ENCORE ACQUISITION CO
Form 10-K
February 24, 2009

Table of Contents

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

Form 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2008

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number: 001-16295

ENCORE ACQUISITION COMPANY
(Exact name of registrant as specified in its charter)

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

Registrant s telephone number, including area code: (817) 877-9955

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange
Rights to Purchase Series A Junior Participating Preferred Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No þ

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity of the registrant was last sold as of June 30, 2008 (the last business day of the registrant s most recently completed second fiscal quarter)	$ 3,715,001,806
Number of shares of Common Stock, $0.01 par value, outstanding as of February 18, 2009	51,819,037

DOCUMENTS INCORPORATED BY REFERENCE

Parts of the definitive proxy statement for the registrant s 2009 annual meeting of stockholders are incorporated by reference into Part III of this report on Form 10-K.

ENCORE ACQUISITION COMPANY

INDEX

Table of Contents

ENCORE ACQUISITION COMPANY

GLOSSARY

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

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

Bbl/D. One Bbl per day.

Bcf. One billion cubic feet, used in reference to natural gas.

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

BOE/D. One BOE per day.

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

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

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

Developed Acreage. The number of acres allocated or assignable to producing wells or wells capable of production.

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 oil or natural gas in an unproved area, to find a new reservoir in a field previously producing oil or natural gas in another reservoir, or to extend a known reservoir.

Farm-out. Transfer of all or part of the operating rights from the working interest holder to an assignee, who assumes all or some of the burden of development, in return for an interest in the property. The assignor usually retains an overriding royalty, but may retain any type of interest.

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.

ENCORE ACQUISITION COMPANY

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

Horizontal Drilling. A drilling operation in which a portion of a well is drilled horizontally within a productive or potentially productive formation. This operation usually yields a well which has the ability to produce higher volumes than a vertical well drilled in the same formation.

Lease Operations Expense (LOE). All direct and allocated indirect costs of producing oil and natural gas after completion of drilling and before removal of production from the property. 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.

MBOE/D. One thousand BOE per day.

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

Mcf/D. One Mcf per day.

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

Mcfe/D. One Mcfe per day.

MMBbl. One million Bbls.

MMBOE. One million BOE.

MMBtu. One million British thermal units. One British thermal unit is the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

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 production of hydrocarbons.

NYMEX. New York Mercantile Exchange.

NYSE. The New York Stock Exchange.

Oil. Crude oil, condensate, and NGLs.

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

Present Value of Future Net Revenues (PV-10). The present value of estimated future revenues to be generated from the production of proved reserves, net of estimated future production and development costs, using prices and costs as of the date of estimation without future escalation, without

ENCORE ACQUISITION COMPANY

giving effect to commodity derivative activities, non-property related expenses such as general and administrative expenses, debt service, depletion, depreciation, and amortization, and income taxes, discounted at an annual rate of 10 percent.

Production Margin. Oil and natural gas wellhead revenues less production expenses.

Productive Well. A producing well or a well capable of production, 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 crude oil, natural gas, and NGLs that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved Undeveloped Reserves. Proved reserves that are expected to be recovered from new wells 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. Proved undeveloped reserves include 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 of an existing well bore 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 oil and/or natural gas 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.

SEC. The United States Securities and Exchange Commission.

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

SFAS. Statement of Financial Accounting Standards.

Standardized Measure. Future cash inflows from proved oil and natural gas reserves, less future production costs, development costs, net abandonment costs, and income taxes, discounted at 10 percent per annum to reflect the timing of future net cash flows. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of estimated future income taxes.

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

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

Table of Contents

ENCORE ACQUISITION COMPANY

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

Unit. A specifically defined area within which acreage is treated as a single consolidated lease for operations and for allocations of costs and benefits without regard to ownership of the acreage. Units are established for the purpose of recovering oil and natural gas from specified zones or formations.

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

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

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

ENCORE ACQUISITION COMPANY

References in this Report to EAC, we, our, us, or similar terms refer to Encore Acquisition Company and its subsidiaries. References in this Report to ENP refers to Encore Energy Partners LP and its subsidiaries. The financial position, results of operations, and cash flows of ENP are consolidated with those of EAC. This Report contains forward-looking statements, which give our current expectations and forecasts of future events. The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements made by us or on our behalf. Please read Item 1A. Risk Factors for a description of various factors that could materially affect our ability to achieve the anticipated results described in the forward-looking statements. Certain terms commonly used in the oil and natural gas industry and in this Report are defined above under the caption Glossary. In addition, all production and reserve volumes disclosed in this Report represent amounts net to us, unless otherwise noted.

PART I

ITEMS 1 and 2. ***BUSINESS AND PROPERTIES***

General

Our Business. We are a Delaware corporation engaged in the acquisition and development of oil and natural gas reserves from onshore fields in the United States. Since 1998, we have acquired producing properties with proven reserves and leasehold acreage and grown the production and proven reserves by drilling, exploring, and reengineering or expanding existing waterflood projects. Our properties and our oil and natural gas reserves are located in four core areas:

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

Proved Reserves. Our estimated total proved reserves at December 31, 2008 were 134.5 MMBbls of oil and 307.5 Bcf of natural gas, based on December 31, 2008 spot market prices of $44.60 per Bbl for oil and $5.62 per Mcf for natural gas. On a BOE basis, our proved reserves were 185.7 MMBOE at December 31, 2008, of which approximately 72 percent was oil and approximately 80 percent was proved developed. Based on 2008 production, our ratio of reserves to production was approximately 12.9 years for total proved reserves and 10.3 years for proved developed reserves as of December 31, 2008.

Most Valuable Asset. The CCA represented approximately 40 percent of our total proved reserves as of December 31, 2008 and is our most valuable asset today and in the foreseeable future. A large portion of our future success revolves around current and future CCA exploitation and production through primary, secondary, and tertiary recovery techniques.

Drilling. In 2008, we drilled 88 gross (67.8 net) operated productive wells and participated in drilling 194 gross (37.0 net) non-operated productive wells for a total of 282 gross (104.8 net) productive wells. Also in 2008, we drilled

7 gross (4.9 net) operated dry holes and participated in drilling another 6 gross (1.9 net) dry holes for a total of 13 gross (6.8 net) dry holes. This represents a success rate of over 95 percent during 2008. We invested $619.0 million in development, exploitation, and exploration activities in 2008, of which $14.7 million related to exploratory dry holes.

Table of Contents

ENCORE ACQUISITION COMPANY

Oil and Natural Gas Reserve Replacement. Our average reserve replacement for the three years ended December 31, 2008 was 125 percent. The following table sets forth the calculation of our reserve replacement for the periods indicated:

	Year Ended December 31, 2008	2007	2006	Three-Year Average
	(In MBOE, except percentages)			
Acquisition Reserve Replacement:				
Changes in Proved Reserves:				
Acquisitions of minerals-in-place	1,303	43,146	64	14,838
Divided by:				
Production	14,446	13,539	11,244	13,076
Acquisition Reserve Replacement	9%	319%	1%	113%
Development Reserve Replacement:				
Changes in Proved Reserves:				
Extensions, discoveries, and improved recovery	19,952	15,983	27,504	21,146
Revisions of previous estimates	(52,432)	896	(7,461)	(19,666)
Total development program	(32,480)	16,879	20,043	1,480
Divided by:				
Production	14,446	13,539	11,244	13,076
Development Reserve Replacement	(225)%	125%	178%	11%
Total Reserve Replacement:				
Changes in Proved Reserves:				
Acquisitions of minerals-in-place	1,303	43,146	64	14,838
Extensions, discoveries, and improved recovery	19,952	15,983	27,504	21,146
Revisions of previous estimates	(52,432)	896	(7,461)	(19,666)
Total reserve additions	(31,177)	60,025	20,107	16,318
Divided by:				
Production	14,446	13,539	11,244	13,076
Total Reserve Replacement	(216)%	443%	179%	125%

During the three years ended December 31, 2008, we invested $1.0 billion in acquiring proved oil and natural gas properties and leasehold acreage and $1.3 billion on development, exploitation, and exploration.

Given the inherent decline of reserves resulting from production, we must more than offset produced volumes with new reserves in order to grow. Management uses reserve replacement as an indicator of our ability to replenish annual production volumes and grow our reserves. Management believes that reserve replacement is relevant and useful information as it is commonly used to evaluate the performance and prospects of entities engaged in the production and sale of depleting natural resources. It should be noted that reserve replacement is a statistical indicator that has limitations. As an annual measure, reserve replacement is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. The predictive and comparative value of reserve replacement is also limited for the same reasons. In addition, since reserve replacement does not consider the cost or timing of future production of new reserves or the prices used to determine period end reserve volumes, it cannot be used as a measure of value creation. Reserve replacement does not distinguish between changes in reserve quantities that are developed and those that will require additional time and funding to develop. The lower commodity prices and higher service costs at December 31, 2008 had the effect of decreasing the economic life of our oil and natural gas properties and making development of some previously recorded undeveloped reserves uneconomic.

Table of Contents

ENCORE ACQUISITION COMPANY

Encore Energy Partners. As of February 18, 2009, we owned 20,924,055 of ENP s outstanding common units, representing an approximate 62 percent limited partner interest. Through our indirect ownership of ENP s general partner, we also hold all 504,851 general partner units, representing a 1.5 percent general partner interest in ENP. As we control ENP s general partner, ENP s financial position, results of operations, and cash flows are consolidated with ours.

In February 2008, we sold certain oil and natural gas producing properties and related assets in the Permian and Williston Basins to ENP. The consideration for the sale consisted of approximately $125.3 million in cash and 6,884,776 common units representing limited partner interests in ENP.

In January 2009, we sold certain oil and natural gas producing properties and related assets in the Arkoma Basin and royalty interest properties in Oklahoma as well as 10,300 unleased mineral acres to ENP. The purchase price was $49 million in cash, subject to customary adjustments (including a reduction in the purchase price for acquisition-related commodity derivative premiums of approximately $3 million).

Financial Information About Operating Segments. We have operations in only one industry segment: the oil and natural gas exploration and production industry in the United States. However, we are organizationally structured along two operating segments: EAC Standalone and ENP. The contribution of each operating segment to revenues and operating income (loss), and the identifiable assets and liabilities attributable to each operating segment, are set forth in Note 18 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

Business Strategy

Our primary business objective is to maximize shareholder value by growing production, repaying debt or repurchasing shares of our common stock, prudently investing internally generated cash flows, efficiently operating our properties, and maximizing long-term profitability. Our strategy for achieving this objective is to:

Maintain a development program to maximize existing reserves and production. Our technological expertise, combined with our proficient field operations and reservoir engineering, has allowed us to increase production on our properties through infill, offset, and re-entry drilling, workovers, and recompletions. Our plan is to maintain an inventory of exploitation and development projects that provide a good source of future production.

Utilize enhanced oil recovery techniques to maximize existing reserves and production. We budget a portion of internally generated cash flows for secondary and tertiary recovery projects that are longer-term in nature to increase production and proved reserves on our properties. Throughout our Williston and Permian Basin properties, we have successfully used waterfloods to increase production. On certain of our non-operated properties in the Rockies, a tertiary recovery technique that uses carbon dioxide instead of water is being used successfully. Throughout our Bell Creek properties, we have successfully used a polymer injection program to increase our production. We believe that these enhanced oil recovery projects will continue to be a source of reserve and production growth.

Expand our reserves, production, and development inventory through a disciplined acquisition program. Using our experience, we have developed and refined an acquisition program designed to increase our reserves and complement our core properties. We have a staff of engineering and geoscience professionals who manage our core properties and use their experience and expertise to target and evaluate attractive acquisition opportunities. Following an acquisition, our technical professionals seek to enhance the value of the new assets through a proven development and exploitation program. We will continue to evaluate acquisition opportunities with the same disciplined commitment to acquire assets that fit our existing portfolio of properties and create value for our shareholders.

Explore for reserves. We believe exploration programs can provide a rate of return comparable to property acquisitions in certain areas. We seek to acquire undeveloped acreage and/or enter into

Table of Contents

development arrangements to explore in areas that complement our existing portfolio of properties. Successful exploration projects would expand our existing fields and could set up multi-well exploitation projects in the future.

Operate in a cost effective, efficient, and safe manner. As of December 31, 2008, we operated properties representing approximately 79 percent of our proved reserves, which allows us to better control expenses, capital allocation, operate in a safe manner, and control timing of investments.

Challenges to Implementing Our Strategy. We face a number of challenges to implementing our strategy and achieving our goals. One challenge is to generate superior rates of return on our investments in a volatile commodity pricing environment, while replenishing our development inventory. Changing commodity prices and increased costs of goods and services affect the rate of return on property acquisitions, and the amount of our internally generated cash flows, and, in turn, can affect our capital budget. For example, if cash flow is invested in periods of higher commodity prices, a subsequent decline in commodity prices could result in a lower rate of return, if any. In addition to commodity price risk, we face strong competition from other independents and major oil and natural gas companies. Our views and the views of our competitors about future commodity prices affect our success in acquiring properties and the expected rate of return on each acquisition. For more information on the challenges to implementing our strategy and achieving our goals, please read Item 1A. Risk Factors.

Operations

Well Operations

In general, we seek to be the operator of wells in which we have a working interest. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. We do not own drilling rigs or other oilfield service equipment used for drilling or maintaining wells on properties we operate. Independent contractors engaged by us provide all the equipment and personnel associated with these activities.

As of December 31, 2008, we operated properties representing approximately 79 percent of our proved reserves. As the operator, we are able to better control expenses, capital allocation, and the timing of exploitation and development activities on our properties. We also own working interests in properties that are operated by third parties, and are required to pay our share of production, exploitation, and development costs. Please read Properties Nature of Our Ownership Interests. During 2008, 2007, and 2006, our costs for development activities on non-operated properties were approximately 22 percent, 40 percent, and 47 percent, respectively, of our total development costs. We also own royalty interests in wells operated by third parties that are not burdened by production or capital costs; however, we have little or no control over the implementation of projects on these properties.

Natural Gas Gathering

We own and operate a network of natural gas gathering systems in our Elk Basin area of operation. These systems gather and transport our natural gas and a small amount of third-party natural gas to larger gathering systems and intrastate, interstate, and local distribution pipelines. Our network of natural gas gathering systems permits us to transport production from our wells with fewer interruptions and also minimizes any delays associated with a gathering company extending its lines to our wells. Our ownership and control of these lines enables us to:

realize faster connection of newly drilled wells to the existing system;

control pipeline operating pressures and capacity to maximize our production;

control compression costs and fuel use;

maintain system integrity;

Table of Contents

ENCORE ACQUISITION COMPANY

control the monthly nominations on the receiving pipelines to prevent imbalances and penalties; and

track sales volumes and receipts closely to assure all production values are realized.

Seasonal Nature of Business

Oil and gas producing operations are generally not seasonal. However, demand for some of our products can fluctuate season to season, which impacts price. In particular, heavy oil is typically in higher demand in the summer for its use in road construction, and natural gas is generally in higher demand in the winter for heating.

Production and Price History

The following table sets forth information regarding our net production volumes, average realized prices, and average costs per BOE for the periods indicated:

	Year Ended December 31,		
	2008	**2007**	**2006**
Total Production Volumes:			
Oil (MBbls)	10,050	9,545	7,335
Natural gas (MMcf)	26,374	23,963	23,456
Combined (MBOE)	14,446	13,539	11,244
Average Daily Production Volumes:			
Oil (Bbls/D)	27,459	26,152	20,096
Natural gas (Mcf/D)	72,060	65,651	64,262
Combined (BOE/D)	39,470	37,094	30,807
Average Realized Prices:			
Oil (per Bbl)	$ 89.30	$ 58.96	$ 47.30
Natural gas (per Mcf)	8.63	6.26	6.24
Combined (per BOE)	77.87	52.66	43.87
Average Costs per BOE:			
Lease operations expense	$ 12.12	$ 10.59	$ 8.73
Production, ad valorem, and severance taxes	7.66	5.51	4.43
Depletion, depreciation, and amortization	15.80	13.59	10.09
Impairment of long-lived assets	4.12		
Exploration	2.71	2.05	2.71
Derivative fair value loss (gain)	(23.97)	8.31	(2.17)
General and administrative	3.35	2.89	2.06
Provision for doubtful accounts	0.14	0.43	0.18
Other operating expense	0.90	1.26	0.71
Marketing loss (gain)	(0.06)	(0.11)	0.09

ENCORE ACQUISITION COMPANY

Productive Wells

The following table sets forth information relating to productive wells in which we owned a working interest at December 31, 2008. Wells are classified as oil or natural gas wells according to their predominant production stream. Gross wells are the total number of productive wells in which we have an interest, and net wells are determined by multiplying gross wells by our average working interest. As of December 31, 2008, we owned a working interest in 5,774 gross wells. We also hold royalty interests in units and acreage beyond the wells in which we own a working interest.

	Oil Wells			Natural Gas Wells		
	Gross Wells(a)	Net Wells	Average Working Interest	Gross Wells(a)	Net Wells	Average Working Interest
CCA	743	659	89%	22	6	27%
Permian Basin	1,967	769	39%	634	314	50%
Rockies	1,437	837	58%	60	45	75%
Mid-Continent	235	141	60%	676	181	27%
Total	4,382	2,406	55%	1,392	546	39%

(a) Our total wells include 3,094 operated wells and 2,680 non-operated wells. At December 31, 2008, 52 of our wells had multiple completions.

Table of Contents

ENCORE ACQUISITION COMPANY

Acreage

The following table sets forth information relating to our leasehold acreage at December 31, 2008. Developed acreage is assigned to productive wells. Undeveloped acreage is acreage held under lease, permit, contract, or option that is not in a spacing unit for a producing well, including leasehold interests identified for exploitation or exploratory drilling. As of December 31, 2008, our undeveloped acreage in the Rockies represented approximately 60 percent of our total net undeveloped acreage. Our current leases expire at various dates between 2009 and 2028, with leases representing $18.6 million of cost set to expire in 2009 if not developed.

	Gross Acreage	Net Acreage
CCA:		
Developed	117,209	109,775
Undeveloped	150,283	117,793
	267,492	227,568
Permian Basin:		
Developed	66,280	45,173
Undeveloped	21,564	17,232
	87,844	62,405
Rockies:		
Developed	231,846	156,350
Undeveloped	809,323	574,323
	1,041,169	730,673
Mid-Continent:		
Developed	79,231	41,122
Undeveloped	344,963	245,472
	424,194	286,594
Total:		
Developed	494,566	352,420
Undeveloped	1,326,133	954,820
	1,820,699	1,307,240

ENCORE ACQUISITION COMPANY

Development Results

The following table sets forth information with respect to wells completed during the periods indicated, regardless of when development was initiated. This information should not be considered indicative of future performance, nor should a correlation be assumed between productive wells drilled, quantities of reserves discovered, or economic value.

	Year Ended December 31,					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	186	73	165	62	182	72
Dry holes	5	3	5	3	4	3
	191	76	170	65	186	75
Exploratory Wells:						
Productive	96	32	63	21	71	19
Dry holes	8	4	5	3	14	8
	104	36	68	24	85	27
Total:						
Productive	282	105	228	83	253	91
Dry holes	13	7	10	6	18	11
	295	112	238	89	271	102

Present Activities

As of December 31, 2008, we had a total of 63 gross (31.6 net) wells that had begun drilling and were in varying stages of drilling operations, of which 31 gross (17.9 net) were development wells. As of December 31, 2008, we had a total of 29 gross (14.7 net) wells that had reached total depth and were in the process of being completed pending first production, of which 19 gross (13.7 net) were development wells.

Delivery Commitments and Marketing Arrangements

Our oil and natural gas production is generally sold to marketers, processors, refiners, and other purchasers that have access to nearby pipeline, processing, and gathering facilities. In areas where there is no practical access to pipelines, oil is trucked to central storage facilities where it is aggregated and sold to various markets and downstream purchasers. Our production sales agreements generally contain customary terms and conditions for the oil and natural gas industry, provide for sales based on prevailing market prices in the area, and generally have terms of one year or less.

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 have been subject to apportionment since December 2005, we were allocated sufficient pipeline capacity to move our crude oil production effective January 1, 2007. Enbridge Pipeline completed an expansion, 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

ENCORE ACQUISITION COMPANY

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 quoted 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 crude oil and natural gas differentials. Increases in the percentage differential between the NYMEX price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial position, and cash flows. The following table illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices by quarter for 2008, as well as our expected differentials for the first quarter of 2009:

	Actual				Forecast
	First Quarter of 2008	**Second Quarter of 2008**	**Third Quarter of 2008**	**Fourth Quarter of 2008**	**First Quarter of 2009**
Oil wellhead to NYMEX percentage	91%	94%	91%	80%	78%
Natural gas wellhead to NYMEX percentage	103%	102%	93%	86%	103%

Principal Customers

For 2008, our largest purchasers were Eighty-Eight Oil and Tesoro, which accounted for approximately 14 percent and 12 percent, respectively, of our total sales of oil and natural gas production. Our marketing of oil and natural gas can be affected by factors beyond our control, the potential effects of which cannot be accurately predicted. Management believes that the loss of any one purchaser would not have a material adverse effect on our ability to market our oil and natural gas production.

Competition

The oil and natural gas industry is highly competitive. We encounter strong competition from other independents and major oil and natural gas companies in acquiring properties, contracting for development equipment, and securing trained personnel. Many of these competitors have resources substantially greater than ours. As a result, our competitors may be able to pay more for desirable leases, or to evaluate, bid for, and purchase a greater number of properties or prospects than our resources will permit.

We are also affected by competition for rigs and the availability of related equipment. The oil and natural gas industry has experienced shortages of rigs, equipment, pipe, and personnel, which has delayed development and exploitation activities and has caused significant price increases. We are unable to predict when, or if, such shortages may occur or how they would affect our development and exploitation program.

Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases, and development rights, and we may not be able to compete satisfactorily when attempting to acquire additional properties.

Table of Contents

ENCORE ACQUISITION COMPANY

Properties

Nature of Our Ownership Interests

The following table sets forth the net production, proved reserve quantities, and PV-10 of our properties by principal area of operation as of and for the periods indicated:

	2008 Net Production				Proved Reserve Quantities at December 31, 2008				PV-10 at December 31, 2008	
	Oil	Natural Gas	Total	Percent	Oil	Natural Gas	Total	Percent	Amount(a)	Percent
	(MBbls)	(MMcf)	(MBOE)		(MBbls)	(MMcf)	(MBOE)		(In thousands)	
CA	4,146	978	4,309	30%	71,892	13,327	74,113	40%	$ 550,734	39
ermian Basin	1,246	12,442	3,320	23%	19,736	161,720	46,689	25%	362,000	26
ockies	4,256	1,870	4,567	32%	40,074	16,552	42,833	23%	326,196	23
id-Continent	402	11,084	2,250	15%	2,750	115,921	22,070	12%	170,019	12
otal	10,050	26,374	14,446	100%	134,452	307,520	185,705	100%	$ 1,408,949	100

(a) Giving effect to commodity derivative contracts, our PV-10 would increase by $339.1 million at December 31, 2008. Standardized Measure at December 31, 2008 was $1.2 billion. Standardized Measure differs from PV-10 by $189.0 million because Standardized Measure includes the effects of future net abandonment costs and future income taxes. Since we are taxed at the corporate level, future income taxes are determined on a combined property basis and cannot be accurately subdivided among our core areas. Therefore, we believe PV-10 provides the best method for assessing the relative value of each of our areas.

The estimates of our proved oil and natural gas reserves are based on estimates prepared by Miller and Lents, Ltd. (Miller and Lents), independent petroleum engineers. Guidelines established by the SEC regarding our PV-10 were used to prepare these reserve estimates. Oil and natural gas reserve engineering is and must be recognized as a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way, and estimates of other engineers might differ materially from those included herein. The accuracy of any reserve estimate is a function of the quality of available data and engineering, and estimates may justify revisions based on the results of drilling, testing, and production activities. Accordingly, reserve estimates and their PV-10 are inherently imprecise, subject to change, and should not be construed as representing the actual quantities of future production or cash flows to be realized from oil and natural gas properties or the fair market value of such properties.

During 2008, we filed the estimates of our oil and natural gas reserves as of December 31, 2007 with the U.S. Department of Energy on Form EIA-23. As required by Form EIA-23, the filing reflected only gross production that comes from our operated wells at year-end. Those estimates came directly from our reserve report prepared by Miller and Lents.

Table of Contents

ENCORE ACQUISITION COMPANY

CCA Properties

Our initial purchase of interests in the CCA was in 1999, and we continue to acquire additional working interests. As of December 31, 2008, we operated virtually all of our CCA properties with an average working interest of approximately 89 percent in the oil wells and 27 percent in the natural gas wells.

The CCA is a major structural feature of the Williston Basin in southeastern Montana and northwestern North Dakota. Our acreage is concentrated on the two-to-six-mile-wide crest of the CCA, giving us access to the greatest accumulation of oil in the structure. Our holdings extend for approximately 120 continuous miles along the crest of the CCA across five counties in two states. Primary producing reservoirs are the Red River, Stony Mountain, Interlake, and Lodgepole formations at depths of between 7,000 and 9,000 feet. Our fields in the CCA include the North Pine, South Pine, Cabin Creek, Coral Creek, Little Beaver, Monarch, Glendive North, Glendive, Gas City, and Pennel fields.

Our CCA reserves are primarily produced through waterfloods. Our average daily net production from the CCA remained approximately constant at 12,153 BOE/D in the fourth quarter of 2008 as compared to 12,080 BOE/D in the fourth quarter of 2007. We have been able to maintain or grow production through a combination of:

- effective management of the existing wellbores;
- addition of strategically positioned horizontal and vertical wellbores;
- re-entry horizontal drilling using existing wellbores;
- waterflood enhancements;

ENCORE ACQUISITION COMPANY

extensional drilling; and

other enhanced oil recovery techniques.

In 2008, we drilled 10 gross wells in the CCA, some of which were horizontal re-entry wells that (1) reestablished production from non-producing wells, (2) added additional production to existing producing wells, or (3) served as injection wells for secondary and tertiary recovery projects. We invested $37.3 million, $41.6 million, and $103.9 million in capital projects in the CCA during 2008, 2007, and 2006, respectively.

The CCA represents approximately 40 percent of our total proved reserves as of December 31, 2008 and is our most valuable asset today and in the foreseeable future. A large portion of our future success revolves around current and future exploitation of and production from this area.

We pursued HPAI in the CCA beginning in 2002 because CO_2 was not readily available and HPAI was an attractive alternative. The initial project was successful and continues to be successful; however, the political environment is changing in favor of CO_2 sequestration. We believe this will increase the amount of CO_2 available to be used in tertiary recovery projects. Although CO_2 is currently not readily available, we believe we will be able to secure an economical source of CO_2 in the future. Therefore, we have made a strategic decision to move away from HPAI and focus on CO_2.

Existing HPAI project areas in the CCA are in Pennel and Cedar Creek fields. In both fields, HPAI wells will be converted to water injection in three to four phases over a period of approximately 18 months. Priority will be largely based on economics of incremental production uplift and air injection utilization. We anticipate that we will continue injecting air in a small number of HPAI patterns beyond the planned 18-month conversion period. We expect to realize significant LOE savings while achieving current production estimates.

Net Profits Interest. A major portion of our acreage position in the CCA is subject to net profits interests ranging from one percent to 50 percent. The holders of these net profits interests are entitled to receive a fixed percentage of the cash flow remaining after specified costs have been subtracted from net revenue. The net profits calculations are contractually defined. In general, net profits are determined after considering operating expense, overhead expense, interest expense, and development costs. The amounts of reserves and production attributable to net profits interests are deducted from our reserves and production data, and our revenues are reported net of net profits interests. The reserves and production attributed to net profits interests are calculated by dividing estimated future net profits interests (in the case of reserves) or prior period actual net profits interests (in the case of production) by commodity prices at the determination date. Fluctuations in commodity prices and the levels of development activities in the CCA from period to period will impact the reserves and production attributable to the net profits interests and will have an inverse effect on our reported reserves and production. For 2008, 2007, and 2006, we reduced revenue for net profits interests by $56.5 million, $32.5 million, and $23.4 million, respectively.

Permian Basin Properties

West Texas. Our West Texas properties include seventeen operated fields, including the East Cowden Grayburg Unit, Fuhrman-Mascho, Crockett County, Sand Hills, Howard Glasscock, Nolley, Deep Rock, and others; and seven non-operated fields. Production from the central portion of the Permian Basin comes from multiple reservoirs, including the Grayburg, San Andres, Glorieta, Clearfork, Wolfcamp, and Pennsylvanian zones. Production from the southern portion of the Permian Basin comes mainly from the Canyon, Devonian, Ellenberger, Mississippian, Montoya, Strawn, and Wolfcamp formations with multiple pay intervals.

In March 2006, we entered into a joint development agreement with ExxonMobil Corporation (ExxonMobil) to develop legacy natural gas fields in West Texas. The agreement covers certain formations in the Parks, Pegasus, and Wilshire Fields in Midland and Upton Counties, the Brown Bassett Field in Terrell County, and Block 16, Coyanosa, and Waha Fields in Ward, Pecos, and Reeves Counties. Targeted formations include the Barnett, Devonian, Ellenberger, Mississippian, Montoya, Silurian, Strawn, and Wolfcamp horizons.

ENCORE ACQUISITION COMPANY

Under the terms of the agreement, we have the opportunity to develop approximately 100,000 gross acres. We earn 30 percent of ExxonMobil s working interest and 22.5 percent of ExxonMobil s net revenue interest in each well drilled. We operate each well during the drilling and completion phase, after which ExxonMobil assumes operational control of the well.

In July 2008, we earned the right to participate in all fields by drilling the final well of the 24-well commitment phase and are entitled to a 30 percent working interest in future drilling locations. We also have the right to propose and drill wells for as long as we are engaged in continuous drilling operations.

We have entered into a side letter agreement with ExxonMobil to: (1) combine a group of specified fields into one development area, and extend the period within which we must drill a well in this development area and one additional development area in order to be considered as conducting continuous drilling operations; (2) transfer ExxonMobil s full working interest in a specified well along with a majority of its net royalty interest to us, while reserving its portion of an overriding royalty interest; (3) allow ExxonMobil to participate in any re-entry of the specified well under the original terms of a subsequent well (as defined in the joint development agreement), in which they will pay their proportional share of agreed costs incurred; and (4) reduce the non-consent penalty for 10 specified wells from 200 percent to 150 percent in exchange for ExxonMobil agreeing not to elect the carry for reduced working interest option for these wells.

Average daily production for our West Texas properties increased 19 percent from 7,122 BOE/D in the fourth quarter of 2007 to 8,497 BOE/D in the fourth quarter of 2008. We believe these properties will be an area of growth over the next several years. During 2008, we drilled 36 gross wells and invested approximately $203.8 million of capital to develop these properties.

In 2009, we intend to drill approximately 7 gross wells and invest approximately $51 million of net capital in the development areas. We anticipate operating one to two rigs in West Texas for most of 2009.

New Mexico. We began investing in New Mexico in May 2006 with the strategy of deploying capital to develop low- to medium-risk development projects in southeastern New Mexico where multiple reservoir targets are available. Average daily production for these properties decreased 14 percent from 7,793 Mcfe/D in the fourth quarter of 2007 to 6,732 Mcfe/D in the fourth quarter of 2008. During 2008, we drilled 8 gross operated wells and invested approximately $39.7 million of capital to develop these properties.

Mid-Continent Properties

In January 2009, we sold certain oil and natural gas producing properties and related assets in the Arkoma Basin and royalty interest properties in Oklahoma as well as 10,300 unleased mineral acres to ENP for $49 million in cash, subject to customary adjustments (including a reduction in the purchase price for acquisition-related commodity derivative premiums of approximately $3 million).

Oklahoma, Arkansas, and Kansas. We own various interests, including operated, non-operated, royalty, and mineral interests, on properties located in the Anadarko Basin of western Oklahoma and the Arkoma Basin of eastern Oklahoma and western Arkansas. Our average daily production for these properties decreased 5 percent from 8,555 Mcfe/D in the fourth quarter of 2007 to 8,159 Mcfe/D for the fourth quarter of 2008. During 2008, we drilled 52 gross wells and invested $29.9 million of development and exploration capital in these properties.

North Louisiana Salt Basin and East Texas Basin. Our North Louisiana Salt Basin and East Texas Basin properties consist of operated working interests, non-operated working interests, and undeveloped leases acquired primarily in the Elm Grove and Overton acquisitions in 2004 and development in the Stockman and Danville fields in east Texas. Our interests acquired in the Elm Grove acquisition are located in the Elm Grove Field in Bossier Parish, Louisiana, and include non-operated working interests ranging from one percent to 47 percent across 1,800 net acres in 15 sections.

ENCORE ACQUISITION COMPANY

Our East Texas and North Louisiana properties are in the same core area and have similar geology. The properties are producing primarily from multiple tight sandstone reservoirs in the Travis Peak and Lower Cotton Valley formations at depths ranging from 8,000 to 11,500 feet.

In the fourth quarter of 2008, we began our Haynesville shale drilling program with the spudding of the first Haynesville shale well at the Greenwood Waskom field in Caddo Parish, Louisiana. This well reached total depth in January 2009 ahead of schedule. We plan to complete the well with an 11 stage fracture stimulation in the first quarter of 2009 and have recently spud our second horizontal well in the area. Since entering the Haynesville play, we have accumulated over 18,000 acres.

Tuscaloosa Marine Shale. Since entering into the Tuscaloosa Marina Shale, we have accumulated over 290,000 gross (220,000 net) acres, the majority of which is locked up through the end of 2010. During 2008, we drilled 4 gross wells at a drilling cost of over $11 million per well. As a result of the significant decline in commodity prices during the second half of 2008, we recorded a $59.5 million impairment on these wells and have approximately $15 million of net unproved costs remaining in these properties.

During 2008, we drilled 95 gross wells and invested approximately $147.6 million of capital to develop our Mid-Continent properties. Average daily production for these properties increased 81 percent from 20,038 Mcfe/D in the fourth quarter of 2007 to 36,239 Mcfe/D for the fourth quarter of 2008. We drilled 8 gross operated wells in the Stockman and Danville fields.

Rockies Properties

Big Horn Basin. In March 2007, ENP acquired the Big Horn Basin properties, which are located in the Big Horn Basin in northwestern Wyoming and south central Montana. The Big Horn Basin is characterized by oil and natural gas fields with long production histories and multiple producing formations. The Big Horn Basin is a prolific basin and has produced over 1.8 billion Bbls of oil since its discovery in 1906.

ENP also owns and operates (1) the Elk Basin natural gas processing plant near Powell, Wyoming, (2) the Clearfork crude oil pipeline extending from the South Elk Basin Field to the Elk Basin Field in Wyoming, (3) the Wildhorse natural gas gathering system that transports low sulfur natural gas from the Elk Basin and South Elk Basin fields to our Elk Basin natural gas processing plant, and (4) a natural gas gathering system that transports higher sulfur natural gas from the Elk Basin Field to our Elk Basin natural gas processing facility.

Average daily production for these properties decreased slightly from 4,255 BOE/D in the fourth quarter of 2007 to 4,212 BOE/D in the fourth quarter of 2008. During 2008, ENP drilled 3 gross wells and invested approximately $10.8 million of capital to develop these properties.

Williston Basin. Our Williston Basin properties have historically consisted of working and overriding royalty interests in several geographically concentrated fields. The properties are located in western North Dakota and eastern Montana, near our CCA properties. In April 2007, we acquired additional properties in the Williston Basin including 50 different fields across Montana and North Dakota. As part of this acquisition, we also acquired approximately 70,000 net unproved acres in the Bakken play of Montana and North Dakota. Since the acquisition, we have increased our acreage position in the Bakken play to approximately 300,000 acres. During 2008, we drilled and completed twelve wells in the Bakken and Sanish. The average seven day initial production rate of these wells was 411 BOE/D. Also during 2008, we re-fraced a total of six wells in North Dakota. The average thirty-day uplift in production rate for these re-frac wells was 118 BOE/D. In the first quarter of 2009, we plan to complete our first Sanish well in the Almond prospect. The Almond prospect contains 70,000 net acres and is located near the northeast border of Mountrail County, North Dakota.

Average daily production for our Rockies properties increased nine percent from 6,363 BOE/D in the fourth quarter of 2007 to 6,919 BOE/D in the fourth quarter of 2008. During 2008, we drilled 59 gross wells and invested approximately $125.6 million of capital to develop our Rockies properties.

ENCORE ACQUISITION COMPANY

Bell Creek. Our Bell Creek properties are located in the Powder River Basin of southeastern Montana. We operate seven production units in Bell Creek, each with a 100 percent working interest. The shallow (less than 5,000 feet) Cretaceous-aged Muddy Sandstone reservoir produces oil. We have successfully implemented a polymer injection program on both injection and producing wells on our Bell Creek properties whereby a polymer is injected into a well to reduce the amount of water cycling in the higher permeability interval of the reservoir, reducing operating costs and increasing reservoir recovery. This process is generally more efficient than standard waterflooding.

We invested $11.5 million of capital to develop these properties in 2008. Average daily production from these properties decreased seven percent from 958 BOE/D in the fourth quarter of 2007 to 890 BOE/D in the fourth quarter of 2008.

In 2009, we plan to initiate a CO_2 pilot in Bell Creek. We believe the field is an excellent candidate for CO_2 tertiary recovery and are attempting to procure a CO_2 source.

Paradox Basin. The Paradox Basin properties, located in southeast Utah s Paradox Basin, are divided between two prolific oil producing units: the Ratherford Unit and the Aneth Unit. In 2008, the operator continued the implementation of a tertiary project in the Aneth Unit. We believe these properties have additional potential in horizontal redevelopment, secondary development, and tertiary recovery potential.

Average daily production for these properties decreased approximately eight percent from 688 BOE/D in the fourth quarter of 2007 to 631 BOE/D in the fourth quarter of 2008. During 2008, we invested approximately $8.0 million of capital to develop these properties.

Title to Properties

We believe that we have satisfactory title to our oil and natural gas properties in accordance with standards generally accepted in the oil and natural gas industry.

Our properties are subject, in one degree or another, to one or more of the following:

- royalties, overriding royalties, net profits interests, and other burdens under oil and natural gas leases;

- contractual obligations, including, in some cases, development obligations arising under joint operating agreements, farm-out agreements, production sales contracts, and other agreements that may affect the properties or their titles;

- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing unpaid suppliers and contractors, and contractual liens under joint operating agreements;

- pooling, unitization, and communitization agreements, declarations, and orders; and

- easements, restrictions, rights-of-way, and other matters that commonly affect property.

We believe that the burdens and obligations affecting our properties do not in the aggregate materially interfere with the use of the properties. As previously discussed, a major portion of our acreage position in the CCA, our primary asset, is subject to net profits interests.

We have granted mortgage liens on substantially all of our oil and natural gas properties in favor of Bank of America, N.A., as agent, to secure borrowings under our revolving credit facility. These mortgages and the revolving credit facility contain substantial restrictions and operating covenants that are customarily found in loan agreements of this type.

ENCORE ACQUISITION COMPANY

Environmental Matters and Regulation

General. Our operations are subject to stringent and complex federal, state, and local laws and regulations governing environmental protection, including air emissions, water quality, wastewater discharges, and solid waste management. These laws and regulations may, among other things:

- require the acquisition of various permits before development commences;
- require the installation of pollution control equipment;
- enjoin some or all of the operations of facilities deemed in non-compliance with permits;
- restrict the types, quantities, and concentration of various substances that can be released into the environment in connection with oil and natural gas development, production, and transportation activities;
- restrict the way in which wastes are handled and disposed;
- limit or prohibit development activities on certain lands lying within wilderness, wetlands, areas inhabited by threatened or endangered species, and other protected areas;
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells;
- impose substantial liabilities for pollution resulting from operations; and
- require preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement for operations affecting federal lands or leases.

These laws, rules, and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and the clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Any changes that result in indirect compliance costs or additional operating restrictions, including costly waste handling, disposal, and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The following is a discussion of relevant environmental and safety laws and regulations that relate to our operations.

Waste Handling. The Resource Conservation and Recovery Act (RCRA), and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal, and cleanup of hazardous and non-hazardous solid wastes. Under the auspices of the federal Environmental Protection Agency (the EPA), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil or natural gas are regulated under RCRA s non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, and waste oils that may be regulated as hazardous wastes.

Site Remediation. The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current and past owner or operator of the site where

Table of Contents

ENCORE ACQUISITION COMPANY

the release occurred, and anyone who disposed of or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA authorizes the EPA, and in some cases third parties, to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although petroleum, including crude oil, and natural gas are excluded from CERCLA s definition of hazardous substance, in the course of our ordinary operations, we generate wastes that may fall within the definition of a hazardous substance. We believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, yet hazardous substances, wastes, or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. In fact, there is evidence that petroleum spills or releases have occurred in the past at some of the properties owned or leased by us. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial plugging or pit closure operations to prevent future contamination.

ENP s Elk Basin assets have been used for oil and natural gas exploration and production for many years. There have been known releases of hazardous substances, wastes, or hydrocarbons at the properties, and some of these sites are undergoing active remediation. The risks associated with these environmental conditions, and the cost of remediation, were assumed by ENP, subject only to limited indemnity from the seller of the Elk Basin assets. Releases may also have occurred in the past that have not yet been discovered, which could require costly future remediation. In addition, ENP assumed the risk of various other unknown or unasserted liabilities associated with the Elk Basin assets that relate to events that occurred prior to ENP s acquisition. If a significant release or event occurred in the past, the liability for which was not retained by the seller or for which indemnification from the seller is not available, it could adversely affect our results of operations, financial position, and cash flows.

ENP s Elk Basin assets include a natural gas processing plant. Previous environmental investigations of the Elk Basin natural gas processing plant indicate historical soil and groundwater contamination by hydrocarbons and the presence of asbestos-containing material at the site. Although the environmental investigations did not identify an immediate need for remediation of the suspected historical contamination, the extent of the contamination is not known and, therefore, the potential liability for remediating this contamination may be significant. In the event ENP ceased operating the gas plant, the cost of decommissioning it and addressing the previously identified environmental conditions and other conditions, such as waste disposal, could be significant. ENP does not anticipate ceasing operations at the Elk Basin natural gas processing plant in the near future nor a need to commence remedial activities at this time. However, a regulatory agency could require ENP to investigate and remediate any contamination even while the gas plant remains in operation. As of December 31, 2008, ENP has recorded $4.4 million as future abandonment liability for decommissioning the Elk Basin natural gas processing plant. Due to the significant level of uncertainty associated with the known and unknown environmental liabilities at the gas plant, ENP s estimate of the future abandonment liability includes a large contingency. ENP s estimates of the future abandonment liability and compliance costs are subject to change and the actual cost of these items could vary significantly from those estimates.

17

Table of Contents

ENCORE ACQUISITION COMPANY

Water Discharges. The Clean Water Act (CWA), and analogous state laws, impose strict controls on the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. CWA regulates storm water run-off from oil and natural gas facilities and requires a storm water discharge permit for certain activities. Such a permit requires the regulated facility to monitor and sample storm water run-off from its operations. CWA and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Spill prevention, control, and countermeasure requirements of CWA require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture, or leak. Federal and state regulatory agencies can impose administrative, civil, and criminal penalties for non-compliance with discharge permits or other requirements of CWA and analogous state laws and regulations.

The primary federal law for oil spill liability is the Oil Pollution Act (OPA), which addresses three principal areas of oil pollution prevention, containment, and cleanup. OPA applies to vessels, offshore facilities, and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties, including owners and operators of onshore facilities, may be subject to oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills.

Air Emissions. Oil and natural gas exploration and production operations are subject to the federal Clean Air Act (CAA), and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including oil and natural gas exploration and production facilities, and also impose various monitoring and reporting requirements. Such laws and regulations may require a facility to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions.

Permits and related compliance obligations under CAA, as well as changes to state implementation plans for controlling air emissions in regional non-attainment areas, may require oil and natural gas exploration and production operations to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies. In addition, some oil and natural gas facilities may be included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under CAA. Failure to comply with these requirements could subject a regulated entity to monetary penalties, injunctions, conditions or restrictions on operations, and enforcement actions. Oil and natural gas exploration and production facilities may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

Scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the atmosphere. In response to such studies, Congress is considering legislation to reduce emissions of greenhouse gases. In addition, at least 17 states have declined to wait on Congress to develop and implement climate control legislation and have already taken legal measures to reduce emissions of greenhouse gases. Also, as a result of the Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA must consider whether it is required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Supreme Court s holding in *Massachusetts* that greenhouse gases fall under CAA s definition of air pollutant may also result in future regulation of greenhouse gas emissions from stationary sources under various CAA programs, including those used in oil and natural gas exploration and production operations. It is not possible to predict how legislation that may be enacted to address greenhouse gas emissions would impact the oil and natural gas exploration and production business. However, future laws and regulations could result in increased

Table of Contents

ENCORE ACQUISITION COMPANY

compliance costs or additional operating restrictions and could have a material adverse effect on our business, financial position, demand for our operations, results of operations, and cash flows.

Activities on Federal Lands. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act (NEPA). NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect, and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Our current exploration and production activities and planned exploration and development activities on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of our oil and natural gas projects.

Occupational Safety and Health Act (OSH Act) and Other Laws and Regulation. We are subject to the requirements of OSH Act and comparable state statutes. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The Occupational Safety and Health Administration s hazard communication standard, EPA community right-to-know regulations under Title III of CERCLA, and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSH Act and comparable requirements.

We believe that we are in substantial compliance with all existing environmental laws and regulations applicable to our operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. We did not incur any material capital expenditures for remediation or pollution control activities during 2008, and, as of the date of this Report, we are not aware of any environmental issues or claims that will require material capital expenditures during 2009. However, accidental spills or releases may occur in the course of our operations, and we may incur substantial costs and liabilities as a result of such spills or releases, including those relating to claims for damage to property and persons. Moreover, the passage of more stringent laws or regulations in the future may have a negative impact on our business, financial condition, or results of operations.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state, and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities, and locations of production.

Legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including oil and natural gas facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Development and Production. Our operations are subject to various types of regulation at the federal, state, and local levels. These types of regulation include requiring permits for the development of wells, development bonds, and reports concerning operations. Most states, and some counties and municipalities, in which we operate also regulate one or more of the following:

- location of wells;

ENCORE ACQUISITION COMPANY

methods of developing and casing wells;

surface use and restoration of properties upon which wells are drilled;

plugging and abandoning of wells; and

notification of surface owners and other third parties.

State laws regulate the size and shape of development and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts in order to facilitate exploitation while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil and natural gas within its jurisdiction.

Interstate Crude Oil Transportation. ENP s Clearfork crude oil pipeline is an interstate common carrier pipeline, which is subject to regulation by the Federal Energy Regulatory Commission (the FERC) under the Interstate Commerce Act (the ICA) and the Energy Policy Act of 1992 (EP Act 1992). The ICA and its implementing regulations give the FERC authority to regulate the rates ENP charges for service on that interstate common carrier pipeline and generally require the rates and practices of interstate oil pipelines to be just, reasonable, and nondiscriminatory. The ICA also requires ENP to maintain tariffs on file with the FERC that set forth the rates ENP charges for providing transportation services on its interstate common carrier liquids pipeline as well as the rules and regulations governing these services. Shippers may protest, and the FERC may investigate, the lawfulness of new or changed tariff rates. The FERC can suspend those tariff rates for up to seven months and require refunds of amounts collected pursuant to rates that are ultimately found to be unlawful. The FERC and interested parties can also challenge tariff rates that have become final and effective. EP Act 1992 deemed certain rates in effect prior to its passage to be just and reasonable and limited the circumstances under which a complaint can be made against such grandfathered rates. EP Act 1992 and its implementing regulations also allow interstate common carrier oil pipelines to annually index their rates up to a prescribed ceiling level. In addition, the FERC retains cost-of-service ratemaking, market-based rates, and settlement rates as alternatives to the indexing approach.

Natural Gas Gathering. Section 1(b) of the Natural Gas Act (NGA), exempts natural gas gathering facilities from the jurisdiction of the FERC. ENP owns a number of facilities that it believes would meet the traditional tests the FERC has used to establish a pipeline s status as a gatherer not subject to the FERC s jurisdiction. In the states in which ENP operates, regulation of gathering facilities and intrastate pipeline facilities generally includes various safety, environmental, and in some circumstances, nondiscriminatory take requirement and complaint-based rate regulation.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels since the FERC has taken a less stringent approach to regulation of the offshore gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. ENP s gathering operations could be adversely affected should they become subject to the application of state or federal regulation of rates and services. ENP s gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement, and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on ENP s operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

ENCORE ACQUISITION COMPANY

Sales of Natural Gas. The price at which we buy and sell natural gas is not subject to federal regulation and, for the most part, is not subject to state regulation. Our sales of natural gas are affected by the availability, terms, and cost of pipeline transportation. The price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to the FERC s jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry, and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of these regulatory changes on our natural gas marketing operations, and we note that some of the FERC s more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action materially differently than other natural gas marketers with which we compete.

The Energy Policy Act of 2005 (EP Act 2005) gave the FERC increased oversight and penalty authority regarding market manipulation and enforcement. EP Act 2005 amended NGA to prohibit market manipulation and also amended NGA and the Natural Gas Policy Act of 1978 (NGPA) to increase civil and criminal penalties for any violations of NGA, NGPA, and any rules, regulations, or orders of the FERC to up to $1,000,000 per day, per violation. In 2006, the FERC issued a rule regarding market manipulation, which makes it unlawful for any entity, in connection with the purchase or sale of natural gas or transportation service subject to the FERC s jurisdiction, to defraud, make an untrue statement, or omit a material fact, or engage in any practice, act, or course of business that operates or would operate as a fraud. This rule works together with the FERC s enhanced penalty authority to provide increased oversight of the natural gas marketplace.

State Regulation. The various states regulate the development, production, gathering, and sale of oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Reduced rates or credits may apply to certain types of wells and production methods.

In addition to production taxes, Texas and Montana each impose ad valorem taxes on oil and natural gas properties and production equipment. Wyoming imposes an ad valorem tax on the gross value of oil and natural gas production in lieu of an ad valorem tax on the underlying oil and natural gas properties. Wyoming also imposes an ad valorem tax on production equipment. North Dakota imposes an ad valorem tax on gross oil and natural gas production in lieu of an ad valorem tax on the underlying oil and gas leases or on production equipment used on oil and gas leases.

States also regulate the method of developing new fields, the spacing and operation of wells, and the prevention of waste of oil and natural gas resources. States may regulate rates of production and establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but they may do so in the future. The effect of these regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, and to limit the number of wells or locations we can drill.

Federal, State, or Native American Leases. Our operations on federal, state, or Native American oil and natural gas leases are subject to numerous restrictions, including nondiscrimination statutes. Such operations must be conducted pursuant to certain on-site security regulations and other permits and authorizations issued by the Federal Bureau of Land Management, Minerals Management Service, and other agencies.

Operating Hazards and Insurance

The oil and natural gas business involves a variety of operating risks, including fires, explosions, blowouts, environmental hazards, and other potential events that can adversely affect our ability to conduct

ENCORE ACQUISITION COMPANY

operations and cause us to incur substantial losses. Such losses could reduce or eliminate the funds available for exploration, exploitation, or leasehold acquisitions or result in loss of properties.

In accordance with industry practice, we maintain insurance against some, but not all, potential risks and losses. We do not carry business interruption insurance. We may not obtain insurance for certain risks if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable at a reasonable cost. If a significant accident or other event occurs that is not fully covered by insurance, it could adversely affect us.

Employees

As of December 31, 2008, we had a staff of 394 persons, including 34 engineers, 17 geologists, and 14 landmen, none of which are represented by labor unions or covered by any collective bargaining agreement. We believe that relations with our employees are satisfactory.

Principal Executive Office

Our principal executive office is located at 777 Main Street, Suite 1400, Fort Worth, Texas 76102. Our main telephone number is (817) 877-9955.

Available Information

We make available electronically, free of charge through our website (www.encoreacq.com), our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and other filings with the SEC pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the Exchange Act) as soon as reasonably practicable after we electronically file such material with or furnish such material to the SEC. In addition, you may read and copy any materials that we file with the SEC at its public reference room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Information concerning the operation of the public reference room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website (www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers, like us, that file electronically with the SEC.

We have adopted a code of business conduct and ethics that applies to all directors, officers, and employees, including our principal executive and financial officers. The code of business conduct and ethics is available on our website. In the event that we make changes in, or provide waivers from, the provisions of this code of business conduct and ethics that the SEC or the NYSE require us to disclose, we intend to disclose these events on our website.

We have filed the required certifications under Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2 to this Report. In 2008, we submitted to the NYSE the CEO certification required by Section 303A.12(a) of the NYSE s Listed Company Manual. In 2009, we expect to submit this certification to the NYSE after our annual meeting of stockholders.

Our board of directors (the Board) has four standing committees: (1) audit; (2) compensation; (3) nominating and corporate governance; and (4) special stock award. Our Board committee charters, code of business conduct and ethics, and corporate governance guidelines are available on our website and are also available in print upon written request to: Corporate Secretary, Encore Acquisition Company, 777 Main Street, Suite 1400, Fort Worth, Texas 76102.

The information on our website or any other website is not incorporated by reference into this Report.

Table of Contents

ENCORE ACQUISITION COMPANY

ITEM 1A. *RISK FACTORS*

You should carefully consider each of the following risks and all of the information provided elsewhere in this Report. If any of the risks described below or elsewhere in this Report were actually to occur, our business, financial condition, results of operations, or cash flows could be materially and adversely affected. In that case, we may be unable to pay interest on, or the principal of, our debt securities, the trading price of our common stock could decline, and you could lose all or part of your investment.

Oil and natural gas prices are very volatile. A decline in commodity prices could materially and adversely affect our financial condition, results of operations, liquidity, and cash flows.

The oil and natural gas markets are very volatile, and we cannot accurately predict future oil and natural gas prices. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty, and a variety of additional factors that are beyond our control, such as:

- overall domestic and global economic conditions;
- weather conditions;
- political and economic conditions in oil and natural gas producing countries, including those in the Middle East, Africa, and South America;
- actions of the Organization of Petroleum Exporting Countries and state-controlled oil companies relating to oil price and production controls;
- the impact of U.S. dollar exchange rates on oil and natural gas prices;
- technological advances affecting energy consumption and energy supply;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the proximity, capacity, cost, and availability of oil and natural gas pipelines and other transportation facilities;
- the availability of refining capacity; and
- the price and availability of alternative fuels.

The worldwide financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with substantial losses in worldwide equity markets could lead to an extended worldwide economic recession. A slowdown in economic activity caused by a recession has reduced worldwide demand for energy and resulted in lower oil and natural gas prices. Oil prices declined from record levels in early July 2008 of over $140 per Bbl to below $39 per Bbl in mid-February 2009 and natural gas prices have declined from over $13 per Mcf to below $4.25 per Mcf over the same period. In addition, the forecasted prices for 2009 have also declined. Notwithstanding significant declines in oil and natural gas prices since July 2008, there has not been a corresponding decrease in oilfield service costs as of February 2009. If oilfield service costs remain elevated in relation to prevailing oil and natural gas prices, our results of operations and cash flows could be adversely affected.

Our revenue, profitability, and cash flow depend upon the prices of and demand for oil and natural gas, and a drop in prices can significantly affect our financial results and impede our growth. In particular, declines in commodity prices will:

- negatively impact the value of our reserves, because declines in oil and natural gas prices would reduce the amount of oil and natural gas that we can produce economically;

ENCORE ACQUISITION COMPANY

- reduce the amount of cash flow available for capital expenditures, repayment of indebtedness, and other corporate purposes; and

- result in a decrease in the borrowing base under our revolving credit facility or otherwise limit our ability to borrow money or raise additional capital.

An increase in the differential between benchmark prices of oil and natural gas and the wellhead price we receive could adversely affect our financial condition, results of operations, and cash flows.

The prices that we receive for our oil and natural gas production sometimes trade at a discount to the relevant benchmark prices, such as NYMEX. The difference between the benchmark price and the price we receive is called a differential. We cannot accurately predict oil and natural gas differentials. For example, the oil production from our Elk Basin assets has historically been sold at a higher discount to NYMEX as compared to our Permian Basin assets due to competition from Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity from the Rocky Mountain area, and corresponding deep pricing discounts by regional refiners. Increases in differentials could significantly reduce our cash available for development of our properties and adversely affect our financial condition, results of operations, and cash flows.

Our estimated proved reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

It is not possible to measure underground accumulations of oil or natural gas in an exact way. In estimating our oil and natural gas reserves, we and our independent reserve engineers make certain assumptions that may prove to be incorrect, including assumptions relating to oil and natural gas prices, production levels, capital expenditures, operating and development costs, the effects of regulation, and availability of funds. If these assumptions prove to be incorrect, our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classification of reserves based on risk of recovery, and our estimates of the future net cash flows from our reserves could change significantly.

Our Standardized Measure is calculated using prices and costs in effect as of the date of estimation, less future development, production, abandonment, and income tax expenses, and discounted at 10 percent per annum to reflect the timing of future net revenue in accordance with the rules and regulations of the SEC. The Standardized Measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved reserves. We base the estimated discounted future net cash flows from our estimated proved reserves on prices and costs in effect on the day of estimate. Over time, we may make material changes to reserve estimates to take into account changes in our assumptions and the results of actual development and production.

The reserve estimates we make for fields that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. A lack of production history may contribute to inaccuracy in our estimates of proved reserves, future production rates, and the timing of development expenditures.

The timing of both our production and our incurrence of expenses in connection with the development, production, and abandonment of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10 percent discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

ENCORE ACQUISITION COMPANY

Our oil and natural gas reserves naturally decline and the failure to replace our reserves could adversely affect our financial condition.

Because our oil and natural gas properties are a depleting asset, our future oil and natural gas reserves, production volumes, and cash flows depend on our success in developing and exploiting our current reserves efficiently and finding or acquiring additional recoverable reserves economically. We may not be able to develop, find, or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, financial condition, and results of operations.

We need to make substantial capital expenditures to maintain and grow our asset base. If lower oil and natural gas prices or operating difficulties result in our cash flows from operations being less than expected or limit our ability to borrow under our revolving credit facility, we may be unable to expend the capital necessary to find, develop, or acquire additional reserves.

Price declines may result in a write-down of our asset carrying values, which could have a material adverse effect on our results of operations and limit our ability to borrow funds under our revolving credit facility.

Declines in oil and natural gas prices may result in our having to make substantial downward revisions to our estimated reserves. If this occurs, or if our estimates of development costs increase, production data factors change, or development results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties and goodwill. If we incur such impairment charges, it could have a material adverse effect on our results of operations in the period incurred and on our ability to borrow funds under our revolving credit facility. In addition, any write-downs that result in a reduction in our borrowing base could require prepayments of indebtedness under our revolving credit facility.

If we do not make acquisitions, our future growth could be limited.

Acquisitions are an essential part of our growth strategy, and our ability to acquire additional properties on favorable terms is important to our long-term growth. We may be unable to make acquisitions because we are:

- unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;
- unable to obtain financing for these acquisitions on economically acceptable terms; or
- outbid by competitors.

Competition for acquisitions is intense and may increase the cost of, or cause us to refrain from, completing acquisitions. If we are unable to acquire properties containing proved reserves, our total level of proved reserves could decline as a result of our production. Future acquisitions could result in our incurring additional debt, contingent liabilities, and expenses, all of which could have a material adverse effect on our financial condition and results of operations. Furthermore, our financial position and results of operations may fluctuate significantly from period to period based on whether significant acquisitions are completed in particular periods.

Any acquisitions we complete are subject to substantial risks that could adversely affect our financial condition and results of operations.

Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, revenues, capital expenditures, and operating costs, including synergies;

ENCORE ACQUISITION COMPANY

- an inability to integrate the businesses we acquire successfully;
- a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown liabilities, losses, or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management s attention from other business concerns;
- an inability to hire, train, or retain qualified personnel to manage and operate our growing business and assets;
- natural disasters;
- the incurrence of other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation, or restructuring charges;
- unforeseen difficulties encountered in operating in new geographic areas; and
- customer or key employee losses at the acquired businesses.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses, and seismic and other information, the results of which are often inconclusive and subject to various interpretations.

Also, our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition given time constraints imposed by sellers. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken.

A substantial portion of our producing properties is located in one geographic area and adverse developments in any of our operating areas would negatively affect our financial condition and results of operations.

We have extensive operations in the CCA. Our CCA properties represented approximately 40 percent of our proved reserves as of December 31, 2008 and accounted for 30 percent of our 2008 production. Any circumstance or event that negatively impacts production or marketing of oil and natural gas in the CCA would materially affect our results of operations and cash flows.

Our commodity derivative contract activities could result in financial losses or could reduce our income and cash flows. Furthermore, in the future our commodity derivative contract positions may not adequately protect us from

changes in commodity prices.

To reduce our exposure to fluctuations in the price of oil and natural gas, we enter into derivative arrangements for a significant portion of our forecasted oil and natural gas production. The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities, as well as to the ability of counterparties under our commodity derivative contracts to satisfy their obligations to us. For example, the derivative instruments we utilize are based on posted market prices, which may differ significantly from the actual prices we realize on our production. Changes in oil and natural gas prices could result in losses under our commodity derivative contracts.

Table of Contents

ENCORE ACQUISITION COMPANY

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the notional amount of our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from the sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our derivative activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, our derivative activities are subject to the following risks:

- a counterparty may not perform its obligation under the applicable derivative instrument, which risk may have been exacerbated by the worldwide financial and credit crisis; and

- there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received, which may result in payments to our derivative counterparty that are not accompanied by our receipt of higher prices from our production in the field.

In addition, certain commodity derivative contracts that we may enter into may limit our ability to realize additional revenues from increases in the prices for oil and natural gas.

We have oil and natural gas commodity derivative contracts covering a significant portion of our forecasted production for 2009. These contracts are intended to reduce our exposure to fluctuations in the price of oil and natural gas. We have a much smaller commodity derivative contract portfolio covering our forecasted production for 2010, 2011, and 2012, and no commodity derivative contracts covering production beyond 2012. After 2009 and unless we enter into new commodity derivative contracts, our exposure to oil and natural gas price volatility will increase significantly each year as our commodity derivative contracts expire. We may not be able to obtain additional commodity derivative contracts on acceptable terms, if at all. Our failure to mitigate our exposure to commodity price volatility through commodity derivative contracts could have a negative effect on our financial condition and results of operation and significantly reduce our cash flows.

The counterparties to our derivative contracts may not be able to perform their obligations to us, which could materially affect our cash flows and results of operations.

As of December 31, 2008, we were entitled to future payments of approximately $387.6 million from counterparties under our commodity derivative contracts. The worldwide financial and credit crisis may have adversely affected the ability of these counterparties to fulfill their obligations to us. If one or more of our counterparties is unable or unwilling to make required payments to us under our commodity derivative contracts, it could have a material adverse effect on our financial condition and results of operations.

We have limited control over the activities on properties we do not operate.

Other companies operated approximately 21 percent of our properties (measured by total reserves) and approximately 46 percent of our wells as of December 31, 2008. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in development or acquisition activities and lead to unexpected future costs.

Our development and exploratory drilling efforts may not be profitable or achieve our targeted returns.

Development and exploratory drilling and production activities are subject to many risks, including the risk that we will not discover commercially productive oil or natural gas reserves. In order to further our development efforts, we acquire both producing and unproved properties as well as lease undeveloped acreage

ENCORE ACQUISITION COMPANY

that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not be required to impair our initial investments.

In addition, there can be no assurance that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us will be productive, or that we will recover all or any portion of our investment in such unproved property or wells. The costs of drilling and completing wells are often uncertain, and drilling operations may be curtailed, delayed, or canceled as a result of a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, weather conditions, and shortages or delays in the delivery of equipment. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry holes, but also from wells that are productive but do not produce sufficient commercial quantities to cover the development, operating, and other costs. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and future market prices for oil and natural gas, costs associated with producing oil and natural gas, and our ability to add reserves at an acceptable cost.

Seismic technology does not allow us to obtain conclusive evidence that oil or natural gas reserves are present or economically producible prior to spudding a well. We rely to a significant extent on seismic data and other advanced technologies in identifying unproved property prospects and in conducting our exploration activities. The use of seismic data and other technologies also requires greater up-front costs than development on proved properties.

Developing and producing oil and natural gas are costly and high-risk activities with many uncertainties that could adversely affect our financial condition or results of operations.

The cost of developing, completing, and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. If commodity prices decline, the cost of developing, completing and operating a well may not decline in proportion to the prices that we receive for our production, resulting in higher operating and capital costs as a percentage of oil and natural gas revenues. For instance, oil and natural gas prices declined from record levels in early July 2008 of over $140 per Bbl and $13 per Mcf, respectively, to below $39 per Bbl and $4.25 per Mcf, respectively, in mid-February 2009. Notwithstanding significant declines in oil and natural gas prices since July 2008, there has not been a corresponding decrease in oilfield service costs as of February 2009. If oilfield service costs remain elevated in relation to prevailing oil and natural gas prices, our results of operations and cash flows could be adversely affected. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce as much oil and natural gas as we had estimated. Furthermore, our development and production operations may be curtailed, delayed, or canceled as a result of other factors, including:

- higher costs, shortages, or delivery delays of rigs, equipment, labor, or other services;
- unexpected operational events and/or conditions;
- reductions in oil and natural gas prices;
- increases in severance taxes;
- limitations in the market for oil and natural gas;
- adverse weather conditions and natural disasters;

facility or equipment malfunctions, and equipment failures or accidents;

title problems;

pipe or cement failures and casing collapses;

compliance with environmental and other governmental requirements;

ENCORE ACQUISITION COMPANY

- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures, and discharges of toxic gases;
- lost or damaged oilfield development and service tools;
- unusual or unexpected geological formations, and pressure or irregularities in formations;
- loss of drilling fluid circulation;
- fires, blowouts, surface craterings, and explosions;
- uncontrollable flows of oil, natural gas, or well fluids; and
- loss of leases due to incorrect payment of royalties.

If any of these factors were to occur with respect to a particular field, we could lose all or a part of our investment in the field, or we could fail to realize the expected benefits from the field, either of which could materially and adversely affect our revenue and profitability.

Secondary and tertiary recovery techniques may not be successful, which could adversely affect our financial condition or results of operations.

A significant portion of our production and reserves rely on secondary and tertiary recovery techniques. If production response is less than forecasted for a particular project, then the project may be uneconomic or generate less cash flow and reserves than we had estimated prior to investing capital. Risks associated with secondary and tertiary recovery techniques include, but are not limited to, the following:

- lower than expected production;
- longer response times;
- higher operating and capital costs;
- shortages of equipment; and
- lack of technical expertise.

If any of these risks occur, it could adversely affect our financial condition or results of operations.

Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured.

There are a variety of operating risks inherent in our wells, gathering systems, pipelines, and other facilities, such as leaks, explosions, mechanical problems, and natural disasters, all of which could cause substantial financial losses. Any of these or other similar occurrences could result in the disruption of our operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution, impairment of our operations, and substantial revenue losses. The location of our wells, gathering systems, pipelines, and other facilities near populated areas, including residential areas, commercial business centers, and industrial sites, could significantly increase the level of damages resulting from these risks.

We are not fully insured against all risks, including development and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Changes in the insurance markets due to weather and adverse economic conditions have made it more difficult for us to obtain certain types of coverage. We may not be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes, and our insurance may contain large deductibles or fail to cover certain hazards or cover all potential losses. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our business, financial condition, and results of operations.

Our development, exploitation, and exploration operations require substantial capital, and we may be unable to obtain needed financing on satisfactory terms.

We make and will continue to make substantial capital expenditures in development, exploitation, and exploration projects. For example, our Board approved a $310 million capital budget for 2009, excluding proved property acquisitions. We intend to finance these capital expenditures through operating cash flows. However, additional financing sources may be required in the future to fund our capital expenditures. Financing may not continue to be available under existing or new financing arrangements, or on acceptable terms, if at all. If additional capital resources are not available, we may be forced to curtail our development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

Shortages of rigs, equipment, and crews could delay our operations.

Higher oil and natural gas prices generally increase the demand for rigs, equipment, and crews and can lead to shortages of, and increasing costs for, development equipment, services, and personnel. Shortages of, or increasing costs for, experienced development crews and oil field equipment and services could restrict our ability to drill the wells and conduct the operations that we have planned. Any delay in the development of new wells or a significant increase in development costs could reduce our revenues.

The loss of key personnel could adversely affect our business.

We depend to a large extent on the efforts and continued employment of I. Jon Brumley, our Chairman of the Board, Jon S. Brumley, our Chief Executive Officer and President, and other key personnel. The loss of the services of any of these persons could adversely affect our business, and we do not have employment agreements with, and do not maintain key person insurance on the lives of, any of these persons.

Our development success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, and other professionals. Competition for experienced geologists, engineers, and other professionals is extremely intense and the cost of attracting and retaining technical personnel has increased significantly in recent years. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed. Furthermore, escalating personnel costs could adversely affect our results of operations and financial condition.

Our business depends in part on gathering and transportation facilities owned by others. Any limitation in the availability of those facilities could interfere with our ability to market our oil and natural gas production and could harm our business.

The marketability of our oil and natural gas production depends in part on the availability, proximity, and capacity of pipelines, oil and natural gas gathering systems, and processing facilities. The amount of oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage, or lack of contracted capacity on such systems.

The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or pipeline capacity could reduce our ability to market our oil and natural gas production and harm our business.

Table of Contents

ENCORE ACQUISITION COMPANY

Competition in the oil and natural gas industry is intense, and many of our competitors have greater resources than we do. As a result, we may be unable to effectively compete with larger competitors.

The oil and natural gas industry is intensely competitive with respect to acquiring prospects and productive properties, marketing oil and natural gas, and securing equipment and trained personnel, and we compete with other companies that have greater resources. Many of our competitors are major and large independent oil and natural gas companies, and possess and employ financial, technical, and personnel resources substantially greater than us. Those companies may be able to develop and acquire more prospects and productive properties than our resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Some of our competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national, or worldwide basis. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for, and purchase a greater number of properties than our resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These companies may have a greater ability to continue development activities during periods of low oil and natural gas prices and to absorb the burden of present and future federal, state, local, and other laws and regulations. Our inability to compete effectively could have a material adverse impact on our business activities, financial condition, and results of operations.

We are subject to complex federal, state, local, and other laws and regulations that could adversely affect the cost, manner, or feasibility of conducting our operations.

Our oil and natural gas exploration and production operations are subject to complex and stringent laws and regulations. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate, and abandon oil and natural gas wells and related pipeline and processing facilities. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals, and certificates from various federal, state, and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations.

Our business is subject to federal, state, and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and production of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, financial condition, and results of operations. Please read Items 1 and 2. Business and Properties Environmental Matters and Regulation and Other Regulation of the Oil and Natural Gas Industry for a description of the laws and regulations that affect us.

We have significant indebtedness and may incur significant additional indebtedness, which could negatively impact our financial condition, results of operations, and business prospects.

As of December 31, 2008, we had total consolidated debt of $1.3 billion and $615 million of consolidated available borrowing capacity under our revolving credit facility. We have the ability to incur additional debt under our revolving credit facilities, subject to borrowing base limitations. Our future indebtedness could have important consequences to us, including:

our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions, or other purposes may not be available on favorable terms, if at all;

covenants contained in future debt arrangements may require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;

ENCORE ACQUISITION COMPANY

we will need a substantial portion of our cash flow to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations and future business opportunities; and

our debt level will make us more vulnerable to competitive pressures, or a downturn in our business or the economy in general, than our competitors with less debt.

Our ability to service our indebtedness depends upon, among other things, our future financial and operating performance, which is affected by prevailing economic conditions and financial, business, regulatory, and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing or delaying business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to effect any of these remedies on satisfactory terms or at all.

In addition, we are not currently permitted to offset the value of our commodity derivative contracts with a counterparty against amounts that may be owing to such counterparty under our revolving credit facilities.

We are unable to predict the impact of the recent downturn in the credit markets and the resulting costs or constraints in obtaining financing on our business and financial results.

U.S. and global credit and equity markets have recently undergone significant disruption, making it difficult for many businesses to obtain financing on acceptable terms. In addition, equity markets are continuing to experience wide fluctuations in value. If these conditions continue or worsen, our cost of borrowing may increase, and it may be more difficult to obtain financing in the future. In addition, an increasing number of financial institutions have reported significant deterioration in their financial condition. If any of the financial institutions are unable to perform their obligations under our revolving credit agreements and other contracts, and we are unable to find suitable replacements on acceptable terms, our results of operations, liquidity and cash flows could be adversely affected. We also face challenges relating to the impact of the disruption in the global financial markets on other parties with which we do business, such as customers and suppliers. The inability of these parties to obtain financing on acceptable terms could impair their ability to perform under their agreements with us and lead to various negative effects on us, including business disruption, decreased revenues, and increases in bad debt write-offs. A sustained decline in the financial stability of these parties could have an adverse impact on our business, results of operations, and liquidity.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant costs and liabilities as a result of environmental and safety requirements applicable to our oil and natural gas production activities. In addition, we often indemnify sellers of oil and natural gas properties for environmental liabilities they or their predecessors may have created. These costs and liabilities could arise under a wide range of federal, state, and local environmental and safety laws and regulations, which have become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, imposition of cleanup and site restoration costs, liens and, to a lesser extent, issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations.

Strict, joint, and several liability may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations, or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we are not able to recover the resulting costs through insurance or increased revenues, our profitability and our ability to make distributions to unitholders could be adversely affected.

Table of Contents

ENCORE ACQUISITION COMPANY

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

There were no unresolved SEC staff comments as of December 31, 2008.

ITEM 3. *LEGAL PROCEEDINGS*

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

ITEM 4. *SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS*

There were no matters submitted to a vote of stockholders during the fourth quarter of 2008.

ENCORE ACQUISITION COMPANY

PART II

ITEM 5. ***MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES***

Our common stock, par value $0.01 per share, is listed on the NYSE under the symbol EAC. The following table sets forth high and low sales prices of our common stock for the periods indicated:

	High	Low
2008		
Quarter ended December 31	$ 41.05	$ 17.89
Quarter ended September 30	$ 79.62	$ 36.84
Quarter ended June 30	$ 77.35	$ 38.45
Quarter ended March 31	$ 40.74	$ 26.10
2007		
Quarter ended December 31	$ 38.55	$ 30.59
Quarter ended September 30	$ 33.00	$ 25.79
Quarter ended June 30	$ 29.96	$ 24.21
Quarter ended March 31	$ 26.50	$ 21.74

On February 18, 2009, the closing sales price of our common stock as reported by the NYSE was $23.09 per share, and we had approximately 387 shareholders of record. This number does not include owners for whom common stock may be held in street name.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

In October 2008, we announced that the Board authorized a share repurchase program of up to $40 million of our common stock. As of December 31, 2008, 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. The following table summarizes purchases of our common stock during the fourth quarter of 2008:

Month	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs

October	620,265	$	27.68	620,265		
November(a)	4,753	$	21.31			
December		$				
Total	625,018	$	27.63	620,265	$	22,830,139

(a) During the fourth quarter of 2008, certain employees directed us to withhold 4,753 shares of common stock to satisfy minimum tax withholding obligations in conjunction with vesting of restricted shares.

Dividends

No dividends have been declared or paid on our common stock. We anticipate that we will retain all future earnings and other cash resources for the future operation and development of our business. Accordingly, we do not intend to declare or pay any cash dividends in the foreseeable future. Payment of any future dividends will be at the discretion of the Board after taking into account many factors, including our operating results, financial condition, current and anticipated cash needs, and plans for expansion. The

ENCORE ACQUISITION COMPANY

declaration and payment of dividends is restricted by our existing revolving credit facility and the indentures governing our senior subordinated notes. Future debt agreements may also restrict our ability to pay dividends.

Stock Performance Graph

The following graph compares our cumulative total stockholder return during the period from January 1, 2004 to December 31, 2008 with total stockholder return during the same period for the Independent Oil and Gas Index and the Standard & Poor s 500 Index. The graph assumes that $100 was invested in our common stock and each index on January 1, 2004 and that all dividends, if any, were reinvested. The following graph is being furnished pursuant to SEC rules and will not be incorporated by reference into any filing under the Securities Act of 1933 or the Exchange Act except to the extent we specifically incorporate it by reference.

Comparison of Total Return Since January 1, 2004 Among Encore Acquisition Company, the Standard & Poor s 500 Index, and the Independent Oil and Gas Index

Table of Contents

ENCORE ACQUISITION COMPANY

ITEM 6. ***SELECTED FINANCIAL DATA***

The following selected consolidated financial and operating data should be read in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data :

	Year Ended December 31,(f)				
	2008	**2007**	**2006**	**2005**	**2004**
	(In thousands, except per share amounts)				
Consolidated Statements of Operations Data:					
Revenues(a):					
Oil	$ 897,443	$ 562,817	$ 346,974	$ 307,959	$ 220,649
Natural gas	227,479	150,107	146,325	149,365	77,884
Marketing(b)	10,496	42,021	147,563		
Total revenues	1,135,418	754,945	640,862	457,324	298,533
Expenses:					
Production:					
Lease operations(c)	175,115	143,426	98,194	69,744	47,807
Production, ad valorem, and severance taxes	110,644	74,585	49,780	45,601	30,313
Depletion, depreciation, and amortization	228,252	183,980	113,463	85,627	48,522
Impairment of long-lived assets(g)	59,526				
Exploration	39,207	27,726	30,519	14,443	3,935
General and administrative(c)	48,421	39,124	23,194	17,268	12,059
Marketing(b)	9,570	40,549	148,571		
Derivative fair value loss (gain)(d)	(346,236)	112,483	(24,388)	5,290	5,011
Loss on early redemption of debt				19,477	
Provision for doubtful accounts	1,984	5,816	1,970	231	
Other operating	12,975	17,066	8,053	9,254	5,028
Total expenses	339,458	644,755	449,356	266,935	152,675
Operating income	795,960	110,190	191,506	190,389	145,858
Other income (expenses):					
Interest	(73,173)	(88,704)	(45,131)	(34,055)	(23,459)
Other	3,898	2,667	1,429	1,039	240
Total other expenses	(69,275)	(86,037)	(43,702)	(33,016)	(23,219)

Income before income taxes and minority interest	726,685	24,153	147,804	157,373	122,639
Income tax provision	(241,621)	(14,476)	(55,406)	(53,948)	(40,492)
Minority interest in loss (income) of consolidated partnership	(54,252)	7,478			
Net income	$ 430,812	$ 17,155	$ 92,398	$ 103,425	$ 82,147
Net income per common share:					
Basic	$ 8.24	$ 0.32	$ 1.78	$ 2.12	$ 1.74(e)
Diluted	$ 8.07	$ 0.32	$ 1.75	$ 2.09	$ 1.72(e)
Weighted average common shares outstanding:					
Basic	52,270	53,170	51,865	48,682	47,090(e)
Diluted	53,414	54,144	52,736	49,522	47,738(e)

Table of Contents

ENCORE ACQUISITION COMPANY

	Year Ended December 31,(f)				
	2008	2007	2006	2005	2004
	(In thousands, except per unit amounts)				
Total Production Volumes:					
Oil (Bbls)	10,050	9,545	7,335	6,871	6,679
Natural gas (Mcf)	26,374	23,963	23,456	21,059	14,089
Combined (BOE)	14,446	13,539	11,244	10,381	9,027
Average Realized Prices:					
Oil ($/Bbl)	$ 89.30	$ 58.96	$ 47.30	$ 44.82	$ 33.04
Natural gas ($/Mcf)	8.63	6.26	6.24	7.09	5.53
Combined ($/BOE)	77.87	52.66	43.87	44.05	33.07
Average Costs per BOE:					
Lease operations	$ 12.12	$ 10.59	$ 8.73	$ 6.72	$ 5.30
Production, ad valorem, and severance taxes	7.66	5.51	4.43	4.39	3.36
Depletion, depreciation, and amortization	15.80	13.59	10.09	8.25	5.38
Impairment of long-lived assets	4.12				
Exploration	2.71	2.05	2.71	1.39	0.44
General and administrative	3.35	2.89	2.06	1.67	1.33
Derivative fair value loss (gain)	(23.97)	8.31	(2.17)	0.51	0.56
Provision for doubtful accounts	0.14	0.43	0.18	0.02	
Other operating expense	0.90	1.26	0.72	0.89	0.56
Marketing loss (gain)	(0.06)	(0.11)	0.09		
Consolidated Statements of Cash Flows Data:					
Cash provided by (used in):					
Operating activities	$ 663,237	$ 319,707	$ 297,333	$ 292,269	$ 171,821
Investing activities	(728,346)	(929,556)	(397,430)	(573,560)	(433,470)
Financing activities	65,444	610,790	99,206	281,842	262,321
Proved Reserves:					
Oil (Bbls)	134,452	188,587	153,434	148,387	134,048
Natural gas (Mcf)	307,520	256,447	306,764	283,865	234,030
Combined (BOE)	185,705	231,328	204,561	195,698	173,053
Consolidated Balance Sheets Data:					
Working capital	$ 188,678	$ (16,220)	$ (40,745)	$ (56,838)	$ (15,566)
Total assets	3,633,195	2,784,561	2,006,900	1,705,705	1,123,400
Long-term debt	1,319,811	1,120,236	661,696	673,189	379,000
Stockholders equity	1,314,128	948,155	816,865	546,781	473,575

(a) For 2008, 2007, 2006, 2005, and 2004, we reduced oil and natural gas revenues for net profits interests by $56.5 million, $32.5 million, $23.4 million, $21.2 million, and $12.6 million, respectively.

(b) In 2006, we began purchasing third-party oil Bbls from a counterparty other than to whom the Bbls were sold for aggregation and sale with our own equity production in various markets. These purchases assisted us in marketing our production by decreasing our dependence on individual markets. These activities allowed us to aggregate larger volumes, facilitated our efforts to maximize the prices we received for production, provided for a greater allocation of future pipeline capacity in the event of curtailments, and enabled us to reach other markets. In 2007, we discontinued purchasing oil from third party companies as market conditions changed and pipeline space was gained. Implementing this change allowed us to focus on the marketing of our own oil production, leveraging newly gained pipeline space, and delivering oil to various newly developed markets in an effort to maximize the value of the oil at the wellhead. In March

ENCORE ACQUISITION COMPANY

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

(c) On January 1, 2006, we adopted the provisions of SFAS No. 123R, *Share-Based Payment* (SFAS 123R). Due to the adoption of SFAS 123R, non-cash equity-based compensation expense for 2005 and 2004 has been reclassified to allocate the amount to the same respective income statement lines as the respective employees cash compensation. This resulted in increases in LOE of $1.3 million and $0.7 million during 2005 and 2004, respectively, increases in general and administrative (G&A) expense of $2.6 million and $1.1 million during 2005 and 2004, respectively.

(d) During July 2006, we elected to discontinue hedge accounting prospectively for all of our remaining commodity derivative contracts which were previously accounted for as hedges. From that point forward, all mark-to-market gains or losses on all commodity derivative contracts are recorded in Derivative fair value loss (gain) while in periods prior to that point, only the ineffective portions of commodity derivative contracts which were designated as hedges were recorded in Derivative fair value loss (gain).

(e) Adjusted for the effects of the 3-for-2 stock split in July 2005.

(f) We acquired certain oil and natural gas properties and related assets in the Big Horn and Williston Basins in March 2007 and April 2007, respectively. We also acquired Crusader Energy Corporation in October 2005 and Cortez Oil & Gas, Inc. in April 2004. The operating results of these acquisitions are included in our Consolidated Statements of Operations from the date of acquisition forward. We disposed of certain oil and natural gas properties and related assets in the Mid-Continent in June 2007. The operating results of this disposition are included in our Consolidated Statements of Operations through the date of disposition.

(g) During 2008, circumstances indicated that the carrying amounts of certain oil and natural gas properties, primarily four wells in the Tuscaloosa Marine Shale, may not be recoverable. We compared the assets carrying amounts to the undiscounted expected future net cash flows, which indicated a need for an impairment charge. We then compared the net carrying amounts of the impaired assets to their estimated fair value, which resulted in a write-down of the value of proved oil and natural gas properties of $59.5 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.

ENCORE ACQUISITION COMPANY

ITEM 7. *MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS*

The following discussion and analysis of our consolidated financial condition and results of operations should be read in conjunction with our consolidated financial statements and notes and supplementary data thereto included in Item 8. Financial Statements and Supplementary Data. The following discussion and analysis contains forward-looking statements including, without limitation, statements relating to our plans, strategies, objectives, expectations, intentions, and resources. Actual results could differ materially from those discussed in the forward-looking statements. We do not undertake to update, revise, or correct any of the forward-looking information unless required to do so under federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with our disclosures under the headings: Information Concerning Forward-Looking Statements and Item 1A. Risk Factors.

Introduction

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

- Overview of Business
- 2008 Highlights
- Recent Developments
- 2009 Outlook
- Results of Operations
  - Comparison of 2008 to 2007
  - Comparison of 2007 to 2006
- Capital Commitments, Capital Resources, and Liquidity
- Changes in Prices
- Critical Accounting Policies and Estimates
- New Accounting Pronouncements
- Information Concerning Forward-Looking Statements

Overview of Business

We are a Delaware corporation engaged in the acquisition, development, exploitation, exploration, and production of oil and natural gas reserves from onshore fields in the United States. Our business strategies include:

Maintaining an active development program to maximize existing reserves and production;

Utilizing enhanced oil recovery techniques to maximize existing reserves and production;

Expanding our reserves, production, and development inventory through a disciplined acquisition program;

Exploring for reserves; and

Operating in a cost effective, efficient, and safe manner.

At December 31, 2008, our oil and natural gas properties had estimated total proved reserves of 134.5 MMBbls of oil and 307.5 Bcf of natural gas, based on December 31, 2008 spot market prices of $44.60

ENCORE ACQUISITION COMPANY

per Bbl of oil and $5.62 per Mcf of natural gas. On a BOE basis, our proved reserves were 185.7 MMBOE at December 31, 2008, of which approximately 72 percent was oil and approximately 80 percent was proved developed. Based on 2008 production, our ratio of reserves to production was approximately 12.9 years for total proved reserves and 10.3 years for proved developed reserves as of December 31, 2008.

Our financial results and ability to generate cash depend upon many factors, particularly the price of oil and natural gas. Average NYMEX oil prices strengthened in the first half of 2008 to record levels, but have since experienced a significant deterioration. In addition, our oil wellhead differentials to NYMEX improved in 2008 as we realized 90 percent of the average NYMEX oil price, as compared to 88 percent in 2007. Average NYMEX natural gas prices strengthened in the first half of 2008 to their highest levels since 2005, but have since experienced a significant deterioration. Our natural gas wellhead differentials to NYMEX deteriorated slightly in 2008 as we realized 95 percent of the average NYMEX natural gas price, as compared to 98 percent in 2007. Commodity prices are influenced by many factors that are outside of our control. We cannot accurately predict future commodity prices. For this reason, we attempt to mitigate the effect of commodity price risk by entering into commodity derivative contracts for a portion of our forecasted future production. For a discussion of factors that influence commodity prices and risks associated with our commodity derivative contracts, please read Item 1A. Risk Factors.

During 2008, we did not make a significant acquisition of proved reserves. Instead, we acquired unproved acreage in our core areas, continued to make significant investments within our core areas to develop proved undeveloped reserves and increase production from proved developed reserves through various recovery techniques, and made significant investments for exploration within our areas of unproved acreage. We continue to believe that a portfolio of long-lived quality assets will position us for future success.

In May 2008, we announced that our Board had authorized our management team to explore a broad range of strategic alternatives to further enhance shareholder value, including, but not limited to, a sale or merger of the company. In conjunction, our Board approved a retention plan for all of our then-current employees, excluding members of our strategic team, providing for the payment of four months of base salary or base rate of pay, as applicable, upon the completion of the strategic alternatives process, subject to continued employment. This bonus was paid in August 2008.

In July 2008, our Board and management team decided that a sale or merger of the company was not currently in the best interest of our shareholders. In conjunction, our Board approved a separate retention plan for all of our then-current employees, excluding our Chairman and Chief Executive Officer, providing for the payment of eight months of base salary or base rate of pay, as applicable, in August 2009, subject to continued employment.

Our 2008 results of operations include approximately $7.6 million of pre-tax expense related to the four-month retention plan and approximately $6.9 million of pre-tax expense related to the eight-month retention plan.

2008 Highlights

Our financial and operating results for 2008 included the following:

Our oil and natural gas revenues increased 58 percent to $1.1 billion as compared to $712.9 million in 2007 as a result of increased production volumes and higher average realized prices.

Our average realized oil price increased 51 percent to $89.30 per Bbl as compared to $58.96 per Bbl in 2007. Our average realized natural gas price increased 38 percent to $8.63 per Mcf as compared to $6.26 per Mcf in 2007.

Our average daily production volumes increased six percent to 39,470 BOE/D as compared to 37,094 BOE/D in 2007. Oil represented 70 percent and 71 percent of our total production volumes in 2008 and 2007, respectively.

ENCORE ACQUISITION COMPANY

Our production margin (defined as oil and natural gas wellhead revenues less production expenses) increased 54 percent to $842.0 million as compared to $548.5 million in 2007. Total oil and natural gas wellhead revenues per BOE increased by 38 percent while total production expenses per BOE increased by 23 percent. On a per BOE basis, our production margin increased 44 percent to $58.29 per BOE as compared to $40.52 per BOE for 2007.

We reported record net income for 2008, which increased to $430.8 million ($8.07 per diluted share) from the $17.2 million ($0.32 per diluted share) reported for 2007.

We invested $775.9 million in oil and natural gas activities (excluding asset retirement obligations of $0.6 million), of which $618.5 million was invested in development, exploitation, and exploration activities, yielding 282 gross (104.8 net) productive wells, and $157.4 million was invested in acquisitions, primarily of unproved acreage.

Recent Developments

In January 2009, we sold certain oil and natural gas producing properties and related assets in the Arkoma Basin and royalty interest properties in Oklahoma as well as 10,300 unleased mineral acres to ENP. The sales price was $49 million in cash, subject to customary adjustments (including a reduction in the purchase price for acquisition-related commodity derivative premiums of approximately $3 million).

2009 Outlook

For 2009, the Board has approved a $310 million capital budget for oil and natural gas related activities, excluding proved property acquisitions. We expect to fund our 2009 capital expenditures within cash flows from operations and use the additional cash flows from operations to reduce our debt levels. The following table represents the components of our 2009 capital budget (in thousands):

Drilling	$ 215,000
Improved oil recovery, workovers	60,000
Land, seismic, and other	35,000
Total	$ 310,000

The prices we receive for our oil and natural gas production are largely based on current market prices, which are beyond our control. For comparability and accountability, we take a constant approach to budgeting commodity prices. We presently analyze our inventory of capital projects based on management s outlook of future commodity prices. If NYMEX prices continue to trend downward, we may further reevaluate our capital projects. Since the end of 2008, oil NYMEX prices have declined from $44.60 per Bbl to below $39.00 per Bbl in mid-February 2009 and natural gas NYMEX prices have declined from $5.62 per Mcf to below $4.25 per Mcf over the same period. The price risk on a significant portion of our forecasted oil and natural gas production for 2009 is mitigated using commodity derivative contracts. Please read Item 7A. Quantitative and Qualitative Disclosures about Market Risk for additional information regarding our commodity derivative contracts. We intend to continue to enter into commodity derivative transactions to mitigate the impact of price volatility on our oil and natural gas revenues. Significant factors that will impact near-term commodity prices include the following:

- the duration and severity of the worldwide economic recession;
- political developments in Iraq, Iran, Venezuela, Nigeria, and other oil-producing countries;
- the extent to which members of OPEC and other oil exporting nations are able to manage oil supply through export quotas;
- Russia s increasing position as a major supplier of natural gas to world markets;

Table of Contents

ENCORE ACQUISITION COMPANY

- the level of economic growth in China, India, and other developing countries;
- concerns that major oil fields throughout the world have reached peak production;
- the level of interest rates;
- oilfield service costs;
- the potential for terrorist activity; and
- the value of the U.S. dollar relative to other currencies.

We expect to continue to pursue asset acquisitions, but expect to confront intense competition for these assets from third parties.

First Quarter 2009 Outlook

We expect our total average daily production volumes to be approximately 39,900 to 41,100 BOE/D in the first quarter of 2009, net of average daily net profits production volumes of approximately 900 to 1,100 BOE/D. We expect our oil wellhead differentials as a percentage of NYMEX to widen in the first quarter of 2009 to a negative 22 percent as compared to the negative 20 percent differential we realized in the fourth quarter of 2008. We expect our natural gas wellhead differentials as a percentage of NYMEX to improve in the first quarter of 2009 to a positive three percent as compared to the negative 14 percent differential we realized in the fourth quarter of 2008.

In the first quarter of 2009, we expect our LOE to average $12.75 to $13.25 per BOE, including approximately $2.5 million ($0.68 per BOE) for retention bonuses related to the strategic alternatives process to be paid in August 2009. We expect our production taxes to average approximately 9.5 percent of wellhead revenues in the first quarter of 2009. In the first quarter of 2009, we expect our depletion, depreciation, and amortization (DD&A) expense to average $18.00 to $18.50 per BOE. In the first quarter of 2009, we expect our G&A expense to average $3.50 to $4.00 per BOE, including approximately $1.7 million ($0.46 per BOE) for retention bonuses related to the strategic alternatives process to be paid in August 2009.

During the first quarter of 2009, we expect our effective tax rate to be approximately 38 percent, 95 percent of which is expected to be deferred.

We do not expect to reduce our total debt levels during the first quarter of 2009.

ENCORE ACQUISITION COMPANY

Results of Operations

Comparison of 2008 to 2007

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

	Year Ended December 31, 2008	Year Ended December 31, 2007	*Increase* *$*	*%*
Revenues (in thousands):				
Oil wellhead	$ 900,300	$ 606,112	*$ 294,188*	
Oil commodity derivative contracts	(2,857)	(43,295)	*40,438*	
Total oil revenues	$ 897,443	$ 562,817	*$ 334,626*	*59%*
Natural gas wellhead	$ 227,479	$ 160,399	*$ 67,080*	
Natural gas commodity derivative contracts		(10,292)	*10,292*	
Total natural gas revenues	$ 227,479	$ 150,107	*$ 77,372*	*52%*
Combined wellhead	$ 1,127,779	$ 766,511	*$ 361,268*	
Combined commodity derivative contracts	(2,857)	(53,587)	*50,730*	
Total combined oil and natural gas revenues	$ 1,124,922	$ 712,924	*$ 411,998*	*58%*
Average realized prices:				
Oil wellhead ($/Bbl)	$ 89.58	$ 63.50	*$ 26.08*	
Oil commodity derivative contracts ($/Bbl)	(0.28)	(4.54)	*4.26*	
Total oil revenues ($/Bbl)	$ 89.30	$ 58.96	*$ 30.34*	*51%*
Natural gas wellhead ($/Mcf)	$ 8.63	$ 6.69	*$ 1.94*	
Natural gas commodity derivative contracts ($/Mcf)		(0.43)	*0.43*	
Total natural gas revenues ($/Mcf)	$ 8.63	$ 6.26	*$ 2.37*	*38%*
Combined wellhead ($/BOE)	$ 78.07	$ 56.62	*$ 21.45*	
Combined commodity derivative contracts ($/BOE)	(0.20)	(3.96)	*3.76*	
Total combined oil and natural gas revenues ($/BOE)	$ 77.87	$ 52.66	*$ 25.21*	*48%*
Total production volumes:				
Oil (MBbls)	10,050	9,545	*505*	*5%*
Natural gas (MMcf)	26,374	23,963	*2,411*	*10%*

Combined (MBOE)		14,446		13,539		*907*	*7%*
Average daily production volumes:							
Oil (Bbl/D)		27,459		26,152		*1,307*	*5%*
Natural gas (Mcf/D)		72,060		65,651		*6,409*	*10%*
Combined (BOE/D)		39,470		37,094		*2,376*	*6%*
Average NYMEX prices:							
Oil (per Bbl)	$	99.75	$	72.45	*$*	*27.30*	*38%*
Natural gas (per Mcf)	$	9.04	$	6.86	*$*	*2.18*	*32%*

Oil revenues increased 59 percent from $562.8 million in 2007 to $897.4 million in 2008 as a result of an increase in our average realized oil price and an increase in oil production volumes of 505 MBbls. The

ENCORE ACQUISITION COMPANY

increase in oil production volumes contributed approximately $32.1 million in additional oil revenues and was primarily the result of a full year of production from our Big Horn Basin acquisition in March 2007 and our Williston Basin acquisition in April 2007, as well as our development program in the Bakken.

Our average realized oil price increased $30.34 per Bbl from 2007 to 2008 primarily as a result of an increase in our average realized oil wellhead price, which increased oil revenues by approximately $262.1 million, or $26.08 per Bbl. Our average realized oil wellhead price increased primarily as a result of the increase in the average NYMEX price from $72.45 per Bbl in 2007 to $99.75 per Bbl in 2008.

During July 2006, we elected to discontinue hedge accounting prospectively for all remaining commodity derivative contracts which were previously accounted for as hedges. While this change had no effect on our cash flows, results of operations are affected by mark-to-market gains and losses, which fluctuate with the changes in oil and natural gas prices. As a result, oil revenues for 2008 included amortization of net losses on certain commodity derivative contracts that were previously designated as hedges of approximately $2.9 million, or $0.28 per Bbl, while 2007 included approximately $43.3 million, or $4.54 per Bbl, of net losses.

Our average daily production volumes were decreased by 1,530 BOE/D and 1,466 BOE/D in 2008 and 2007, respectively, for net profits interests related to our CCA properties, which reduced our oil wellhead revenues by $55.3 million and $31.9 million in 2008 and 2007, respectively.

Natural gas revenues increased 52 percent from $150.1 million in 2007 to $227.5 million in 2008 as a result of an increase in our average realized natural gas price and an increase in natural gas production volumes of 2,411 MMcf. The increase in natural gas production volumes contributed approximately $16.1 million in additional natural gas revenues and was primarily the result of our development program in our Permian Basin and Mid-Continent regions.

Our average realized natural gas price increased $2.37 per Mcf from 2007 to 2008 primarily as a result of an increase in our average realized natural gas wellhead price, which increased natural gas revenues by approximately $50.9 million, or $1.94 per Mcf. Our average realized natural gas wellhead price increased primarily as a result of the increase in the average NYMEX price from $6.86 per Mcf in 2007 to $9.04 per Mcf in 2008. In addition, as a result of our discontinuance of hedge accounting in July 2006, natural gas revenues for 2007 included amortization of net losses on certain commodity derivative contracts that were previously designated as hedges of approximately $10.3 million, or $0.43 per Mcf.

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

	Year Ended December 31,	
	2008	**2007**
Oil wellhead ($/Bbl)	$ 89.58	$ 63.50
Average NYMEX ($/Bbl)	$ 99.75	$ 72.45
Differential to NYMEX	$ (10.17)	$ (8.95)
Oil wellhead to NYMEX percentage	90%	88%

Natural gas wellhead ($/Mcf)	$ 8.63	$ 6.69
Average NYMEX ($/Mcf)	$ 9.04	$ 6.86
Differential to NYMEX	$ (0.41)	$ (0.17)
Natural gas wellhead to NYMEX percentage	95%	98%

Our oil wellhead price as a percentage of the average NYMEX price was 90 percent in 2008 as compared to 88 percent in 2007. Our natural gas wellhead price as a percentage of the average NYMEX price was 95 percent in 2008 as compared to 98 percent in 2007.

ENCORE ACQUISITION COMPANY

Marketing revenues and expenses. In 2007, we discontinued purchasing oil from third party companies as market conditions changed and pipeline space was gained. Implementing this change allowed us to focus on the marketing of our own oil production, leveraging newly gained pipeline space, and delivering oil to various newly developed markets in an effort to maximize the value of the oil at the wellhead. In March 2007, ENP acquired a natural gas pipeline from Anadarko as part of the Big Horn Basin asset acquisition. Natural gas volumes are purchased from numerous gas producers at the inlet to the pipeline and resold downstream to various local and off-system markets. Marketing expenses include pipeline tariffs, storage, truck facility fees, and tank bottom costs used to support the sale of oil production, the revenues of which are included in our oil revenues instead of marketing revenues. The following table summarizes our marketing activities for the periods indicated:

	Year Ended December 31, 2008	Year Ended December 31, 2007	Decrease $	Decrease %
	(In thousands, except per BOE amounts)			
Marketing revenues	$ 10,496	$ 42,021	*$ (31,525)*	*(75)%*
Marketing expenses	9,570	40,549	*(30,979)*	*(76)%*
Marketing gain	$ 926	$ 1,472	*$ (546)*	*(37)%*
Marketing revenues per BOE	$ 0.72	$ 3.10	*$ (2.38)*	*(77)%*
Marketing expenses per BOE	0.66	2.99	*(2.33)*	*(78)%*
Marketing gain, per BOE	$ 0.06	$ 0.11	*$ (0.05)*	*(45)%*

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

	Year Ended December 31, 2008	Year Ended December 31, 2007	Increase/(Decrease) $	Increase/(Decrease) %
Expenses (in thousands):				
Production:				
Lease operations	$ 175,115	$ 143,426	*$ 31,689*	
Production, ad valorem, and severance taxes	110,644	74,585	*36,059*	
Total production expenses	285,759	218,011	*67,748*	*31%*
Other:				
Depletion, depreciation, and amortization	228,252	183,980	*44,272*	
Impairment of long-lived assets	59,526		*59,526*	
Exploration	39,207	27,726	*11,481*	
General and administrative	48,421	39,124	*9,297*	

Derivative fair value loss (gain)	(346,236)	112,483	*(458,719)*	
Provision for doubtful accounts	1,984	5,816	*(3,832)*	
Other operating	12,975	17,066	*(4,091)*	
Total operating	329,888	604,206	*(274,318)*	*(45)%*
Interest	73,173	88,704	*(15,531)*	
Income tax provision	241,621	14,476	*227,145*	
Total expenses	$ 644,682	$ 707,386	*$ (62,704)*	*(9)%*

ENCORE ACQUISITION COMPANY

	Year Ended December 31, 2008	Year Ended December 31, 2007	*Increase/(Decrease) $*	*Increase/(Decrease) %*
Expenses (per BOE):				
Production:				
Lease operations	$ 12.12	$ 10.59	*$ 1.53*	
Production, ad valorem, and severance taxes	7.66	5.51	*2.15*	
Total production expenses	19.78	16.10	*3.68*	*23%*
Other:				
Depletion, depreciation, and amortization	15.80	13.59	*2.21*	
Impairment of long-lived assets	4.12		*4.12*	
Exploration	2.71	2.05	*0.66*	
General and administrative	3.35	2.89	*0.46*	
Derivative fair value loss (gain)	(23.97)	8.31	*(32.28)*	
Provision for doubtful accounts	0.14	0.43	*(0.29)*	
Other operating	0.90	1.26	*(0.36)*	
Total operating	22.83	44.63	*(21.80)*	*(49)%*
Interest	5.07	6.55	*(1.48)*	
Income tax provision	16.73	1.07	*15.66*	
Total expenses	$ 44.63	$ 52.25	*$ (7.62)*	*(15)%*

Production expenses. Total production expenses increased 31 percent from $218.0 million in 2007 to $285.8 million in 2008 as a result of higher total production volumes and an increase in the per BOE rate.

Production expense attributable to LOE increased $31.7 million from $143.4 million in 2007 to $175.1 million in 2008 as a result of a $1.53 increase in the average per BOE rate, which contributed approximately $22.1 million of additional LOE, and an increase in production volumes, which contributed approximately $9.6 million of additional LOE. The increase in our average LOE per BOE rate was attributable to:

- increases in prices paid to oilfield service companies and suppliers;
- increases in natural gas prices resulting in higher electricity costs and gas plant fuel costs;
- higher compensation levels for engineers and other technical professionals; and
- an increase of (1) approximately $4.7 million ($0.32 per BOE) for retention bonuses paid in August 2008 and (2) approximately $4.1 million ($0.28 per BOE) for retention bonuses to be paid in August 2009, related to our strategic alternatives process.

Production expense attributable to production, ad valorem, and severance taxes (production taxes) increased $36.1 million from $74.6 million in 2007 to $110.6 million in 2008 primarily due to higher wellhead revenues. As a percentage of oil and natural gas wellhead revenues, production taxes remained approximately constant at 9.8 percent in 2008 as compared to 9.7 percent in 2007.

DD&A expense. DD&A expense increased $44.3 million from $184.0 million in 2007 to $228.3 million in 2008 as a result of a $2.21 increase in the per BOE rate, which contributed approximately $32.0 million of additional DD&A expense, and an increase in production volumes, which contributed approximately $12.3 million of additional DD&A expense. The increase in our average DD&A per BOE rate was attributable to higher costs incurred resulting from increases in rig rates, pipe costs, and acquisition costs and the decrease in our total proved reserves to 185.7 MMBOE as of December 31, 2008 as compared to 231.3 MMBOE as of December 31, 2007.

Table of Contents

ENCORE ACQUISITION COMPANY

Impairment of long-lived assets. During 2008, circumstances indicated that the carrying amounts of certain oil and natural gas properties, primarily four wells in the Tuscaloosa Marine Shale, may not be recoverable. We compared the assets carrying amounts to the undiscounted expected future net cash flows, which indicated a need for an impairment charge. We then compared the net carrying amounts of the impaired assets to their estimated fair value, which resulted in a write-down of the value of proved oil and natural gas properties of $59.5 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 $11.5 million from $27.7 million in 2007 to $39.2 million in 2008. During 2008, we expensed 8 exploratory dry holes totaling $14.7 million. During 2007, we expensed 5 exploratory dry holes totaling $14.7 million. Impairment of unproved acreage increased $9.4 million from $10.8 million in 2007 to $20.2 million in 2008, 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 illustrates the components of exploration expenses for the periods indicated:

	Year Ended December 31, 2008	**Year Ended December 31, 2007**	***Increase***
	(In thousands)		
Dry holes	$ 14,683	$ 14,673	*$ 10*
Geological and seismic	2,851	1,455	*1,396*
Delay rentals	1,482	784	*698*
Impairment of unproved acreage	20,191	10,814	*9,377*
Total	$ 39,207	$ 27,726	*$ 11,481*

G&A expense. G&A expense increased $9.3 million from $39.1 million in 2007 to $48.4 million in 2008, primarily due to:

- a full year of ENP public entity expenses;
- higher activity levels;
- increased personnel costs due to intense competition for human resources within the industry; and
- an increase of (1) approximately $2.9 million for retention bonuses paid in August 2008 and (2) approximately $2.8 million for retention bonuses to be paid in August 2009, related to our strategic alternatives process;
- partially offset by a $3.1 million decrease in non-cash equity-based compensation.

Derivative fair value loss (gain). During 2008, we recorded a $346.2 million derivative fair value gain as compared to a $112.5 million derivative fair value loss in 2007, the components of which were as follows:

	Year Ended December 31, 2008	Year Ended December 31, 2007	*Increase/ (Decrease)*
	(In thousands)		
Ineffectiveness on designated derivative contracts	$ 372	$	*$ 372*
Mark-to-market loss (gain) on derivative contracts	(365,495)	36,272	*(401,767)*
Premium amortization	62,352	41,051	*21,301*
Settlements on commodity derivative contracts	(43,465)	35,160	*(78,625)*
Total derivative fair value loss (gain)	$ (346,236)	$ 112,483	*$ (458,719)*

The change in our derivative fair value loss (gain) was a result of the addition of commodity derivative contracts in the first part of 2008 when prices were high and the significant decrease in prices during the end of 2008, which favorably impacted the fair values of those contracts.

ENCORE ACQUISITION COMPANY

During 2009, 2010, and 2011, we expect to make payments for deferred premiums of commodity derivative contracts of $67.0 million, $15.7 million, and $0.9 million, respectively.

Provision for doubtful accounts. In 2008 and 2007, we recorded a provision for doubtful accounts of $2.0 million and $5.8 million, respectively, for the payout allowance related to the ExxonMobil joint development agreement.

Other operating expense. Other operating expense decreased $4.1 million from $17.1 million in 2007 to $13.0 million in 2008, primarily due to a $7.4 million loss on the sale of certain Mid-Continent properties in 2007, partially offset by a $3.4 million increase during 2008 in third-party transportation costs to move our production to markets outside the immediate area of production.

Interest expense. Interest expense decreased $15.5 million from $88.7 million in 2007 to $73.2 million in 2008, primarily due to (1) the use of net proceeds from our Mid-Continent asset disposition and ENP s IPO to reduce weighted average outstanding borrowings on our revolving credit facilities, (2) a reduction in LIBOR, and (3) our use of interest rate swaps to fix the rate on a portion of outstanding borrowings on ENP s revolving credit facility. The weighted average interest rate for all long-term debt for 2008 was 5.6 percent as compared to 6.9 percent for 2007.

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

	Year Ended December 31, 2008	Year Ended December 31, 2007	*Increase/ (Decrease)*
	(In thousands)		
6.25% Notes	$ 9,727	$ 9,705	*$ 22*
6.0% Notes	18,550	18,517	*33*
7.25% Notes	10,996	10,988	*8*
Revolving credit facilities	31,038	46,085	*(15,047)*
Other	2,862	3,409	*(547)*
Total	$ 73,173	$ 88,704	*$ (15,531)*

Minority interest. As of December 31, 2008, public unitholders owned approximately 37 percent of ENP s common units. We consolidate ENP s results of operations in our consolidated financial statements and show the public ownership as minority interest. Minority interest in income of ENP was approximately $54.3 million for 2008 as compared to a loss of $7.5 million for 2007.

Income taxes. In 2008, we recorded an income tax provision of $241.6 million as compared to $14.5 million in 2007. In 2008, we had income before income taxes, net of minority interest, of $672.4 million as compared to $31.6 million in 2007. Our effective tax rate decreased to 35.9 percent in 2008 as compared to 45.8 percent in 2007 primarily due to the 2007 recognition of non-deductible deferred compensation.

ENCORE ACQUISITION COMPANY

Comparison of 2007 to 2006

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

	Year Ended December 31,		*Increase/ (Decrease)*	
	2007	2006	*$*	*%*
Revenues (in thousands):				
Oil wellhead	$ 606,112	$ 399,180	*$ 206,932*	
Oil commodity derivative contracts	(43,295)	(52,206)	*8,911*	
Total oil revenues	$ 562,817	$ 346,974	*$ 215,843*	*62%*
Natural gas wellhead	$ 160,399	$ 154,458	*$ 5,941*	
Natural gas commodity derivative contracts	(10,292)	(8,133)	*(2,159)*	
Total natural gas revenues	$ 150,107	$ 146,325	*$ 3,782*	*3%*
Combined wellhead	$ 766,511	$ 553,638	*$ 212,873*	
Combined commodity derivative contracts	(53,587)	(60,339)	*6,752*	
Total combined oil and natural gas revenues	$ 712,924	$ 493,299	*$ 219,625*	*45%*
Average realized prices:				
Oil wellhead ($/Bbl)	$ 63.50	$ 54.42	*$ 9.08*	
Oil commodity derivative contracts ($/Bbl)	(4.54)	(7.12)	*2.58*	
Total oil revenues ($/Bbl)	$ 58.96	$ 47.30	*$ 11.66*	*25%*
Natural gas wellhead ($/Mcf)	$ 6.69	$ 6.59	*$ 0.10*	
Natural gas commodity derivative contracts ($/Mcf)	(0.43)	(0.35)	*(0.08)*	
Total natural gas revenues ($/Mcf)	$ 6.26	$ 6.24	*$ 0.02*	*0%*
Combined wellhead ($/BOE)	$ 56.62	$ 49.24	*$ 7.38*	
Combined commodity derivative contracts ($/BOE)	(3.96)	(5.37)	*1.41*	
Total combined oil and natural gas revenues ($/BOE)	$ 52.66	$ 43.87	*$ 8.79*	*20%*
Total production volumes:				
Oil (MBbls)	9,545	7,335	*2,210*	*30%*
Natural gas (MMcf)	23,963	23,456	*507*	*2%*
Combined (MBOE)	13,539	11,244	*2,295*	*20%*

Average daily production volumes:							
Oil (Bbl/D)		26,152		20,096		*6,056*	*30%*
Natural gas (Mcf/D)		65,651		64,262		*1,389*	*2%*
Combined (BOE/D)		37,094		30,807		*6,287*	*20%*
Average NYMEX prices:							
Oil (per Bbl)	$	72.45	$	66.26	*$*	*6.19*	*9%*
Natural gas (per Mcf)	$	6.86	$	7.17	*$*	*(0.31)*	*(4)%*

Oil revenues increased $215.8 million from $347.0 million in 2006 to $562.8 million in 2007, primarily due to an increase in oil production volumes and an increase in our average realized oil price. Our production volumes increased 2,210 MBbls from 2007 to 2008, which contributed approximately $120.3 million in

ENCORE ACQUISITION COMPANY

additional oil revenues. The increase in production volumes was the result of our Big Horn Basin acquisition in March 2007, our Williston Basin acquisition in April 2007, and our development program.

Our average realized oil price increased $11.66 per Bbl primarily as a result of an increase in our average realized wellhead price, which increased oil revenues by $86.7 million, or $9.08 per Bbl. Our average realized oil wellhead price increased primarily as a result of the increase in the average NYMEX price from $66.26 per Bbl in 2006 to $72.45 per Bbl in 2007. In addition, as a result of our discontinuance of hedge accounting in July 2006, oil revenues for 2007 included amortization of net losses of certain commodity derivative contracts that were previously designated as hedges of approximately $43.3 million, or $4.54 per Bbl, while 2006 included approximately $52.2 million, or $7.12 per Bbl, of net losses.

Our oil wellhead revenue was reduced by $31.9 million and $22.8 million in 2007 and 2006, respectively, for net profits interests related to our CCA properties.

Natural gas revenues increased $3.8 million from $146.3 million in 2006 to $150.1 million in 2007, primarily due to an increase in production volumes of 507 MMcf, which contributed approximately $3.3 million in additional natural gas revenues. The increase in natural gas production volumes was the result of our West Texas joint development agreement with ExxonMobil and our development program in the Mid-Continent area, partially offset by natural gas production sold in conjunction with our Mid-Continent asset disposition in 2007.

Our average realized natural gas price increased $0.02 per Mcf primarily as a result of an increase in our wellhead price, which increased natural gas revenues by $2.6 million, or $0.10 per Mcf. Our average natural gas wellhead price increased as a result of the tightening of our natural gas differential despite decreases in the overall market price for natural gas, as reflected in the decrease in the average NYMEX price from $7.17 per Mcf in 2006 to $6.86 per Mcf in 2007. In addition, as a result of our discontinuance of hedge accounting in July 2006, natural gas revenues for 2007 included amortization of net losses of certain commodity derivative contracts that were previously designated as hedges of approximately $10.3 million, or $0.43 per Mcf, while 2006 included approximately $8.1 million, or $0.35 per Mcf, of net losses.

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

	Year Ended December 31,	
	2007	**2006**
Oil wellhead ($/Bbl)	$ 63.50	$ 54.42
Average NYMEX ($/Bbl)	$ 72.45	$ 66.26
Differential to NYMEX	$ (8.95)	$ (11.84)
Oil wellhead to NYMEX percentage	88%	82%
Natural gas wellhead ($/Mcf)	$ 6.69	$ 6.59
Average NYMEX ($/Mcf)	$ 6.86	$ 7.17
Differential to NYMEX	$ (0.17)	$ (0.58)
Natural gas wellhead to NYMEX percentage	98%	92%

Our oil wellhead price as a percentage of the average NYMEX price tightened to 88 percent in 2007 as compared to 82 percent in 2006. Our natural gas wellhead price as a percentage of the average NYMEX price improved to 98 percent in 2007 as compared to 92 percent in 2006. The differential improved because of efforts to reduce natural gas transportation and gathering costs.

Marketing revenues and expenses. In 2006, we purchased third-party oil Bbls from counterparties other than to whom the Bbls were sold for aggregation and sale with our own production in various markets. These purchases assisted us in marketing our production by decreasing our dependence on individual markets. These

ENCORE ACQUISITION COMPANY

activities allowed us to aggregate larger volumes, facilitated our efforts to maximize the prices we received for production, provided for a greater allocation of future pipeline capacity in the event of curtailments, and enabled us to reach other markets.

In 2007, we discontinued purchasing oil from third party companies as market conditions changed and historical pipeline space was realized. Implementing this change allowed us to focus on the marketing of our own production, leveraging newly gained pipeline space, and delivering oil to various newly developed markets in an effort to maximize the value of the oil at the wellhead. In March 2007, ENP acquired a natural gas pipeline from Anadarko as part of the Big Horn Basin asset acquisition. Natural gas volumes are purchased from numerous gas producers at the inlet to the pipeline and resold downstream to various local and off-system markets.

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

	Year Ended December 31,		***Increase/(Decrease)***	
	2007	**2006**	***$***	***%***
	(In thousands, except per BOE amounts)			
Marketing revenues	$ 42,021	$ 147,563	*$ (105,542)*	*(72)%*
Marketing expenses	40,549	148,571	*(108,022)*	*(73)%*
Marketing gain (loss)	$ 1,472	$ (1,008)	*$ 2,480*	*(246)%*
Marketing revenues per BOE	$ 3.10	$ 13.12	*$ (10.02)*	*(76)%*
Marketing expenses per BOE	2.99	13.21	*(10.22)*	*(77)%*
Marketing gain (loss), per BOE	$ 0.11	$ (0.09)	*$ 0.20*	*(222)%*

ENCORE ACQUISITION COMPANY

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

	Year Ended December 31,		*Increase/ (Decrease)*	
	2007	**2006**	***$***	***%***
Expenses (in thousands):				
Production:				
Lease operations	$ 143,426	$ 98,194	*$ 45,232*	
Production, ad valorem, and severance taxes	74,585	49,780	*24,805*	
Total production expenses	218,011	147,974	*70,037*	*47%*
Other:				
Depletion, depreciation, and amortization	183,980	113,463	*70,517*	
Exploration	27,726	30,519	*(2,793)*	
General and administrative	39,124	23,194	*15,930*	
Derivative fair value loss (gain)	112,483	(24,388)	*136,871*	
Provision for doubtful accounts	5,816	1,970	*3,846*	
Other operating	17,066	8,053	*9,013*	
Total operating	604,206	300,785	*303,421*	*101%*
Interest	88,704	45,131	*43,573*	
Income tax provision	14,476	55,406	*(40,930)*	
Total expenses	$ 707,386	$ 401,322	*$ 306,064*	*76%*
Expenses (per BOE):				
Production:				
Lease operations	$ 10.59	$ 8.73	*$ 1.86*	
Production, ad valorem, and severance taxes	5.51	4.43	*1.08*	
Total production expenses	16.10	13.16	*2.94*	*22%*
Other:				
Depletion, depreciation, and amortization	13.59	10.09	*3.50*	
Exploration	2.05	2.71	*(0.66)*	
General and administrative	2.89	2.06	*0.83*	
Derivative fair value loss (gain)	8.31	(2.17)	*10.48*	
Provision for doubtful accounts	0.43	0.18	*0.25*	
Other operating	1.26	0.71	*0.55*	
Total operating	44.63	26.74	*17.89*	*67%*
Interest	6.55	4.01	*2.54*	
Income tax provision	1.07	4.93	*(3.86)*	

Total expenses	$	52.25	$	35.68	*$*	*16.57*		*46%*

Production expenses. Total production expenses increased $70.0 million from $148.0 million in 2006 to $218.0 million in 2007 due to higher total production volumes and a $2.94 increase in production expenses per BOE. Our production margin increased by $142.8 million (35 percent) to $548.5 million in 2007 as compared to $405.7 million in 2006. Total production expenses per BOE increased by 22 percent while total oil and natural gas wellhead revenues per BOE increased by 15 percent. On a per BOE basis, our production margin increased 12 percent to $40.52 per BOE for 2007 as compared to $36.08 per BOE for 2006.

ENCORE ACQUISITION COMPANY

Production expense attributable to LOE increased $45.2 million from $98.2 million in 2006 to $143.4 million in 2007, primarily as a result of a $1.86 increase in the average per BOE rate, which contributed approximately $25.2 million of additional LOE, and higher production volumes, which contributed approximately $20.0 million of additional LOE. The increase in our average LOE per BOE rate was attributable to:

- increases in prices paid to oilfield service companies and suppliers;
- increased operational activity to maximize production;
- HPAI expenses at the CCA; and
- higher salary levels for engineers and other technical professionals.

Production expense attributable to production taxes increased $24.8 million from $49.8 million in 2006 to $74.6 million in 2007. The increase was primarily due to higher wellhead revenues. As a percentage of oil and natural gas revenues (excluding the effects of commodity derivative contracts), production taxes increased to 9.7 percent in 2007 as compared to 9.0 percent in 2006 as a result of higher rates in the states where the properties associated with our Big Horn Basin and Williston Basin asset acquisitions are located.

DD&A expense. DD&A expense increased $70.5 million from $113.5 million in 2006 to $184.0 million in 2007 due to a $3.50 increase in the per BOE rate and higher production volumes. The per BOE rate increased due to the higher cost basis of the properties associated with our Big Horn Basin and Williston Basin asset acquisitions, development of proved undeveloped reserves, and higher costs incurred resulting from increases in rig rates, oilfield services costs, and acquisition costs. These factors resulted in additional DD&A expense of approximately $47.3 million, while the increase in production volumes resulted in additional DD&A expense of approximately $23.2 million.

Exploration expense. Exploration expense decreased $2.8 million from $30.5 million in 2006 to $27.7 million in 2007. During 2007, we expensed 5 exploratory dry holes totaling $14.7 million. During 2006, we expensed 14 exploratory dry holes totaling $17.3 million. The following table details our exploration expenses for the periods indicated:

	Year Ended December 31, 2007	Year Ended December 31, 2006	*Increase/ (Decrease)*
	(In thousands)		
Dry holes	$ 14,673	$ 17,257	*$ (2,584)*
Geological and seismic	1,455	1,720	*(265)*
Delay rentals	784	670	*114*
Impairment of unproved acreage	10,814	10,872	*(58)*
Total	$ 27,726	$ 30,519	*$ (2,793)*

G&A expense. G&A expense increased $15.9 million from $23.2 million in 2006 to $39.1 million in 2007, primarily due to:

- a $6.4 million increase in non-cash equity-based compensation expense;
- increased staffing to manage our larger asset base;
- higher activity levels; and
- increased personnel costs due to intense competition for human resources within the industry.

Table of Contents

ENCORE ACQUISITION COMPANY

Derivative fair value loss (gain). During 2007, we recorded a $112.5 million derivative fair value loss as compared to a $24.4 million derivative fair value gain in 2006, the components of which were as follows:

	Year Ended December 31, 2007	Year Ended December 31, 2006	*Increase/ (Decrease)*
	(In thousands)		
Ineffectiveness on designated cash flow hedges	$	$ 1,748	*$ (1,748)*
Mark-to-market loss (gain) on commodity derivative contracts	36,272	(31,205)	*67,477*
Premium amortization	41,051	13,926	*27,125*
Settlements on commodity derivative contracts	35,160	(8,857)	*44,017*
Total derivative fair value loss (gain)	$ 112,483	$ (24,388)	*$ 136,871*

Provision for doubtful accounts. Provision for doubtful accounts increased $3.8 million from $2.0 million in 2006 to $5.8 million in 2007, primarily due to an increase in the payout allowance related to the ExxonMobil joint development agreement.

Other operating expense. Other operating expense increased $9.0 million from $8.1 million in 2006 to $17.1 million in 2007, primarily due to a $7.4 million loss on the sale of certain Mid-Continent properties and increases in third-party transportation costs attributable to moving our CCA production into markets outside the immediate area of production.

Interest expense. Interest expense increased $43.6 million from $45.1 million in 2006 to $88.7 million in 2007, primarily due to additional debt used to finance the Big Horn Basin and Williston Basin asset acquisitions. The weighted average interest rate for all long-term debt for 2007 was 6.9 percent as compared to 6.1 percent for 2006.

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

	Year Ended December 31, 2007	Year Ended December 31, 2006	*Increase/ (Decrease)*
	(In thousands)		
6.25% Notes	$ 9,705	$ 9,684	*$ 21*
6.0% Notes	18,517	18,418	*99*
7.25% Notes	10,988	10,984	*4*
Revolving credit facilities	46,085	3,609	*42,476*
Other	3,409	2,436	*973*
Total	$ 88,704	$ 45,131	*$ 43,573*

Minority interest. As of December 31, 2007, public unitholders in ENP had a limited partner interest of approximately 40 percent. We consolidate ENP in our consolidated financial statements and show the ownership by the public as a minority interest. The minority interest loss in ENP was $7.5 million for 2007.

Income taxes. During 2007, we recorded an income tax provision of $14.5 million as compared to $55.4 million in 2006. Our effective tax rate increased to 45.8 percent in 2007 as compared to 37.5 percent in 2006 primarily due to a permanent rate adjustment for ENP s management incentive units, a state rate adjustment due to larger apportionment of future taxable income to states with higher tax rates, and permanent timing adjustments that will not reverse in future periods.

Capital Commitments, Capital Resources, and Liquidity

Capital commitments. Our primary needs for cash are:

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

Table of Contents

ENCORE ACQUISITION COMPANY

Acquisitions of oil and natural gas properties;

Funding of necessary working capital; and

Contractual obligations.

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

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Development and exploitation	$ 362,111	$ 270,016	$ 253,484
Exploration	256,437	97,453	95,205
Total	$ 618,548	$ 367,469	$ 348,689

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 2008 yielded 186 gross (73.4 net) successful wells and 5 gross (3.1 net) dry holes. Our exploration expenditures primarily relate to drilling exploratory wells, seismic costs, delay rentals, and geological and geophysical costs. Our exploration capital for 2008 yielded 96 gross (31.4 net) successful wells and 8 gross (3.8 net) dry holes. Please read Items 1 and 2. Business and Properties Development Results for a description of the areas in which we drilled wells during 2008.

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:

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Acquisitions of proved property	$ 28,729	$ 787,988	$ 4,486
Acquisitions of leasehold acreage	128,635	52,306	24,462
Total	$ 157,364	$ 840,294	$ 28,948

In March 2007, Encore Operating and OLLC acquired oil and natural gas properties in the Big Horn Basin, including properties in the Elk Basin and the Gooseberry fields for approximately $393.6 million. In April 2007, we acquired oil and natural gas properties in the Williston Basin for approximately $392.1 million.

During 2008, our capital expenditures for leasehold acreage costs totaled $128.6 million, $45.2 million of which related to the exercise of preferential rights in the Haynesville area and the remainder of which related to the acquisition of unproved acreage in various areas. During 2007, our capital expenditures for leasehold acreage costs totaled $52.3 million, $16.1 million of which related to the Williston Basin asset acquisition and the remainder of which related to the acquisition of unproved acreage in various areas. During 2006, our capital expenditures for leasehold acreage costs totaled $24.5 million, all of which related to the acquisition of unproved acreage in various areas.

Funding of necessary working capital. As of December 31, 2008 and 2007, our working capital (defined as total current assets less total current liabilities) was $188.7 million and negative $16.2 million, respectively. The increase in 2008 as compared to 2007 was primarily attributable to a decrease in commodity prices at December 31, 2008 as compared to December 31, 2007, which positively impacted the fair value of our outstanding commodity derivative contracts.

Table of Contents

ENCORE ACQUISITION COMPANY

For 2009, we expect working capital to remain positive, primarily due to the fair value of our outstanding derivative contracts. 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 constant or increasing production volumes, our operating cash flow should remain positive in 2009.

The Board approved a capital budget of $310 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 borrowings under our revolving credit facility.

Off-balance sheet arrangements. We have no investments in unconsolidated entities or persons that could materially affect our liquidity or the availability of capital resources. We have no off-balance sheet arrangements that are material to our financial position or results of operations.

Contractual obligations. The following table illustrates our contractual obligations and commitments at December 31, 2008:

Contractual Obligations and Commitments	Maturity Date	Total	2009	2010 - 2011	2012 - 2013	Thereafter
			Payments Due by Period (In thousands)			
6.25% Notes(a)	4/15/2014	$ 201,563	$ 9,375	$ 18,750	$ 18,750	$ 154,688
6.0% Notes(a)	7/15/2015	426,000	18,000	36,000	36,000	336,000
7.25% Notes(a)	12/1/2017	247,875	10,875	21,750	21,750	193,500
Revolving credit facilities(a)	3/7/2012	789,626	19,885	39,770	729,971	
Commodity derivative contracts(b)						
Interest rate swaps		4,342	1,269	3,071	2	
Capital lease obligations		1,747	466	932	349	
Development commitments(c)		134,860	134,860			
Operating leases and commitments(d)		17,493	3,952	7,577	5,964	
Asset retirement obligations(e)		178,889	1,511	3,022	3,022	171,334
Total		$ 2,002,395	$ 200,193	$ 130,872	$ 815,808	$ 855,522

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

(b) At December 31, 2008, our commodity derivative contracts were in a net asset position. With the exception of $67.6 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 7A. Quantitative and Qualitative Disclosures about Market Risk and Notes 13 and 14 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our commodity derivative contracts.

ENCORE ACQUISITION COMPANY

(c) Development commitments include: authorized purchases for work in process of $116.7 million and future minimum payments for drilling rig operations of $18.1 million. Also at December 31, 2008, we had $178.2 million of authorized purchases not placed to vendors (authorized AFEs), which were not accrued and are excluded from the above table but are budgeted for and are expected to be made unless circumstances change.

(d) Operating leases and commitments include office space and equipment obligations that have non-cancelable lease terms in excess of one year of $16.8 million and future minimum payments for other operating commitments of $0.7 million. Please read Note 4 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our operating leases.

(e) Asset retirement obligations represent the undiscounted future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal at the end of field life. Please read Note 5 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data 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 have been subject to apportionment since December 2005, we were allocated sufficient pipeline capacity to move our crude oil production effective January 1, 2007. Enbridge completed an expansion, 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 crude oil and natural gas differentials. Increases in the percentage differential between the NYMEX price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial position, and cash flows. The following table illustrates the relationship between oil and natural gas wellhead

ENCORE ACQUISITION COMPANY

prices as a percentage of average NYMEX prices by quarter for 2008, as well as our expected differentials for the first quarter of 2009:

	Actual				Forecast
	First Quarter of 2008	Second Quarter of 2008	Third Quarter of 2008	Fourth Quarter of 2008	First Quarter of 2009
Oil wellhead to NYMEX percentage	91%	94%	91%	80%	78%
Natural gas wellhead to NYMEX percentage	103%	102%	93%	86%	103%

Capital resources

Cash flows from operating activities. Cash provided by operating activities increased $343.5 million from $319.7 million in 2007 to $663.2 million in 2008, primarily due to an increase in our production margin, partially offset by increased settlements on our commodity derivative contracts as a result of higher commodity prices in the first half of 2008.

Cash provided by operating activities increased $22.4 million from $297.3 million in 2006 to $319.7 million in 2007, primarily due to an increase in our production margin, partially offset by increased settlements on our commodity derivative contracts as a result of increases in oil prices and an increase in accounts receivable as a result of increased oil and natural gas production.

Cash flows from investing activities. Cash used in investing activities decreased $201.3 million from $929.6 million in 2007 to $728.3 million in 2008, primarily due to a $706.0 million decrease in amounts paid for acquisitions of oil and natural gas properties and a $283.7 million decrease in proceeds received for the disposition of assets, partially offset by a $225.1 million increase in development of oil and natural gas properties. In 2007, we paid approximately $393.6 million in conjunction with the Big Horn Basin asset acquisition and approximately $392.1 million in conjunction with the Williston Basin asset acquisition. In 2007, we also completed the sale of certain oil and natural gas properties in the Mid-Continent for net proceeds of approximately $294.8 million. During 2008, we advanced $24.8 million (net of collections) to ExxonMobil for their portion of costs incurred drilling wells under the joint development agreement as compared to advancements of $29.5 million (net of collections) in 2007.

Cash used in investing activities increased $532.2 million from $397.4 million in 2006 to $929.6 million in 2007, primarily due to a $818.4 million increase in amounts paid for acquisitions of oil and natural gas properties, primarily our Big Horn Basin and Williston Basin asset acquisitions, partially offset by a $286.4 million increase in proceeds received for the disposition of assets, primarily our Mid-Continent asset disposition. During 2007, we advanced $29.5 million (net of collections) to ExxonMobil for their portion of costs incurred drilling the commitment wells under the joint development agreement as compared to advancements of $22.4 million (net of collections) in 2006.

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

During 2008, we received net cash of $65.4 million from financing activities, including net borrowings on our revolving credit facilities of $199 million, which resulted in an increase in outstanding borrowings under our revolving credit facilities from $526 million at December 31, 2007 to $725 million at December 31, 2008.

In December 2007, we announced that the Board approved a share repurchase program authorizing us to repurchase up to $50 million of our common stock. During 2008, we completed the share repurchase program by repurchasing and retiring 1,397,721 shares of our outstanding common stock at an average price of approximately $35.77 per share.

ENCORE ACQUISITION COMPANY

In October 2008, we announced that the Board authorized a new share repurchase program of 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 December 31, 2008, 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 new share repurchase program.

During 2007, we received net cash of $610.8 million from financing activities, including net borrowings on our revolving credit facilities of $444.8 million and net proceeds of $193.5 million from ENP s issuance of common units. Net borrowings on our revolving credit facilities were primarily due to borrowings used to finance our Big Horn Basin and Williston Basin asset acquisitions, which were partially offset by repayments from the net proceeds received from the Mid-Continent asset disposition and ENP s issuance of common units.

During 2006, we received net cash of $99.2 million from financing activities. In April 2006, we received net proceeds of $127.1 million from a public offering of 4,000,000 shares of our common stock, which were used to (1) reduce outstanding borrowings under our revolving credit facility, (2) invest in oil and natural gas activities, and (3) pay general corporate expenses.

Liquidity. Our primary sources of liquidity are internally generated cash flows and the borrowing capacity under our revolving credit facility. We also have the ability to adjust our capital expenditures. We may use other sources of capital, including the issuance of additional debt or equity securities, to fund acquisitions or maintain our financial flexibility. 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 continue to decline or the capital markets remain tight, the borrowing capacity under our revolving credit facilities could be adversely affected. We are currently in a process of redetermining the borrowing base under our revolving credit facilities. We expect that the banks will reaffirm our current borrowing base but we recognize that this process could result in a reduction. 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 given our relatively low levels of borrowings under those facilities in relation to the existing borrowing base.

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 2008, our average realized oil and natural gas prices increased by 51 percent and 38 percent, respectively, as compared to 2007. Realized oil and natural gas prices fluctuate widely in response to changing market forces. In 2008, approximately 70 percent of our production was oil. As previously discussed, our oil wellhead differentials during 2008 improved as compared to 2007, favorably impacting the prices we received for our oil production. To the extent oil and natural gas prices continue to decline from levels in mid-February 2009 or we experience a significant widening of our differentials, earnings, cash flows from operations, and availability under our revolving credit facility may be adversely impacted. Prolonged periods of low oil and natural gas prices or sustained wider differentials could cause us to not be in compliance with financial covenants under our revolving credit facility and thereby affect our liquidity. However, we have protected a significant portion of our forecasted production for 2009 against declining commodity prices. Please read Item 7A. Quantitative and Qualitative Disclosures about Market Risk and Notes 13 and 14 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our commodity derivative contracts.

Revolving credit facilities. Our principal source of short-term liquidity is our revolving credit facility. The syndicate of lenders underwriting our facility includes 30 banking and other financial institutions, and the syndicate of lenders underwriting ENP s facility includes 13 banking and other financial institutions, both after taking into consideration recent mergers and acquisitions within the financial services industry. None of the lenders are underwriting more than eight percent of the respective total commitments. We believe the large

Table of Contents

ENCORE ACQUISITION COMPANY

number of lenders, the relatively small percentage participation of each, and the relatively high level of availability under each facility provides adequate diversity and flexibility should further consolidation occur within the financial services industry.

Certain of the lenders underwriting our facility are also counterparties to our commodity derivative contracts. At December 31, 2008, we had committed greater than 10 percent of either our outstanding oil or natural gas commodity derivative contracts to the following counterparties:

Counterparty	Percentage of Oil Derivative Contracts Committed	Percentage of Natural Gas Derivative Contracts Committed
BNP Paribas	22%	24%
Calyon	15%	31%
Fortis	11%	
UBS	16%	
Wachovia	11%	38%

Encore Acquisition Company Senior Secured Credit Agreement

In March 2007, we entered into a five-year amended and restated credit agreement (as amended, the EAC Credit Agreement) with a bank syndicate including Bank of America, N.A. and other lenders. The EAC Credit Agreement matures on March 7, 2012. Effective February 7, 2008, we amended the EAC Credit Agreement to, among other things, provide that certain negative covenants in the EAC Credit Agreement restricting hedge transactions do not apply to any oil and natural gas hedge transaction that is a floor or put transaction not requiring any future payments or delivery by us or any of our restricted subsidiaries. Effective May 22, 2008, we amended the EAC Credit Agreement to, among other things, increase the interest rate margins applicable to loans made under the EAC Credit Agreement, as set forth in the table below, and increase the borrowing base to $1.1 billion. The EAC Credit Agreement provides for revolving credit loans to be made to us from time to time and letters of credit to be issued from time to time for our account or the account of 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 on April 1 and October 1 and upon requested special redeterminations. On December 5, 2008, the borrowing base under the EAC Credit Agreement was redetermined with no change. As of December 31, 2008, the borrowing base was $1.1 billion. We are currently in a process of redetermining the borrowing base under the EAC Credit Agreement which could result in a reduction to the borrowing base.

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

Loans under the EAC Credit Agreement are subject to varying rates of interest based on (1) the total 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

ENCORE ACQUISITION COMPANY

following table, and base rate loans bear interest at the base rate plus the applicable margin indicated in the following table:

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

The Eurodollar rate for any interest period (either one, two, three, or six months, as selected by us) is the rate per year equal to LIBOR, as published by Reuters or another source designated by Bank of America, N.A., for deposits in dollars for a similar interest period. The base rate is calculated as the higher of (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate and (2) the federal funds effective rate plus 0.5 percent.

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

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

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

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

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

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

ENCORE ACQUISITION COMPANY

On December 31, 2008, there were $575 million of outstanding borrowings and $525 million of borrowing capacity under the EAC Credit Agreement. On February 18, 2009, there were $543 million of outstanding borrowings and $557 million of borrowing capacity under the EAC Credit Agreement.

Encore Energy Partners Operating LLC Credit Agreement

OLLC is a party to a five-year credit agreement dated March 7, 2007 (as amended, the OLLC Credit Agreement) with a bank syndicate including Bank of America, N.A. and other lenders. The OLLC Credit Agreement matures on March 7, 2012. On August 22, 2007, OLLC amended its credit agreement to revise certain financial covenants. The OLLC Credit Agreement provides for revolving credit loans to be made to OLLC from time to time and letters of credit to be issued from time to time for the account of OLLC or any of its restricted subsidiaries.

The aggregate amount of the commitments of the lenders under the OLLC Credit Agreement is $300 million. Availability under the OLLC Credit Agreement is subject to a borrowing base, which is redetermined semi-annually on April 1 and October 1 and upon requested special redeterminations. On December 5, 2008, the borrowing base under the OLLC Credit Agreement was redetermined with no change. As of December 31, 2008, the borrowing base was $240 million. We are currently in a process of redetermining the borrowing base under the OLLC Credit Agreement which could result in a reduction to the borrowing base.

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

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

The Eurodollar rate for any interest period (either one, two, three, or six months, as selected by us) is the rate per year equal to LIBOR, as published by Reuters or another source designated by Bank of America, N.A., for deposits in dollars for a similar interest period. The base rate is calculated as the higher of (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate and (2) the federal funds effective rate plus 0.5 percent.

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

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

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

ENCORE ACQUISITION COMPANY

- a restriction on creating liens on the assets of ENP, OLLC and its restricted subsidiaries, subject to permitted exceptions;
- restrictions on merging and selling assets outside the ordinary course of business;
- restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business;
- a provision limiting oil and natural gas hedging transactions (other than puts) to a volume not exceeding 75 percent of anticipated production from proved producing reserves;
- a requirement that ENP and OLLC maintain a ratio of consolidated current assets (as defined in the OLLC Credit Agreement) to consolidated current liabilities (as defined in the OLLC Credit Agreement) of not less than 1.0 to 1.0;
- a requirement that ENP and OLLC maintain a ratio of consolidated EBITDA (as defined in the OLLC Credit Agreement) to the sum of consolidated net interest expense plus letter of credit fees of not less than 1.5 to 1.0;
- a requirement that ENP and OLLC maintain a ratio of consolidated EBITDA (as defined in the OLLC Credit Agreement) to consolidated senior interest expense of not less than 2.5 to 1.0; and
- a requirement that ENP and OLLC maintain a ratio of consolidated funded debt (excluding certain related party debt) to consolidated adjusted EBITDA (as defined in the OLLC Credit Agreement) of not more than 3.5 to 1.0.

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

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

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

On December 31, 2008, there were $150 million of outstanding borrowings and $90 million of borrowing capacity under the OLLC Credit Agreement. On February 18, 2009, there were $201 million of outstanding borrowings and $39 million of borrowing capacity under the OLLC Credit Agreement.

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

Indentures governing our senior subordinated notes. We and our restricted subsidiaries are subject to certain negative and financial covenants under the indentures governing the 6.25% Notes, the 6.0% Notes, and the 7.25% Notes (collectively, the Notes). The provisions of the indentures limit our and our restricted subsidiaries ability to, among other things:

- incur additional indebtedness;
- pay dividends on our capital stock or redeem, repurchase, or retire our capital stock or subordinated indebtedness;
- make investments;

ENCORE ACQUISITION COMPANY

incur liens;

create any consensual limitation on the ability of our restricted subsidiaries to pay dividends, make loans, or transfer property to us;

engage in transactions with our affiliates;

sell assets, including capital stock of our subsidiaries;

consolidate, merge, or transfer assets;

a requirement that we maintain a current ratio (as defined in the indentures) of not less than 1.0 to 1.0; and

a requirement that we maintain a ratio of consolidated EBITDA (as defined in the indentures) to consolidated interest expense of not less than 2.5 to 1.0.

If we experience a change of control (as defined in the indentures), subject to certain conditions, we must give holders of the Notes the opportunity to sell to us their Notes at 101 percent of the principal amount, plus accrued and unpaid interest.

Debt covenants. At December 31, 2008, we and ENP were in compliance with all debt covenants.

Capitalization. At December 31, 2008, we had total assets of $3.6 billion and total capitalization of $2.6 billion, of which 50 percent was represented by stockholders equity and 50 percent by long-term debt. At December 31, 2007, we had total assets of $2.8 billion and total capitalization of $2.1 billion, of which 46 percent was represented by stockholders equity and 54 percent by long-term debt. The percentages of our capitalization represented by stockholders equity and long-term debt could vary in the future if debt or equity is used to finance capital projects or acquisitions.

Changes in Prices

Our oil and natural gas revenues, the value of our assets, and our ability to obtain bank loans or additional capital on attractive terms are affected by changes in oil and natural gas prices, which fluctuate significantly. The following table illustrates our average oil and natural gas prices for the periods presented. Our average realized prices for 2008, 2007, and 2006 were decreased by $0.20, $3.96, and $5.37 per BOE, respectively, as a result of commodity derivative contracts, which were previously designated as hedges.

	Year Ended December 31,		
	2008	**2007**	**2006**
Average realized prices:			
Oil ($/Bbl)	$ 89.30	$ 58.96	$ 47.30
Natural gas ($/Mcf)	8.63	6.26	6.24
Combined ($/BOE)	77.87	52.66	43.87

Average wellhead prices:			
Oil ($/Bbl)	$ 89.58	$ 63.50	$ 54.42
Natural gas ($/Mcf)	8.63	6.69	6.59
Combined ($/BOE)	78.07	56.62	49.24

Increases in oil and natural gas prices may be accompanied by or result in: (1) increased development costs, as the demand for drilling operations increases; (2) increased severance taxes, as we are subject to higher severance taxes due to the increased value of oil and natural gas extracted from our wells; (3) increased LOE, as the demand for services related to the operation of our wells increases; and (4) increased electricity costs. Decreases in oil and natural gas prices may be accompanied by or result in: (1) decreased development costs, as the demand for drilling operations decreases; (2) decreased severance taxes, as we are subject to lower severance taxes due to the decreased value of oil and natural gas extracted from our wells; (3) decreased

ENCORE ACQUISITION COMPANY

LOE, as the demand for services related to the operation of our wells decreases; (4) decreased electricity costs; (5) impairment of oil and natural gas properties; and (6) decreased revenues and cash flows. We believe our risk management program and available borrowing capacity under our revolving credit facility provide means for us to manage commodity price risks.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures. Management considers an accounting estimate to be critical if it requires assumptions to be made that were uncertain at the time the estimate was made, and changes in the estimate or different estimates that could have been selected, could have a material impact on our consolidated results of operations or financial condition. Management has identified the following critical accounting policies and estimates.

Oil and Natural Gas Properties

Successful efforts method. We use the successful efforts method of accounting for oil and natural gas properties under SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*. Under this method, all costs associated with productive and nonproductive development wells are capitalized. Exploration expenses, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Costs associated with drilling exploratory wells are initially capitalized pending determination of whether the well is economically productive or nonproductive.

If an exploratory well does not find reserves or does not find reserves in a sufficient quantity as to make them economically producible, the previously capitalized costs would be expensed in the period in which the determination is made. If an exploratory well finds reserves but they cannot be classified as proved, we continue to capitalize the associated cost as long as the well has found a sufficient quantity of reserves to justify its completion as a producing well and sufficient progress is being made in assessing the reserves and the operating viability of the project. If subsequently it is determined that these conditions do not continue to exist, all previously capitalized costs associated with the exploratory well would be expensed in the period in which the determination is made. Re-drilling or directional drilling in a previously abandoned well is classified as development or exploratory based on whether it is in a proved or unproved reservoir. Costs for repairs and maintenance to sustain or increase production from the existing producing reservoir are charged to expense as incurred. Costs to recomplete a well in a different unproved reservoir are capitalized pending determination that economic reserves have been added. If the recompletion is not successful, the costs would be charged to expense.

DD&A expense is directly affected by our reserve estimates. Significant revisions to reserve estimates can be and are made by our reserve engineers each year. Mostly these are the result of changes in price, but as reserve quantities are estimates, they can also change as more or better information is collected, especially in the case of estimates in newer fields. Downward revisions have the effect of increasing our DD&A rate, while upward revisions have the effect of decreasing our DD&A rate. Assuming no other changes, such as an increase in depreciable base, as our reserves increase, the amount of DD&A expense in a given period decreases and vice versa. DD&A expense associated with lease and well equipment and intangible drilling costs is based upon proved developed reserves, while DD&A expense for capitalized leasehold costs is based upon total proved reserves. As a result, changes in the classification of our reserves could have a material impact on our DD&A expense.

Miller & Lents estimates our reserves annually at December 31. This results in a new DD&A rate which we use for the preceding fourth quarter after adjusting for fourth quarter production. We internally estimate reserve additions and reclassifications of reserves from proved undeveloped to proved developed at the end of the first, second, and third quarters for use in determining a DD&A rate for the respective quarter.

ENCORE ACQUISITION COMPANY

Significant tangible equipment added or replaced that extends the useful or productive life of the property is capitalized. Costs to construct facilities or increase the productive capacity from existing reservoirs are capitalized. Internal costs directly associated with the development of proved properties are capitalized as a cost of the property and are classified accordingly in our consolidated financial statements. Capitalized costs are amortized on a unit-of-production basis over the remaining life of proved developed reserves or total proved reserves, as applicable. Natural gas volumes are converted to BOE at the rate of six Mcf of natural gas to one Bbl of oil.

The costs of retired, sold, or abandoned properties that constitute part of an amortization base are charged or credited, net of proceeds received, to accumulated DD&A.

In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS 144), we assess the need for an impairment of long-lived assets to be held and used, including proved oil and natural gas properties, whenever events and circumstances indicate that the carrying value of the asset may not be recoverable. If impairment is indicated based on a comparison of the asset s carrying value to its undiscounted expected future net cash flows, then an impairment charge is recognized to the extent that the asset s carrying value exceeds its fair value. Expected future net cash flows are based on existing proved reserves (and appropriately risk-adjusted probable reserves), forecasted production information, and management s outlook of future commodity prices. Any impairment charge incurred is expensed and reduces our net basis in the asset. Management aggregates proved property for impairment testing the same way as for calculating DD&A. The price assumptions used to calculate undiscounted cash flows is based on judgment. We use prices consistent with the prices used in bidding on acquisitions and/or assessing capital projects. These price assumptions are critical to the impairment analysis as lower prices could trigger impairment. During 2008, events and circumstances indicated that a portion of our oil and natural gas properties, primarily four wells in the Tuscaloosa Marine Shale, might be impaired. As a result, we completed an impairment assessment and recorded a $59.5 million impairment charge. Our estimates of undiscounted cash flows indicated that the remaining carrying amounts of our oil and natural gas properties are expected to be recovered. Nonetheless, if oil and natural gas prices continue to decline, it is reasonably possible that our estimates of undiscounted cash flows may change in the near term resulting in the need to record an additional write down of our oil and natural gas properties to fair value.

Unproved properties, the majority of which relate to the acquisition of leasehold interests, are assessed for impairment on a property-by-property basis for individually significant balances and on an aggregate basis for individually insignificant balances. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance at the level at which impairment was assessed. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms, and potential shifts in business strategy employed by management. In the case of individually insignificant balances, the amount of the impairment loss recognized is determined by amortizing the portion of the unproved properties costs which we believe will not be transferred to proved properties over the life of the lease. One of the primary factors in determining what portion will not be transferred to proved properties is the relative proportion of the unproved properties on which proved reserves have been found in the past. Since the wells drilled on unproved acreage are inherently exploratory in nature, actual results could vary from estimates especially in newer areas in which we do not have a long history of drilling.

Oil and natural gas reserves. Our estimates of proved reserves are based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Miller & Lents prepares a reserve and economic evaluation of all of our properties on a well-by-well basis. Assumptions used by Miller & Lents in calculating reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. The accuracy of reserve estimates is a function of the:

- quality and quantity of available data;
- interpretation of that data;

ENCORE ACQUISITION COMPANY

accuracy of various mandated economic assumptions; and

judgment of the independent reserve engineer.

Future prices received for production and future production costs may vary, perhaps significantly, from the prices and costs assumed for purposes of calculating reserve estimates. We may not be able to develop proved reserves within the periods estimated. Furthermore, prices and costs may not remain constant. Actual production may not equal the estimated amounts used in the preparation of reserve projections. As these estimates change, calculated reserves change. Any change in reserves directly impacts our estimate of future cash flows from the property, the property s fair value, and our DD&A rate.

Asset retirement obligations. In accordance with SFAS No. 143, *Accounting for Asset Retirement* Obligations, we recognize the fair value of a liability for an asset retirement obligation in the period in which the liability is incurred. For oil and natural gas properties, this is the period in which an oil or natural gas property is acquired or a new well is drilled. An amount equal to and offsetting the liability is capitalized as part of the carrying amount of our oil and natural gas properties. The liability is recorded at its discounted fair value and then accreted each period until it is settled or the asset is sold, at which time the liability is reversed.

The fair value of the liability associated with the asset retirement obligation is determined using significant assumptions, including estimates of the plugging and abandonment costs, annual expected inflation of these costs, the productive life of the asset, and our credit-adjusted risk-free interest rate used to discount the expected future cash flows. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the obligation are recorded with an offsetting change to the carrying amount of the related oil and natural gas properties, resulting in prospective changes to DD&A and accretion expense. Because of the subjectivity of assumptions and the relatively long life of most of our oil and natural gas properties, the costs to ultimately retire these assets may vary significantly from our estimates.

Goodwill and Other Intangible Assets

We account for goodwill and other intangible assets under the provisions of SFAS No. 142, *Goodwill and Other Intangible Assets*. Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations. Goodwill and other intangible assets with indefinite useful lives are assessed for impairment annually on December 31 or whenever indicators of impairment exist. The goodwill test is performed at the reporting unit level. We have determined that we have two reporting units: EAC Standalone and ENP. If indicators of impairment are determined to exist, an impairment charge would be recognized for the amount by which the carrying value of an indefinite lived intangible asset exceeds its implied fair value.

We utilize both a market capitalization and an income approach to determine the fair value of our reporting units. The primary component of the income approach is the estimated discounted future net cash flows expected to be recovered from the reporting unit s oil and natural gas properties. Our analysis concluded that there was no impairment of goodwill as of December 31, 2008. Prices for oil and natural gas have deteriorated sharply in recent months and significant uncertainty remains on how prices for these commodities will behave in the future. Any additional decreases in the prices of oil and natural gas or any negative reserve adjustments from the December 31, 2008 assessment could change our estimates of the fair value of our reporting units and could result in an impairment charge.

Intangible assets with definite useful lives are amortized over their estimated useful lives. In accordance with SFAS 144, we evaluate the recoverability of intangible assets with definite useful lives whenever events or changes in circumstances indicate that the carrying value of the asset may not be fully recoverable. An impairment loss exists when estimated undiscounted cash flows expected to result from the use of the asset and its eventual disposition are less than its carrying amount.

ENCORE ACQUISITION COMPANY

We allocate the purchase price paid for the acquisition of a business to the assets and liabilities acquired based on the estimated fair values of those assets and liabilities. Estimates of fair value are based upon, among other things, reserve estimates, anticipated future prices and costs, and expected net cash flows to be generated. These estimates are often highly subjective and may have a material impact on the amounts recorded for acquired assets and liabilities.

Net Profits Interests

A major portion of our acreage position in the CCA is subject to net profits interests ranging from one percent to 50 percent. The holders of these net profits interests are entitled to receive a fixed percentage of the cash flow remaining after specified costs have been subtracted from net revenue. The net profits calculations are contractually defined. In general, net profits are determined after considering costs associated with production, overhead, interest, and development. The amounts of reserves and production attributable to net profits interests are deducted from our reserves and production data, and our revenues are reported net of net profits interests. The reserves and production attributed to the net profits interests are calculated by dividing estimated future net profits interests (in the case of reserves) or prior period actual net profits interests (in the case of production) by commodity prices at the determination date. Fluctuations in commodity prices and the levels of development activities in the CCA from period to period will impact the reserves and production attributed to the net profits interests and will have an inverse effect on our oil and natural gas revenues, production, reserves, and net income.

Oil and Natural Gas Revenue Recognition

Oil and natural gas revenues are recognized as oil and natural gas is produced and sold, net of royalties and net profits interests. Royalties, net profits interests, and severance taxes are incurred based upon the actual price received from the sales. To the extent actual quantities and values of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded. Natural gas revenues are reduced by any processing and other fees incurred except for transportation costs paid to third parties, which are recorded as expense. Natural gas revenues are recorded using the sales method of accounting whereby revenue is recognized based on actual sales of natural gas rather than our proportionate share of natural gas production. If our overproduced imbalance position (i.e., we have cumulatively been over-allocated production) is greater than our share of remaining reserves, a liability is recorded for the excess at period-end prices unless a different price is specified in the contract in which case that price is used. Revenue is not recognized for the production in tanks, oil marketed on behalf of joint interest owners in our properties, or oil in pipelines that has not been delivered to the purchaser.

Income Taxes

Our effective tax rate is subject to variability from period to period as a result of factors other than changes in federal and state tax rates and/or changes in tax laws which can affect tax paying companies. Our effective tax rate is affected by changes in the allocation of property, payroll, and revenues between states in which we own property as rates vary from state to state. Our deferred taxes are calculated using rates we expect to be in effect when they reverse. As the mix of property, payroll, and revenues varies by state, our estimated tax rate changes. Due to the size of our gross deferred tax balances, a small change in our estimated future tax rate can have a material effect on earnings.

Derivatives

We utilize various financial instruments for non-trading purposes to manage and reduce price volatility and other market risks associated with our oil and natural gas production. These arrangements are structured to reduce our exposure to commodity price decreases, but they can also limit the benefit we might otherwise receive from commodity price increases. Our risk management activity is generally accomplished through

ENCORE ACQUISITION COMPANY

over-the-counter forward derivative or option contracts with large financial institutions. We also use derivative instruments in the form of interest rate swaps, which hedge our risk related to interest rate fluctuation.

We apply the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133) and its amendments, which requires each derivative instrument to be recorded in the balance sheet at fair value. If a derivative does not qualify for hedge accounting, it must be adjusted to fair value through earnings. However, if a derivative qualifies for hedge accounting, depending on the nature of the hedge, changes in fair value can be recorded in accumulated other comprehensive income until such time as the hedged item is recognized in earnings.

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. Cash flow hedges are marked to market through accumulated other comprehensive income each period.

We have elected to designate our current 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 income in stockholders equity 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 immediately in earnings. While management does not anticipate changing the designation of our interest rate swaps as hedges, factors beyond our control can preclude the use of hedge accounting.

We have elected to not designate our current portfolio of commodity derivative contracts as hedges and therefore, changes in fair value of these instruments are recognized in earnings each period.

Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk for discussion regarding our sensitivity analysis for financial instruments.

New Accounting Pronouncements

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

In September 2006, the FASB issued SFAS 157, which: (1) standardizes the definition of fair value; (2) establishes a framework for measuring fair value in GAAP; and (3) expands disclosures related to the use of fair value measures in financial statements. SFAS 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value, but does not require any new fair value measurements. SFAS 157 was prospectively effective for financial assets and liabilities for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. In February 2008, the FASB issued FASB Staff Position (FSP) No. FAS 157-2, *Effective Date of FASB Statement No. 157* (FSP FAS 157-2), which delayed the effective date of SFAS 157 for one year for nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). We elected a partial deferral of SFAS 157 for all instruments within the scope of FSP FAS 157-2, including, but not limited to, our asset retirement obligations and indefinite lived assets. The adoption of SFAS 157 on January 1, 2008, as it relates to financial assets and liabilities, did not have a material impact on our results of operations or financial condition. We do not expect the adoption of SFAS 157 on January 1, 2009, as it relates to all instruments within the scope of FSP FAS 157-2, to have a material impact on our results of operations or financial condition.

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

In February 2007, the FASB issued SFAS 159, which permits entities to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis. SFAS 159 also allows entities an irrevocable option to measure eligible items at fair value at specified election dates, with resulting changes in fair value reported in earnings. SFAS 159 was effective for fiscal years beginning

ENCORE ACQUISITION COMPANY

after November 15, 2007. We did not elect the fair value option for eligible instruments and therefore, the adoption of SFAS 159 on January 1, 2008 did not impact our results of operations or financial condition. We will assess the impact of electing the fair value option for any eligible instruments acquired in the future. Electing the fair value option for such instruments could have a material impact on our future results of operations or financial condition.

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

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

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

In December 2007, the FASB issued SFAS 141R, which replaces SFAS No. 141, *Business Combinations*. SFAS 141R establishes principles and requirements for the reporting entity in a business combination, including: (1) recognition and measurement in the financial statements of the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (2) recognition and measurement of goodwill acquired in the business combination or a gain from a bargain purchase; and (3) determination of the information to be disclosed to enable financial statement users to evaluate the nature and financial effects of the business combination. SFAS 141R is prospectively effective for business combinations consummated in fiscal years beginning on or after December 15, 2008, with early application prohibited. We currently do not have any pending acquisitions that would fall within the scope of SFAS 141R. Future acquisitions could have an impact on our results of operations and financial condition.

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

In December 2007, the FASB issued SFAS 160, which amends Accounting Research Bulletin No. 51, *Consolidated Financial Statements* to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS 160 is effective for fiscal years beginning on or after December 15, 2008. SFAS 160 clarifies that a noncontrolling interest in a subsidiary, which is sometimes referred to as minority interest, is an ownership interest in the consolidated entity that should be reported as a component of equity in the consolidated financial statements. Among other requirements, SFAS 160 requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest and the disclosure of consolidated net income attributable to the parent and to the noncontrolling interest on the face of the consolidated statement of operations. We are evaluating the impact the adoption of SFAS 160 will have on our results of operations and financial condition.

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

In March 2008, the FASB issued SFAS 161, which amends SFAS 133, to require enhanced disclosures about: (1) how and why an entity uses derivative instruments; (2) how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations; and (3) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS 161 is effective for fiscal years beginning on or after November 15, 2008, with early application

ENCORE ACQUISITION COMPANY

encouraged. The adoption of SFAS 161 will require additional disclosures regarding our derivative instruments; however, it will not impact our results of operations or financial condition.

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

In May 2008, the FASB issued SFAS 162, which identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with GAAP. SFAS 162 was effective November 15, 2008. The adoption of SFAS 162 did not impact our results of operations or financial condition.

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

In June 2008, the FASB issued FSP EITF 03-6-1, which addresses whether instruments granted in equity-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation for computing basic earnings per share (EPS) under the two-class method described by SFAS No. 128, *Earnings per Share*. FSP EITF 03-6-1 is retroactively effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years, with early application prohibited. We are evaluating the impact the adoption of FSP EITF 03-6-1 will have on our EPS calculations.

Information Concerning Forward-Looking Statements

This Report contains forward-looking statements, which 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, inten believe, should, predict, potential, pursue, target, continue, and other words and terms of similar meaning. particular, forward-looking statements included in this Report relate to, among other things, the following:

items of income and expense (including, without limitation, LOE, production taxes, DD&A, G&A, and effective tax rates);

expected capital expenditures and the focus of our capital program;

areas of future growth;

our development and exploitation programs;

future secondary development and tertiary recovery potential;

anticipated prices for oil and natural gas and expectations regarding differentials between wellhead prices and benchmark prices (including, without limitation, the effects of the worldwide economic recession);

projected results of operations;

timing and amount of future production of oil and natural gas;

availability of pipeline capacity;

expected commodity derivative positions and payments related thereto (including the ability of counterparties to fulfill obligations);

expectations regarding working capital, cash flow, and liquidity;

ENCORE ACQUISITION COMPANY

projected borrowings under our revolving credit facility (and the ability of lenders to fund their commitments); and

the marketing of our oil and natural gas production.

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 this Report 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.

ITEM 7A. *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.

Derivative policy. Due to the volatility of crude oil and natural gas prices, we enter into various derivative instruments to manage our exposure to changes in the market price of crude oil and natural gas. We use options (including floors and collars) and fixed price swaps to mitigate the impact of downward swings in prices. All contracts are settled with cash and do not require the delivery of physical volumes to satisfy settlement. While this strategy may result in us having lower net cash inflows in times of higher oil and natural gas prices than we would otherwise have, had we not utilized these instruments, management believes that the resulting reduced volatility of cash flow is beneficial.

Counterparties. At December 31, 2008, we had committed greater than 10 percent of either our outstanding oil or natural gas commodity derivative contracts to the following counterparties:

Counterparty	Percentage of Oil Derivative Contracts Committed	Percentage of Natural Gas Derivative Contracts Committed
BNP Paribas	22%	24%
Calyon	15%	31%
Fortis	11%	
UBS	16%	
Wachovia	11%	38%

In order to mitigate the credit risk of financial instruments, we enter into master netting agreements with significant counterparties. The master netting agreement is a standardized, bilateral contract between a given counterparty and us. Instead of treating separately each derivative financial transaction between our counterparty and us, the master netting agreement enables our counterparty and us to aggregate all financial trades and treat them as a single agreement. This arrangement benefits us in three ways: (1) the netting of the value of all trades reduces the likelihood of our counterparties requiring daily collateral posting by us; (2) default by a counterparty under one financial trade can trigger rights for us to terminate all financial trades with such counterparty; and (3) netting of settlement amounts reduces our credit exposure to a given counterparty in the event of close-out.

Commodity price sensitivity. We manage 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

Table of Contents

ENCORE ACQUISITION COMPANY

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, we sell floors with a strike price below the strike price of the purchased floors in order to partially finance the premiums paid on the purchased floors. Together the two floors, known as a floor spread or put spread, have a lower premium cost than a traditional floor contract but provide price protection only down to the strike price of the short floor.

As of December 31, 2008, the fair market values of our oil and natural gas commodity derivative contracts were net assets of approximately $374.8 million and $12.8 million, respectively. Based on our open commodity derivative positions at December 31, 2008, a 10 percent increase in the respective NYMEX prices for oil and natural gas would decrease our net derivative fair value asset by approximately $29.2 million, while a 10 percent decrease in the respective NYMEX prices for oil and natural gas would increase our net derivative fair value asset by approximately $29.8 million. These amounts exclude deferred premiums of $67.6 million at December 31, 2008 that are not subject to changes in commodity prices.

The following tables summarize our open commodity derivative contracts as of December 31, 2008:

Oil Derivative Contracts

Period	Average Daily Floor Volume (Bbl)	Weighted Average Floor Price (per Bbl)	Average Daily Short Floor Volume (Bbl)	Weighted Average Short Floor Price (per Bbl)	Average Daily Cap Volume (Bbl)	Weighted Average Cap Price (per Bbl)	Average Daily Swap Volume (Bbl)	Weighted Average Swap Price (per Bbl)	Asset Fair Market Value (In thousands)
2009(a)									$ 342,063
	11,630	$ 110.00		$		$	2,000	$ 90.46	
	8,000	80.00			440	97.75	500	89.39	
			(5,000)	50.00			1,000	68.70	
2010									17,618
	880	80.00			440	93.80			
	2,000	75.00			1,000	77.23			
2011	1,880	80.00			1,440	95.41			15,112
	1,000	70.00							
									$ 374,793

(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.

Table of Contents

ENCORE ACQUISITION COMPANY

Natural Gas Derivative Contracts

Period	Average Daily Floor Volume (Mcf)	Weighted Average Floor Price (per Mcf)	Average Daily Short Floor Volume (Mcf)	Weighted Average Short Floor Price (per Mcf)	Average Daily Cap Volume (Mcf)	Weighted Average Cap Price (per Mcf)	Average Daily Swap Volume (Mcf)	Weighted Average Swap Price (per Mcf)	Asset Fair Market Value (In thousands)
2009									$ 7,281
	3,800	$ 8.20		$	3,800	$ 9.83		$	
	3,800	7.20							
	1,800	6.76							
2010									4,690
	3,800	8.20			3,800	9.58	902	6.30	
	4,698	7.26							
2011									424
	898	6.76					902	6.70	
2012									424
	898	6.76					902	6.66	
									$ 12,819

Interest rate sensitivity. At December 31, 2008, we had total long-term debt of $1.3 billion, net of discount of $5.2 million. Of this amount, $150 million bears interest at a fixed rate of 6.25 percent, $300 million bears interest at a fixed rate of 6.0 percent, and $150 million bears interest at a fixed rate of 7.25 percent. The remaining long-term debt balance of $725 million consists of outstanding borrowings on our revolving credit facilities and is subject to floating market rates of interest that are linked to LIBOR.

At this level of floating rate debt, if LIBOR increased 10 percent, we would incur an additional $2.0 million of interest expense per year on our revolving credit facilities, and if LIBOR decreased 10 percent, we would incur $2.0 million less. Additionally, if the bond discount rate increased 10 percent, we estimate the fair value of our fixed rate debt at December 31, 2008 would decrease from approximately $390 million to approximately $351 million, and if the bond discount rate decreased 10 percent, we estimate the fair value would increase to approximately $429 million.

ENP manages interest rate risk with interest rate swaps whereby it swaps floating rate debt under the OLLC Credit Agreement with a weighted average fixed rate. As of December 31, 2008, the fair market value of ENP s interest rate swaps was a net liability of approximately $4.6 million. If LIBOR increased 10 percent, we estimate the liability would decrease to approximately $4.1 million, and if LIBOR decreased 10 percent, we estimate the liability would increase to approximately $5.0 million.

The following table summarizes ENP s open interest rate swaps as of December 31, 2008:

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

ENCORE ACQUISITION COMPANY

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

Index to Consolidated Financial Statements

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Encore Acquisition Company:

We have audited the accompanying consolidated balance sheets of Encore Acquisition Company (the Company) as of December 31, 2008 and 2007, and the related consolidated statements of operations, stockholders equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Encore Acquisition Company at December 31, 2008 and 2007, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 9 to the consolidated financial statements, effective January 1, 2007, the Company adopted Financial Accounting Standards Board Interpretation No. 48, Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company s internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Fort Worth, Texas
February 24, 2009

Table of Contents

ENCORE ACQUISITION COMPANY

CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(In thousands, except share and per share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,039	$ 1,704
Accounts receivable, net of allowance for doubtful accounts of $381 and $0, respectively	129,065	134,880
Inventory	24,798	16,257
Derivatives	349,344	9,722
Deferred taxes		20,420
Income taxes receivable	29,445	2,661
Other	6,239	2,866
Total current assets	540,930	188,510
Properties and equipment, at cost successful efforts method:		
Proved properties, including wells and related equipment	3,538,459	2,845,776
Unproved properties	124,339	63,352
Accumulated depletion, depreciation, and amortization	(771,564)	(489,004)
	2,891,234	2,420,124
Other property and equipment	25,192	21,750
Accumulated depreciation	(12,753)	(10,733)
	12,439	11,017
Goodwill	60,606	60,606
Derivatives	38,497	34,579
Long-term receivables, net of allowance for doubtful accounts of $7,643 and $6,045, respectively	60,915	40,945
Other	28,574	28,780
Total assets	$ 3,633,195	$ 2,784,561
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 10,017	$ 21,548
Accrued liabilities:		
Lease operations expense	19,108	15,057
Development capital	79,435	48,359

Interest	11,808	12,795
Production, ad valorem, and severance taxes	25,133	24,694
Marketing	3,594	8,721
Derivatives	63,476	39,337
Oil and natural gas revenues payable	10,821	13,076
Deferred taxes	105,768	
Other	23,092	21,143
Total current liabilities	352,252	204,730
Derivatives	8,922	47,091
Future abandonment cost, net of current portion	48,058	27,371
Deferred taxes	416,915	312,914
Long-term debt	1,319,811	1,120,236
Other	3,989	1,530
Total liabilities	2,149,947	1,713,872
Commitments and contingencies (see Note 4)		
Minority interest in consolidated partnership	169,120	122,534
Stockholders equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none issued and outstanding		
Common stock, $.01 par value, 144,000,000 shares authorized, 51,551,937 and 53,303,464 issued and outstanding, respectively	516	534
Additional paid-in capital	525,763	538,620
Treasury stock, at cost, of 4,753 and 17,690 shares, respectively	(101)	(590)
Retained earnings	789,698	411,377
Accumulated other comprehensive loss	(1,748)	(1,786)
Total stockholders equity	1,314,128	948,155
Total liabilities and stockholders equity	$ 3,633,195	$ 2,784,561

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

Table of Contents

ENCORE ACQUISITION COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2008	2007	2006
	(In thousands, except per share amounts)		
Revenues:			
Oil	$ 897,443	$ 562,817	$ 346,974
Natural gas	227,479	150,107	146,325
Marketing	10,496	42,021	147,563
Total revenues	1,135,418	754,945	640,862
Expenses:			
Production:			
Lease operations	175,115	143,426	98,194
Production, ad valorem, and severance taxes	110,644	74,585	49,780
Depletion, depreciation, and amortization	228,252	183,980	113,463
Impairment of long-lived assets	59,526		
Exploration	39,207	27,726	30,519
General and administrative	48,421	39,124	23,194
Marketing	9,570	40,549	148,571
Derivative fair value loss (gain)	(346,236)	112,483	(24,388)
Provision for doubtful accounts	1,984	5,816	1,970
Other operating	12,975	17,066	8,053
Total expenses	339,458	644,755	449,356
Operating income	795,960	110,190	191,506
Other income (expenses):			
Interest	(73,173)	(88,704)	(45,131)
Other	3,898	2,667	1,429
Total other expenses	(69,275)	(86,037)	(43,702)
Income before income taxes and minority interest	726,685	24,153	147,804
Income tax provision	(241,621)	(14,476)	(55,406)
Minority interest in loss (income) of consolidated partnership	(54,252)	7,478	
Net income	$ 430,812	$ 17,155	$ 92,398
Net income per common share:			
Basic	$ 8.24	$ 0.32	$ 1.78

Diluted	$ 8.07	$ 0.32	$ 1.75
Weighted average common shares outstanding:			
Basic	52,270	53,170	51,865
Diluted	53,414	54,144	52,736

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

ENCORE ACQUISITION COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME

	Issued Shares of Common Stock	Common Stock	Additional Paid-in Capital	Shares of Treasury Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders Equity
				(In thousands)				
Balance at December 31, 2005	48,785	$ 488	$ 316,619	(11)	$ (375)	$ 302,875	$ (72,826)	$ 546,781
Exercise of stock options and vesting of restricted stock	280	3	3,641					3,644
Purchase of treasury stock				(25)	(633)			(633)
Cancellation of treasury stock	(18)		(195)	18	551	(356)		
Issuance of common stock	4,000	40	127,061					127,101
Non-cash stock-based compensation			10,075					10,075
Components of comprehensive income:								
Net income						92,398		92,398
Change in deferred hedge gain/loss, net of tax of $22,365							37,499	37,499
Total comprehensive income								129,897
Balance at December 31, 2006	53,047	531	457,201	(18)	(457)	394,917	(35,327)	816,865
Exercise of stock options and vesting of	313	3	1,587					1,590

restricted stock								
Purchase of treasury stock				(39)	(1,136)			(1,136)
Cancellation of treasury stock	(39)		(338)	39	1,003	(665)		
Non-cash equity-based compensation			14,632					14,632
EAC s share of ENP s offering costs			(12,088)					(12,088)
ENP distributions to holders of management incentive units						(30)		(30)
Adjustment to reflect gain on sale of ENP common units			77,626					77,626
Components of comprehensive income:								
Net income						17,155		17,155
Amortization of deferred hedge losses, net of tax of $20,047							33,541	33,541
Total comprehensive income								50,696
Balance at December 31, 2007	53,321	534	538,620	(18)	(590)	411,377	(1,786)	948,155
Exercise of stock options and vesting of restricted stock	300	2	2,620					2,622
Repurchase and retirement of common stock	(2,018)	(20)	(19,279)			(47,871)		(67,170)
Purchase of treasury stock				(33)	(1,055)			(1,055)
Cancellation of treasury stock	(46)		(465)	46	1,544	(1,079)		
Non-cash equity-based compensation			14,505					14,505
						(3,541)		(3,541)

ENP distributions to holders of management incentive units								
Adjustment to reflect gain on issuance of ENP common units			3,458					3,458
Economic uniformity adjustment related to conversion of management incentive units			(13,920)					(13,920)
Other			224					224
Components of comprehensive income:								
Net income						430,812		430,812
Change in deferred hedge loss on interest rate swaps, net of tax of $957 and net of minority interest of $1,568							(1,748)	(1,748)
Amortization of deferred loss on commodity derivative contracts, net of tax of $1,071							1,786	1,786
Total comprehensive income								430,850
Balance at December 31, 2008	51,557	$ 516	$ 525,763	(5)	$ (101)	$ 789,698	$ (1,748)	$ 1,314,128

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

Table of Contents

ENCORE ACQUISITION COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 430,812	$ 17,155	$ 92,398
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation, and amortization	228,252	183,980	113,463
Impairment of long-lived assets	59,526		
Non-cash exploration expense	34,874	25,487	28,128
Deferred taxes	232,614	12,588	51,220
Non-cash equity-based compensation expense	14,115	15,997	8,980
Non-cash derivative loss (gain)	(299,914)	130,910	(10,434)
Loss (gain) on disposition of assets	(3,623)	7,409	(297)
Minority interest in income (loss) of consolidated partnership	54,252	(7,478)	
Provision for doubtful accounts	1,984	5,816	1,970
Other	6,479	10,182	7,577
Changes in operating assets and liabilities, net of effects from acquisitions:			
Accounts receivable	(8,488)	(48,647)	(2,275)
Current derivatives	(13,681)	(17,430)	
Other current assets	(35,495)	3,108	(4,945)
Long-term derivatives	(8,601)	(35,750)	
Other assets	(2,174)	(1,214)	(365)
Accounts payable	(11,468)	4,461	1,833
Other current liabilities	(14,351)	14,788	10,080
Other noncurrent liabilities	(1,876)	(1,655)	
Net cash provided by operating activities	663,237	319,707	297,333
Cash flows from investing activities:			
Proceeds from disposition of assets	4,235	287,928	1,522
Purchases of other property and equipment	(4,208)	(3,519)	(4,290)
Acquisition of oil and natural gas properties	(142,559)	(848,545)	(30,119)
Development of oil and natural gas properties	(560,997)	(335,897)	(340,582)
Net advances to working interest partners	(24,817)	(29,523)	(22,425)
Other			(1,536)
Net cash used in investing activities	(728,346)	(929,556)	(397,430)
Cash flows from financing activities:			
Proceeds from issuance of common stock, net of issuance costs			127,101
		193,461	

Proceeds from issuance of ENP common units, net of issuance costs			
Repurchase and retirement of common stock	(67,170)		
Exercise of stock options and vesting of restricted stock, net of treasury stock purchases	1,567	454	3,011
Proceeds from long-term debt, net of issuance costs	1,370,339	1,479,259	281,853
Payments on long-term debt	(1,172,500)	(1,034,428)	(294,000)
Payment of commodity derivative contract premiums	(39,184)	(26,195)	(7,848)
ENP distributions to holder of management incentive units and public units	(27,545)	(568)	
Change in cash overdrafts	(63)	(1,193)	(10,911)
Net cash provided by financing activities	65,444	610,790	99,206
Increase (decrease) in cash and cash equivalents	335	941	(891)
Cash and cash equivalents, beginning of period	1,704	763	1,654
Cash and cash equivalents, end of period	$ 2,039	$ 1,704	$ 763

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

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Description of Business

Encore Acquisition Company (together with its subsidiaries, EAC), a Delaware corporation, 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, and reengineering or expanding existing waterflood projects. EAC s properties and oil and natural gas reserves are located in four core areas:

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

Note 2. Summary of Significant Accounting Policies

Principles of Consolidation

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 February 2007, EAC formed Encore Energy Partners LP (together with its subsidiaries, ENP), a publicly traded Delaware limited partnership, to acquire, exploit, and develop oil and natural gas properties and to acquire, own, and operate related assets. In September 2007, ENP completed its initial public offering (IPO). As of December 31, 2008 and 2007, EAC owned approximately 63 percent and 58 percent, respectively, of ENP s common units, as well as all of the interests of Encore Energy Partners GP LLC (GP LLC), a Delaware limited liability company and ENP s general partner, which is an indirect wholly owned non-guarantor subsidiary of EAC. Considering the presumption of control of GP LLC in accordance with Emerging Issues Task Force Issue No. 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights*, the financial position, results of operations, and cash flows of ENP are consolidated with those of EAC. EAC elected to account for gains on ENP s issuance of common units as capital transactions as permitted by Staff Accounting Bulletin (SAB) Topic 5H, *Accounting for Sales of Stock by a Subsidiary*. Please read Note 10. Stockholders Equity for additional discussion.

As presented in the accompanying Consolidated Balance Sheets, Minority interest in consolidated partnership as of December 31, 2008 and 2007 of $169.1 million and $122.5 million, respectively, represents third-party ownership interests in ENP. As presented in the accompanying Consolidated Statements of Operations, Minority interest in income of consolidated partnership for 2008 of $54.3 million and Minority interest in loss of consolidated partnership for 2007 of $7.5 million represents ENP s results of operations attributable to third-party owners.

Use of Estimates

Preparing financial statements in conformity with accounting principles generally accepted in the United States (GAAP) requires management to make certain estimations and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities in the consolidated financial statements and the reported amounts of revenues and expenses. Actual results could differ materially from those estimates.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Estimates made in preparing these consolidated financial statements include, among other things, estimates of the proved oil and natural gas reserve volumes used in calculating depletion, depreciation, and amortization (DD&A) expense; the estimated future cash flows and fair value of properties used in determining the need for any impairment write-down; operating costs accrued; volumes and prices for revenues accrued; estimates of the fair value of equity-based compensation awards; and the timing and amount of future abandonment costs used in calculating asset retirement obligations. Changes in the assumptions used could have a significant impact on reported results in future periods.

Cash and Cash Equivalents

Cash and cash equivalents include cash in banks, money market accounts, and all highly liquid investments with an original maturity of three months or less. On a bank-by-bank basis and considering legal right of offset, cash accounts that are overdrawn are reclassified to current liabilities and any change in cash overdrafts is shown as Change in cash overdrafts in the Financing activities section of EAC s Consolidated Statements of Cash Flows.

Supplemental Disclosures of Cash Flow Information

The following table sets forth supplemental disclosures of cash flow information for the periods indicated:

	Year Ended December 31,		
	2008	**2007**	**2006**
		(In thousands)	
Cash paid during the period for:			
Interest	$ 67,519	$ 82,649	$ 46,389
Income taxes	33,110	260	464
Non-cash investing and financing activities:			
Deferred premiums on commodity derivative contracts	53,387	20,341	30,319
ENP s issuance of common units in connection with acquisition of net profits interest in certain Crockett County properties	5,748		

Accounts Receivable

Trade accounts receivable, which are primarily from oil and natural gas sales, are recorded at the invoiced amount and do not bear interest with the exception of the current portion of balances due from ExxonMobil Corporation (ExxonMobil) in connection with EAC s joint development agreement. Please read Note 4. Commitments and Contingencies for additional discussion of this agreement. EAC routinely reviews outstanding accounts receivable balances and assesses the financial strength of its customers and records a reserve for amounts not expected to be fully recovered. Actual balances are not applied against the reserve

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

until substantially all collection efforts have been exhausted. The following table summarizes the changes in allowance for doubtful accounts for the periods indicated:

	Year Ended December 31, 2008	Year Ended December 31, 2007
	(In thousands)	
Allowance for doubtful accounts at January 1	$ 6,045	$ 2,329
Bad debt expense	1,984	5,816
Write off	(5)	(2,100)
Allowance for doubtful accounts at December 31	$ 8,024	$ 6,045

Of the $8.0 million in allowance for doubtful accounts at December 31, 2008, $0.4 million is short-term and $7.6 million is long-term.

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:

	December 31, 2008	December 31, 2007
	(In thousands)	
Materials and supplies	$ 15,933	$ 11,030
Oil in pipelines	8,865	5,227
Total inventory	$ 24,798	$ 16,257

Properties and Equipment

Oil and Natural Gas Properties. EAC uses the successful efforts method of accounting for its oil and natural gas properties under Statement of Financial Accounting Standards (SFAS) No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies* (SFAS 19). Under this method, all costs associated with productive and nonproductive development wells are capitalized. Exploration expenses, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Costs associated with drilling exploratory wells are initially capitalized pending determination of whether the well is economically productive or nonproductive.

If an exploratory well does not find reserves or does not find reserves in a sufficient quantity as to make them economically producible, the previously capitalized costs would be expensed in EAC s Consolidated Statements of Operations and shown as a non-cash adjustment to net income in the Operating activities section of EAC s Consolidated Statements of Cash Flows in the period in which the determination was made. If an exploratory well finds reserves but they cannot be classified as proved, EAC continues to capitalize the associated cost as long as the well has found a sufficient quantity of reserves to justify its completion as a producing well and sufficient progress is being made in assessing the reserves and the operating viability of the project. If subsequently it is determined that these conditions do not continue to exist, all previously capitalized costs associated with the exploratory well would be expensed and shown as a non-cash adjustment to net income in the Operating activities section of EAC s Consolidated Statements of Cash Flows in the period in which the determination is made. Re-drilling or directional drilling in a previously abandoned well is classified as development or exploratory based on whether it is in a proved or unproved reservoir. Costs for

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

repairs and maintenance to sustain or increase production from the existing producing reservoir are charged to expense as incurred. Costs to recomplete a well in a different unproved reservoir are capitalized pending determination that economic reserves have been added. If the recompletion is not successful, the costs would be charged to expense. All capitalized costs associated with both development and exploratory wells are shown as Development of oil and natural gas properties in the Investing activities section of EAC s Consolidated Statements of Cash Flows.

Significant tangible equipment added or replaced that extends the useful or productive life of the property is capitalized. Costs to construct facilities or increase the productive capacity from existing reservoirs are capitalized. Internal costs directly associated with the development of proved properties are capitalized as a cost of the property and are classified accordingly in EAC s consolidated financial statements. Capitalized costs are amortized on a unit-of-production basis over the remaining life of proved developed reserves or total proved reserves, as applicable. Natural gas volumes are converted to barrels of oil equivalent (BOE) at the rate of six thousand cubic feet (Mcf) of natural gas to one barrel (Bbl) of oil.

The costs of retired, sold, or abandoned properties that constitute part of an amortization base are charged or credited, net of proceeds received, to accumulated DD&A.

Miller and Lents, Ltd., EAC s independent reserve engineer, estimates EAC s reserves annually on December 31. This results in a new DD&A rate which EAC uses for the preceding fourth quarter after adjusting for fourth quarter production. EAC internally estimates reserve additions and reclassifications of reserves from proved undeveloped to proved developed at the end of the first, second, and third quarters for use in determining a DD&A rate for the respective quarter.

In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS 144), EAC assesses the need for an impairment of long-lived assets to be held and used, including proved oil and natural gas properties, whenever events and circumstances indicate that the carrying value of the asset may not be recoverable. If impairment is indicated based on a comparison of the asset s carrying value to its undiscounted expected future net cash flows, then an impairment charge is recognized to the extent that the asset s carrying value exceeds its fair value. Expected future net cash flows are based on existing proved reserves (and appropriately risk-adjusted probable reserves), forecasted production information, and management s outlook of future commodity prices. Any impairment charge incurred is expensed and reduces the net basis in the asset. Management aggregates proved property for impairment testing the same way as for calculating DD&A. The price assumptions used to calculate undiscounted cash flows is based on judgment. EAC uses prices consistent with the prices used in bidding on acquisitions and/or assessing capital projects. These price assumptions are critical to the impairment analysis as lower prices could trigger impairment.

Unproved properties, the majority of which relate to the acquisition of leasehold interests, are assessed for impairment on a property-by-property basis for individually significant balances and on an aggregate basis for individually insignificant balances. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance at the level at which impairment was assessed. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms, and potential shifts in business strategy employed by management. In the case of individually insignificant balances, the amount of the impairment loss recognized is determined by amortizing the portion of these properties costs which EAC believes will not be transferred to proved properties over the remaining life of the lease.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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:

	December 31, 2008	December 31, 2007
	(In thousands)	
Proved leasehold costs	$ 1,421,859	$ 1,346,516
Wells and related equipment Completed	1,943,275	1,408,512
Wells and related equipment In process	173,325	90,748
Total proved properties	$ 3,538,459	$ 2,845,776

Other Property and Equipment. Other property and equipment is carried at cost. Depreciation is recognized on a straight-line basis over estimated useful lives, which range from three to seven years. Leasehold improvements are capitalized and depreciated over the remaining term of the lease, which is through 2013 for EAC s corporate headquarters. Gains or losses from the disposal of other property and equipment are recognized in the period realized and included in Other operating expense of EAC s Consolidated Statements of Operations.

Goodwill and Other Intangible Assets

EAC accounts for goodwill and other intangible assets under the provisions of SFAS No. 142, *Goodwill and Other Intangible Assets*. Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations. Goodwill and other intangible assets with indefinite useful lives are tested for impairment annually on December 31 or whenever indicators of impairment exist. If indicators of impairment are determined to exist, an impairment charge would be recognized for the amount by which the carrying value of the asset exceeds its implied fair value. The goodwill test is performed at the reporting unit level. EAC has determined that it has two reporting units: EAC Standalone and ENP. ENP has been allocated $2.6 million of goodwill and the remainder has been allocated to the EAC Standalone segment.

EAC utilizes both a market capitalization and an income approach to determine the fair value of its reporting units. The primary component of the income approach is the estimated discounted future net cash flows expected to be recovered from the reporting unit s oil and natural gas properties. EAC s analysis concluded that there was no impairment of goodwill as of December 31, 2008. Prices for oil and natural gas have deteriorated sharply in recent months and significant uncertainty remains on how prices for these commodities will behave in the future. Any additional decreases in the prices of oil and natural gas or any negative reserve adjustments from the December 31, 2008 assessment could change EAC s estimates of the fair value of its reporting units and could result in an impairment charge.

Intangible assets with definite useful lives are amortized over their estimated useful lives. In accordance with SFAS 144, EAC evaluates the recoverability of intangible assets with definite useful lives whenever events or changes in circumstances indicate that the carrying value of the asset may not be fully recoverable. An impairment loss exists when estimated undiscounted cash flows expected to result from the use of the asset and its eventual disposition are less than its carrying amount.

ENP is a party to a contract allowing it to purchase a certain amount of natural gas at a below market price for use as field fuel. The fair value of this contract, net of related amortization, is included in Other noncurrent assets on the accompanying Consolidated Balance Sheets. The gross carrying amount of this contract is $4.2 million and as of December 31, 2008 and 2007, accumulated amortization was $0.6 million and $0.3 million, respectively. During each of 2008 and 2007, ENP recorded $0.3 million of amortization expense related to this contract. The net carrying amount is being amortized on a straight-line basis through July 2019. ENP expects to recognize $0.3 million of amortization expense during each of the next five years related to this contract.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Asset Retirement Obligations

In accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations*, EAC recognizes the fair value of a liability for an asset retirement obligation in the period in which the liability is incurred. For oil and natural gas properties, this is the period in which the property is acquired or a new well is drilled. An amount equal to and offsetting the liability is capitalized as part of the carrying amount of EAC s oil and natural gas properties. The liability is recorded at its discounted fair value and then accreted each period until it is settled or the asset is sold, at which time the liability is reversed. Estimates are based on historical experience in plugging and abandoning wells and estimated remaining field life based on reserve estimates. EAC does not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined. Please read Note 5. Asset Retirement Obligations for additional information.

Equity-Based Compensation

EAC accounts for equity-based compensation according to the provisions of SFAS No. 123 (revised 2004), *Share-Based Payment* (SFAS 123R), which requires the recognition of compensation expense for equity-based awards over the requisite service period in an amount equal to the grant date fair value of the awards. EAC utilizes a standard option pricing model (i.e., Black-Scholes) to measure the fair value of employee stock options under SFAS 123R. Please read Note 12. Employee Benefit Plans for additional discussion of EAC s employee benefit plans.

SFAS 123R also requires that the benefits associated with the tax deductions in excess of recognized compensation cost be reported as a financing cash flow. This requirement reduces net operating cash flows and increases net financing cash flows. EAC recognizes compensation costs related to awards with graded vesting on a straight-line basis over the requisite service period for each separately vesting portion of the award as if the award was, in-substance, multiple awards. Compensation expense associated with awards to employees who are eligible for retirement is fully expensed on the date of grant.

Segment Reporting

EAC operates in only one industry: the oil and natural gas exploration and production industry in the United States. However, EAC is organizationally structured along two reportable segments: EAC Standalone and ENP. EAC s segments are components of its business for which separate financial information related to operating and development costs are available and regularly evaluated by the chief operating decision maker in deciding how to allocate capital resources to projects and in assessing performance. Please read Note 18. Segment Information for additional discussion. Prior to the fourth quarter of 2007, segment reporting was not applicable to EAC.

Major Customers/Concentration of Credit Risk

In 2008, Eighty-Eight Oil and Tesoro accounted for approximately 14 percent and 12 percent, respectively, of EAC s sales of oil and natural gas production. On the EAC Standalone segment, two companies accounted for 16 percent and 13 percent of EAC Standalone s sales of oil and natural gas production. On the ENP segment, three companies accounted for 24 percent, 23 percent, and 10 percent of ENP s sales of oil and natural gas production.

In 2007, Eighty-Eight Oil accounted for 14 percent of EAC s sales of oil and natural gas production. On the EAC Standalone segment, one company accounted for 15 percent of EAC Standalone s sales of oil and natural gas production. On the ENP segment, two companies accounted for 52 percent and 16 percent of ENP s sales of oil and natural gas production.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In 2006, Shell Trading Company and ConocoPhillips accounted for 15 percent and 12 percent, respectively, of EAC s sales of oil and natural gas production.

Income Taxes

Deferred tax assets and liabilities are recognized for future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Valuation allowances are established when necessary to reduce net deferred tax assets to amounts expected to be realized. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled.

Oil and Natural Gas Revenue Recognition

Oil and natural gas revenues are recognized as oil and natural gas is produced and sold, net of royalties and net profits interests. Royalties, net profits interests, and severance taxes are incurred based upon the actual price received from the sales. To the extent actual quantities and values of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded as Accounts receivable, net in the accompanying Consolidated Balance Sheets. Natural gas revenues are reduced by any processing and other fees incurred except for transportation costs paid to third parties, which are recorded in Other operating expense in the accompanying Consolidated Statements of Operations. Natural gas revenues are recorded using the sales method of accounting whereby revenue is recognized based on actual sales of natural gas rather than EAC s proportionate share of natural gas production. If EAC s overproduced imbalance position (i.e., EAC has cumulatively been over-allocated production) is greater than EAC s share of remaining reserves, a liability is recorded for the excess at period-end prices unless a different price is specified in the contract in which case that price is used. Revenue is not recognized for the production in tanks, oil marketed on behalf of joint owners in EAC s properties, or oil in pipelines that has not been delivered to the purchaser.

EAC s net oil inventories in pipelines were 173,119 Bbls and 124,410 Bbls at December 31, 2008 and 2007, respectively. Natural gas imbalances at December 31, 2008 and 2007, were 28,717 million British thermal units (MMBtu) and 128,856 MMBtu under-delivered to EAC, respectively.

Marketing Revenues and Expenses

Marketing revenues include the sales of natural gas purchased from third parties as well as pipeline tariffs charged for transportation volumes through EAC s pipelines. Marketing revenues derived from sales of oil and natural gas purchased from third parties are recognized when persuasive evidence of a sales arrangement exists, delivery has occurred, the sales price is fixed or determinable, and collectibility is reasonably assured. Marketing expenses include the cost of oil and natural gas volumes purchased from third parties, pipeline tariffs, storage, truck facility fees, and tank bottom costs used to support the sale of oil production. As EAC takes title to the oil and natural gas and has risks and rewards of ownership, these transactions are presented gross in the Consolidated Statements of Operations, unless they meet the criteria for netting as outlined in EITF Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*.

Shipping Costs

Shipping costs in the form of pipeline fees and trucking costs paid to third parties are incurred to transport oil and natural gas production from certain properties to a different market location for ultimate sale. These costs are included in Other operating expense and Marketing expense, as applicable, in the accompanying Consolidated Statements of Operations.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Derivatives

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 forward derivative or option 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 No. 133, *Accounting for Derivative Instruments and Hedging Activities* and its amendments, which requires each derivative instrument to be recorded in the balance sheet at fair value. If a derivative does not qualify for hedge accounting, it must be adjusted to fair value through earnings. However, if a derivative qualifies for hedge accounting, depending on the nature of the hedge, changes in fair value can be recognized in accumulated other comprehensive income until such time as the hedged item is recognized in earnings.

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. Cash flow hedges are marked to market through accumulated other comprehensive income each period.

EAC has elected to designate its current 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 other Accumulated other comprehensive income 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 immediately as Derivative fair value loss (gain) in the Consolidated Statements of Operations.

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

Comprehensive Income

EAC has elected to show comprehensive income as part of its Consolidated Statements of Stockholders Equity and Comprehensive Income rather than in its Consolidated Statements of Operations.

Reclassifications

Certain amounts in prior periods have been reclassified to conform to the current period presentation. In particular, Income taxes receivable has been presented separately on the accompanying Consolidated Balance Sheets.

New Accounting Pronouncements

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

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS 157, which: (1) standardizes the definition of fair value; (2) establishes a framework for measuring fair value in GAAP; and (3) expands disclosures related to the use of fair value measures in financial statements. SFAS 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value, but does not require any new fair value measurements. SFAS 157 was prospectively effective for financial assets and liabilities for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. In February 2008, the FASB issued FASB Staff Position (FSP)

88

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

No. FAS 157-2, *Effective Date of FASB Statement No. 157* (FSP FAS 157-2), which delayed the effective date of SFAS 157 for one year for nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). EAC elected a partial deferral of SFAS 157 for all instruments within the scope of FSP FAS 157-2, including, but not limited to, its asset retirement obligations and indefinite lived assets. EAC will continue to evaluate the impact of SFAS 157 on these instruments during the deferral period. The adoption of SFAS 157 on January 1, 2008, as it relates to financial assets and liabilities, did not have a material impact on EAC s results of operations or financial condition. EAC does not expect the adoption of SFAS 157 on January 1, 2009, as it relates to all instruments within the scope of FSP FAS 157-2, to have a material impact on its results of operations or financial condition. Please read Note 14. Fair Value Measurements for additional discussion.

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

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

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

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

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

In December 2007, the FASB issued SFAS 141R, which replaces SFAS No. 141, *Business Combinations.* SFAS 141R establishes principles and requirements for the reporting entity in a business combination, including: (1) recognition and measurement in the financial statements of the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (2) recognition and measurement of goodwill acquired in the business combination or a gain from a bargain purchase; and (3) determination of the information to be disclosed to enable financial statement users to evaluate the nature and financial effects of the business combination. SFAS 141R is prospectively effective for business combinations consummated in fiscal years beginning on or after December 15, 2008, with early application prohibited. EAC currently does not have any pending acquisitions that would fall within the scope of SFAS 141R. Future acquisitions could impact EAC s results of operations and financial condition and the reporting in the consolidated financial statements.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

In December 2007, the FASB issued SFAS 160, which amends Accounting Research Bulletin No. 51, *Consolidated Financial Statements* to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS 160 is effective for fiscal years beginning on or after December 15, 2008. SFAS 160 clarifies that a noncontrolling interest in a subsidiary, which is sometimes referred to as minority interest, is an ownership interest in the consolidated entity that should be reported as a component of equity in the consolidated financial statements. Among other requirements, SFAS 160 requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest and the disclosure of consolidated net income attributable to the parent and to the noncontrolling interest on the face of the consolidated statement of operations. EAC is evaluating the impact the adoption of SFAS 160 will have on its results of operations and financial condition.

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

In March 2008, the FASB issued SFAS 161, which amends SFAS 133, to require enhanced disclosures about: (1) how and why an entity uses derivative instruments; (2) how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations; and (3) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS 161 is effective for fiscal years beginning on or after November 15, 2008, with early application encouraged. The adoption of SFAS 161 will require additional disclosures regarding EAC s derivative instruments; however, it will not impact EAC s results of operations or financial condition.

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

In May 2008, the FASB issued SFAS 162, which identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with GAAP. SFAS 162 was effective November 15, 2008. The adoption of SFAS 162 did not impact EAC s results of operations or financial condition.

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

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

Note 3. Acquisitions and Dispositions

Acquisitions

In January 2007, EAC entered into a purchase and sale agreement with certain subsidiaries of Anadarko Petroleum Corporation (Anadarko) to acquire oil and natural gas properties and related assets in the Williston Basin of Montana and North Dakota. The closing of the Williston Basin acquisition occurred in April 2007. The Williston Basin acquisition was treated as a reverse like-kind exchange under Section 1031 of

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the Internal Revenue Code of 1986, as amended, (the Code) and I.R.S. Revenue Procedure 2000-37 with the Mid-Continent disposition discussed below. The total purchase price for the Williston Basin assets was approximately $392.1 million, including transaction costs of approximately $1.3 million.

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

EAC financed the acquisitions of the Gooseberry assets and Williston Basin assets through borrowings under its revolving credit facility. ENP financed the acquisition of the Elk Basin assets through a $93.7 million contribution from EAC, $120 million of borrowings under a subordinated credit agreement with EAP Operating, LLC, a Delaware limited liability company and direct wholly owned guarantor subsidiary of EAC, and borrowings under OLLC s revolving credit facility. Please read Note 8. Long-Term Debt for additional discussion of EAC s long-term debt.

Dispositions

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

Pro Formas

The following unaudited pro forma condensed financial data was derived from the historical financial statements of EAC and from the accounting records of Anadarko to give effect to the Big Horn Basin and Williston Basin asset acquisitions and the Mid-Continent asset disposition as if they had each occurred on January 1, 2006. The unaudited pro forma condensed financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Big Horn Basin and Williston Basin asset acquisitions and the Mid-Continent asset disposition taken place on January 1, 2006 and is not intended to be a projection of future results.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31, 2007	2006
	(In thousands, except per share amounts)	
Pro forma total revenues	$ 749,659	$ 785,281
Pro forma net income	$ 20,685	$ 100,702
Pro forma net income per common share:		
Basic	$ 0.39	$ 1.94
Diluted	$ 0.38	$ 1.91

Note 4. Commitments and Contingencies

Litigation

EAC is a party to ongoing legal proceedings in the ordinary course of business. Management does not believe the result of these proceedings will have a material adverse effect on EAC s business, financial position, results of operations, or liquidity.

Leases

EAC leases office space and equipment that have remaining non-cancelable lease terms in excess of one year. The following table summarizes by year the remaining non-cancelable future payments under these operating leases as of December 31, 2008 (in thousands):

2009	$ 3,603
2010	3,609
2011	3,598
2012	3,358
2013	2,607
Thereafter	
	$ 16,775

EAC s operating lease rental expense was approximately $5.8 million, $5.5 million, and $4.6 million in 2008, 2007, and 2006, respectively.

ExxonMobil

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

In July 2008, EAC earned the right to participate in all fields by drilling the final well of the 24-well commitment program and is entitled to a 30 percent working interest in future drilling locations. EAC has the right to propose and drill wells for as long as it is engaged in continuous drilling operations.

During 2008 and 2007, EAC advanced $38.0 million and $37.7 million, respectively, to ExxonMobil for its portion of costs incurred drilling wells under the joint development agreement. At December 31, 2008, EAC had a net receivable from ExxonMobil of $79.0 million, of which $11.2 million was included in Accounts receivable, net and $67.8 million was included in Long-term receivables on the accompanying

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Consolidated Balance Sheet based on when EAC expects repayment. At December 31, 2007, EAC had a net receivable from ExxonMobil of $51.7 million, of which $12.3 million was included in Accounts receivable, net and $39.4 million was included in Long-term receivables, net on the accompanying Consolidated Balance Sheet.

Note 5. Asset Retirement Obligations

Asset retirement obligations relate to future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal. As of December 31, 2008 and 2007, EAC had $9.2 million and $6.7 million, respectively, held in escrow from which funds are released only for reimbursement of plugging and abandonment expenses on its Bell Creek properties, which is included in other long-term assets in the accompanying Consolidated Balance Sheets. The following table summarizes the changes in EAC s asset retirement obligations for the periods indicated:

	Year Ended December 31,	
	2008	2007
	(In thousands)	
Future abandonment liability at January 1	$ 28,079	$ 19,841
Wells drilled	498	145
Acquisition of properties	111	8,251
Disposition of properties		(959)
Accretion of discount	1,361	1,145
Plugging and abandonment costs incurred	(1,756)	(1,655)
Revision of previous estimates	21,276	1,311
Future abandonment liability at December 31	$ 49,569	$ 28,079

As of December 31, 2008, $48.1 million of EAC s asset retirement obligations were long-term and recorded in Future abandonment cost, net of current portion and $1.5 million were current and included in Other current liabilities on the accompanying Consolidated Balance Sheets. Approximately $4.4 million of the future abandonment liability as of December 31, 2008 represents the estimated cost for decommissioning ENP s Elk Basin natural gas processing plant. ENP expects to continue reserving additional amounts based on the estimated timing to cease operations of the natural gas processing plant.

Note 6. Capitalization of Exploratory Well Costs

EAC follows FSP No. 19-1 *Accounting for Suspended Well Costs* (FSP 19-1), which permits the continued capitalization of exploratory well costs if the well found a sufficient quantity of reserves to justify its completion as a producing well and 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

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

capitalized exploratory well costs during the periods indicated, and does not include amounts that were capitalized and subsequently expensed in the same period.

	Year Ended December 31,		
	2008	2007	2006
	(In thousands)		
Beginning balance at January 1	$ 19,479	$ 13,048	$ 6,560
Additions to capitalized exploratory well costs pending the determination of proved reserves	28,757	19,479	13,048
Reclassification to proved property and equipment based on the determination of proved reserves	(19,229)	(9,390)	(1,457)
Capitalized exploratory well costs charged to expense	(250)	(3,658)	(5,103)
Total	$ 28,757	$ 19,479	$ 13,048

All capitalized exploratory well costs have been capitalized for less than one year.

Note 7. Other Current Liabilities

Other current liabilities consisted of the following as of the dates indicated:

	December 31,	
	2008	2007
	(In thousands)	
Net profits interests payable	$ 995	$ 3,996
Income taxes payable	940	2,789
Accrued compensation	16,216	8,431
Current portion of future abandonment liability	1,511	708
Other	3,430	5,219
Total	$ 23,092	$ 21,143

Note 8. Long-Term Debt

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

	Maturity	December 31,

	Date	2008	2007
		(In thousands)	
Revolving credit facilities	3/7/2012	$ 725,000	$ 526,000
6.25% Senior Subordinated Notes	4/15/2014	150,000	150,000
6.0% Senior Subordinated Notes, net of unamortized discount of $3,960 and $4,440, respectively	7/15/2015	296,040	295,560
7.25% Senior Subordinated Notes, net of unamortized discount of $1,229 and $1,324, respectively	12/1/2017	148,771	148,676
Total		$ 1,319,811	$ 1,120,236

Senior Subordinated Notes

As of December 31, 2008 certain of EAC s subsidiaries were subsidiary guarantors of EAC s senior subordinated notes. The subsidiary guarantors may without restriction transfer funds to EAC in the form of

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

cash dividends, loans, and advances. Please read Note 16. Financial Statements of Subsidiary Guarantors for additional discussion.

The indentures governing EAC s senior subordinated notes contain certain affirmative, negative, and financial covenants, which include:

- limitations on incurrence of additional debt, restrictions on asset dispositions, and restricted payments;
- a requirement that EAC maintain a current ratio (as defined in the indentures) of not less than 1.0 to 1.0; and
- a requirement that EAC maintain a ratio of consolidated EBITDA (as defined in the indentures) to consolidated interest expense of not less than 2.5 to 1.0.

As of December 31, 2008, EAC was in compliance with all covenants of its senior subordinated notes.

If EAC experiences a change of control (as defined in the indentures), subject to certain conditions, it must give holders of its senior subordinated notes the opportunity to sell them to EAC at 101 percent of the principal amount, plus accrued and unpaid interest.

Revolving Credit Facilities

Encore Acquisition Company Senior Secured Credit Agreement

In March 2007, EAC 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 February 7, 2008, EAC amended the EAC Credit Agreement to, among other things, provide that certain negative covenants in the EAC Credit Agreement restricting hedge transactions do not apply to any oil and natural gas hedge transaction that is a floor or put transaction not requiring any future payments or delivery by EAC or any of its restricted subsidiaries. Effective May 22, 2008, EAC amended the EAC Credit Agreement to, among other things, increase interest rate margins applicable to loans made under the EAC Credit Agreement, as set forth in the table below, and increase the borrowing base to $1.1 billion. The EAC Credit Agreement provides for revolving credit loans to be made to EAC from time to time and letters of credit to be issued from time to time for the account of EAC or the account of 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 on April 1 and October 1 and upon requested special redeterminations. On December 5, 2008, the borrowing base under the EAC Credit Agreement was redetermined with no change. As of December 31, 2008, the borrowing base was $1.1 billion.

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

Loans under the EAC Credit Agreement are subject to varying rates of interest based on (1) the total 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

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

following table, and base rate loans bear interest at the base rate plus the applicable margin indicated in the following table:

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

The Eurodollar rate for any interest period (either one, two, three, or six months, as selected by EAC) is the rate per year equal to LIBOR, as published by Reuters or another source designated by Bank of America, N.A., for deposits in dollars for a similar interest period. The base rate is calculated as the higher of (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate and (2) the federal funds effective rate plus 0.5 percent.

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

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

a prohibition against incurring debt, subject to permitted exceptions;

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

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

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

restrictions on use of proceeds, investments, transactions with affiliates, 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 (as defined in the EAC Credit Agreement) to consolidated current liabilities (as defined in the EAC Credit Agreement) of not less than 1.0 to 1.0; and

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

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

EAC incurs a commitment fee on the unused portion of the EAC Credit Agreement determined based on the ratio of amounts outstanding under the EAC Credit Agreement to the borrowing base in effect on such

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

date. The following table summarizes the calculation of the commitment fee under the EAC Credit Agreement:

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

On December 31, 2008, there were $575 million of outstanding borrowings and $525 million of borrowing capacity under the EAC Credit Agreement. As of December 31, 2008, EAC was in compliance with all covenants of the EAC Credit Agreement.

Encore Energy Partners Operating LLC Credit Agreement

OLLC is a party to a five-year credit agreement dated March 7, 2007 (as amended, the OLLC Credit Agreement) with a bank syndicate including Bank of America, N.A. and other lenders. The OLLC Credit Agreement matures on March 7, 2012. On August 22, 2007, OLLC amended its credit agreement to revise certain financial covenants. The OLLC Credit Agreement provides for revolving credit loans to be made to OLLC from time to time and letters of credit to be issued from time to time for the account of OLLC or any of its restricted subsidiaries.

The aggregate amount of the commitments of the lenders under the OLLC Credit Agreement is $300 million. Availability under the OLLC Credit Agreement is subject to a borrowing base, which is redetermined semi-annually on April 1 and October 1 and upon requested special redeterminations. On December 5, 2008, the borrowing base under the OLLC Credit Agreement was redetermined with no change. As of December 31, 2008, the borrowing base was $240 million.

OLLC s obligations under the OLLC Credit Agreement are secured by a first-priority security interest in OLLC s proved oil and natural gas reserves and in the equity interests in OLLC and its restricted subsidiaries. In addition, OLLC s obligations under the OLLC Credit Agreement are guaranteed by ENP and OLLC s restricted subsidiaries. EAC consolidates the debt of ENP with that of its own; however, 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) the total 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 Total Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans

Less than .50 to 1	1.000%	0.000%
Greater than or equal to .50 to 1 but less than .75 to 1	1.250%	0.000%
Greater than or equal to .75 to 1 but less than .90 to 1	1.500%	0.250%
Greater than or equal to .90 to 1	1.750%	0.500%

The Eurodollar rate for any interest period (either one, two, three, or six months, as selected by ENP) is the rate per year equal to LIBOR, as published by Reuters or another source designated by Bank of America, N.A., for deposits in dollars for a similar interest period. The base rate is calculated as the higher of (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate and (2) the federal funds effective rate plus 0.5 percent.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 that include, among others:

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against purchasing or redeeming capital stock, or prepaying indebtedness, subject to permitted exceptions;
- a restriction on creating liens on the assets of ENP, OLLC and its restricted subsidiaries, subject to permitted exceptions;
- restrictions on merging and selling assets outside the ordinary course of business;
- restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business;
- a provision limiting oil and natural gas hedging transactions (other than puts) to a volume not exceeding 75 percent of anticipated production from proved producing reserves;
- a requirement that ENP and OLLC maintain a ratio of consolidated current assets (as defined in the OLLC Credit Agreement) to consolidated current liabilities (as defined in the OLLC Credit Agreement) of not less than 1.0 to 1.0;
- a requirement that ENP and OLLC maintain a ratio of consolidated EBITDA (as defined in the OLLC Credit Agreement) to the sum of consolidated net interest expense plus letter of credit fees of not less than 1.5 to 1.0;
- a requirement that ENP and OLLC maintain a ratio of consolidated EBITDA (as defined in the OLLC Credit Agreement) to consolidated senior interest expense of not less than 2.5 to 1.0; and
- a requirement that ENP and OLLC maintain a ratio of consolidated funded debt (excluding certain related party debt) to consolidated adjusted EBITDA (as defined in the OLLC Credit Agreement) of not more than 3.5 to 1.0.

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

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

	Commitment

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

On December 31, 2008, there were $150 million of outstanding borrowings and $90 million of borrowing capacity under the OLLC Credit Agreement. As of December 31, 2008, OLLC was in compliance with all covenants of the OLLC Credit Agreement.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Long-Term Debt Maturities

The following table illustrates EAC s long-term debt maturities as of December 31, 2008:

	Payments Due by Period (In thousands)						
	Total	2009	2010	2011	2012	2013	Thereafter
6.25% Notes	$ 150,000	$	$	$	$	$	$ 150,000
6.0% Notes	300,000						300,000
7.25% Notes	150,000						150,000
Revolving credit facilities	725,000				725,000		
Total	$ 1,325,000	$	$	$	$ 725,000	$	$ 600,000

During 2008, 2007, and 2006, the weighted average interest rate for total indebtedness was 5.6 percent, 6.9 percent, and 6.1 percent, respectively.

Note 9. Taxes

Income Taxes

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

	Year Ended December 31, (In thousands)		
	2008	2007	2006
Federal:			
Current	$ (7,626)	$ (1,888)	$ (3,785)
Deferred	(222,651)	(11,229)	(48,327)
Total federal	(230,277)	(13,117)	(52,112)
State, net of federal benefit:			
Current	(1,381)		(401)
Deferred	(9,963)	(1,359)	(2,893)
Total state	(11,344)	(1,359)	(3,294)
Income tax provision(a)	$ (241,621)	$ (14,476)	$ (55,406)

(a) Excludes an excess tax benefit related to stock option exercises and vesting of restricted stock, which was recorded directly to additional paid-in capital, of $2.1 million and $1.3 million during 2008 and 2006, respectively. During 2007, EAC did not recognize an excess tax benefit related to stock option exercises and vesting of restricted stock.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended December 31, 2008	2007	2006
		(In thousands)	
Income before income taxes, net of minority interest	$ 672,433	$ 31,631	$ 147,804
Income taxes at the Federal statutory rate	$ (235,352)	$ (11,071)	$ (51,731)
State income taxes, net of federal benefit	(12,861)	(716)	(3,440)
Enactment of the Texas margin tax			(1,062)
Change in estimated future state tax rate	2,113	(495)	1,208
Nondeductible deferred compensation expense	(1,124)	(1,963)	
Permanent and other	5,603	(231)	(381)
Income tax provision	$ (241,621)	$ (14,476)	$ (55,406)

A Texas franchise tax reform measure signed into law in May 2006 caused the Texas franchise tax to be applicable to numerous types of entities that previously were not subject to the tax, including several of EAC s subsidiaries. EAC adjusted its net deferred tax balances using the new higher marginal tax rate it expects to be effective when those deferred taxes reverse resulting in a charge of $1.1 million during 2006.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The major components of net current deferred taxes and net long-term deferred taxes were as follows as of the dates indicated:

	December 31, 2008	December 31, 2007
	(In thousands)	
Current:		
Assets:		
Unrealized hedge loss in accumulated other comprehensive loss	$ 222	$ 1,071
Derivative fair value loss		15,442
Other	2,422	3,907
Total current deferred tax assets	2,644	20,420
Liabilities:		
Derivative fair value gain	(108,412)	
Total current deferred tax liabilities	(108,412)	
Net current deferred tax asset (liability)	$ (105,768)	$ 20,420
Long-term:		
Assets:		
Alternative minimum tax credits	$ 2,300	$ 2,676
Unrealized hedge loss in accumulated other comprehensive loss	735	
Derivative fair value loss		10,775
Section 43 credits	8,889	13,227
Net operating loss carryforward	1,439	23,806
Change in accounting method	5,583	
Asset retirement obligations	17,842	11,266
Deferred equity-based compensation	6,757	6,599
Other	1,556	
Total long-term deferred tax assets	45,101	68,349
Liabilities:		
Derivative fair value gain	(2,711)	
Other		(11,076)
Book basis of oil and natural gas properties in excess of tax basis	(459,305)	(370,187)
Total current deferred tax liabilities	(462,016)	(381,263)

Net long-term deferred tax liability	$ (416,915)	$ (312,914)

At December 31, 2008, EAC had state net operating loss (NOL) carryforwards, which are available to offset future regular state taxable income, if any. At December 31, 2008, EAC also had federal alternative minimum tax (AMT) credits, which are available to reduce future federal regular tax liabilities in excess of AMT. EAC believes it is more likely than not that the NOL carryforwards will offset future taxable income prior to their expiration. The AMT credits have no expiration. Therefore, a valuation allowance against these

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

deferred tax assets is not considered necessary. If unused, these carryforwards and credits will expire as follows:

Expiration Date	Federal AMT Credits	State NOL
	(In thousands)	
2012	$	$ 41
2014		299
2024		196
2025		656
2026		152
2027		95
Indefinite	2,300	
	$ 2,300	$ 1,439

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

EAC performs a periodic evaluation of tax positions to review the appropriate recognition threshold for each tax position recognized in EAC s financial statements, including, but not limited to:

a review of documentation of tax positions taken on previous returns including an assessment of whether EAC followed industry practice or the applicable requirements under the tax code;

a review of open tax returns (on a jurisdiction by jurisdiction basis) as well as supporting documentation used to support those tax returns;

a review of the results of past tax examinations;

a review of whether tax returns have been filed in all appropriate jurisdictions;

a review of existing permanent and temporary differences; and consideration of any tax planning strategies that may have been used to support realization of deferred tax assets.

On the date of adoption of FIN 48 and as of December 31, 2008 and 2007, all of EAC s tax positions met the more-likely-than-not threshold prescribed by FIN 48. As a result, no additional tax expense, interest, or penalties have been accrued. EAC includes interest assessed by taxing authorities in Interest expense and penalties related to income taxes in Other expense on its Consolidated Statements of Operations. For 2008, 2007, and 2006, EAC recorded only a nominal amount of interest and penalties on certain tax positions.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Taxes Other than Income Taxes

Taxes other than income taxes included the following for the periods indicated:

	Year Ended December 31, 2008	2007	2006
	(In thousands)		
Production and severance taxes	$ 96,468	$ 65,145	$ 43,458
Ad valorem taxes	14,176	9,440	6,322
Franchise, payroll, and other taxes	2,479	2,263	1,745
Total	$ 113,123	$ 76,848	$ 51,525

Note 10. Stockholders Equity

Public Offering of Common Stock

In April 2006, EAC issued 4,000,000 shares of its common stock at a price of $32.00 per share. The net proceeds of approximately $127.1 million were used to (1) reduce outstanding borrowings under EAC s revolving credit facility, (2) invest in oil and natural gas activities, and (3) pay general corporate expenses.

Stock Option Exercises and Restricted Stock Vestings

During 2008, 2007, and 2006, employees of EAC exercised 45,616 options, 128,709 options, and 178,174 options, respectively, for which EAC received proceeds of $0.6 million, $1.6 million, and $2.3 million in 2008, 2007, and 2006, respectively. During 2008, 2007, and 2006, employees elected to satisfy minimum tax withholding obligations related to the vesting of restricted stock by directing EAC to withhold 32,946 shares, 38,978 shares, and 24,362 shares of common stock, respectively, which are accounted for as treasury stock until they are formally retired.

Preferred Stock

EAC s authorized capital stock includes 5,000,000 shares of preferred stock, none of which were issued and outstanding at December 31, 2008 or 2007. EAC does not plan to issue any shares of preferred stock.

Stock Repurchase Programs

In December 2007, EAC announced that the Board approved a share repurchase program authorizing EAC to repurchase up to $50 million of its common stock. During 2008, EAC completed the share repurchase program by repurchasing and retiring 1,397,721 shares of its outstanding common stock at an average price of approximately $35.77 per share.

In October 2008, EAC announced that the Board approved a new share repurchase program authorizing EAC to repurchase up to $40 million of its common stock. As of December 31, 2008, 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 new share repurchase program.

Issuance of ENP Common Units

In May 2008, ENP acquired an existing net profits interest in certain of its properties in the Permian Basin of West Texas in exchange for 283,700 common units which were valued at $5.8 million at the time of the acquisition. As a result, EAC s percentage ownership in ENP went from approximately 67 percent to approximately 66 percent. Additionally, EAC reclassified $3.5 million from Minority interest in consolidated

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

partnership to Additional paid-in capital on the accompanying Consolidated Balance Sheets to recognize gains on the issuance of ENP s common units.

In December 2008, as a result of the conversion of ENP s management incentive units into ENP common units, EAC recorded a $13.9 million economic uniformity adjustment by reducing Additional paid-in capital and increasing Minority interest in consolidated partnership in the accompanying Consolidated Balance Sheets.

In September 2007, ENP completed its IPO of 9,000,000 common units at a price to the public of $21.00 per unit, and in October 2007, the underwriters exercised their over-allotment option to purchase an additional 1,148,400 common units. As a result, EAC s percentage ownership in ENP went from 100 percent to approximately 58 percent. Additionally, EAC reclassified $77.6 million from Minority interest in consolidated partnership to Additional paid-in capital on the accompanying Consolidated Balance Sheets to recognize gains on the issuance of ENP s common units.

Rights Plan

In October 2008, the Board declared a dividend of one right for each outstanding share of EAC s common stock to stockholders of record at the close of business on November 7, 2008. Each right entitles the registered holder to purchase from EAC a unit consisting of one one-hundredth of a share of Series A Junior Participating Preferred Stock, par value $0.01 per share, at a purchase price of $120 per fractional share, subject to adjustment.

The rights will separate from the common stock and a Distribution Date will occur, with certain exceptions, upon the earlier of (1) ten days following a public announcement that a person or group of affiliated or associated persons (an Acquiring Person) has acquired, or obtained the right to acquire, beneficial ownership of more than 10 percent of EAC s then-outstanding shares of common stock, or (2) ten business days following the commencement of a tender offer or exchange offer that would result in a person s becoming an Acquiring Person. In certain circumstances, the Distribution Date may be deferred by the Board. The rights are not exercisable until the Distribution Date and will expire at the close of business on October 28, 2011, unless earlier redeemed or exchanged by EAC.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 11. EPS

EAC calculates EPS in accordance with SFAS 128. The following table reflects EPS computations for the periods indicated:

	Year Ended December 31,		
	2008	2007	2006
	(In thousands, except per share data)		
Numerator:			
Net income	$ 430,812	$ 17,155	$ 92,398
Denominator:			
Denominator for basic EPS:			
Weighted average shares outstanding	52,270	53,170	51,865
Effect of dilutive options(a)	596	459	491
Effect of dilutive restricted stock(b)	548	515	380
Denominator for diluted EPS	53,414	54,144	52,736
Net income per common share:			
Basic	$ 8.24	$ 0.32	$ 1.78
Diluted	$ 8.07	$ 0.32	$ 1.75

(a) For 2008, 2007, and 2006, options to purchase 157,614, 121,651, and 103,856 shares of common stock, respectively, were outstanding but excluded from the diluted EPS calculations because their effect would have been antidilutive.

(b) For 2008 and 2007, 17,511 and 59,865 shares of restricted stock, respectively, were outstanding but excluded from the diluted EPS calculations because their effect would have been antidilutive. There were no antidilutive shares of restricted stock for 2006.

Note 12. Employee Benefit Plans

401(k) Plan

EAC made contributions to its 401(k) plan, which is a voluntary and contributory plan for eligible employees based on a percentage of employee contributions, of $3.6 million, $2.2 million, and $1.1 million during 2008, 2007, and 2006, respectively. EAC s 401(k) plan does not allow employees to invest in securities of EAC.

Incentive Stock Plans

In May 2008, EAC s stockholders approved the 2008 Incentive Stock Plan (the 2008 Plan). No additional awards will be granted under EAC s 2000 Incentive Stock Plan (the 2000 Plan) and any previously granted awards outstanding under the 2000 Plan will remain outstanding in accordance with their terms. The purpose of the 2008 Plan is to attract, motivate, and retain selected employees of EAC and to provide EAC with the ability to provide incentives more directly linked to the profitability of the business and increases in shareholder value. All directors and full-time regular employees of EAC and its subsidiaries and affiliates are eligible to be granted awards under the 2008 Plan.
The total number of shares of common stock reserved for issuance pursuant to the 2008 Plan is 2,400,000. No more than 1,600,000 shares of EAC s common stock will be available for grants of full value stock awards, such as restricted stock or stock units. As of December 31, 2008, there were 2,389,000 shares available for issuance under the 2008 Plan. Shares delivered or withheld for payment of the exercise price of an option, shares withheld for payment of tax

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

withholding, shares subject to options or other awards that expire or are forfeited, and restricted shares that are forfeited will again become available for issuance under the 2008 Plan. The 2008 Plan provides for the granting of cash awards, incentive stock options, non-qualified stock options, restricted stock, and stock appreciation rights at the discretion of the Compensation Committee of the Board. The Board also has a Restricted Stock Award Committee whose sole member is Jon S. Brumley, EAC s Chief Executive Officer and President. The Restricted Stock Award Committee may grant up to 25,000 shares of restricted stock on an annual basis to non-executive employees at its discretion.

The 2008 Plan contains the following individual limits:

- an employee may not be granted awards covering or relating to more than 300,000 shares of common stock during any calendar year;

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

- an employee may not receive awards consisting of cash (including cash awards that are granted as performance awards) in respect of any calendar year having a value determined on the grant date in excess of $5.0 million.

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

During 2008, 2007, and 2006, EAC recorded non-cash stock-based compensation expense related to its incentive stock plans in the accompanying Consolidated Statements of Operations of $9.0 million, $9.2 million, and $9.0 respectively, and recognized income tax benefits related thereto of $3.4 million, $3.4 million, and $3.2 million, respectively. During 2008, 2007, and 2006, EAC also capitalized $2.3 million, $1.3 million, and $1.1 million, respectively, of non-cash stock-based compensation cost as a component of Properties and equipment in the accompanying Consolidated Balance Sheets. Non-cash stock-based compensation expense has been allocated to LOE and general and administrative (G&A) expense based on the allocation of the respective employees cash compensation.

Please read Note 17. ENP for a discussion of ENP s equity-based compensation plan.

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 was estimated on the grant date using a Black-Scholes option valuation model based on the assumptions noted in the following table. The expected volatility was based on the historical volatility of EAC s common stock for a period of time commensurate with the expected term of the options. For options granted prior to January 1, 2008, EAC used the simplified method prescribed by SAB No. 107, *Valuation of Share-Based Payment Arrangements for Public Companies* to estimate the expected term of the options, which was calculated as the average midpoint between each vesting date and the life of the option. For options granted subsequent to December 31, 2007, EAC determined the expected life of the options based on an analysis of historical exercise and forfeiture behavior as well as expectations about future behavior. The risk-free interest rate is

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

	Year Ended December 31, 2008	2007	2006
Expected volatility	33.7%	35.7%	42.8%
Expected dividend yield	0.0%	0.0%	0.0%
Expected term (in years)	6.25	6.0	6.0
Risk-free interest rate	3.0%	4.8%	4.6%

The following table summarizes the changes in EAC s outstanding options for the periods indicated:

	Year Ended December 31, 2008				2007		2006	
	Number of Options	Weighted Average Strike Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (In thousands)	Number of Options	Weighted Average Strike Price	Number of Options	Weighted Average Strike Price
Outstanding at beginning of year	1,381,782	$ 16.03			1,337,118	$ 14.44	1,440,812	$ 13.20
Granted	176,170	33.76			200,059	25.73	122,890	31.10
Forfeited or expired	(14,923)	30.83			(26,686)	27.15	(48,410)	24.65
Exercised	(45,616)	14.11			(128,709)	12.34	(178,174)	13.14
Outstanding at end of year	1,497,413	18.02	5.1	$ 13,224	1,381,782	16.03	1,337,118	14.44
Exercisable at end of year	1,177,015	14.65	4.2	13,224	1,103,018	13.25	1,076,815	11.90

The weighted average fair value per share of options granted during 2008, 2007, and 2006 was $13.15, $11.16, and $14.96, respectively. The total intrinsic value of options exercised during 2008, 2007, and 2006 was $1.6 million, $2.3 million, and $2.4 million, respectively. During 2008, 2007, and 2006, EAC received proceeds from the exercise of stock options of $0.5 million, $1.6 million, and $2.3 million, respectively. During 2008 and 2006, EAC recognized income tax benefits related to stock options of $0.5 million and $0.9 million, respectively. During 2007, EAC did not recognize any income tax benefits related to stock options. At December 31, 2008, EAC had $1.1 million of total unrecognized compensation cost related to unvested stock options, which is expected to be recognized over a weighted average period of 1.9 years.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Additional information about options outstanding and exercisable at December 31, 2008 is as follows:

Year of Grant	Range of Strike Prices Per Share	Weighted Number of Options Outstanding	Average Life (Years)	Weighted Average Strike Price	Number of Options Exercisable
2001	$8.33 to $9.33	409,486	2.5	$ 8.85	409,486
2002	$8.50 to $12.40	284,085	3.8	11.94	284,085
2003	$11.49 to $13.61	35,965	4.5	12.28	35,965
2004	$17.17 to $19.77	259,075	5.1	17.55	259,075
2005	$26.55	68,105	6.1	26.55	68,105
2006	$31.10	92,823	7.1	31.10	61,716
2007	$25.73	181,174	8.1	25.73	58,583
2008	$33.76	166,700	9.1	33.76	
		1,497,413			1,177,015

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 2008, 2007, and 2006, EAC recognized expense related to restricted stock of $7.6 million, $7.6 million, and $7.3 million, respectively. During 2008 and 2006, EAC recognized income tax benefits related to the vesting of restricted stock of $1.6 million and $0.4 million, respectively. During 2007, EAC did not recognize any income tax benefits related to the vesting of restricted stock. The following table summarizes the changes in the number of EAC s unvested restricted stock awards and their related weighted average grant date fair value for 2008:

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2008	918,338	$ 27.07
Granted	314,086	37.02
Vested	(256,785)	25.63
Forfeited	(37,232)	29.59
Outstanding at December 31, 2008	938,407	30.67

During 2008, 2007, and 2006, EAC issued 241,515 shares, 169,453 shares, and 277,162 shares, respectively, of restricted stock to employees and members of the Board, the vesting of which is dependent only on the passage of time and continued employment. The following table illustrates outstanding restricted stock at December 31, 2008 the vesting of which is dependent only on the passage of time and continued employment:

	Year of Vesting				
Year of Grant	**2009**	**2010**	**2011**	**2012**	**Total**
2004	25,119				25,119
2005	71,483	71,483			142,966
2006	169,408	60,793			230,201
2007	75,014	79,183	79,184	4,167	237,548
2008	52,827	52,832	76,836	52,839	235,334
Total	393,851	264,291	156,020	57,006	871,168

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During 2008, 2007, and 2006, EAC issued 72,571 shares, 175,180 shares, and 151,447 shares of restricted stock to certain members of senior management, the vesting of which is dependent not only on the passage of time and continued employment, but also on the achievement of certain performance measures. The performance measures related to the 2007 and 2006 awards were met and therefore, vesting depends only on the passage of time and continued employment. The following table illustrates outstanding restricted stock at December 31, 2008 the vesting of which is dependent not only on the passage of time and continued employment, but also on the achievement of certain performance measures:

	Year of Vesting				
Year of Grant	**2009**	**2010**	**2011**	**2012**	**Total**
2008	16,810	16,810	16,810	16,809	67,239

As of December 31, 2008, EAC had $8.2 million of total unrecognized compensation cost related to unvested restricted stock, which is expected to be recognized over a weighted average period of 2.7 years. None of EAC s unvested restricted stock is subject to variable accounting. During 2008, 2007, and 2006, there were 256,785 shares, 184,867 shares, and 101,377 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 32,946 shares, 38,978 shares, and 24,362 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 2008, 2007, and 2006 was $8.7 million, $5.3 million, and $2.6 million, respectively.

Note 13. Financial Instruments

The following table sets forth EAC s book value and estimated fair value of financial instrument assets (liabilities) as of the dates indicated:

	December 31,			
	2008		2007	
	Book Value	Fair Value	Book Value	Fair Value
	(In thousands)			
Cash and cash equivalents	$ 2,039	$ 2,039	$ 1,704	$ 1,704
Accounts receivable, net	129,065	129,065	134,880	134,880
Plugging bond	824	1,202	777	921
Bell Creek escrow	9,229	9,241	6,701	6,728
Accounts payable	10,017	10,017	(21,548)	(21,548)
6.25% Notes	(150,000)	(101,250)	(150,000)	(138,375)
6.0% Notes	(296,040)	(194,250)	(295,560)	(264,750)
7.25% Notes	(148,771)	(94,500)	(148,676)	(143,813)

Revolving credit facilities	(725,000)	(725,000)	(526,000)	(526,000)
Commodity derivative contracts	387,612	387,612	9,798	9,798
Deferred premiums on commodity derivative contracts	(67,610)	(67,610)	(51,926)	(51,926)
Interest rate swaps	(4,559)	(4,559)		

The book value of cash and cash equivalents, accounts receivable, net, and accounts payable approximate fair value due to the short-term nature of these instruments. The fair values of the Notes were determined using open market quotes. The difference between book value and fair value 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. The plugging bond and Bell Creek escrow are included in Other assets on the accompanying

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 and Bell Creek escrow were determined using open market quotes. Commodity derivative contracts and interest rate swaps are marked-to-market each quarter.

Derivative Financial Instruments

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.

As of December 31, 2008, EAC had $67.6 million of deferred premiums payable of which $5.4 million was long-term and included in Derivatives in the non-current liabilities section of the accompanying Consolidated Balance Sheet and $62.2 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 January 2009 to January 2010. EAC recorded these premiums at their net present value at the time the contract was entered into and accretes that value to the eventual settlement price by recording interest expense each period.

From time to time, EAC sells floors with a strike price below the strike price of the purchased floors in order to partially finance the premiums paid on the purchased floors. Together the two floors, known as a floor spread or put spread, have a lower premium cost than a traditional floor contract but provide price protection only down to the strike price of the short floor. As with EAC s other commodity derivative contracts, these are marked-to-market each quarter through Derivative fair value loss (gain) in the accompanying Consolidated Statements of Operations. In the following tables, the purchased floor component of these floor spreads are shown net and included with EAC s other floor contracts.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following tables summarize EAC s open commodity derivative contracts as of December 31, 2008:

Oil Derivative Contracts

Period	Average Daily Floor Volume (Bbl)	Weighted Average Floor Price (per Bbl)	Average Daily Short Floor Volume (Bbl)	Weighted Average Short Floor Price (per Bbl)	Average Daily Cap Volume (Bbl)	Weighted Average Cap Price (per Bbl)	Average Daily Swap Volume (Bbl)	Weighted Average Swap Price (per Bbl)	Asset Fair Market Value (In thousands)
2009(a)									$ 342,063
	11,630	$ 110.00		$		$	2,000	$ 90.46	
	8,000	80.00			440	97.75	500	89.39	
			(5,000)	50.00			1,000	68.70	
2010									17,618
	880	80.00			440	93.80			
	2,000	75.00			1,000	77.23			
2011									15,112
	1,880	80.00			1,440	95.41			
	1,000	70.00							
									$ 374,793

(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

Period	Average Daily Floor Volume (Mcf)	Weighted Average Floor Price (per Mcf)	Average Daily Short Floor Volume (Mcf)	Weighted Average Short Floor Price (per Mcf)	Average Daily Cap Volume (Mcf)	Weighted Average Cap Price (per Mcf)	Average Daily Swap Volume (Mcf)	Weighted Average Swap Price (per Mcf)	Asset Fair Market Value (In thousands)
2009									$ 7,281
	3,800	$ 8.20		$	3,800	$ 9.83		$	
	3,800	7.20							
	1,800	6.76							

2010							4,690
	3,800	8.20	3,800	9.58	902	6.30	
	4,698	7.26					
2011							424
	898	6.76			902	6.70	
2012							424
	898	6.76			902	6.66	
							$ 12,819

Interest Rate Swaps. ENP manages interest rate risk with interest rate swaps whereby it swaps floating rate debt under the OLLC Credit Agreement with a weighted average fixed rate. These interest rate swaps

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

were designated as cash flow hedges. The following table summarizes ENP s open interest rate swaps as of December 31, 2008:

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

As of December 31, 2008, the fair market value of ENP s interest rate swaps was a net liability of $4.6 million of which, $1.3 million was current and included in the current liabilities line Derivatives and $3.3 million was long-term and included in the other liabilities line Derivatives in the accompanying Consolidated Balance Sheets. During 2008, settlements of interest rate swaps increased EAC s consolidated interest expense by approximately $0.2 million.

Current Period Impact. As a result of commodity derivative contracts which were previously designated as hedges, EAC recognized a pre-tax reduction in oil and natural gas revenues of approximately $2.9 million, $53.6 million, and $60.3 million in 2008, 2007, and 2006, respectively. EAC also recognized derivative fair value gains and losses related to: (1) ineffectiveness on designated derivative contracts; (2) changes in the market value of derivative contracts; (3) settlements on commodity derivative contracts; and (4) premium amortization. The following table summarizes the components of Derivative fair value loss (gain) for the periods indicated:

	Year Ended December 31, 2008	2007 (In thousands)	2006
Ineffectiveness on designated derivative contracts	$ 372	$	$ 1,748
Mark-to-market loss (gain) derivative contracts	(365,495)	36,272	(31,205)
Premium amortization	62,352	41,051	13,926
Settlements on commodity derivative contracts	(43,465)	35,160	(8,857)
Total derivative fair value loss (gain)	$ (346,236)	$ 112,483	$ (24,388)

Counterparty Risk. At December 31, 2008, EAC had committed greater than 10 percent of either its oil or natural gas commodity derivative contracts to the following counterparties:

	Percentage of Oil Derivative	Percentage of

Counterparty	**Contracts Committed**	**Natural Gas Derivative Contracts Committed**
BNP Paribas	22%	24%
Calyon	15%	31%
Fortis	11%	
UBS	16%	
Wachovia	11%	38%

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 separately each derivative financial transaction between the counterparty and EAC, 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

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Accumulated Other Comprehensive Loss. At December 31, 2008, accumulated other comprehensive loss consisted entirely of deferred losses, net of tax, on ENP s interest rate swaps that are designated as hedges of $1.7 million. At December 31, 2007, accumulated other comprehensive loss consisted entirely of deferred losses, net of tax, on commodity derivative contracts that were previously designated as hedges of $1.8 million.

EAC expects to reclassify $1.3 million of deferred losses associated with ENP s interest rate swaps from accumulated other comprehensive loss to interest expense during 2009. EAC also expects to reclassify $0.2 million of income taxes associated with ENP s interest rate swaps from accumulated other comprehensive loss to income tax benefit during 2009.

Note 14. Fair Value Measurements

As discussed in Note 2. Summary of Significant Accounting Policies, EAC adopted SFAS 157 on January 1, 2008, as it relates to financial assets and liabilities. SFAS 157 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 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 are used to estimate the fair values of EAC s financial 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 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 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 Fair values of oil and natural gas floors and caps were estimated using pricing models and discounted cash flow methodologies based on inputs that are not readily available in public markets.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth EAC s financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008:

Description	December 31, 2008	Fair Value Measurements at Reporting Date Using: 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	$ 37,458	$	$ 37,458	$
Oil derivative contracts floors and caps	337,335			337,335
Natural gas derivative contracts swaps	78		78	
Natural gas derivative contracts floors and caps	12,741			12,741
Interest rate swaps	(4,559)		(4,559)	
Total	$ 383,053	$	$ 32,977	$ 350,076

The following table summarizes the changes in the fair value of EAC s Level 3 financial assets and liabilities for 2008:

	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, 2008	$ 16,647	$ 7,081	$ 23,728
Total gains (losses):			
Included in earnings	350,584	5,104	355,688
Purchases, issuances, and settlements	(29,896)	556	(29,340)

Balance at December 31, 2008	$ 337,335	$ 12,741	$ 350,076
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	$ 350,584	$ 5,104	$ 355,688

Since EAC does not use hedge accounting for its commodity derivative contracts, all gains and losses on its Level 3 financial assets and liabilities are included in Derivative fair value loss (gain) in the accompanying Consolidated Statements of Operations. All fair values reflected in the table above and in the accompanying Consolidated Balance Sheet have been adjusted for non-performance risk, resulting in a reduction of the net asset of approximately $3.4 million as of December 31, 2008.

Note 15. Related Party Transactions

During 2008, 2007, and 2006, EAC received approximately $160.5 million, $85.3 million, and $7.4 million, respectively, from affiliates of Tesoro Corporation (Tesoro) related to gross oil and natural gas production sold from wells operated by Encore Operating. Mr. John V. Genova, a member of the Board, served as an employee of Tesoro until May 2008.

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

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 16. Financial Statements of Subsidiary Guarantors

In February 2007, EAC formed certain non-guarantor subsidiaries in connection with the formation of ENP. Please read Note 17. ENP for additional discussion of ENP s formation and other matters. As of December 31, 2008 and 2007, certain of EAC s wholly owned subsidiaries were subsidiary guarantors of EAC s senior subordinated notes. The subsidiary guarantees are full and unconditional, and joint and several. The subsidiary guarantors may, without restriction, transfer funds to EAC in the form of cash dividends, loans, and advances. In accordance with the United States Securities and Exchange Commission (SEC) rules, EAC has prepared condensed consolidating financial statements in order to quantify the financial position, results of operations, and cash flows of the subsidiary guarantors. The following Condensed Consolidating Balance Sheets as of December 31, 2008 and 2007 and Condensed Consolidating Statements of Operations and Comprehensive Income (Loss) and Condensed Consolidating Statements of Cash Flows for the years ended December 31, 2008 and 2007 present consolidating financial information for Encore Acquisition Company (Parent) on a stand alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries. As of December 31, 2008, EAC s guarantor subsidiaries were:

EAP Properties, Inc.;

EAP Operating, LLC;

Encore Operating; and

Encore Operating Louisiana, LLC.

As of December 31, 2008, 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, and revenues and expenses between the Parent, guarantor subsidiaries, and non-guarantor subsidiaries are shown prior to consolidation with the Parent and then eliminated to arrive at consolidated totals per the accompanying consolidated financial statements of EAC. Prior to February 2007, all of EAC s subsidiaries were subsidiary guarantors of EAC s senior subordinated notes. Therefore, a Condensed Consolidating Statement of Operations and Comprehensive Income (Loss) and a Condensed Consolidating

Statement of Cash Flows are not presented for 2006.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONDENSED CONSOLIDATING BALANCE SHEET
December 31, 2008

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
			(In thousands)		
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				