Increase / (Decrease)*
		(in thousands)	
Dry holes	$ 9,759	$ 7,161	*$ 2,598*
Geological and seismic	282	1,070	*(788)*
Delay rentals	276	157	*119*
Impairment of unproved acreage	6,351	4,993	*1,358*
Total	$ 16,668	$ 13,381	*$ 3,287*

General and administrative expense (G&A). G&A expense decreased $2.0 million from $15.3 million in the third quarter of 2008 to $13.3 million in the third quarter of 2009 primarily due to retention bonuses paid in August 2008 related to our 2008 strategic alternatives process and a decrease in non-cash equity-based compensation related to ENP s management incentive units, partially offset by the expensing of transaction costs related to our EXCO asset acquisition.

Marketing expenses. Marketing expenses decreased $1.5 million from $1.9 million in the third quarter of 2008 to $0.4 million in the third quarter of 2009 primarily due to a reduction in natural gas throughput in our Wildhorse pipeline and the decrease in natural gas prices. Natural gas volumes are purchased from numerous gas producers at the inlet of the pipeline and resold downstream to various local and off-system markets.

Derivative fair value gain. During the third quarter of 2009, we recorded a $13.3 million derivative fair value gain as compared to $239.4 million in the third quarter of 2008, the components of which were as follows:

	Three months ended September 30,	*Increase /*

	2009	2008	(Decrease)
		(in thousands)	
Ineffectiveness	$ 18	$ (6)	*$ 24*
Mark-to-market loss (gain)	576	(276,932)	*277,508*
Premium amortization	6,838	14,773	*(7,935)*
Settlements	(20,688)	22,730	*(43,418)*
Total derivative fair value gain	$ (13,256)	$ (239,435)	*$ 226,179*

Other operating expense. Other operating expense increased $4.2 million from $4.1 million in the third quarter of 2008 to $8.2

million in the third quarter of 2009 primarily due to a $0.7 million adjustment to the carrying value of pipe and other tubular inventory whose market value had declined below cost, a $2.4 million adjustment to the carrying value of certain receivables, primarily from ExxonMobil related to our West Texas joint venture, and higher gathering and transportation fees.

Interest expense. Interest expense increased $3.8 million from $18.1 million in the third quarter of 2008 to $21.9 million in the third quarter of 2009 primarily due to the issuance of $225 million of our 9.5% Notes. We received net proceeds of approximately $202.5 million from the issuance of the 9.5% Notes, which we used to reduce outstanding borrowings under our revolving credit facility. Our weighted average interest rate was 6.5 percent for the third quarter of 2009 as compared to 5.6 percent for the third quarter of 2008.

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

	Three months ended September 30,		***Increase /***
	2009	**2008**	***(Decrease)***
		(in thousands)	
6.25% Senior Subordinated Notes	$ 2,439	$ 2,433	*$ 6*
6.0% Senior Subordinated Notes	4,648	4,640	*8*
9.5% Senior Subordinated Notes	5,904		*5,904*
7.25% Senior Subordinated Notes	2,752	2,749	*3*
Revolving credit facilities	4,786	7,478	*(2,692)*
Other	1,391	824	*567*
Total	$ 21,920	$ 18,124	*$ 3,796*

Income taxes. In the third quarter of 2009, we recorded an income tax provision of $11.2 million as compared to $121.2 million in the third quarter of 2008. In the third quarter of 2009, we had income before income taxes and noncontrolling interest of $9.4 million as compared to $358.6 million in the third quarter of 2008. Our effective tax rate increased to 118.9 percent in the third quarter of 2009 as compared to 33.8 percent in the third quarter of 2008 primarily due to the loss of the production activities deduction in 2009, the 2008 provision to return difference in the production activities deduction estimated at the end of 2008 due to a change in tax planning as a result of the hedge monetization in the first quarter of 2009, and an increase in the effective state income tax rate due to changes in apportionment associated with our 2009 acquisitions.

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Comparison of Nine Months Ended September 30, 2009 to Nine Months Ended September 30, 2008

Revenues. The following table provides the components of our revenues for the periods indicated, as well as each period s respective production volumes and average prices:

	Nine months ended September 30,		Increase / (Decrease)	
	2009	2008	$	%
Revenues (in thousands):				
Oil wellhead	$ 374,915	$ 778,858	$ (403,943)	
Oil hedges		(2,857)	2,857	
Total oil revenues	$ 374,915	$ 776,001	$ (401,086)	-52%
Natural gas wellhead	$ 86,908	$ 182,973	$ (96,065)	-53%
Combined wellhead	$ 461,823	$ 961,831	$ (500,008)	
Combined hedges		(2,857)	2,857	
Total combined oil and natural gas revenues	461,823	958,974	(497,151)	-52%
Marketing	2,008	8,740	(6,732)	-77%
Total revenues	$ 463,831	$ 967,714	$ (503,883)	-52%
Average realized prices:				
Oil wellhead ($/Bbl)	$ 50.34	$ 104.61	$ (54.27)	
Oil hedges ($/Bbl)		(0.38)	0.38	
Total oil revenues ($/Bbl)	$ 50.34	$ 104.23	$ (53.89)	-52%
Natural gas wellhead ($/Mcf)	$ 3.56	$ 9.67	$ (6.11)	-63%
Combined wellhead ($/BOE)	$ 40.10	$ 90.76	$ (50.66)	
Combined hedges ($/BOE)		(0.27)	0.27	
Total combined oil and natural gas revenues ($/BOE)	$ 40.10	$ 90.49	$ (50.39)	-56%
Total production volumes:				
Oil (MBbls)	7,448	7,446	2	0%
Natural gas (MMcf)	24,408	18,915	5,493	29%
Combined (MBOE)	11,516	10,598	918	9%

Average daily production volumes:				
Oil (Bbls/D)	27,281	27,174	*107*	*0%*
Natural gas (Mcf/D)	89,405	69,031	*20,374*	*30%*
Combined (BOE/D)	42,182	38,679	*3,503*	*9%*
Average NYMEX prices:				
Oil (per Bbl)	$ 57.22	$ 113.59	*$ (56.37)*	*-50%*
Natural gas (per Mcf)	$ 3.93	$ 9.74	*$ (5.81)*	*-60%*

Oil revenues decreased 52 percent from $776.0 million in the first nine months of 2008 to $374.9 million in the first nine months of 2009 as a result of a $53.89 per Bbl decrease in our average realized oil price. Our lower average oil wellhead price decreased oil revenues by approximately $404.2 million, or $54.27 per Bbl, and was primarily due to a lower average NYMEX price, which decreased from $113.59 per Bbl in the first nine months of 2008 to $57.22 Bbl in the first nine months of 2009. Oil revenues in the first nine months of 2008 were also reduced by approximately $2.9 million, or $0.38 per Bbl, for oil derivative contracts previously designated as hedges.

In the first nine months of 2009 and 2008, our average daily production volumes were decreased by 1,710 BOE/D and 1,766 BOE/D, respectively, for net profits interests related to our CCA properties, which reduced our oil wellhead revenues by approximately $21.1 million and $49.7 million, respectively.

Natural gas revenues decreased 53 percent from $183.0 million in the first nine months of 2008 to $86.9 million in the first nine months of 2009 as a result of a $6.11 per Mcf decrease in our average realized natural gas price, partially offset by a 5,493 MMcf increase in our natural gas production volumes. Our lower average realized natural gas price decreased natural gas revenues by approximately $149.2 million and was primarily due to a lower average NYMEX price, which decreased from $9.74 per Mcf in the

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first nine months of 2008 to $3.93 per Mcf in the first nine months of 2009. Our higher natural gas production increased natural gas revenues by approximately $53.1 million and was primarily due to successful development programs in our Permian Basin and Mid-Continent areas and our acquisitions of properties from EXCO in August 2009.

The following table shows the relationship between our oil and natural gas wellhead prices as a percentage of average NYMEX prices for the periods indicated:

	Nine months ended September 30,	
	2009	**2008**
Average oil wellhead ($/Bbl)	$ 50.34	$ 104.61
Average NYMEX ($/Bbl)	$ 57.22	$ 113.59
Differential to NYMEX	$ (6.88)	$ (8.98)
Average oil wellhead to NYMEX percentage	88%	92%
Average natural gas wellhead ($/Mcf)	$ 3.56	$ 9.67
Average NYMEX ($/Mcf)	$ 3.93	$ 9.74
Differential to NYMEX	$ (0.37)	$ (0.07)
Average natural gas wellhead to NYMEX percentage	91%	99%

Our average oil wellhead price as a percentage of the average NYMEX price was 88 percent in the first nine months of 2009 as compared to 92 percent in the first nine months of 2008. The percentage differential widened as a result of a 50 percent decrease in NYMEX as compared to the first nine months of 2008. However, the per Bbl differential improved from $8.98 per Bbl in the first nine months of 2008 to $6.88 per Bbl in the first nine months of 2009.

Our average natural gas wellhead price as a percentage of the average NYMEX price was 91 percent in the first nine months of 2009 as compared to 99 percent in the first nine months of 2008. 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. During the first nine months of 2008, the price of NGLs increased at a much faster pace than did the price of natural gas resulting in a price we were paid per Mcf under certain contracts to be higher than the average NYMEX price. However, in the first nine months of 2009, the total average natural gas index prices related to our West Texas, East Texas, and Rocky Mountains natural gas contracts all deteriorated in their relationship to NYMEX widening the year-to-date average differential.

Marketing revenues decreased 77 percent from $8.7 million in the first nine months of 2008 to $2.0 million in the first nine months of 2009 primarily as a result of a reduction in natural gas throughput in our Wildhorse pipeline and the decrease in natural gas prices. Natural gas volumes are purchased from numerous gas producers at the inlet of the pipeline and resold downstream to various local and off-system markets.

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Expenses. The following table provides the components of our expenses for the periods indicated:

	Nine months ended September 30,		Increase / (Decrease)	
	2009	2008	$	%
Expenses (in thousands):				
Production:				
Lease operating	$ 122,817	$ 130,013	*$ (7,196)*	
Production, ad valorem, and severance taxes	48,074	95,845	*(47,771)*	
Total production expenses	170,891	225,858	*(54,967)*	*-24%*
Other:				
Depletion, depreciation, and amortization	217,361	159,114	*58,247*	
Impairment of long-lived assets		26,292	*(26,292)*	
Exploration	43,801	30,462	*13,339*	
General and administrative	40,743	36,549	*4,194*	
Marketing	1,612	9,362	*(7,750)*	
Derivative fair value loss (gain)	(741)	82,093	*(82,834)*	
Other operating	29,419	9,805	*19,614*	
Total operating expenses	503,086	579,535	*(76,449)*	*-13%*
Interest	57,009	54,669	*2,340*	
Income tax provision (benefit)	(25,254)	118,595	*(143,849)*	
Total expenses	$ 534,841	$ 752,799	*$ (217,958)*	*-29%*
Expenses (per BOE):				
Production:				
Lease operating	$ 10.67	$ 12.27	*$ (1.60)*	
Production, ad valorem, and severance taxes	4.17	9.04	*(4.87)*	
Total production expenses	14.84	21.31	*(6.47)*	*-30%*
Other:				
Depletion, depreciation, and amortization	18.88	15.01	*3.87*	
Impairment of long-lived assets		2.48	*(2.48)*	
Exploration	3.80	2.87	*0.93*	
General and administrative	3.54	3.45	*0.09*	
Marketing	0.14	0.88	*(0.74)*	
Derivative fair value loss (gain)	(0.06)	7.75	*(7.81)*	
Other operating	2.55	0.93	*1.62*	
Total operating expenses	43.69	54.68	*(10.99)*	*-20%*
Interest	4.95	5.16	*(0.21)*	
Income tax provision (benefit)	(2.19)	11.19	*(13.38)*	
Total expenses	$ 46.45	$ 71.03	*$ (24.58)*	*-35%*

Production expenses. Total production expenses decreased 24 percent from $225.9 million in the first nine months of 2008 to $170.9 million in the first nine months of 2009. Our production margin decreased 60 percent from $736.0 million in the first nine months of 2008 to $290.9 million in the first nine months of 2009. Total oil and natural gas wellhead revenues per BOE decreased by 56 percent and total production expenses per BOE decreased by 30 percent. On a per BOE basis, our production margin decreased 64 percent to $25.26 per BOE in the first nine months of 2009 as compared to $69.45 per BOE in the first nine months of 2008.

Production expense attributable to LOE decreased $7.2 million from $130.0 million in the first nine months of 2008 to $122.8 million in the first nine months of 2009 as a result of a $1.60 decrease in the per BOE rate, partially offset by higher production volumes. Our lower average LOE per BOE rate decreased LOE by approximately $18.5 million and was primarily due to decreases in natural gas prices resulting in lower electricity costs and gas plant fuel costs and lower prices paid to oilfield service companies and suppliers. Our higher production volumes increased LOE by approximately $11.3 million.

Production expense attributable to production taxes decreased $47.8 million from $95.8 million in the first nine months of 2008 to $48.1 million in the first nine months of 2009 primarily due to lower wellhead revenues, which exclude the effects of commodity derivative contracts. As a percentage of wellhead revenues, production taxes increased to 10.4 percent in the first nine months of 2009 as compared to 10.0 percent in the first nine months of 2008 primarily due to higher ad valorem taxes, which are based on production volumes as opposed to a percentage of wellhead revenues.

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DD&A expense. DD&A expense increased $58.2 million from $159.1 million in the first nine months of 2008 to $217.4 million in the first nine months of 2009 as a result of a $3.87 increase in the per BOE rate and higher production volumes. Our higher average DD&A per BOE rate increased DD&A expense by approximately $44.5 million and was primarily due to the decrease in our proved reserves as a result of lower average commodity prices, partially offset by reserves added through our EXCO asset acquisition. Our higher production volumes increased DD&A expense by approximately $13.8 million.

Impairment of long-lived assets. During the third quarter of 2008, circumstances indicated that the carrying value of the two wells we drilled in the Tuscaloosa Marine Shale may not be recoverable. We compared the assets carrying value to the undiscounted expected future net cash flows, which indicated a need for an impairment charge. We then compared the net book value of the impaired assets to their estimated discounted value, which resulted in a write-down of the value of proved oil and natural gas properties of $26.3 million. Fair value was determined using estimates of future production volumes and estimates of future prices we might receive for these volumes, discounted to a present value.

Exploration expense. Exploration expense increased $13.3 million from $30.5 million in the first nine months of 2008 to $43.8 million in the first nine months of 2009. During the first nine months of 2009, we expensed 5.6 net exploratory dry holes totaling $24.3 million. During the first nine months of 2008, we expensed 3.8 net exploratory dry holes totaling $14.4 million. Impairment of unproved acreage increased $4.8 million from $13.3 million in the first nine months of 2008 to $18.1 million in the first nine months of 2009, primarily due to our larger unproved property base, as well as the impairment of certain acreage through the normal course of evaluation. The following table provides the components of exploration expense for the periods indicated:

	Nine months ended September 30, 2009	2008	*Increase / (Decrease)*
		(in thousands)	
Dry holes	$ 24,272	$ 14,395	*$ 9,877*
Geological and seismic	921	1,903	*(982)*
Delay rentals	506	860	*(354)*
Impairment of unproved acreage	18,102	13,304	*4,798*
Total	$ 43,801	$ 30,462	*$ 13,339*

G&A expense. G&A expense increased $4.2 million from $36.5 million in the first nine months of 2008 to $40.7 million in the first nine months of 2009 primarily due to retention bonuses paid in August 2009 related to our 2008 strategic alternatives process and the expensing of transaction costs related to our EXCO asset acquisition.

Marketing expenses. Marketing expenses decreased $7.8 million from $9.4 million in the first nine months of 2008 to $1.6 million in the first nine months of 2009 primarily due to a reduction in natural gas throughput in our Wildhorse pipeline and the decrease in natural gas prices. Natural gas volumes are purchased from numerous gas producers at the inlet of the pipeline and resold downstream to various local and off-system markets.

Derivative fair value loss (gain). During the first nine months of 2009, we recorded a $0.7 million derivative fair value gain as compared to an $82.1 million derivative fair value loss in the first nine months of 2008, the components of which were as follows:

	Nine Months Ended September 30, 2009	2008	*Increase / (Decrease)*
		(in thousands)	
Ineffectiveness	$ (16)	$ (349)	*$ 333*

Mark-to-market loss (gain)	281,569	(11,884)	*293,453*
Premium amortization	91,557	47,579	*43,978*
Settlements	(373,851)	46,747	*(420,598)*
Total derivative fair value loss (gain)	$ (741)	$ 82,093	*$ (82,834)*

Other operating expense. Other operating expense increased $19.6 million from $9.8 million in the first nine months of 2008 to $29.4 million in the first nine months of 2009 primarily due to a $6.5 million adjustment to the carrying value of pipe and other tubular inventory whose market value had declined below cost, a $7.1 million adjustment to the carrying value of certain receivables, primarily from ExxonMobil related to our West Texas joint venture, and higher gathering and transportation fees.

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Interest expense. Interest expense increased $2.3 million from $54.7 million in the first nine months of 2008 to $57.0 million in the first nine months of 2009 primarily due to the issuance of our 9.5% Notes. Our weighted average interest rate was 5.5 percent for the first nine months of 2009 as compared to 5.8 percent for the first nine months of 2008.

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

	Nine months ended September 30, 2009	Nine months ended September 30, 2008	*Increase / (Decrease)*
	(in thousands)		
6.25% Senior Subordinated Notes	$ 7,312	$ 7,294	*$ 18*
6.0% Senior Subordinated Notes	13,936	13,910	*26*
9.5% Senior Subordinated Notes	10,073		*10,073*
7.25% Senior Subordinated Notes	8,253	8,247	*6*
Revolving credit facilities	13,472	23,082	*(9,610)*
Other	3,963	2,136	*1,827*
Total	$ 57,009	$ 54,669	*$ 2,340*

Income taxes. In the first nine months of 2009, we recorded an income tax benefit of $25.3 million as compared to an income tax provision of $118.6 million in the first nine months of 2008. In the first nine months of 2009, we had a loss before income taxes and noncontrolling interest of $94.5 million as compared to income before income taxes and noncontrolling interest of $336.6 million in the first nine months of 2008. Our effective tax rate decreased to 26.7 percent in the first nine months of 2009 as compared to 35.2 percent in the first nine months of 2008 primarily due to the 2008 provision to return difference in the production activities deduction estimated at the end of 2008 due to a change in tax planning as a result of the hedges monetization in the first quarter of 2009 and an increase in the effective state income tax rate due to changes in apportionment associated with our 2009 acquisitions.

Capital Commitments, Capital Resources, and Liquidity

Capital commitments

Our primary uses of cash are:

- Development, exploitation, and exploration of oil and natural gas properties;
- Acquisitions of oil and natural gas properties;
- Funding of 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 September 30, 2009	Three months ended September 30, 2008	Nine months ended September 30, 2009	Nine months ended September 30, 2008
	(in thousands)			
Development and exploitation	$ 22,670	$ 116,376	$ 94,934	$ 250,624
Exploration	20,046	69,960	140,138	179,217

Total	$ 42,716	$ 186,336	$ 235,072	$ 429,841

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 third quarter of 2009 yielded 6 gross (2.0 net) successful wells and no dry holes. Our development and exploitation capital for the first nine months of 2009 yielded 54 gross (24.7 net) successful wells and no 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 third quarter of 2009 yielded 16 gross (5.7 net) successful wells and 3 gross (1.6 net) dry holes. Our exploration capital for the first nine months of 2009 yielded 48 gross (15.5 net) successful wells and 7 gross (5.6 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 September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
	(in thousands)			
Acquisitions of proved property	$ 366,930	$ 8,725	$ 394,482	$ 29,193
Acquisitions of leasehold acreage	1,828	61,275	6,004	95,916
Total	$ 368,758	$ 70,000	$ 400,486	$ 125,109

In August 2009, we acquired certain oil and natural gas properties from EXCO for approximately $357.0 million in cash (including a deposit of $37.5 million made in June 2009). In May 2009, ENP acquired the Vinegarone Assets for approximately $27.5 million in cash.

During the three and nine months ended September 30, 2009, our capital expenditures for leasehold acreage related to the acquisition of unproved acreage in various areas. During the three and nine months ended September 30, 2008, $44.0 million of our capital expenditures for leasehold acreage related to the exercise of preferential rights in the Haynesville area and the remainder related to the acquisition of unproved acreage in various areas.

Funding of working capital. As of September 30, 2009 and December 31, 2008, our working capital (defined as total current assets less total current liabilities) was a negative $61.9 million and a positive $188.7 million, respectively. The decrease was primarily due to the monetization of certain of our 2009 oil derivative contracts in March 2009 and higher oil prices at September 30, 2009 as compared to December 31, 2008, which negatively impacted the fair value of our outstanding oil derivative contracts.

For the remainder of 2009, we expect working capital to remain negative primarily due to higher oil prices as compared to December 31, 2008. 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 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. Given our current commodity derivative contracts, assuming relatively stable commodity prices and constant or increasing production volumes, our operating cash flow should remain positive for the remainder of 2009.

The Board approved a capital budget of $340 million for 2009, excluding proved property acquisitions. The level of these and other future expenditures are 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 availability 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. We have no off-balance sheet arrangements that are material to our financial position or results of operations.

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Contractual obligations. The following table provides the components of our contractual obligations and commitments at September 30, 2009:

Contractual Obligations and Commitments	Maturity Date	Total	Three Months Ending December 31, 2009	Years Ending December 31, 2010 - 2011	Years Ending December 31, 2012 - 2013	Thereafter
			Payments Due by Period (in thousands)			
6.25% Senior Subordinated Notes (a)	4/15/2014	$ 196,875	$ 4,687	$ 18,750	$ 18,750	$ 154,688
6.0% Senior Subordinated Notes (a)	7/15/2015	408,000		36,000	36,000	336,000
9.5% Senior Subordinated Notes (a)	5/1/2016	374,625	10,687	42,750	42,750	278,438
7.25% Senior Subordinated Notes (a)	12/1/2017	242,438	5,438	21,750	21,750	193,500
Revolving credit facilities (a)	3/7/2012	467,527	5,005	20,020	442,502	
Commodity derivative contracts (b)		44,652		38,810	5,842	
Interest rate swaps (c)		4,239	942	3,297		
Capital lease obligations		1,398	117	932	349	
Development commitments (d)		47,704	12,044	35,660		
Operating leases and commitments (e)		14,556	988	7,603	5,965	
Asset retirement obligations (f)		192,735	511	4,093	4,093	184,038
Total		$ 1,994,749	$ 40,419	$ 229,665	$ 578,001	$ 1,146,664

(a) Includes principal and projected interest payments. Please read Note 8 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our long-term debt.

(b) Represents net liabilities for

commodity derivative contracts. With the exception of $43.2 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 Note 6 of Notes to Consolidated Financial Statements included in "Item 1. Financial Statements" for additional information regarding our commodity derivative contracts.

(c) Represents net liabilities for interest rate swaps, the ultimate settlement of which are unknown because they are subject to continuing market risk. Please read Item 3. Quantitative and Qualitative Disclosures about Market Risk and Note 6 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our interest rate swaps.

(d) Includes authorized purchases for work in process of $47.5 million and future minimum payments for drilling rig operations of $0.2 million. Also at September 30, 2009, we had approximately $155.1 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.

(e) Includes office space and equipment obligations that have non-cancelable initial lease terms in excess of one year of $14.1 million and future minimum payments for other operating commitments of $0.5 million.

(f) Represents 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 7 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. 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 oversubscribed and subject to apportionment, we have been allocated sufficient pipeline capacity to move our crude oil production. An expansion of the Enbridge Pipeline was completed in early 2008, which moved the total Rockies area pipeline takeaway closer to a balancing point with increasing production volumes and thereby provided greater stability to oil differentials in the area. In spite of the increase in capacity, the Enbridge Pipeline continues to run at full 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, 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.

The difference between NYMEX market prices and the price received at the wellhead for oil and natural gas production is commonly referred to as a differential. 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. We cannot accurately predict future oil and natural gas differentials. Increases in the percentage differential between the NYMEX

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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 $104.2 million from $529.0 million for the first nine months of 2008 to $633.2 million for the first nine months of 2009, primarily due to the monetization of certain of our 2009 oil derivative contracts in March 2009 and decreased settlements paid under our oil derivative contracts as a result of lower average oil prices in the first nine months of 2009 as compared to the first nine months of 2008, partially offset by a decrease in our production margin.

Cash flows from investing activities. Cash used in investing activities increased $174.2 million from $536.1 million in the first nine months of 2008 to $710.3 million in the first nine months of 2009, primarily due to a $307.2 million increase in amounts paid to acquire oil and natural gas properties, namely our EXCO asset acquisition, partially offset by a $91.4 million decrease in amounts paid to develop oil and natural gas properties and a $38.7 million decrease in net advancements to working interest partners. During the first nine months of 2009, we collected $5.5 million (net of advancements) from ExxonMobil for their portion of costs incurred drilling wells under the joint development agreement. During the first nine months of 2008, we advanced $33.3 million (net of collections) to ExxonMobil for their portion of costs incurred drilling wells under the joint development agreement.

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

During the first nine months of 2009, we received net cash of $81.8 million in financing activities, including $202.5 million of net proceeds from the issuance of the 9.5% Notes, $100.7 million of net proceeds from EAC s issuance of common stock, and $170.1 million of net proceeds from ENP s issuance of common units, partially offset by net repayments on revolving credit facilities of $285 million, payments for deferred commodity derivative contract premiums of $70.5 million, and ENP distributions to noncontrolling interests of $24.6 million. Net repayments decreased the outstanding borrowings under revolving credit facilities from $725 million at December 31, 2008 to $440 million at September 30, 2009.

In October 2008, we announced that the Board approved a share repurchase program authorizing us to repurchase up to $40 million of our common stock. The shares may be repurchased from time to time in the open market or through privately negotiated transactions. The repurchase program is subject to business and market conditions, and may be suspended or discontinued at any time. The share repurchase program will be funded using our available cash. As of September 30, 2009, we had repurchased and retired 620,265 shares of our outstanding common stock for approximately $17.2 million, or an average price of $27.68 per share, under the share repurchase program. During the first nine months of 2009, we did not repurchase any shares of our outstanding common stock under the share repurchase program. As of September 30, 2009, approximately $22.8 million of our common stock remained authorized for repurchase.

During the first nine months of 2008, we received net cash of $9.2 million from financing activities, including net borrowings on revolving credit facilities of $96.9 million, partially offset by $50 million of share repurchases, payments for deferred commodity derivative contract premiums of $30.8 million, and ENP distributions to noncontrolling interests of $19.5 million.

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 the level of our capital expenditures. We may use other sources of capital, including the issuance of debt or equity securities, to fund acquisitions or maintain our financial flexibility. 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. However, should commodity prices decline or the capital markets remain tight, the borrowing capacity under our revolving credit facilities could be adversely affected. In the event of a reduction in the borrowing base under our revolving credit facilities, we do not believe it will result in any required prepayments of indebtedness.

We plan to make substantial capital expenditures in the future for the acquisition, exploitation, and development of oil and natural gas properties. We intend to finance these capital expenditures with cash flows from operations. We intend to finance our acquisition

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and future development and exploitation activities with a combination of cash flows from operations and issuances of debt, equity, or a combination thereof.

Issuance of 9.5% Senior Subordinated Notes Due 2016. On April 27, 2009, we issued $225 million of our 9.5% Notes at 92.228 percent of par value. We used the net proceeds of approximately $202.5 million to reduce outstanding borrowings under our revolving credit facility. Interest on the 9.5% Notes is due semi-annually on May 1 and November 1, beginning November 1, 2009. The 9.5% Notes mature on May 1, 2016.

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 nine months of 2009, our average realized oil and natural gas prices decreased by 52 percent and 63 percent, respectively, as compared to the first nine months of 2008. Realized oil and natural gas prices fluctuate widely in response to changing market forces. If oil and natural gas prices decline or we experience a significant widening of our differentials, then our earnings, cash flows from operations, and borrowing base under our revolving credit facilities may be adversely impacted. Prolonged periods of lower oil and natural gas prices or sustained wider differentials could cause us to not be in compliance with financial covenants under our revolving credit facilities and thereby affect our liquidity. However, we have protected a portion of our forecasted production through 2012 against declining commodity prices. Please read Item 3. Quantitative and Qualitative Disclosures about Market Risk and Note 6 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our commodity derivative contracts.

Revolving credit facilities. The syndicate of lenders underwriting our revolving credit facility includes 29 banking and other financial institutions, and the syndicate of lenders underwriting ENP s revolving credit facility includes 15 banking and other financial institutions. None of the lenders are underwriting more than ten percent of the respective total commitment. We believe the number of lenders, the small percentage participation of each, and the level of availability under each facility provides adequate diversity and flexibility should further consolidation occur within the financial services industry.

Encore Acquisition Company 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. The EAC Credit Agreement matures on March 7, 2012. Effective March 10, 2009, we amended the EAC Credit Agreement to, among other things, increase the interest rate margins and commitment fees applicable to loans made under the EAC Credit Agreement. 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 the account of us 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. In March 2009, the borrowing base of our revolving credit facility was reaffirmed at $1.1 billion before a reduction of $200 million solely as a result of the monetization of certain of our 2009 oil derivative contracts during the first quarter of 2009. In addition, the provisions of the EAC Credit Agreement require the borrowing base to be reduced by 33 1/3 percent of the principal amount of the 9.5% Notes. As a result, the borrowing base on the EAC Credit Agreement was reduced by $75 million in April 2009. The reductions in the borrowing base under the EAC Credit Agreement did not result in any required prepayments of indebtedness. As of September 30, 2009, the borrowing base was $825 million.

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

Ratio of Outstanding Borrowings to Borrowing Base	Commitment Fee Percentage
Less than .90 to 1	0.375%
Greater than or equal to .90 to 1	0.500%

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

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Loans under the EAC Credit Agreement are subject to varying rates of interest based on (1) outstanding borrowings 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 Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans
Less than .50 to 1	1.750%	0.500%
Greater than or equal to .50 to 1 but less than .75 to 1	2.000%	0.750%
Greater than or equal to .75 to 1 but less than .90 to 1	2.250%	1.000%
Greater than or equal to .90 to 1	2.500%	1.250%

The Eurodollar rate for any interest period (either one, two, three, or six months, as selected by us) is the rate equal to the British Bankers Association LIBOR for deposits in dollars for a similar interest period. The Base Rate is calculated as the highest of: (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate ; (2) the federal funds effective rate plus 0.5 percent; or (3) except during a LIBOR Unavailability Period, the Eurodollar rate (for dollar deposits for a one-month term) for such day plus 1.0 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 including, among others, the following:

- 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 (the EAC Current Ratio); and
- a requirement that we maintain a ratio of consolidated EBITDA to the sum of consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0 (the EAC Interest Coverage Ratio).

In order to show EAC s compliance with the covenants of the EAC Credit Agreement, the use of non-GAAP financial measures is required. The presentation of these non-GAAP financial measures provides useful information to investors as they allow readers to understand how much cushion there is between the required ratios and the actual ratios. These non-GAAP financial measures should not be considered an alternative to any measure of financial performance presented in accordance with GAAP.

As of September 30, 2009, EAC was in compliance with all covenants in the EAC Credit Agreement, including the following financial covenants:

Financial Covenant	**Required Ratio**	**Actual Ratio as of September 30, 2009**
EAC Current Ratio	Minimum 1.0 to 1.0	3.3 to 1.0
EAC Interest Coverage Ratio	Minimum 2.5 to 1.0	9.4 to 1.0

The following table shows the calculation of the EAC Current Ratio as of September 30, 2009 ($ in thousands):

EAC current assets	$ 161,219
Availability under the EAC Credit Agreement	644,700
EAC consolidated current assets	$ 805,919
Divided by: EAC consolidated current liabilities	$ 244,299
EAC Current Ratio	3.3

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The following table shows the calculation of the EAC Interest Coverage Ratio for the twelve months ended September 30, 2009 ($ in thousands):

EAC Consolidated EBITDA (a)	$599,808
Divided by: EAC consolidated net interest expense and letter of credit fees	$ 63,726
EAC Interest Coverage Ratio	9.4

(a) EAC Consolidated EBITDA is defined in the EAC Credit Agreement and generally means earnings before interest, income taxes, depletion, depreciation, and amortization, and exploration expense. EAC Consolidated EBITDA is a non-GAAP financial measure, which is reconciled to its most directly comparable GAAP measure below.

The following table presents a calculation of EAC Consolidated EBITDA for the twelve months ended September 30, 2009 (in thousands) as required under the EAC Credit Agreement, together with a reconciliation of such amount to its most directly comparable financial measures calculated and presented in accordance with GAAP. This EBITDA measure should not be considered an alternative to consolidated net income (loss), operating income (loss), cash flow from operating activities, or any other measure of financial performance or liquidity presented in accordance with GAAP. This EBITDA measure may not be comparable to similarly titled measures of another company because all companies may not calculate this measure in the same manner.

EAC consolidated net income	$ 108,314
EAC unrealized non-cash hedge gain	(21,456)
EAC consolidated net interest expense	63,726
EAC income and franchise taxes	97,025
EAC depletion, depreciation, and amortization expense	242,358
EAC non-cash equity-based compensation	11,805
EAC exploration expense	82,638
EAC other non-cash	15,398

EAC Consolidated EBITDA	$ 599,808

The EAC Credit Agreement contains customary events of default, which would permit the lenders to accelerate the debt if not cured within applicable grace periods. 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.

On September 30, 2009, there were $180 million of outstanding borrowings, $0.3 million of outstanding letters of credit, and $644.7 million of borrowing capacity under the EAC Credit Agreement. On October 27, 2009, there were $200 million of outstanding borrowings, $0.3 million of outstanding letters of credit, and $624.7 million of borrowing capacity under the EAC Credit Agreement.

Encore Energy Partners Operating LLC Credit Agreement

In March 2007, OLLC entered into a five-year credit agreement (as amended, the OLLC Credit Agreement) with a bank syndicate including Bank of America, N.A. and other lenders. The OLLC Credit Agreement matures on March 7, 2012. Effective March 10, 2009, OLLC amended the OLLC Credit Agreement to, among other things, increase the interest rate margins and commitment fees applicable to loans made under the OLLC Credit Agreement. Effective August 11, 2009, OLLC amended the OLLC Credit Agreement to, among other things, (1) increase the borrowing base from $240 million to $375 million, (2) increase the aggregate commitments of the lenders from $300 million to $475 million, and (3) increase the interest rate margins and commitment fees applicable to loans made under the OLLC Credit Agreement. 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 $475 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 September 30, 2009, the borrowing base was $375 million.

OLLC incurs a commitment fee of 0.5 percent on the unused portion of the OLLC Credit Agreement.

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Obligations under the OLLC Credit Agreement are secured by a first-priority security interest in substantially all of OLLC s proved oil and natural gas reserves and in the equity interests of OLLC and its restricted subsidiaries. In addition, 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) outstanding borrowings 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 Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans (a)	Applicable Margin for Base Rate Loans (a)
Less than .50 to 1	2.250%	1.250%
Greater than or equal to .50 to 1 but less than .75 to 1	2.500%	1.500%
Greater than or equal to .75 to 1 but less than .90 to 1	2.750%	1.750%
Greater than or equal to .90 to 1	3.000%	2.000%

The Eurodollar rate for any interest period (either one, two, three, or six months, as selected by ENP) is the rate equal to the British Bankers Association LIBOR for deposits in dollars for a similar interest period. The Base Rate is calculated as the highest of: (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate ; (2) the federal funds effective rate plus 0.5 percent; or (3) except during a LIBOR Unavailability Period, the Eurodollar rate (for dollar deposits for a one-month term) for such day plus 1.0 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.

The OLLC Credit Agreement contains covenants including, among others, the following:

- 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 OLLC s 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 ENP and OLLC maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0 (the ENP Current Ratio);
- a requirement that ENP and OLLC maintain a ratio of consolidated EBITDA to the sum of consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0 (the ENP Interest Coverage Ratio); and

- a requirement that ENP and OLLC maintain a ratio of consolidated funded debt to consolidated adjusted EBITDA of not more than 3.5 to 1.0 (the ENP Leverage Ratio).

In order to show ENP s and OLLC s compliance with the covenants of the OLLC Credit Agreement, the use of non-GAAP financial measures is required. The presentation of these non-GAAP financial measures provides useful information to investors as they allow readers to understand how much cushion there is between the required ratios and the actual ratios. These non-GAAP financial measures should not be considered an alternative to any measure of financial performance presented in accordance with GAAP.

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As of September 30, 2009, ENP and OLLC were in compliance with all covenants in the OLLC Credit Agreement, including the following financial covenants:

Financial Covenant	Required Ratio	Actual Ratio as of September 30, 2009
ENP Current Ratio	Minimum 1.0 to 1.0	5.1 to 1.0
ENP Interest Coverage Ratio	Minimum 2.5 to 1.0	10.8 to 1.0
ENP Leverage Ratio	Maximum 3.5 to 1.0	2.2 to 1.0

The following table shows the calculation of the ENP Current Ratio as of September 30, 2009 ($ in thousands):

ENP current assets	$ 54,806
Availability under the OLLC Credit Agreement	115,000
ENP consolidated current assets	$ 169,806
Divided by: ENP consolidated current liabilities	$ 33,567
ENP Current Ratio	5.1

The following table shows the calculation of the ENP Interest Coverage Ratio for the twelve months ended September 30, 2009 ($ in thousands):

ENP Consolidated EBITDA (a)	$ 98,721
Divided by:	
ENP consolidated interest expense and letter of credit fees	$ 9,204
ENP consolidated interest income	(36)
ENP consolidated net interest expense and letter of credit fees	$ 9,168
ENP Interest Coverage Ratio	10.8

(a) ENP Consolidated EBITDA is defined in the OLLC Credit Agreement and generally means earnings before interest, income taxes, depletion, depreciation, and amortization, and exploration expense. ENP Consolidated EBITDA is a non-GAAP financial measure, which is reconciled to its most directly comparable GAAP measure below.

The following table shows the calculation of the ENP Leverage Ratio for the twelve months ended September 30, 2009 ($ in thousands):

ENP consolidated funded debt	$260,000
Divided by: ENP Consolidated Adjusted EBITDA (a)	$116,179
ENP Leverage Ratio	2.2

(a) ENP Consolidated Adjusted EBITDA is defined in the OLLC Credit Agreement and generally means earnings before interest, income taxes, depletion, depreciation, and amortization, and exploration expense, after giving pro forma effect to one or more acquisitions or dispositions in excess of $20 million in the aggregate. ENP Consolidated Adjusted EBITDA is a non-GAAP financial measure, which is reconciled to its most directly comparable GAAP measure below.

The following table presents a calculation of ENP Consolidated EBITDA and ENP Consolidated Adjusted EBITDA for the twelve months ended September 30, 2009 (in thousands) as required under the OLLC Credit Agreement, together with a reconciliation of such amounts to their most directly comparable financial measures calculated and presented in accordance with GAAP. These EBITDA measures should not be considered an alternative to net income (loss), operating income (loss), cash flow from operating activities, or any other measure of financial performance or liquidity presented in accordance with GAAP. These EBITDA measures may not be comparable to similarly titled measures of another company because all companies may not calculate these measures in the same manner.

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ENP consolidated net income	$ 90,122
ENP unrealized non-cash hedge gain	(51,881)
ENP consolidated net interest expense	9,168
ENP income and franchise taxes	638
ENP depletion, depreciation, amortization, and exploration expense	47,282
ENP non-cash unit-based compensation	2,108
ENP other non-cash	1,284
ENP Consolidated EBITDA	98,721
Pro forma effect of acquisitions	17,458
ENP Consolidated Adjusted EBITDA	$ 116,179

The OLLC Credit Agreement contains customary events of default, which would permit the lenders to accelerate the debt if not cured within applicable grace periods. 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.

On September 30, 2009 and October 27, 2009, there were $260 million of outstanding borrowings and $115 million of borrowing capacity under the OLLC Credit Agreement.

Please read Note 8 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our long-term debt.

Capitalization. At September 30, 2009, we had total assets of $3.7 billion and total capitalization of $2.9 billion, of which 57 percent was represented by equity and 43 percent by long-term debt. At December 31, 2008, we had total assets of $3.6 billion and total capitalization of $2.8 billion, of which 53 percent was represented by equity and 47 percent by long-term debt. The percentages of our capitalization represented by 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 2008 Annual Report on Form 10-K for information regarding our critical accounting policies and estimates.

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 primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of exposure, but rather indicators of potential exposure. This information provides indicators of how we view and manage our ongoing market risk exposures. We do not enter into market risk sensitive instruments for speculative trading purposes.

The information included in Item 7A. Quantitative and Qualitative Disclosures about Market Risk in our 2008 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 commodity derivative contracts are discussed in Note 6 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements. The counterparties to our commodity derivative contracts are a diverse group of seven institutions, all of

which are currently rated A- or better by Standard & Poor s and/or Fitch. As of September 30, 2009, the fair market value of our oil derivative contracts was a net asset of approximately $59.4 million and the fair market value of our natural gas derivative contracts was a net asset of approximately $11.0 million. These amounts exclude deferred premiums of $43.2 million that are not subject to changes in commodity prices. Based on our open commodity derivative positions at September 30, 2009, a 10 percent increase in the respective NYMEX prices for oil and natural gas would decrease our net commodity derivative asset by approximately $50.4 million, while a 10 percent decrease in the respective NYMEX prices for oil and natural gas would increase our net commodity derivative asset by approximately $52.4 million.

Interest Rate Sensitivity

Our long-term debt is discussed in Note 8 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements. At September 30, 2009, we had total long-term debt of $1.2 billion, net of discount of $21.5 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, $225 million bears interest at a fixed rate of 9.5 percent, and $150 million bears interest at a fixed rate of 7.25 percent. The remaining long-term debt balance of $440 million as of September 30, 2009 consisted of outstanding borrowings under revolving credit facilities, which are subject to floating market rates of interest that are linked to the Eurodollar rate.

At this level of floating rate debt, if the Eurodollar rate increased by 10 percent, we would incur an additional $1.0 million of interest expense per year on revolving credit facilities, and if the Eurodollar rate decreased by 10 percent, we would incur $1.0 million less. Additionally, if the discount rates on our senior notes increased by 10 percent, we estimate the fair value of our fixed rate debt at September 30, 2009 would increase from approximately $790.5 million to approximately $794.0 million, and if the discount rates on our senior notes decreased by 10 percent, we estimate the fair value would decrease to approximately $787.1 million.

ENP s interest rate swaps are discussed in Note 6 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements. As of September 30, 2009, the fair market value of ENP s interest rate swaps was a net liability of approximately $4.1 million. If the Eurodollar rate increased by 10 percent, we estimate the liability would decrease to approximately $3.9 million, and if the Eurodollar rate decreased by 10 percent, we estimate the liability would increase to approximately $4.4 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 our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2009 to ensure that information required to be disclosed in the reports we file or submit 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 third quarter of 2009 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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ENCORE ACQUISITION COMPANY
PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We are a party to ongoing legal proceedings in the ordinary course of business. Management does not believe the result of these legal proceedings will have a material adverse effect on our business, financial condition, results of operations, or liquidity.

Item 1A. Risk Factors

In addition to the other information set forth in this Report, you should carefully consider the factors discussed in Item 1A. Risk Factors and elsewhere in our 2008 Annual Report on Form 10-K, which could materially affect our business, financial condition, or results of operations. The risks described in our 2008 Annual Report on Form 10-K are not the only risks we face. Unknown risks and uncertainties or risks and uncertainties that we currently believe to be immaterial may also have a material adverse effect on 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 October 2008, the Board approved a share repurchase program authorizing us to repurchase up to $40 million of our common stock. As of September 30, 2009, we had repurchased and retired 620,265 shares of our outstanding common stock for approximately $17.2 million, or an average price of $27.68 per share, under the share repurchase program. During the third quarter of 2009, we did not repurchase any shares of our outstanding common stock under the share repurchase program. As of September 30, 2009, approximately $22.8 million of our common stock remained authorized for repurchase.

The following table summarizes purchases of our common stock during the third quarter of 2009:

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
July		$		
August		$		
September		$		
Total		$		$ 22,830,139

Item 6. Exhibits

Exhibit No.	Description
3.1	Second Amended and Restated Certificate of Incorporation of Encore Acquisition Company (incorporated by reference from Exhibit 3.1 of 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 Exhibit 3.1.2 of EAC s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, filed with the SEC on May 5, 2005).

3.1.3	Certificate of Designations of Series A Junior Participating Preferred Stock of Encore Acquisition Company (incorporated by reference from Exhibit 3.1 of EAC s Current Report on Form 8-K, filed with the SEC on October 31, 2008).
3.2	Second Amended and Restated Bylaws of Encore Acquisition Company (incorporated by reference from Exhibit 3.2 of EAC s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, filed with the SEC on November 7, 2001).
10.1*+	Encore Acquisition Company Employee Severance Protection Plan (As Amended and Restated Effective May 6, 2008).
10.2*+	First Amendment to Encore Acquisition Company Employee Severance Protection Plan (As Amended and Restated Effective May 6, 2008), dated as of September 29, 2009.
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).

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ENCORE ACQUISITION COMPANY

Exhibit No.	Description
32.2*	Section 1350 Certification (Principal Financial Officer).
99.1*	Statement showing computation of ratios of earnings (loss) to fixed charges.
99.2	Third Amendment to Credit Agreement, dated as of August 11, 2009, by and among Encore Energy Partners Operating LLC, Encore Energy Partners LP, Bank of America, N.A., as the administrative agent and L/C issuer, and the lenders party thereto (incorporated by reference from Exhibit 10.1 of ENP s Current Report on Form 8-K, filed with the SEC on August 13, 2009).

* Filed herewith.

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

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: November 2, 2009

/s/ Andrea Hunter
Andrea Hunter
Vice President, Controller,
and Principal Accounting Officer
(Duly Authorized Signatory)

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nvestments, such as time deposits, are not measured at fair value.

As of September 30, 2018 and December 31, 2017, there were approximately $45 million and $39 million of overseas deposits within other invested assets, which can be redeemed at net asset value in 90 days or less. Overseas deposits are excluded from the fair value hierarchy because their fair value is recorded using the net asset value per share (or equivalent) practical expedient.

Life Settlement Contracts

The Company sold its life settlement contracts to a third party in 2017. The valuation of the life settlement contracts was based on the terms of sale. The contracts were classified as Level 3 as there was not an active market for life settlement contracts.

Derivative Financial Investments

Level 2 investments primarily include the embedded derivative on the funds withheld liability. The embedded derivative on funds withheld liability is valued using the change in fair value of the assets supporting the funds withheld liability, which are fixed maturity securities valued with observable inputs.

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Significant Unobservable Inputs

The following tables present quantitative information about the significant unobservable inputs utilized by the Company in the fair value measurements of Level 3 assets. Valuations for assets and liabilities not presented in the tables below are primarily based on broker/dealer quotes for which there is a lack of transparency as to inputs used to develop the valuations. The quantitative detail of these unobservable inputs is neither provided nor reasonably available to the Company. The weighted average rate is calculated based on fair value.

September 30, 2018	Estimated Fair Value (In millions)	Valuation Technique(s)	Unobservable Input(s)	Range (Weighted Average)
Fixed maturity securities	$ 198	Discounted cash flow	Credit spread	1% - 12% (2%)

December 31, 2017	Estimated Fair Value (In millions)	Valuation Technique(s)	Unobservable Input(s)	Range (Weighted Average)
Fixed maturity securities	$ 136	Discounted cash flow	Credit spread	1% - 12% (3%)

For fixed maturity securities, an increase to the credit spread assumptions would result in a lower fair value measurement.

Financial Assets and Liabilities Not Measured at Fair Value

The carrying amount and estimated fair value of the Company's financial assets and liabilities which are not measured at fair value on the Condensed Consolidated Balance Sheets are presented in the following tables.

September 30, 2018	Carrying	Estimated Fair Value			
(In millions)	Amount	Level 1	Level 2	Level 3	Total
Assets					
Mortgage loans	$ 868	$—	$—	$ 847	$ 847
Note receivable	35	—	—	35	35
Liabilities					
Long term debt	$ 2,680	$—	$2,734	$—	$2,734

December 31, 2017	Carrying	Estimated Fair Value			
(In millions)	Amount	Level 1	Level 2	Level 3	Total
Assets					
Mortgage loans	$ 839	$—	$—	$ 844	$ 844
Note receivable	46	—	—	46	46
Liabilities					
Short term debt	$ 150	$—	$150	$—	$ 150
Long term debt	2,708	—	2,896	—	2,896

The following methods and assumptions were used to estimate the fair value of these financial assets and liabilities.

The fair values of mortgage loans were based on the present value of the expected future cash flows discounted at the current interest rate for origination of similar quality loans, adjusted for specific loan risk.

The fair value of the note receivable was based on the present value of the expected future cash flows discounted at the current interest rate for origination of similar notes, adjusted for specific credit risk. The note receivable is included within Other assets on the Condensed Consolidated Balance Sheets.

The Company's senior notes and debentures were valued based on observable market prices. The fair value for other debt was estimated using discounted cash flows based on current incremental borrowing rates for similar borrowing arrangements.

The carrying amounts reported on the Condensed Consolidated Balance Sheets for Cash, Short term investments not carried at fair value, Accrued investment income and certain Other assets and Other liabilities approximate fair value due to the short term nature of these items. These assets and liabilities are not listed in the tables above.

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Note E. Claim and Claim Adjustment Expense Reserves

The Company's property and casualty insurance claim and claim adjustment expense reserves represent the estimated amounts necessary to resolve all outstanding claims, including incurred but not reported (IBNR) claims as of the reporting date. The Company's reserve projections are based primarily on detailed analysis of the facts in each case, the Company's experience with similar cases and various historical development patterns. Consideration is given to such historical patterns as claim reserving trends and settlement practices, loss payments, pending levels of unpaid claims and product mix, as well as court decisions, economic conditions, including inflation, and public attitudes. All of these factors can affect the estimation of claim and claim adjustment expense reserves.

Establishing claim and claim adjustment expense reserves, including claim and claim adjustment expense reserves for catastrophic events that have occurred, is an estimation process. Many factors can ultimately affect the final settlement of a claim and, therefore, the necessary reserve. Changes in the law, results of litigation, medical costs, the cost of repair materials and labor rates can affect ultimate claim costs. In addition, time can be a critical part of reserving determinations since the longer the span between the incidence of a loss and the payment or settlement of the claim, the more variable the ultimate settlement amount can be. Accordingly, short-tail claims, such as property damage claims, tend to be more reasonably estimable than long-tail claims, such as workers' compensation, general liability and professional liability claims. Adjustments to prior year reserve estimates, if necessary, are reflected in the results of operations in the period that the need for such adjustments is determined. There can be no assurance that the Company's ultimate cost for insurance losses will not exceed current estimates.

Catastrophes are an inherent risk of the property and casualty insurance business and have contributed to material period-to-period fluctuations in the Company's results of operations and/or equity. The Company reported catastrophe losses, net of reinsurance, of $46 million and $106 million for the three and nine months ended September 30, 2018. Net catastrophe losses for the three and nine months ended September 30, 2018 included $35 million related to Hurricane Florence. The remaining catastrophe losses in 2018 resulted primarily from U.S. weather-related events. The Company reported catastrophe losses, net of reinsurance, of $269 million and $342 million for the three and nine months ended September 30, 2017. Net catastrophe losses for the three and nine months ended September 30, 2017 included $149 million related to Hurricane Harvey, $95 million related to Hurricane Irma and $20 million related to Hurricane Maria and also required reinsurance reinstatement premium of $6 million. The remaining catastrophe losses in 2017 resulted primarily from U.S. weather-related events.

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Liability for Unpaid Claim and Claim Adjustment Expenses Rollforward

The following table presents a reconciliation between beginning and ending claim and claim adjustment expense reserves, including claim and claim adjustment expense reserves of the Life & Group segment.

For the nine months ended September 30		
(In millions)	2018	2017
Reserves, beginning of year:		
Gross	$22,004	$22,343
Ceded	3,934	4,094
Net reserves, beginning of year	18,070	18,249
Net incurred claim and claim adjustment expenses:		
Provision for insured events of current year	3,866	3,949
Decrease in provision for insured events of prior years	(173)	(284)
Amortization of discount	136	138
Total net incurred [1]	3,829	3,803
Net payments attributable to:		
Current year events	(658)	(560)
Prior year events	(3,415)	(3,401)
Total net payments	(4,073)	(3,961)
Foreign currency translation adjustment and other	(80)	110
Net reserves, end of period	17,746	18,201
Ceded reserves, end of period	3,858	4,008
Gross reserves, end of period	$21,604	$22,209

(1) Total net incurred above does not agree to Insurance claims and policyholders' benefits as reflected on the Condensed Consolidated Statements of Operations due to amounts related to retroactive reinsurance deferred gain accounting, uncollectible reinsurance and loss deductible receivables, and benefit expenses related to future policy benefits which are not reflected in the table above.

Net Prior Year Development

Changes in estimates of claim and claim adjustment expense reserves, net of reinsurance, for prior years are defined as net prior year loss reserve development (development). These changes can be favorable or unfavorable. The following table presents development recorded for the Specialty, Commercial, International and Corporate & Other segments.

Periods ended September 30	Three Months		Nine Months	
(In millions)	2018	2017	2018	2017
Pretax (favorable) unfavorable development:				
Specialty	$(53)	$(99)	$(127)	$(134)
Commercial	(5)	(17)	(27)	(94)
International	(2)	1	(4)	1
Corporate & Other	(2)	—	(2)	—
Total pretax (favorable) unfavorable development	$(62)	$(115)	$(160)	$(227)

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Specialty

The following table presents further detail of the development recorded for the Specialty segment.

Periods ended September 30	Three Months		Nine Months	
(In millions)	2018	2017	2018	2017
Pretax (favorable) unfavorable development:				
Medical Professional Liability	$15	$8	$38	$30
Other Professional Liability and Management Liability	(45)	(19)	(113)	(88)
Surety	(20)	(82)	(50)	(82)
Warranty	(1)	(1)	(7)	5
Other	(2)	(5)	5	1
Total pretax (favorable) unfavorable development	$(53)	$(99)	$(127)	$(134)

Three Months

2018

Unfavorable development in medical professional liability was primarily driven by higher than expected frequency and severity in aging services in accident years 2014 through 2017.

Favorable development in other professional liability and management liability was primarily driven by favorable outcomes on individual claims in accident years 2013 and prior in financial institutions.

Favorable development in surety was due to continued lower than expected loss emergence for accident years 2017 and prior.

2017

Favorable development in other professional liability and management liability was primarily due to lower than expected claim frequency in accident years 2012 through 2015, primarily for professional liability products.

Favorable development in surety coverages was primarily due to lower than expected frequency of large losses in accident years 2015 and prior.

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Nine Months
2018
Unfavorable development for medical professional liability was primarily due to higher than expected severity in accident years 2014 and 2017 in our hospitals business and higher than expected frequency and severity in aging services in accident years 2014 through 2017.
Favorable development in other professional liability and management liability was primarily due to lower than expected claim frequency for accident years 2013 through 2017 related to financial institutions and professional liability errors and omissions (E&O), favorable severity for accident years 2012 and prior related to professional liability E&O, and favorable outcomes on individual claims in financial institutions in accident years 2013 and prior.
Favorable development for surety was due to lower than expected loss emergence for accident years 2017 and prior.
2017
Unfavorable development in medical professional liability was primarily due to continued higher than expected frequency in aging services.
Favorable development in other professional liability and management liability was primarily due to favorable settlements on closed claims and a lower frequency of large losses for accident years 2011 through 2016 for professional and management liability, lower than expected claim frequency in accident years 2012 through 2015 for professional liability and lower than expected severity in accident years 2014 through 2016 for professional liability.
Favorable development in surety coverages was primarily due to lower than expected frequency of large losses in accident years 2015 and prior.

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Commercial

The following table presents further detail of the development recorded for the Commercial segment.

Periods ended September 30	Three Months		Nine Months	
(In millions)	2018	2017	2018	2017
Pretax (favorable) unfavorable development:				
Commercial Auto	$1	$(12)	$—	$(37)
General Liability	(5)	(2)	13	(19)
Workers' Compensation	(2)	9	(14)	(38)
Property and Other	1	(12)	(26)	—
Total pretax (favorable) unfavorable development	$(5)	$(17)	$(27)	$(94)

Three Months

2017

Favorable development in commercial auto was primarily due to lower than expected severity in accident years 2015 and 2016, as well as a large favorable recovery on a claim in accident year 2012.

Unfavorable development in workers' compensation reflects the recognition of loss estimates related to favorable premium development as well as an adverse arbitration ruling related to reinsurance recoverables from older accident years.

Nine Months

2018

Unfavorable development in general liability was driven by higher than expected claim severity in umbrella in accident years 2013 through 2015.

Favorable development in property and other was driven by lower than expected claim severity in catastrophes in accident year 2017.

2017

Favorable development for commercial auto was primarily due to lower than expected severity in accident years 2013 through 2016, as well as a large favorable recovery on a claim in accident year 2012.

Favorable development for general liability was due to lower than expected severity in life sciences.

Favorable development for workers' compensation was primarily related to decreases in frequency and severity in recent accident years, partially attributable to California reforms related to decreases in medical costs. This was partially offset by unfavorable development related to an adverse arbitration ruling on reinsurance recoverables from older accident years as well as the recognition of loss estimates associated with favorable premium development.

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International

The following table presents further detail of the development recorded for the International segment.

Periods ended September 30	Three Months		Nine Months	
(In millions)	2018	2017	2018	2017
Pretax (favorable) unfavorable development:				
Casualty	$(5)	$ 6	$(11)	$ 7
Property	1	(7)	13	(18)
Energy and Marine	(5)	(6)	(10)	(9)
Specialty	8	5	17	20
Healthcare and Technology	(1)	3	(13)	1
Total pretax (favorable) unfavorable development	$(2)	$ 1	$(4)	$ 1

Nine Months

2018

Favorable development in casualty was primarily driven by better than expected frequency in the liability portion of the package business in Canada and general liability in Europe.

Unfavorable development in property was primarily driven by higher than expected severity in Canada and higher than expected frequency in CNA Hardy, both in accident year 2017.

Favorable development in energy and marine was primarily driven by better than expected large loss frequency in the energy book in recent accident years.

Unfavorable development in specialty was driven by increased severity in accident year 2017 related to professional indemnity.

Favorable development in healthcare and technology was primarily driven by lower than expected frequency in accident years 2015 and prior related to healthcare in Europe.

2017

Favorable development for property was due to better than expected frequency in accident years 2014 through 2016.

Unfavorable development for specialty was primarily due to higher than expected severity in accident year 2015 arising from the management liability business, partially offset by favorable development in accident years 2014 and prior. Additional unfavorable development was related to adverse large claims experience in the CNA Hardy political risks portfolio, relating largely to accident year 2016.

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Asbestos and Environmental Pollution (A&EP) Reserves

In 2010, Continental Casualty Company (CCC) together with several of the Company's other insurance subsidiaries completed a transaction with National Indemnity Company (NICO), a subsidiary of Berkshire Hathaway Inc., under which substantially all of the Company's legacy A&EP liabilities were ceded to NICO through a Loss Portfolio Transfer (LPT). At the effective date of the transaction, the Company ceded approximately $1.6 billion of net A&EP claim and allocated claim adjustment expense reserves to NICO under a retroactive reinsurance agreement with an aggregate limit of $4 billion. The $1.6 billion of claim and allocated claim adjustment expense reserves ceded to NICO was net of $1.2 billion of ceded claim and allocated claim adjustment expense reserves under existing third-party reinsurance contracts. The NICO LPT aggregate reinsurance limit also covers credit risk on the existing third-party reinsurance related to these liabilities. The Company paid NICO a reinsurance premium of $2 billion and transferred to NICO billed third-party reinsurance receivables related to A&EP claims with a net book value of $215 million, resulting in total consideration of $2.2 billion.

In years subsequent to the effective date of the LPT, the Company recognized adverse prior year development on its A&EP reserves resulting in additional amounts ceded under the LPT. As a result, the cumulative amounts ceded under the LPT have exceeded the $2.2 billion consideration paid, resulting in the NICO LPT moving into a gain position, requiring retroactive reinsurance accounting. Under retroactive reinsurance accounting, this gain is deferred and only recognized in earnings in proportion to actual paid recoveries under the LPT. Over the life of the contract, there is no economic impact as long as any additional losses incurred are within the limit of the LPT. In a period in which the Company recognizes a change in the estimate of A&EP reserves that increases or decreases the amounts ceded under the LPT, the proportion of actual paid recoveries to total ceded losses is affected and the change in the deferred gain is recognized in earnings as if the revised estimate of ceded losses was available at the effective date of the LPT. The effect of the deferred retroactive reinsurance benefit is recorded in Insurance claims and policyholders' benefits in the Condensed Consolidated Statement of Operations.

The following table presents the impact of the Loss Portfolio Transfer on the Condensed Consolidated Statements of Operations.

Periods ended September 30	Three Months		Nine Months	
(In millions)	2018	2017	2018	2017
Additional amounts ceded under LPT:				
Net A&EP adverse development before consideration of LPT	$—	$—	$113	$60
Provision for uncollectible third-party reinsurance on A&EP	—	—	(16)	—
Total additional amounts ceded under LPT	—	—	97	60
Retroactive reinsurance benefit recognized	(12)	(17)	(84)	(60)
Pretax impact of deferred retroactive reinsurance	$(12)	$(17)	$13	$—

Based upon the Company's annual A&EP reserve review, net unfavorable prior year development of $113 million and $60 million was recognized before consideration of cessions to the LPT for the nine months ended September 30, 2018 and 2017. Additionally, in 2018, the Company released a portion of its provision for uncollectible third party reinsurance. The 2018 unfavorable development was driven by higher than anticipated defense costs on direct asbestos environmental accounts and paid losses on assumed reinsurance exposures. The 2017 unfavorable development was driven by modestly higher anticipated payouts on claims from known sources of asbestos exposure. The Company expects to complete another A&EP reserve review in the fourth quarter of 2018 and intends to maintain that timing going forward annually.

As of September 30, 2018 and December 31, 2017, the cumulative amounts ceded under the LPT were $3.0 billion and $2.9 billion. The unrecognized deferred retroactive reinsurance benefit was $339 million and $326 million as of September 30, 2018 and December 31, 2017.

NICO established a collateral trust account as security for its obligations to the Company. The fair value of the collateral trust account was $3.2 billion and $3.1 billion as of September 30, 2018 and December 31, 2017. In addition, Berkshire Hathaway Inc. guaranteed the payment obligations of NICO up to the aggregate reinsurance limit as well as certain of NICO's performance obligations under the trust agreement. NICO is responsible for claims handling and billing and collection from third-party reinsurers related to the Company’s A&EP claims.

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Note F. Legal Proceedings, Contingencies and Guarantees

Small Business Premium Rate Adjustment

In 2016 and 2017, the Company identified rating errors related to its multi-peril package product and workers' compensation policies within its Small Business unit and determined that it would voluntarily issue premium refunds along with interest on affected policies. After the rating errors were identified, written and earned premium were reported net of any impact from the premium rate adjustments.

The policyholder refunds for the multi-peril package product were issued in the third quarter of 2017. The policyholder refunds for workers' compensation policies were largely completed in the third quarter of 2018.

For the nine months ended September 30, 2017, earned premium was reduced by $37 million. Earned premium increased by $6 million for the three and nine months ended September 30, 2018 as a result of a change in estimate of the refund payments to policyholders. Additionally, Interest expense increased for interest due to policyholders on the premium rate adjustments by $1 million and $7 million for the three and nine months ended September 30, 2017 and $1 million for the nine months ended September 30, 2018.

Other Litigation

The Company is a party to other routine litigation incidental to its business, which, based on the facts and circumstances currently known, is not material to the Company's results of operations or financial position.

Guarantees

As of September 30, 2018 and December 31, 2017, the Company had recorded liabilities of approximately $5 million related to guarantee and indemnification agreements and management does not believe that any future indemnity claims will be significantly greater than the amounts recorded.

In the course of selling business entities and assets to third parties, the Company agreed to guarantee the performance of certain obligations of previously owned subsidiaries and to indemnify purchasers for losses arising out of breaches of representations and warranties with respect to the business entities or assets sold, including, in certain cases, losses arising from undisclosed liabilities or certain named litigation. Such guarantee and indemnification agreements in effect for sales of business entities, assets and third-party loans may include provisions that survive indefinitely. As of September 30, 2018, the aggregate amount related to quantifiable guarantees was $375 million and the aggregate amount related to quantifiable indemnification agreements was $252 million. In certain cases, should the Company be required to make payments under any such guarantee, it would have the right to seek reimbursement from an affiliate of a previously owned subsidiary.

In addition, the Company has agreed to provide indemnification to third-party purchasers for certain losses associated with sold business entities or assets that are not limited by a contractual monetary amount. As of September 30, 2018, the Company had outstanding unlimited indemnifications in connection with the sales of certain of its business entities or assets that included tax liabilities arising prior to a purchaser's ownership of an entity or asset, defects in title at the time of sale, employee claims arising prior to closing and in some cases losses arising from certain litigation and undisclosed liabilities. Certain provisions of the indemnification agreements survive indefinitely, while others survive until the applicable statutes of limitation expire, or until the agreed-upon contract terms expire.

The Company also provided guarantees, if the primary obligor fails to perform, to holders of structured settlement annuities provided by a previously owned subsidiary. As of September 30, 2018, the potential amount of future payments the Company could be required to pay under these guarantees was approximately $1.8 billion, which will be paid over the lifetime of the annuitants. The Company does not believe any payment is likely under these guarantees, as the Company is the beneficiary of a trust that must be maintained at a level that approximates the discounted reserves for these annuities.

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Note G. Benefit Plans

The components of net periodic pension cost (benefit) are presented in the following table.

Periods ended September 30	Three Months		Nine Months	
(In millions)	2018	2017	2018	2017
Net periodic pension cost (benefit)				
Service cost	$—	$ —	$—	$—
Non-service cost (benefit):				
Interest cost on projected benefit obligation	23	25	70	77
Expected return on plan assets	(40)	(38)	(120)	(116)
Amortization of net actuarial loss	10	9	28	27
Settlement loss	—	6	5	8
Total non-service cost (benefit)	(7)	2	(17)	(4)
Total net periodic pension cost (benefit)	$(7)	$ 2	$(17)	$(4)

For the three and nine months ended September 30, 2018, the Company recognized $3 million and $6 million of non-service benefit in Insurance claims and policyholders' benefits and $4 million and $11 million of non-service benefit in Other operating expenses.

For the three and nine months ended September 30, 2017, the Company recognized $1 million of non-service cost and $1 million of non-service benefit in Insurance claims and policyholders' benefits and $1 million of non-service cost and $3 million of non-service benefit in Other operating expenses.

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Note H. Accumulated Other Comprehensive Income (Loss) by Component

The tables below display the changes in Accumulated other comprehensive income (loss) by component.

(In millions)	Net unrealized gains (losses) on investments with OTTI losses	Net unrealized gains (losses) on other investments	Pension and postretirement benefits	Cumulative foreign currency translation adjustment	Total
Balance as of July 1, 2018	$ 20	$ 271	$ (758)	$ (138)	$ (605)
Other comprehensive income (loss) before reclassifications	(1)	(148)	—	—	(149)
Amounts reclassified from accumulated other comprehensive income (loss) net of tax (expense) benefit of $-, $(2), $1, $- and $(1)	—	10	(7)	—	3
Other comprehensive income (loss) net of tax (expense) benefit of $-, $42, $(1), $- and $41	(1)	(158)	7	—	(152)
Balance as of September 30, 2018	$ 19	$ 113	$ (751)	$ (138)	$ (757)

(In millions)	Net unrealized gains (losses) on investments with OTTI losses	Net unrealized gains (losses) on other investments	Pension and postretirement benefits	Cumulative foreign currency translation adjustment	Total
Balance as of July 1, 2017	$ 26	$ 786	$ (635)	$ (145)	$ 32
Other comprehensive income (loss) before reclassifications	1	35	—	41	77
Amounts reclassified from accumulated other comprehensive income (loss) net of tax (expense) benefit of $-, $(4), $5, $-, and $1	—	12	(10)	—	2
Other comprehensive income (loss) net of tax (expense) benefit of $-, $(16), $(5), $- and $(21)	1	23	10	41	75
Balance as of September 30, 2017	$ 27	$ 809	$ (625)	$ (104)	$ 107

(In millions)	Net unrealized gains (losses) on investments with OTTI losses	Net unrealized gains (losses) on other investments	Pension and postretirement benefits	Cumulative foreign currency translation adjustment	Total
Balance as of January 1, 2018, as previously reported	$ 25	$ 750	$ (645)	$ (98)	$ 32
Cumulative effect adjustment from accounting change for adoption of ASU 2018-02[1]	5	137	(130)	—	12
Cumulative effect adjustment from accounting change for adoption of ASU 2016-01[1] net of tax (expense) benefit of $-, $8, $-, $- and $8	—	(28)	—	—	(28)
Balance as of January 1, 2018, as adjusted	30	859	(775)	(98)	16
Other comprehensive income (loss) before reclassifications	(12)	(718)	—	(40)	(770)
Amounts reclassified from accumulated other comprehensive income (loss) net of tax (expense) benefit of $-, $(7), $6, $- and $(1)	(1)	28	(24)	—	3
Other comprehensive income (loss) net of tax (expense) benefit of $3, $197, $(6), $- and $194	(11)	(746)	24	(40)	(773)
Balance as of September 30, 2018	$ 19	$ 113	$ (751)	$ (138)	$(757)

(1) See Note A to the Condensed Consolidated Financial Statements for additional information.

(In millions)	Net unrealized gains (losses) on investments with OTTI losses	Net unrealized gains (losses) on other investments	Pension and postretirement benefits	Cumulative foreign currency translation adjustment	Total
Balance as of January 1, 2017	$ 30	$ 642	$ (647)	$ (198)	$(173)
Other comprehensive income (loss) before reclassifications	—	228	—	94	322
Amounts reclassified from accumulated other comprehensive income (loss) net of tax (expense) benefit of $(1), $(28), $12, $- and $(17)	3	61	(22)	—	42
Other comprehensive income (loss) net of tax (expense) benefit of $1, $(102), $(12), $- and $(113)	(3)	167	22	94	280
Balance as of September 30, 2017	$ 27	$ 809	$ (625)	$ (104)	$107

Amounts reclassified from Accumulated other comprehensive income (loss) shown above are reported in Net income (loss) as follows:

Component of AOCI	Condensed Consolidated Statements of Operations Line Item Affected by Reclassifications
Net unrealized gains (losses) on investments with OTTI losses	Net realized investment gains (losses)
Net unrealized gains (losses) on other investments	Net realized investment gains (losses)
Pension and postretirement benefits	

Other operating expenses and Insurance claims and policyholders' benefits

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Note I. Business Segments

The Company's property and casualty commercial insurance operations are managed and reported in three business segments: Specialty, Commercial and International. These three segments are collectively referred to as Property & Casualty Operations. The Company's operations outside of Property & Casualty Operations are managed and reported in two segments: Life & Group and Corporate & Other.

Effective January 1, 2018, management changed the segment presentation of the life sciences business and technology and media related errors and omissions business within the Specialty and Commercial business segments. The life sciences business moved from the Specialty business segment to the Commercial business segment and the technology and media related errors and omissions business moved from the Commercial business segment to the Specialty business segment. The new management responsibility for these businesses better aligns with line of business underwriting expertise and the manner in which the products are sold. Prior period information has been conformed to the new segment presentation.

The accounting policies of the segments are the same as those described in Note A to the Consolidated Financial Statements within CNAF's Annual Report on Form 10-K for the year ended December 31, 2017. The Company manages most of its assets on a legal entity basis, while segment operations are generally conducted across legal entities. As such, only Insurance and Reinsurance receivables, Insurance reserves, Deferred acquisition costs and Goodwill are readily identifiable for individual segments. Distinct investment portfolios are not maintained for every individual segment; accordingly, allocation of assets to each segment is not performed. Therefore, a significant portion of Net investment income and Realized investment gains or losses are allocated primarily based on each segment's net carried insurance reserves, as adjusted. All significant intersegment income and expense have been eliminated. Income taxes have been allocated on the basis of the taxable income of the segments.

In the following tables, certain financial measures are presented to provide information used by management to monitor the Company's operating performance. Management utilizes these financial measures to monitor the Company's insurance operations and investment portfolio.

The performance of the Company's insurance operations is monitored by management through core income (loss), which is derived from certain income statement amounts. The Company's investment portfolio is monitored by management through analysis of various factors including unrealized gains and losses on securities, portfolio duration and exposure to market and credit risk.

Core income (loss) is calculated by excluding from net income (loss) the after-tax effects of i) net realized investment gains (losses), ii) income or loss from discontinued operations, iii) any cumulative effects of changes in accounting guidance and iv) deferred tax asset and liability remeasurement as a result of an enacted U.S. Federal tax rate change. The calculation of core income (loss) excludes net realized investment gains or losses because net realized investment gains or losses are generally driven by economic factors that are not necessarily consistent with key drivers of underwriting performance, and are therefore not considered an indication of trends in insurance operations.

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The Company's results of operations and selected balance sheet items by segment are presented in the following tables.

Three months ended September 30, 2018 (In millions)	Specialty	Commercial	International	Life & Group	Corporate & Other	Eliminations	Total
Operating revenues							
Net earned premiums	$ 684	$ 782	$ 255	$ 133	$ —	$ (1)	$ 1,853
Net investment income	124	144	14	200	5	—	487
Non-insurance warranty revenue	258	—	—	—	—	—	258
Other revenues	—	8	1	(1)	2	—	10
Total operating revenues	1,066	934	270	332	7	(1)	2,608
Claims, benefits and expenses							
Net incurred claims and benefits	373	496	172	277	(12)	—	1,306
Policyholders’ dividends	1	5	—	—	—	—	6
Amortization of deferred acquisition costs	153	127	57	—	—	—	337
Non-insurance warranty expense	235	—	—	—	—	—	235
Other insurance related expenses	68	133	36	31	(1)	(1)	266
Other expenses	11	10	3	2	44	—	70
Total claims, benefits and expenses	841	771	268	310	31	(1)	2,220
Core income (loss) before income tax	225	163	2	22	(24)	—	388
Income tax (expense) benefit on core income (loss)	(48)	(36)	(1)	10	4	—	(71)
Core income (loss)	$ 177	$ 127	$ 1	$ 32	$ (20)	$ —	317
Net realized investment gains (losses)							14
Income tax (expense) benefit on net realized investment gains (losses)							(1)
Net realized investment gains (losses), after tax							13
Net deferred tax asset remeasurement (1)							6
Net income							$ 336

(1) The net deferred tax asset remeasurement as of December 31, 2017 was updated based on the filed 2017 tax return resulting in a $6 million benefit for the three months ended September 30, 2018.

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Three months ended September 30, 2017 (In millions)	Specialty	Commercial	International	Life & Group	Corporate & Other	Eliminations	Total
Operating revenues							
Net earned premiums	$ 692	$ 752	$ 226	$ 136	$ —	$ —	$ 1,806
Net investment income	129	166	13	195	6	—	509
Non-insurance warranty revenue	99	—	—	—	—	—	99
Other revenues	1	6	1	—	—	—	8
Total operating revenues	921	924	240	331	6	—	2,422
Claims, benefits and expenses							
Net incurred claims and benefits	358	610	200	322	(15)	—	1,475
Policyholders' dividends	1	4	—	—	—	—	5
Amortization of deferred acquisition costs	151	122	36	—	—	—	309
Non-insurance warranty expense	74	—	—	—	—	—	74
Other insurance related expenses	65	136	48	32	—	—	281
Other expenses	11	6	(4)	2	52	—	67
Total claims, benefits and expenses	660	878	280	356	37	—	2,211
Core income (loss) before income tax	261	46	(40)	(25)	(31)	—	211
Income tax (expense) benefit on core income (loss)	(88)	(14)	2	35	13	—	(52)
Core income (loss)	$ 173	$ 32	$ (38)	$ 10	$ (18)	$ —	159
Net realized investment gains (losses)							(24)
Income tax (expense) benefit on net realized investment gains (losses)							9
Net realized investment gains (losses), after tax							(15)
Net income							$ 144

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Nine months ended September 30, 2018 (In millions)	Specialty	Commercial	International	Life & Group	Corporate & Other	Eliminations	Total
Operating revenues							
Net earned premiums	$ 2,039	$ 2,278	$ 739	$ 398	$ —	$ (1)	$ 5,453
Net investment income	376	450	43	598	16	—	1,483
Non-insurance warranty revenue	744	—	—	—	—	—	744
Other revenues	1	24	—	—	2	(1)	26
Total operating revenues	3,160	2,752	782	996	18	(2)	7,706
Claims, benefits and expenses							
Net incurred claims and benefits	1,124	1,434	480	907	15	—	3,960
Policyholders' dividends	3	15	—	—	—	—	18
Amortization of deferred acquisition costs	447	375	170	—	—	—	992
Non-insurance warranty expense	676	—	—	—	—	—	676
Other insurance related expenses	202	386	102	91	(1)	(1)	779
Other expenses	34	31	6	5	153	(1)	228
Total claims, benefits and expenses	2,486	2,241	758	1,003	167	(2)	6,653
Core income (loss) before income tax	674	511	24	(7)	(149)	—	1,053
Income tax (expense) benefit on core income (loss)	(143)	(108)	(7)	43	30	—	(185)
Core income (loss)	$ 531	$ 403	$ 17	$ 36	$ (119)	$ —	868
Net realized investment gains (losses)							25
Income tax (expense) benefit on net realized investment gains (losses)							(2)
Net realized investment gains (losses), after tax							23
Net deferred tax asset remeasurement [1]							6
Net income							$ 897

(1) The net deferred tax asset remeasurement as of December 31, 2017 was updated based on the filed 2017 tax return resulting in a $6 million benefit for the nine months ended September 30, 2018.

September 30, 2018 (In millions)							
Reinsurance receivables	$ 685	$ 729	$ 239	$ 427	$ 2,173	$ —	$ 4,253
Insurance receivables	942	1,189	259	10	—	—	2,400
Deferred acquisition costs	315	240	99	—	—	—	654
Goodwill	117	—	30	—	—	—	147
Insurance reserves							
Claim and claim adjustment expenses	5,509	8,584	1,689	3,551	2,271	—	21,604
Unearned premiums	2,129	1,520	510	130	—	—	4,289
Future policy benefits	—	—	—	10,605	—	—	10,605

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Nine months ended September 30, 2017 (In millions)	Specialty	Commercial	International	Life & Group	Corporate & Other	Eliminations	Total
Operating revenues							
Net earned premiums	$2,024	$ 2,129	$ 629	$404	$ —	$ (1)	$5,185
Net investment income	394	495	38	587	15	—	1,529
Non-insurance warranty revenue	290	—	—	—	—	—	290
Other revenues	2	24	—	1	1	—	28
Total operating revenues	2,710	2,648	667	992	16	(1)	7,032
Claims, benefits and expenses							
Net incurred claims and benefits	1,152	1,459	444	980	4	—	4,039
Policyholders' dividends	3	11	—	—	—	—	14
Amortization of deferred acquisition costs	440	359	127	—	—	—	926
Non-insurance warranty expense	216	—	—	—	—	—	216
Other insurance related expenses	203	393	106	96	(1)	(1)	796
Other expenses	32	31	(11)	5	146	—	203
Total claims, benefits and expenses	2,046	2,253	666	1,081	149	(1)	6,194
Core income (loss) before income tax	664	395	1	(89)	(133)	—	838
Income tax (expense) benefit on core income (loss)	(223)	(132)	(9)	108	51	—	(205)
Core income (loss)	$441	$ 263	$ (8)	$19	$ (82)	$ —	633
Net realized investment gains (losses)							62
Income tax (expense) benefit on net realized investment gains (losses)							(19)
Net realized investment gains (losses), after tax							43
Net income							$676

December 31, 2017 (In millions)							
Reinsurance receivables	$671	$654	$212	$ 438	$2,315	$—	$4,290
Insurance receivables	969	1,103	254	8	2	—	2,336
Deferred acquisition costs	318	223	93	—	—	—	634
Goodwill	117	—	31	—	—	—	148
Insurance reserves							
Claim and claim adjustment expenses	5,669	8,764	1,636	3,499	2,436	—	22,004
Unearned premiums	2,020	1,409	472	128	—	—	4,029
Future policy benefits	—	—	—	11,179	—	—	11,179

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The following table presents operating revenue by line of business for each reportable segment.

Periods ended September 30	Three Months		Nine Months	
(In millions)	2018	2017	2018	2017
Specialty				
Management & Professional Liability	$616	$638	$1,867	$1,896
Surety	153	143	427	403
Warranty & Alternative Risks(1)	297	140	866	411
Specialty revenues	1,066	921	3,160	2,710
Commercial				
Middle Market	530	513	1,555	1,450
Small Business	125	131	364	353
Other Commercial Insurance	279	280	833	845
Commercial revenues	934	924	2,752	2,648
International				
Canada	66	61	187	164
CNA Europe	94	87	273	238
CNA Hardy	110	92	322	265
International revenues	270	240	782	667
Life & Group revenues	332	331	996	992
Corporate & Other revenues	7	6	18	16
Eliminations	(1)	—	(2)	(1)
Total operating revenues	2,608	2,422	7,706	7,032
Net realized investment gains (losses)	14	(24)	25	62
Total revenues	$2,622	$2,398	$7,731	$7,094

(1) As of January 1, 2018, the Company adopted ASU 2014-09 Revenue Recognition (Topic 606): Revenue from Contracts with Customers. See Note A to the Condensed Consolidated Financial Statements for additional information.

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Note J. Non-Insurance Revenues from Contracts with Customers

Non-Insurance revenue is recognized when obligations under the terms of a contract with a customer are satisfied; generally this occurs over time as obligations are fulfilled. Revenue is measured as the amount of consideration the Company expects to receive in exchange for providing services.

Deferred Non-Insurance Warranty Revenue

Non-insurance warranty revenue is primarily generated from separately-priced service contracts that provide mechanical breakdown and other coverages to vehicle or consumer goods owners. The warranty contracts generally provide coverage from 1 month to 10 years. For warranty products where the Company acts as the principal in the transaction, Non-insurance warranty revenues are reported on a gross basis, with amounts billed to customers reported as Non-insurance warranty revenue and commissions paid to agents reported as Non-insurance warranty expense. Non-insurance warranty revenue is reported net of any premiums related to contractual liability coverage issued by the Company's insurance operations. Additionally, the Company provides warranty administration services for dealer and manufacturer obligor warranty products, which include limited warranties and guaranteed automobile protection waivers.

The Company recognizes Non-insurance warranty revenues over the service period in proportion to the actuarially determined expected claims emergence pattern. Customers pay in full at the inception of the warranty contract. A liability for deferred revenue is recorded when cash payments are received or due in advance of the Company's performance. The deferred revenue balance includes amounts which are refundable on a pro rata basis upon cancellation.

The Company had deferred non-insurance warranty revenue balances of $2.9 billion and $3.3 billion reported in Other liabilities as of January 1, 2018 and September 30, 2018. The increase in the deferred revenue balance for the nine months ended September 30, 2018 was primarily driven by cash payments received or due in advance of satisfying the Company's performance obligations, offset by cancellations and revenues recognized during the period. For the three and nine months ended September 30, 2018, the Company recognized $200 million and $635 million of revenues that were included in the deferred revenue balance as of January 1, 2018. For the three and nine months ended September 30, 2018, Non-insurance warranty revenue recognized from performance obligations related to prior periods due to a change in estimate was not material. The Company expects to recognize approximately $316 million of the deferred revenue in the remainder of 2018, $891 million in 2019, $718 million in 2020, and $1.4 billion thereafter.

Cost to Obtain and Fulfill Non-Insurance Warranty Contracts with Customers

Dealers, retailers and agents earn commission for assisting the Company in obtaining non-insurance warranty contracts. Additionally, the Company utilizes a third-party to perform warranty administrator services for its consumer good warranties. These costs, which are deferred and recorded as Other assets, are amortized to Non-insurance warranty expense consistent with how the related revenue is recognized.

Losses under warranty contracts shall be recognized when it is probable that estimated future costs exceed unrecognized revenue. The Company evaluates deferred costs for recoverability including consideration of anticipated investment income. Adjustments to deferred costs, if necessary, are recorded in the current period results of operations. No adjustments were recorded for the nine months ended September 30, 2018.

As of September 30, 2018, capitalized commission costs were $2.4 billion and capitalized administrator service costs were $22 million. For the three and nine months ended September 30, 2018, the amount of amortization of capitalized costs was $173 million and $494 million and there was no impairment loss related to the costs capitalized.

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Item 2. Management's Discussion and Analysis (MD&A) of Financial Condition and Results of Operations

OVERVIEW

The following discussion highlights significant factors affecting the Company. References to “we,” “our,” “us” or like terms refer to the business of CNA. Based on 2017 statutory net written premiums, we are the ninth largest commercial insurer in the United States of America.

The following discussion should be read in conjunction with the Condensed Consolidated Financial Statements included under Part I, Item 1 of this Form 10-Q and Item 1A Risk Factors and Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations, which are included in our Annual Report on Form 10-K filed with the Securities and Exchange Commission for the year ended December 31, 2017.

We utilize the core income (loss) financial measure to monitor our operations. Core income (loss) is calculated by excluding from net income (loss) the after-tax effects of i) net realized investment gains or losses, ii) income or loss from discontinued operations, iii) any cumulative effects of changes in accounting guidance and iv) deferred tax asset and liability remeasurement as a result of an enacted U.S. Federal tax rate change. The calculation of core income (loss) excludes net realized investment gains or losses because net realized investment gains or losses are generally driven by economic factors that are not necessarily consistent with key drivers of underwriting performance, and are therefore not considered an indication of trends in insurance operations. Management monitors core income (loss) for each business segment to assess segment performance. Presentation of consolidated core income (loss) is deemed to be a non-GAAP financial measure. See further discussion regarding how we manage our business in Note I to the Condensed Consolidated Financial Statements included under Part I, Item 1. For reconciliations of non-GAAP measures to the most comparable GAAP measures and other information, please refer herein and/or to CNA's most recent 10-K on file with the Securities and Exchange Commission.

In evaluating the results of our Specialty, Commercial and International segments, we utilize the loss ratio, the expense ratio, the dividend ratio and the combined ratio. These ratios are calculated using GAAP financial results. The loss ratio is the percentage of net incurred claim and claim adjustment expenses to net earned premiums. The expense ratio is the percentage of insurance underwriting and acquisition expenses, including the amortization of deferred acquisition costs, to net earned premiums. The dividend ratio is the ratio of policyholders' dividends incurred to net earned premiums. The combined ratio is the sum of the loss, expense and dividend ratios. In addition we also utilize renewal premium change, rate, retention and new business in evaluating operating trends. Renewal premium change represents the estimated change in average premium on policies that renew, including rate and exposure changes. Rate represents the average change in price on policies that renew excluding exposure change. Exposure represents the measure of risk used in the pricing of the insurance product. Retention represents the percentage of premium dollars renewed in comparison to the expiring premium dollars from policies available to renew. Renewal premium change, rate and retention presented for the prior year are updated to reflect subsequent activity on policies written in the period. New business represents premiums from policies written with new customers and additional policies written with existing customers.

Changes in estimates of claim and claim adjustment expense reserves, net of reinsurance, for prior years are defined as net prior year loss reserve development within this MD&A. These changes can be favorable or unfavorable. Net prior year loss reserve development does not include the effect of related acquisition expenses. Further information on our reserves is provided in Note E to the Condensed Consolidated Financial Statements included under Part I, Item 1.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Condensed Consolidated Financial Statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the Condensed Consolidated Financial Statements and the amount of revenues and expenses reported during the period. Actual results may differ from those estimates.

Our Condensed Consolidated Financial Statements and accompanying notes have been prepared in accordance with GAAP applied on a consistent basis. We continually evaluate the accounting policies and estimates used to prepare the Condensed Consolidated Financial Statements. In general, our estimates are based on historical experience, evaluation of current trends, information from third-party professionals and various other assumptions that are believed to be reasonable under the known facts and circumstances.

The accounting estimates below are considered by us to be critical to an understanding of our Condensed Consolidated Financial Statements as their application places the most significant demands on our judgment:

- Insurance Reserves
- Reinsurance and Insurance Receivables
- Valuation of Investments and Impairment of Securities
- Long Term Care Policies
- Income Taxes

Due to the inherent uncertainties involved with these types of judgments, actual results could differ significantly from estimates and may have a material adverse impact on our results of operations, equity, business, and insurer financial strength and corporate debt ratings. See the Critical Accounting Estimates section of our Management's Discussion and Analysis of Financial Condition and Results of Operations included under Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2017 for further information.

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CONSOLIDATED OPERATIONS

The following table includes the consolidated results of our operations including our financial measure, Core income (loss). For more detailed components of our business operations and discussion of the core income (loss) financial measure, see the segment sections within this MD&A. For further discussion of Net investment income and Net realized investment results, see the Investments section of this MD&A.

Periods ended September 30	Three Months		Nine Months	
(In millions)	2018	2017	2018	2017
Operating Revenues				
Net earned premiums	$1,853	$1,806	$5,453	$5,185
Net investment income	487	509	1,483	1,529
Non-insurance warranty revenue	258	99	744	290
Other revenues	10	8	26	28
Total operating revenues	2,608	2,422	7,706	7,032
Claims, Benefits and Expenses				
Net incurred claims and benefits	1,306	1,475	3,960	4,039
Policyholders' dividends	6	5	18	14
Amortization of deferred acquisition costs	337	309	992	926
Other insurance related expenses	266	281	779	796
Non-insurance warranty expense	235	74	676	216
Other expenses	70	67	228	203
Total claims, benefits and expenses	2,220	2,211	6,653	6,194
Core income before income tax	388	211	1,053	838
Income tax expense on core income	(71)	(52)	(185)	(205)
Core income	317	159	868	633
Net realized investment gains (losses)	14	(24)	25	62
Income tax (expense) benefit on net realized investment gains (losses)	(1)	9	(2)	(19)
Net realized investment gains (losses), after tax	13	(15)	23	43
Net deferred tax asset remeasurement	6	—	6	—
Net income	$336	$144	$897	$676

Three Month Comparison

Core income increased $158 million for the three months ended September 30, 2018 as compared with the same period in 2017. Excluding the favorable effect of the Federal corporate income tax rate change, core income for our Property & Casualty Operations increased approximately $85 million primarily due to lower net catastrophe losses partially offset by lower favorable net prior year loss reserve development and lower net investment income driven by limited partnership returns. Excluding the unfavorable effect of the Federal corporate income tax rate change which reduced the income tax benefit, core income for our Life & Group segment increased approximately $31 million while core loss for our Corporate & Other segment decreased approximately $1 million.

Pretax net catastrophe losses were $46 million and $269 million for the three months ended September 30, 2018 and 2017. Favorable net prior year loss reserve development of $62 million and $115 million was recorded in the three months ended September 30, 2018 and 2017 related to our Specialty, Commercial, International and Corporate & Other segments. Further information on net prior year loss reserve development is in Note E to the Condensed Consolidated Financial Statements included under Part I, Item 1.

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Nine Month Comparison

Core income increased $235 million for the nine months ended September 30, 2018 as compared with the same period in 2017. Excluding the favorable effect of the Federal corporate income tax rate change, core income for our Property & Casualty Operations increased approximately $92 million primarily due to lower net catastrophe losses partially offset by lower favorable net prior year loss reserve development and lower net investment income driven by limited partnership returns. Excluding the unfavorable effect of the Federal corporate income tax rate change, core income for our Life & Group segment increased approximately $54 million while core loss for our Corporate & Other segment increased approximately $16 million.

Pretax net catastrophe losses were $106 million and $342 million for the nine months ended September 30, 2018 and 2017. Favorable net prior year loss reserve development of $160 million and $227 million was recorded in the nine months ended September 30, 2018 and 2017 related to our Specialty, Commercial, International and Corporate & Other segments. Further information on net prior year loss reserve development is in Note E to the Condensed Consolidated Financial Statements included under Part I, Item 1.

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SEGMENT RESULTS

The following discusses the results of operations for our business segments. Our property and casualty commercial insurance operations are managed and reported in three business segments: Specialty, Commercial and International, which we refer to collectively as Property & Casualty Operations. Our operations outside of Property & Casualty Operations are managed and reported in two segments: Life & Group and Corporate & Other.

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Specialty

The following table details the results of operations for Specialty.

Periods ended September 30	Three Months				Nine Months			
(In millions, except ratios, rate, renewal premium change and retention)	2018		2017		2018		2017	
Net written premiums	$688		$695		$2,062		$2,066	
Net earned premiums	684		692		2,039		2,024	
Net investment income	124		129		376		394	
Core income	177		173		531		441	
Other performance metrics:								
Loss and loss adjustment expense ratio	54.5	%	51.7	%	55.1	%	56.9	%
Expense ratio	32.3		31.2		31.8		31.8	
Dividend ratio	0.2		0.2		0.2		0.1	
Combined ratio	87.0	%	83.1	%	87.1	%	88.8	%
Rate	2	%	0	%	2	%	1	%
Renewal premium change	3		1		3		3	
Retention	84		90		84		89	
New business	$93		$60		$266		$177	

Three Month Comparison

Net written premiums for Specialty decreased $7 million for the three months ended September 30, 2018 as compared with the same period in 2017 driven by a higher level of ceded reinsurance to support growth in management liability and lower retention partially offset by higher new business and positive renewal premium change. The decrease in net earned premiums was consistent with the trend in net written premiums.

Core income increased $4 million for the three months ended September 30, 2018 as compared with the same period in 2017. Excluding the favorable effect of the Federal corporate income tax rate change, core income decreased approximately $27 million driven by lower favorable net prior year loss reserve development partially offset by lower catastrophe losses.

The combined ratio of 87.0% increased 3.9 points for the three months ended September 30, 2018 as compared with the same period in 2017. The loss ratio increased 2.8 points primarily due to lower favorable net prior year loss reserve development partially offset by lower catastrophe losses. Net catastrophe losses were $16 million, or 2.4 points of the loss ratio, for the three months ended September 30, 2018, as compared to $35 million, or 5.0 points of the loss ratio, for the three months ended September 30, 2017. The expense ratio for the three months ended September 30, 2018 increased 1.1 points as compared with the same period in 2017 driven by higher acquisition expenses and lower net earned premiums.

Favorable net prior year loss reserve development of $53 million and $99 million was recorded for the three months ended September 30, 2018 and 2017. Further information on net prior year loss reserve development is in Note E to the Condensed Consolidated Financial Statements included under Part I, Item 1.

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Nine Month Comparison

Net written premiums for Specialty decreased $4 million for the nine months ended September 30, 2018 as compared with the same period in 2017 driven by a higher level of ceded reinsurance to support growth in management liability and lower retention partially offset by higher new business and positive renewal premium change. The increase in net earned premiums was consistent with the trend in net written premiums in recent quarters.

Core income increased $90 million for the nine months ended September 30, 2018 as compared with the same period in 2017. Excluding the favorable effect of the Federal corporate income tax rate change, core income was consistent with the prior period due to improved underwriting results offset by lower net investment income driven by limited partnership returns.

The combined ratio of 87.1% improved 1.7 points for the nine months ended September 30, 2018 as compared with the same period in 2017. The loss ratio improved 1.8 points primarily due to an improved current accident year loss ratio partially offset by lower favorable net prior year loss reserve development. Net catastrophe losses were $22 million, or 1.1 points of the loss ratio, for the nine months ended September 30, 2018, as compared to $44 million, or 2.2 points of the loss ratio, for the nine months ended September 30, 2017. The expense ratio for the nine months ended September 30, 2018 was consistent with the same period in 2017.

Favorable net prior year loss reserve development of $127 million and $134 million was recorded for the nine months ended September 30, 2018 and 2017. Further information on net prior year loss reserve development is in Note E to the Condensed Consolidated Financial Statements included under Part I, Item 1.

The following table summarizes the gross and net carried reserves for Specialty.

(In millions)	September 30, 2018	December 31, 2017
Gross case reserves	$ 1,591	$ 1,742
Gross IBNR reserves	3,918	3,927
Total gross carried claim and claim adjustment expense reserves	$ 5,509	$ 5,669
Net case reserves	$ 1,427	$ 1,600
Net IBNR reserves	3,409	3,407
Total net carried claim and claim adjustment expense reserves	$ 4,836	$ 5,007

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Commercial

The following table details the results of operations for Commercial.

Periods ended September 30	Three Months				Nine Months			
(In millions, except ratios, rate, renewal premium change and retention)	2018		2017		2018		2017	
Net written premiums	$697		$697		$2,339		$2,203	
Net earned premiums	782		752		2,278		2,129	
Net investment income	144		166		450		495	
Core income	127		32		403		263	
Other performance metrics:								
Loss and loss adjustment expense ratio	63.5	%	81.2	%	63.0	%	68.6	%
Expense ratio	33.2		34.2		33.3		35.3	
Dividend ratio	0.7		0.5		0.7		0.5	
Combined ratio	97.4	%	115.9	%	97.0	%	104.4	%
Rate	2	%	0	%	1	%	0	%
Renewal premium change	3		2		3		3	
Retention	84		86		85		86	
New business	$123		$138		$461		$432	

Three Month Comparison

Net written premiums for Commercial for the three months ended September 30, 2018 were consistent with the same period in 2017 as growth in gross written premium was offset by a higher level of ceded reinsurance. The increase in net earned premiums was consistent with the trend in net written premiums in recent quarters.

Core income increased $95 million for the three months ended September 30, 2018 as compared with the same period in 2017. Excluding the favorable effect of the Federal corporate income tax rate change, core income increased approximately $73 million primarily due to lower net catastrophe losses partially offset by lower favorable net prior year loss reserve development and lower net investment income driven by limited partnership returns.

The combined ratio of 97.4% improved 18.5 points for the three months ended September 30, 2018 as compared with the same period in 2017. The loss ratio improved 17.7 points driven by lower net catastrophe losses partially offset by lower favorable net prior year loss reserve development. Net catastrophe losses were $25 million, or 3.1 points of the loss ratio, for the three months ended September 30, 2018, as compared to $176 million, or 23.9 points of the loss ratio, for the three months ended September 30, 2017. The expense ratio improved 1.0 point for the three months ended September 30, 2018 as compared with the same period in 2017 driven by lower employee costs and higher net earned premiums.

Favorable net prior year loss reserve development of $5 million and $17 million was recorded for the three months ended September 30, 2018 and 2017. Further information on net prior year loss reserve development is in Note E to the Condensed Consolidated Financial Statements included under Part I, Item 1.

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Nine Month Comparison

Net written premiums for Commercial increased $136 million for the nine months ended September 30, 2018 as compared with the same period in 2017. The premium rate adjustments in Small Business affected both net written premiums and net earned premiums as more fully discussed in Note F to the Condensed Consolidated Financial Statements under Part 1, Item 1. Excluding the effect of the Small Business premium rate adjustments, net written premiums increased $83 million driven by higher new business and positive renewal premium change. The increase in net earned premiums was consistent with the trend in net written premiums.

Core income increased $140 million for the nine months ended September 30, 2018 as compared with the same period in 2017. Excluding the favorable effect of the Federal corporate income tax rate change and the unfavorable Small Business premium rate adjustments, core income increased approximately $51 million primarily due to lower net catastrophe losses partially offset by lower favorable net prior year loss reserve development and lower net investment income driven by limited partnership returns.

The combined ratio of 97.0% improved 7.4 points for the nine months ended September 30, 2018 as compared with the same period in 2017. The loss ratio improved 5.6 points driven by lower net catastrophe losses partially offset by lower favorable net prior year loss reserve development. Net catastrophe losses were $73 million, or 3.1 points of the loss ratio, for the nine months ended September 30, 2018, as compared to $238 million, or 11.1 points of the loss ratio, for the nine months ended September 30, 2017. Excluding the Small Business premium rate adjustments, the expense ratio improved 1.2 points driven by lower employee costs and IT spend.

Favorable net prior year loss reserve development of $27 million and $94 million was recorded for the nine months ended September 30, 2018 and 2017. Further information on net prior year loss reserve development is in Note E to the Condensed Consolidated Financial Statements included under Part I, Item 1.

The following table summarizes the gross and net carried reserves for Commercial.

(In millions)	September 30, 2018	December 31, 2017
Gross case reserves	$ 4,184	$ 4,427
Gross IBNR reserves	4,400	4,337
Total gross carried claim and claim adjustment expense reserves	$ 8,584	$ 8,764
Net case reserves	$ 3,835	$ 4,103
Net IBNR reserves	4,069	4,033
Total net carried claim and claim adjustment expense reserves	$ 7,904	$ 8,136

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International

The following table details the results of operations for International.

Periods ended September 30	Three Months		Nine Months	
(In millions, except ratios, rate, renewal premium change and retention)	2018	2017	2018	2017
Net written premiums	$196	$207	$762	$664
Net earned premiums	255	226	739	629
Net investment income	14	13	43	38
Core income (loss)	1	(38)	17	(8)
Other performance metrics:				
Loss and loss adjustment expense ratio	67.6 %	88.4 %	65.0 %	70.6 %
Expense ratio	36.3	37.5	36.8	37.2
Combined ratio	103.9%	125.9%	101.8%	107.8%
Rate	3 %	1 %	3 %	0 %
Renewal premium change	8	3	6	2
Retention	67	76	77	79
New business	$72	$69	$248	$207

Three Month Comparison

Net written premiums for International decreased $11 million for the three months ended September 30, 2018 as compared with the same period in 2017. Excluding the effect of foreign currency exchange rates, net written premiums decreased $9 million or 4% for the three months ended September 30, 2018 as compared with the same period in 2017 driven by a higher level of ceded reinsurance. The increase in net earned premiums was consistent with the trend in net written premiums in recent quarters.

Core results improved $39 million for the three months ended September 30, 2018 as compared with the same period in 2017 driven by lower net catastrophe losses. The effect of the Federal corporate income tax rate change was not significant.

The combined ratio of 103.9% improved 22.0 points for the three months ended September 30, 2018 as compared with the same period in 2017. The loss ratio improved 20.8 points, primarily due to lower net catastrophe losses partially offset by a higher number of large property losses in CNA Hardy. Net catastrophe losses were $5 million, or 2.1 points of the loss ratio, for the three months ended September 30, 2018, as compared to $58 million, or 27.5 points of the loss ratio for the three months ended September 30, 2017. The expense ratio improved 1.2 points for the three months ended September 30, 2018 as compared with the same period in 2017 driven by higher net earned premiums.

Favorable net prior year loss reserve development of $2 million was recorded for the three months ended September 30, 2018 as compared with unfavorable net prior year loss reserve development of $1 million for the three months ended September 30, 2017. Further information on net prior year loss reserve development is in Note E to the Condensed Consolidated Financial Statements included under Part I, Item 1.

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Nine Month Comparison

Net written premiums for International increased $98 million for the nine months ended September 30, 2018 as compared with the same period in 2017. Excluding the effect of foreign currency exchange rates, net written premiums increased $69 million or 10% for the nine months ended September 30, 2018 as compared with the same period in 2017 driven by positive renewal premium change and higher new business partially offset by a higher level of ceded reinsurance. The increase in net earned premiums was consistent with the trend in net written premiums.

Core results improved $25 million for the nine months ended September 30, 2018 as compared with the same period in 2017 driven by lower net catastrophe losses partially offset by unfavorable period over period foreign currency exchange results. The effect of the Federal corporate income tax rate change was not significant.

The combined ratio of 101.8% improved 6.0 points for the nine months ended September 30, 2018 as compared with the same period in 2017. The loss ratio improved 5.6 points, primarily due to lower net catastrophe losses partially offset by a higher number of large property losses. Net catastrophe losses were $11 million, or 1.5 points of the loss ratio, for the nine months ended September 30, 2018, as compared to $60 million, or 10.3 points of the loss ratio, for the nine months ended September 30, 2017. The expense ratio improved 0.4 points for the nine months ended September 30, 2018 as compared with the same period in 2017 driven by higher net earned premiums partially offset by higher employee costs.

Favorable net prior year loss reserve development of $4 million was recorded for the nine months ended September 30, 2018 as compared with unfavorable net prior year loss reserve development of $1 million for the nine months ended September 30, 2017. Further information on net prior year loss reserve development is in Note E to the Condensed Consolidated Financial Statements included under Part I, Item 1.

Effective October 1 2018, CNA Hardy will no longer write property treaty, marine hull, and construction all risk/erection all risk through the Lloyd’s platform. While these three classes combined represent a relatively small component of the International segment’s business, it may result in lower net written premiums within the CNA Hardy business.

The following table summarizes the gross and net carried reserves for International.

(In millions)	September 30, 2018	December 31, 2017
Gross case reserves	$ 811	$ 744
Gross IBNR reserves	878	892
Total gross carried claim and claim adjustment expense reserves	$ 1,689	$ 1,636
Net case reserves	$ 677	$ 640
Net IBNR reserves	775	792
Total net carried claim and claim adjustment expense reserves	$ 1,452	$ 1,432

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Life & Group

The following table details the results of operations for Life & Group.

Periods ended September 30	Three Months		Nine Months	
(In millions)	2018	2017	2018	2017
Net earned premiums	$133	$136	$398	$404
Net investment income	200	195	598	587
Core income (loss) before income tax	22	(25)	(7)	(89)
Income tax benefit on core income (loss)	10	35	43	108
Core income	32	10	36	19

Three Month Comparison

Core income increased $22 million for the three months ended September 30, 2018 as compared with the same period in 2017. Excluding the unfavorable effect of the Federal corporate income tax rate change, core income increased approximately $31 million. This increase was driven by a $24 million after-tax reduction in long term care claim reserves resulting from the annual claims experience study. This study was completed in the third quarter of 2018 as compared to the fourth quarter in 2017. Persistency continues to benefit from a high proportion of policyholders choosing to reduce benefits in lieu of premium rate increases. Morbidity continues to trend in line with expectations.

Nine Month Comparison

Core income increased $17 million for the nine months ended September 30, 2018 as compared with the same period in 2017. Excluding the unfavorable effect of the Federal corporate income tax rate change, core income increased approximately $54 million. Persistency continues to benefit from a high proportion of policyholders choosing to reduce benefits in lieu of premium rate increases. The favorable persistency trend was partially offset by a significant number of policies converting to a fully paid-up status with modest future benefits following the termination of a large group account. The reserves associated with these converted policies were, on average, slightly higher than the previously recorded carried reserves, resulting in a negative financial impact. Morbidity continues to trend in line with expectations. Additionally, core income for the nine months ended September 30, 2018 includes the $24 million benefit of the reduction in long term care claim reserves resulting from the annual claims experience study.

Life & Group Policyholder Reserves

Annually, management assesses the adequacy of its long term care future policy benefit reserves by performing a gross premium valuation (GPV) to determine if there is a premium deficiency. The GPV process occurred in the third quarter of 2018 as compared to the fourth quarter in 2017. See Reserves - Estimates and Uncertainties section of our Management's Discussion and Analysis of Financial Condition and Results of Operations included under Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2017 for further information on the reserving process.

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The September 30, 2018 GPV indicated our recorded reserves included a margin of approximately $182 million. A summary of the changes in the estimated reserve margin is presented in the table below:

Long Term Care Active Life Reserve - Change in estimated reserve margin (In millions)	
December 31, 2017 Estimated Margin	$246
Changes in underlying morbidity assumptions	(213)
Changes in underlying persistency assumptions and inforce policy inventory	(86)
Changes in underlying discount rate assumptions	17
Changes in underlying premium rate action assumptions	178
Changes in underlying expense and other assumptions	40
September 30, 2018 Estimated Margin	$182

The decrease in the margin in 2018 was driven by the removal of the future morbidity improvement assumption and extending the period of mortality improvement within the persistency assumptions. These unfavorable drivers were partially offset by higher than expected rate increases on active rate action programs and favorable changes to the underlying expense and discount rate assumptions.

The table below summarizes the estimated pretax impact on our results of operations from various hypothetical revisions to our active life reserve assumptions. The annual GPV process involves updating all assumptions to the then current best estimate, and historically all significant assumptions have been revised each year. In the Hypothetical Revisions table below, we have assumed that revisions to such assumptions would occur in each policy type, age and duration within each policy group and would occur absent any changes, mitigating or otherwise, in the other assumptions. Although such hypothetical revisions are not currently required or anticipated, we believe they could occur based on past variances in experience and our expectations of the ranges of future experience that could reasonably occur. Any required increase in the recorded reserves resulting from the hypothetical revision in the table below would first reduce the margin in our carried reserves before it would affect results of operations. Any actual adjustment would be dependent on the specific policies affected and, therefore, may differ from the estimates summarized below. The estimated impacts to results of operations in the table below are after consideration of the existing margin.

September 30, 2018

Hypothetical revisions (In millions)	Estimated reduction to pretax income
Morbidity:	
5% increase in morbidity	$ 460
10% increase in morbidity	1,103
Persistency:	
5% decrease in active life mortality and lapse	$ 31
10% decrease in active life mortality and lapse	253
Discount Rates:	
50 basis point decline in future interest rates	$ 140
100 basis point decline in future interest rates	500
Premium Rate Actions:	
50% decrease in anticipated future premium rate increases	$ —

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While the GPV process indicated there is margin in the recorded future policy benefit reserves at September 30, 2018, management noted that its projections indicate a pattern of expected profits in earlier future years followed by expected losses in later future years ("profits followed by losses"). In that circumstance, GAAP requires that the future policy benefit reserves should be increased in the profitable years by an amount necessary to offset losses that would be recognized in later years.

As a result, in the fourth quarter of 2018 the Company will begin to establish additional future policy benefit reserves in periods where the long term care business generates core income. The amount of the additional future policy benefit reserves in each quarterly period will be based on the ratio of the present value of future losses divided by the present value of future profits resulting from the most recently completed GPV.

The need for additional future policy benefit reserves for profits followed by losses as well as the percentage used to establish such reserves will be re-evaluated in connection with the next GPV, which is expected to be completed in the third quarter of 2019.

The following table summarizes policyholder reserves for Life & Group.

September 30, 2018

(In millions)	Claim and claim adjustment expenses	Future policy benefits	Total
Long term care	$ 2,689	$9,078	$11,767
Structured settlement annuities	535	—	535
Other	16	—	16
Total	3,240	9,078	12,318
Shadow adjustments (1)	118	1,293	1,411
Ceded reserves (2)	193	234	427
Total gross reserves	$ 3,551	$10,605	$14,156

December 31, 2017

(In millions)	Claim and claim adjustment expenses	Future policy benefits	Total
Long term care	$ 2,568	$8,959	$11,527
Structured settlement annuities	547	—	547
Other	16	—	16
Total	3,131	8,959	12,090
Shadow adjustments (1)	159	1,990	2,149
Ceded reserves (2)	209	230	439
Total gross reserves	$ 3,499	$11,179	$14,678

(1) To the extent that unrealized gains on fixed income securities supporting long term care products and annuity contracts would result in a premium deficiency if those gains were realized, an increase in Insurance reserves is recorded, net of tax, as a reduction of net unrealized gains through Other comprehensive income (loss) (Shadow Adjustments).

(2) Ceded reserves relate to claim or policy reserves fully reinsured in connection with a sale or exit from the underlying business.

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Corporate & Other

The following table details the results of operations for Corporate & Other.

Periods ended September 30	Three Months		Nine Months	
(In millions)	2018	2017	2018	2017
Net investment income	$5	$ 6	$16	$15
Interest expense	33	39	101	116
Core loss	(20)	(18)	(119)	(82)

Three Month Comparison

Core loss increased $2 million for the three months ended September 30, 2018 as compared with the same period in 2017. Excluding the unfavorable effect of the Federal corporate income tax rate change, core loss decreased approximately $1 million.

Nine Month Comparison

Core loss increased $37 million for the nine months ended September 30, 2018 as compared with the same period in 2017. Excluding the unfavorable effect of the Federal corporate income tax rate change, core loss increased approximately $16 million driven by non-recurring costs of $27 million associated with the transition to a new IT infrastructure service provider and higher adverse net prior year reserve development recorded in 2018 for A&EP under the LPT, as compared to the prior year period.

The following table summarizes the gross and net carried reserves for Corporate & Other.

(In millions)	September 30, 2018	December 31, 2017
Gross case reserves	$ 1,170	$ 1,371
Gross IBNR reserves	1,101	1,065
Total gross carried claim and claim adjustment expense reserves	$ 2,271	$ 2,436
Net case reserves	$ 91	$ 94
Net IBNR reserves	105	111
Total net carried claim and claim adjustment expense reserves	$ 196	$ 205

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INVESTMENTS

Net Investment Income

The significant components of Net investment income are presented in the following table. Fixed income securities, as presented, include both fixed maturity and non-redeemable preferred stock.

Periods ended September 30	Three Months		Nine Months	
(In millions)	2018	2017	2018	2017
Fixed income securities:				
Taxable fixed income securities	$366	$350	$1,070	$1,051
Tax-exempt fixed income securities	93	106	298	320
Total fixed income securities	459	456	1,368	1,371
Limited partnership and common stock investments	23	51	96	157
Other, net of investment expense	5	2	19	1
Pretax net investment income	$487	$509	$1,483	$1,529
Fixed income securities, after tax	$378	$330	$1,130	$994
Net investment income, after tax	400	363	1,221	1,096
Effective income yield for the fixed income securities portfolio, pretax	4.7 %	4.7 %	4.7 %	4.7 %
Effective income yield for the fixed income securities portfolio, after tax	3.9 %	3.4 %	3.9 %	3.4 %

Pretax net investment income decreased $22 million for the three months ended September 30, 2018 as compared with the same period in 2017. The decrease was driven by limited partnership and common stock investments, which returned 0.9% in 2018 as compared with 2.2% in the prior year period. However, despite the decline in limited partnership income, net investment income, after tax, increased $37 million for the three months ended September 30, 2018 as compared with the same period in 2017 driven by the lower Federal corporate income tax rate.

Pretax net investment income decreased $46 million for the nine months ended September 30, 2018 as compared with the same period in 2017. The decrease was driven by limited partnership and common stock investments, which returned 4.0% in 2018 as compared with 6.8% in the prior year period. However, despite the decline in limited partnership income, net investment income, after tax, increased $125 million for the nine months ended September 30, 2018 as compared with the same period in 2017 driven by the lower Federal corporate income tax rate.

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Net Realized Investment Gains (Losses)

The components of Net realized investment results are presented in the following table.

Periods ended September 30	Three Months		Nine Months	
(In millions)	2018	2017	2018	2017
Fixed maturity securities:				
Corporate bonds and other	$8	$14	$36	$85
States, municipalities and political subdivisions	9	4	35	14
Asset-backed	(7)	(2)	(39)	(7)
Total fixed maturity securities	10	16	32	92
Non-redeemable preferred stock	2	—	(23)	—
Short term and other	2	(40)	16	(30)
Net realized investment gains (losses)	14	(24)	25	62
Income tax (expense) benefit on net realized investment gains (losses)	(1)	9	(2)	(19)
Net realized investment gains (losses), after tax	$13	$(15)	$23	$43

Pretax net realized investment results improved $38 million for the three months ended September 30, 2018 as compared with the same period in 2017. The prior period Net realized investment losses included a pretax loss of $42 million as a result of the redemption of our $350 million senior notes due November 2019.

Pretax net realized investment gains decreased $37 million for the nine months ended September 30, 2018 as compared with the same period in 2017. The decrease was driven by lower net realized gains on sales of securities and the decline in fair value of non-redeemable preferred stock. Additionally, the prior period included the pretax loss of $42 million discussed above.

Further information on our realized gains and losses, including our OTTI losses, is set forth in Note C to the Condensed Consolidated Financial Statements included under Part I, Item 1.

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Portfolio Quality

The following table presents the estimated fair value and net unrealized gains (losses) of our fixed maturity securities by rating distribution.

(In millions)	September 30, 2018 Estimated Fair Value	September 30, 2018 Net Unrealized Gains (Losses)	December 31, 2017 Estimated Fair Value	December 31, 2017 Net Unrealized Gains (Losses)
U.S. Government, Government agencies and Government-sponsored enterprises	$4,430	$ (96)	$4,514	$ 21
AAA	3,064	221	1,954	152
AA	6,575	459	8,982	914
A	8,838	525	9,643	952
BBB	13,997	417	13,554	1,093
Non-investment grade	2,724	50	2,840	140
Total	$39,628	$ 1,576	$41,487	$ 3,272

As of September 30, 2018 and December 31, 2017, 3% and 2% of our fixed maturity portfolio was rated internally.

The following table presents available-for-sale fixed maturity securities in a gross unrealized loss position by ratings distribution.

(In millions)	September 30, 2018 Estimated Fair Value	September 30, 2018 Gross Unrealized Losses
U.S. Government, Government agencies and Government-sponsored enterprises	$3,735	$ 113
AAA	488	10
AA	1,093	19
A	2,558	57
BBB	6,319	167
Non-investment grade	1,031	37
Total	$15,224	$ 403

The following table presents the maturity profile for these available-for-sale fixed maturity securities. Securities not due to mature on a single date are allocated based on weighted average life.

(In millions)	September 30, 2018 Estimated Fair Value	September 30, 2018 Gross Unrealized Losses
Due in one year or less	$231	$ 6
Due after one year through five years	2,540	37
Due after five years through ten years	10,369	294
Due after ten years	2,084	66
Total	$15,224	$ 403

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Duration

A primary objective in the management of the investment portfolio is to optimize return relative to corresponding liabilities and respective liquidity needs. Our views on the current interest rate environment, tax regulations, asset class valuations, specific security issuer and broader industry segment conditions and domestic and global economic conditions, are some of the factors that enter into an investment decision. We also continually monitor exposure to issuers of securities held and broader industry sector exposures and may from time to time adjust such exposures based on our views of a specific issuer or industry sector.

A further consideration in the management of the investment portfolio is the characteristics of the corresponding liabilities and the ability to align the duration of the portfolio to those liabilities and to meet future liquidity needs, minimize interest rate risk and maintain a level of income sufficient to support the underlying insurance liabilities. For portfolios where future liability cash flows are determinable and typically long term in nature, we segregate investments for asset/liability management purposes. The segregated investments support the long term care and structured settlement liabilities in the Life & Group segment.

The effective durations of fixed income securities and short term investments are presented in the following table. Amounts presented are net of payable and receivable amounts for securities purchased and sold, but not yet settled.

	September 30, 2018		December 31, 2017	
(In millions)	Estimated Fair Value	Effective Duration (In years)	Estimated Fair Value	Effective Duration (In years)
Investments supporting Life & Group	$ 16,155	8.2	$ 16,797	8.4
Other investments	25,407	4.5	26,817	4.4
Total	$ 41,562	5.9	$ 43,614	5.9

The duration of the total portfolio is aligned with the cash flow characteristics of the underlying liabilities.

The investment portfolio is periodically analyzed for changes in duration and related price risk. Additionally, we periodically review the sensitivity of the portfolio to the level of foreign exchange rates and other factors that contribute to market price changes. A summary of these risks and specific analysis on changes is included in the Quantitative and Qualitative Disclosures About Market Risk included under Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2017.

Short Term Investments

The carrying value of the components of the Short term investments are presented in the following table.

(In millions)	September 30, 2018	December 31, 2017
Short term investments:		
Commercial paper	$ 895	$ 905
U.S. Treasury securities	227	355
Other	168	176
Total short term investments	$ 1,290	$ 1,436

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LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

Our primary operating cash flow sources are premiums and investment income from our insurance subsidiaries. Our primary operating cash flow uses are payments for claims, policy benefits and operating expenses, including interest expense on corporate debt. Additionally, cash may be paid or received for income taxes.

For the nine months ended September 30, 2018, net cash provided by operating activities was $868 million as compared with $894 million for the same period in 2017. The decrease in cash provided by operating activities was driven by higher income taxes paid and higher net claim payments partially offset by an increase in premiums collected.

Cash flows from investing activities include the purchase and disposition of available-for-sale financial instruments and may include the purchase and sale of businesses, land, buildings, equipment and other assets not generally held for resale.

Net cash provided by investing activities was $80 million for the nine months ended September 30, 2018, as compared with net cash used of $218 million for the same period in 2017. The cash flow from investing activities is affected by various factors such as the anticipated payment of claims, financing activity, asset/liability management and individual security buy and sell decisions made in the normal course of portfolio management.

Cash flows from financing activities may include proceeds from the issuance of debt and equity securities, outflows for stockholder dividends or repayment of debt and outlays to reacquire equity securities.

For the nine months ended September 30, 2018, net cash used by financing activities was $989 million as compared with $673 million for the same period in 2017. In the third quarter of 2018, we redeemed the $30 million of subordinated variable rate debt of CNA Hardy due September 15, 2036. In the first quarter of 2018, we redeemed the $150 million outstanding aggregate principal balance of our 6.950% senior notes due January 15, 2018. In the third quarter of 2017, we issued $500 million of 3.45% senior notes due August 15, 2027 and redeemed the $350 million outstanding aggregate principal balance of our 7.35% senior notes due November 15, 2019.

Common Stock Dividends

Dividends of $2.95 per share on our common stock, including a special dividend of $2.00 per share, were declared and paid during the nine months ended September 30, 2018. On November 2, 2018, our Board of Directors declared a quarterly dividend of $0.35 per share, payable December 5, 2018 to stockholders of record on November 19, 2018. The declaration and payment of future dividends to holders of our common stock will be at the discretion of our Board of Directors and will depend on many factors, including our earnings, financial condition, business needs and regulatory constraints.

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Liquidity

We believe that our present cash flows from operating, investing and financing activities are sufficient to fund our current and expected working capital and debt obligation needs and we do not expect this to change in the near term. There are currently no amounts outstanding under our $250 million senior unsecured revolving credit facility and no borrowings outstanding through our membership in the FHLBC.

Dividends from CCC are subject to the insurance holding company laws of the State of Illinois, the domiciliary state of CCC. Under these laws, ordinary dividends, or dividends that do not require prior approval by the Illinois Department of Insurance (the Department), are determined based on the greater of the prior year's statutory net income or 10% of statutory surplus as of the end of the prior year, as well as timing and amount of dividends paid in the preceding twelve months. Additionally, ordinary dividends may only be paid from earned surplus, which is calculated by removing unrealized gains from unassigned surplus. As of September 30, 2018 CCC was in a positive earned surplus position. The maximum allowable dividend CCC could pay during 2018 that would not be subject to the Department's prior approval is $1,073 million, less dividends paid during the preceding twelve months measured at that point in time. CCC paid dividends of $100 million during the three months ended December 31, 2017 and $910 million during the nine months ended September 30, 2018. As of September 30, 2018 CCC is able to pay approximately $63 million of dividends that would not be subject to prior approval of the Department. The actual level of dividends paid in any year is determined after an assessment of available dividend capacity, holding company liquidity and cash needs as well as the impact the dividends will have on the statutory surplus of the applicable insurance company.

We have an effective automatic shelf registration statement under which we may publicly issue debt, equity or hybrid securities from time to time.

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ACCOUNTING STANDARDS UPDATE

For a discussion of Accounting Standards Updates adopted in the current period and that will be adopted in the future, see Note A to the Condensed Consolidated Financial Statements included under Part I, Item 1.

FORWARD-LOOKING STATEMENTS

This report contains a number of forward-looking statements which relate to anticipated future events rather than actual present conditions or historical events. These statements are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 and generally include words such as “believes,” “expects,” “intends,” “anticipates,” “estimates” and similar expressions. Forward-looking statements in this report include any and all statements regarding expected developments in our insurance business, including losses and loss reserves for A&EP and other mass tort claims which are more uncertain, and therefore more difficult to estimate than loss reserves respecting traditional property and casualty exposures; the impact of routine ongoing insurance reserve reviews we are conducting; our expectations concerning our revenues, earnings, expenses and investment activities; volatility in investment returns; expected cost savings and other results from our expense reduction activities; and our proposed actions in response to trends in our business. Forward-looking statements, by their nature, are subject to a variety of inherent risks and uncertainties that could cause actual results to differ materially from the results projected in the forward-looking statement. We cannot control many of these risks and uncertainties. These risks and uncertainties include, but are not limited to, the following:

Company-Specific Factors

- the risks and uncertainties associated with our insurance reserves, as outlined in the Critical Accounting Estimates and the Reserves - Estimates and Uncertainties sections of our Annual Report on Form 10-K, including the sufficiency of the reserves and the possibility for future increases, which would be reflected in the results of operations in the period that the need for such adjustment is determined;
- the risk that the other parties to the transaction in which, subject to certain limitations, we ceded our legacy A&EP liabilities will not fully perform their obligations to CNA, the uncertainty in estimating loss reserves for A&EP liabilities and the possible continued exposure of CNA to liabilities for A&EP claims that are not covered under the terms of the transaction;
- the performance of reinsurance companies under reinsurance contracts with us; and
- the risks and uncertainties associated with potential acquisitions and divestitures, including the consummation of such transactions, the successful integration of acquired operations and the potential for subsequent impairment of goodwill or intangible assets.

Industry and General Market Factors

- the impact of competitive products, policies and pricing and the competitive environment in which we operate, including changes in our book of business;
- product and policy availability and demand and market responses, including the level of ability to obtain rate increases and decline or non-renew underpriced accounts, to achieve premium targets and profitability and to realize growth and retention estimates;
- general economic and business conditions, including recessionary conditions that may decrease the size and number of our insurance customers and create additional losses to our lines of business, especially those that provide management and professional liability insurance, as well as surety bonds, to businesses engaged in real estate, financial services and professional services and inflationary pressures on medical care costs, construction costs and other economic sectors that increase the severity of claims;
- conditions in the capital and credit markets, including continuing uncertainty and instability in these markets, as well as the overall economy, and their impact on the returns, types, liquidity and valuation of our investments;
- conditions in the capital and credit markets that may limit our ability to raise significant amounts of capital on favorable terms; and
- the possibility of changes in our ratings by ratings agencies, including the inability to access certain markets or distribution channels and the required collateralization of future payment obligations as a result of such changes, and changes in rating agency policies and practices.

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Regulatory Factors

- regulatory initiatives and compliance with governmental regulations, judicial interpretations within the regulatory framework, including interpretation of policy provisions, decisions regarding coverage and theories of liability, legislative actions that increase claimant activity, trends in litigation and the outcome of any litigation involving us and rulings and changes in tax laws and regulations;
- regulatory limitations, impositions and restrictions upon us, including with respect to our ability to increase premium rates, and the effects of assessments and other surcharges for guaranty funds and second-injury funds, other mandatory pooling arrangements and future assessments levied on insurance companies; and
- regulatory limitations and restrictions, including limitations upon our ability to receive dividends from our insurance subsidiaries, imposed by regulatory authorities, including regulatory capital adequacy standards.

Impact of Catastrophic Events and Related Developments

- weather and other natural physical events, including the severity and frequency of storms, hail, snowfall and other winter conditions, natural disasters such as hurricanes and earthquakes, as well as climate change, including effects on global weather patterns, greenhouse gases, sea, land and air temperatures, sea levels, rain, hail and snow;
- regulatory requirements imposed by coastal state regulators in the wake of hurricanes or other natural disasters, including limitations on the ability to exit markets or to non-renew, cancel or change terms and conditions in policies, as well as mandatory assessments to fund any shortfalls arising from the inability of quasi-governmental insurers to pay claims;
- man-made disasters, including the possible occurrence of terrorist attacks, the unpredictability of the nature, targets, severity or frequency of such events, and the effect of the absence or insufficiency of applicable terrorism legislation on coverages; and
- the occurrence of epidemics.

Referendum on the United Kingdom's Membership in the European Union

- in 2016, the United Kingdom (U.K.) approved an exit from the European Union (E.U.), commonly referred to as "Brexit.” Brexit is scheduled to be completed in early 2019. As treaties between the U.K. and the E.U. have not been finalized, as of January 1, 2019, we intend to write business in the E.U. through our recently established European subsidiary in Luxembourg as our U.K.-domiciled subsidiary will presumably no longer provide a platform for our operations throughout the European continent. As a result of such structural changes and modification to our European operations, the complexity and cost of regulatory compliance of our European business has increased and will likely continue to result in elevated expenses.

Our forward-looking statements speak only as of the date of the filing of this Quarterly Report on Form 10-Q and we do not undertake any obligation to update or revise any forward-looking statement to reflect events or circumstances after the date of the statement, even if our expectations or any related events or circumstances change.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

There were no material changes in our market risk components for the nine months ended September 30, 2018. See the Quantitative and Qualitative Disclosures About Market Risk included in Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2017 for further information. Additional information related to portfolio duration is discussed in the Investments section of our Management's Discussion and Analysis of Financial Condition and Results of Operations included in Part I, Item 2.

Item 4. Controls and Procedures

The Company maintains a system of disclosure controls and procedures which are designed to ensure that information required to be disclosed by the Company in reports that it files or submits to the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), including this report, is recorded, processed, summarized and reported on a timely basis. These disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed under the Exchange Act is accumulated and communicated to the Company's management on a timely basis to allow decisions regarding required disclosure.

As of September 30, 2018, the Company's management, including the Company's Chief Executive Officer (CEO) and Chief Financial Officer (CFO), conducted an evaluation of the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Exchange Act Rules 13a-15(e) and 15d-15(e)). Based on this evaluation, the CEO and CFO have concluded that the Company's disclosure controls and procedures are effective as of September 30, 2018.

There has been no change in the Company's internal control over financial reporting (as defined in Rules 13a-15 (f) and 15d-15(f) under the Exchange Act) during the quarter ended September 30, 2018 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

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PART II. Other Information

Item 1. Legal Proceedings

Information on our legal proceedings is set forth in Note F to the Condensed Consolidated Financial Statements included under Part I, Item 1.

Item 6. Exhibits

See Exhibit Index.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

CNA Financial Corporation

Dated: November 5, 2018 By /s/ James M. Anderson

James M. Anderson
Executive Vice President and
Chief Financial Officer
(Duly authorized officer and principal financial officer)

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EXHIBIT INDEX

Description of Exhibit	Exhibit Number
Certification of Chief Executive Officer	31.1
Certification of Chief Financial Officer	31.2
Written Statement of the Chief Executive Officer of CNA Financial Corporation Pursuant to 18 U.S.C. Section 1350 (As adopted by Section 906 of the Sarbanes-Oxley Act of 2002)	32.1
Written Statement of the Chief Financial Officer of CNA Financial Corporation Pursuant to 18 U.S.C. Section 1350 (As adopted by Section 906 of the Sarbanes-Oxley Act of 2002)	32.2
XBRL Instance Document	101.INS
XBRL Taxonomy Extension Schema	101.SCH
XBRL Taxonomy Extension Calculation Linkbase	101.CAL
XBRL Taxonomy Extension Definition Linkbase	101.DEF
XBRL Taxonomy Label Linkbase	101.LAB
XBRL Taxonomy Extension Presentation Linkbase	101.PRE