ENCORE ACQUISITION CO
Form 10-K
March 11, 2004

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2003

Encore Acquisition Company

(Exact name of registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation)*	**001-16295** *(Commission File Number)*	**75-2759650** *(IRS Employer Identification No.)*
777 Main Street **Suite 1400** **Fort Worth, Texas**		**76102** *(Zip Code)*

(Address of principal executive offices)

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

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

None

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 an accelerated filer (as defined in Exchange Act Rule 12b-2) Yes þ No o

Aggregate market value of the voting and non-voting common stock held by non-affiliates of the Registrant as of June 30, 2003 (the last business day of Registrant s most recently completed second fiscal quarter	$222,980,532
Number of shares of Common Stock, $0.01 par value, outstanding as of February 27, 2004	30,403,189

DOCUMENTS INCORPORATED BY REFERENCE

Parts of the definitive proxy statement for the Registrant s annual meeting of stockholders to be held on April 29, 2004 are incorporated by reference into Part III of this report on Form 10-K.

ENCORE ACQUISITION COMPANY

2003 ANNUAL REPORT ON FORM 10-K

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This annual report on Form 10-K (the 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 or on behalf of Encore Acquisition Company or its subsidiaries. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations for a description of various factors that could materially affect the ability of Encore Acquisition Company 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 at the end of Item 7A, beginning on page 45, under the caption Glossary of Oil and Natural Gas Terms. In addition, all production and reserve volumes disclosed in this Report represent amounts net to Encore Acquisition Company.

PART I

Items 1 and 2. *Business and Properties*

General

Our Business. We are a growing independent energy company engaged in the acquisition, development, exploitation, and production of onshore North American oil and natural gas reserves. Since our inception in 1998, we have sought to acquire high quality assets with potential for upside through low-risk development drilling projects. Our properties are currently located in the Williston Basin of Montana and North Dakota, the Permian Basin of Texas and New Mexico, the Anadarko Basin of Oklahoma, the Powder River Basin of Montana, the Paradox Basin of Utah, and the North Louisiana Salt Basin of Louisiana. During the three years ended December 31, 2003, we invested $134.8 million in acquiring producing oil and natural gas properties and we have invested another $266.5 million on development and exploitation of these properties.

Most Valuable Asset. The Cedar Creek Anticline (CCA), in the Williston Basin of Montana and North Dakota, represented 73% of our total proved reserves as of December 31, 2003. The CCA is our most valuable asset today and in the foreseeable future. A large portion of our future success revolves around future exploitation of and production from this property through primary, secondary, and tertiary recovery techniques.

Recent Acquisitions. On March 2, 2004, we entered into a stock purchase agreement to acquire all of the outstanding common stock of Cortez Oil & Gas, Inc., a privately held, independent oil and gas company (Cortez), for total consideration of approximately $123.0 million. We intend to fund the acquisition initially with bank debt under our existing credit facility. The oil and natural gas assets to be acquired from Cortez are in the same areas as our producing properties located in the CCA of Montana, the Permian Basin of West Texas and Southeastern New Mexico, and in our Mid Continent area, including the Anadarko and Arkoma Basins of Oklahoma and the Barnett Shale north of Fort Worth, Texas. We expect to close the transaction in the second quarter of 2004.

On July 31, 2003, we completed an acquisition of interests in natural gas properties in North Louisiana for $52.5 million before purchase price adjustments. Subsequent to the initial acquisition, we have purchased additional interests in the properties. The properties are located in the Elm Grove Field in Bossier Parish, Louisiana and are non-operated working interests ranging from 2% to 38% across 1,800 net acres in 15 sections. The properties are substantially all natural gas. For the fourth quarter of 2003, the properties average daily production was 8,255 Mcfe.

Drilling. In 2003, we drilled 105 gross operated wells and participated in drilling another 33 gross non-operated wells for a total of 138 gross wells for the year. On a net basis, we drilled 95.7 operated wells and participated in 7.9 non-operated wells in 2003.

Oil and Natural Gas Reserves. In 2003, our reserve growth was achieved through acquisitions, high pressure air injection (HPAI) and organically through the drill bit by developing a portion of our inventory of drilling projects that we expect will extend over the next several years. We continue to pursue high-quality assets and to replenish our drilling inventory through acquisitions. During 2003, we added 20.7 MMBOE of oil and natural gas reserves for finding, development, and acquisition, or FD&A, replacement costs of $7.42 per BOE, which replaced 255% of the 8.1 MMBOE we produced in 2003. Including downward revisions of 3.5 MMBOE, the development program added 14.4 MMBOE (178% of our production) at an average FD&A cost of $6.86 per BOE. Included in our reserve additions are 12.5 MMBOE of HPAI in the CCA of Montana and North Dakota. Our three year average FD&A cost, including revisions, is $5.60 per BOE, with a reserve replacement ratio of 329%.

The following table sets forth our total proved reserves, average daily production and reserve-to-production ratio, or R/ P index, in our principal areas of operation as of December 31, 2003 and for the year then ended.

	Proved Reserves at December 31, 2003 (MBOE)	**Percent of Total**	**Average Daily Production for 2003 (BOE/d)**	**Percent of Total**	**R/P Index**
Cedar Creek Anticline(1)	103,601	73%	13,490	61%	21.0
Permian Basin(2)	22,424	16%	4,554	20%	13.5
Rockies(3)	6,620	5%	2,935	13%	6.2
Mid Continent(4)	8,245	6%	1,239	6%	11.2
Total	140,890	100%	22,218	100%	17.4

(1) Our CCA properties, which produce mainly from porous dolomites drilled on 40 to 80 acre spacing intervals, have longer reserve lives than our other properties because the low permeability level encountered within those producing intervals require a longer time to produce the reserves in place. This results in a lower production decline rate.

(2) Permian Basin includes the Central Permian, Indian Basin and Crockett properties.

(3) Rockies includes the Paradox Basin, Lodgepole and Bell Creek properties.

(4) Mid Continent includes the Elm Grove and Verden properties. The Elm Grove properties were acquired on July 31, 2003, and the R/ P index shown in the table is calculated by annualizing our production since the acquisition.

Public Offering. On November 13, 2003, we priced a public offering of 8.0 million shares of our common stock at a price to the public of $20.25 per share. The underwriters also exercised their over-allotment option for an additional 1.06 million shares of common stock, at a price of $20.25 per share, on December 2, 2003, for a total of 9.06 million shares. We used all of the net proceeds to repurchase 6,866,643 shares of our common stock from J.P. Morgan Partners (SBIC), LLC (J.P. Morgan) and 2,193,357 shares from Warburg, Pincus Equity Partners L.P. (Warburg Pincus) at a price of $19.3775 per share. The 9.06 million shares we purchased were retired upon repurchase. Our total shares outstanding did not change as a result of this offering. Net proceeds from the original offering and the over-allotment option totaled approximately $175.6 million, after deducting underwriting discounts and commissions and the estimated expenses of the offering. After giving effect to the repurchase, J.P. Morgan no longer beneficially owns any of our common stock and Warburg Pincus beneficially owns 24.5% of our common stock.

Business Strategies

Our primary business objective is to maximize internally generated cash flow and shareholder value by executing the following strategies:

Maintain an Active Low-Risk Development Drilling Program. Our technological expertise, combined with our proficient field operations and reservoir engineering, have allowed us to increase production and reserves on our properties through development drilling, workovers, waterflood enhancements, tertiary projects, and recompletions. Our plan is to maintain an inventory of low-risk

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exploitation and development projects that provide us ongoing drilling activity. Each year, we budget a portion of internally generated cash flow to secondary and tertiary recovery projects whose results will not be seen until future years. Our conventional development budget for 2004, exclusive of spending on high pressure air injection, is $93 million.

Maximize Existing Reserves and Production Through High-Pressure Air Injections. In addition to conventional development drilling, we utilize high-pressure air injection techniques on certain properties to enhance our growth. High-pressure air injection involves utilizing compressors to inject air into previously produced oil and natural gas formations in order to displace remaining resident hydrocarbons and force them under pressure to a common lifting point for production. We believe that the HPAI programs on our CCA properties will generate a higher rate of return than other tertiary processes and can be applied throughout our CCA properties. The zone of our initial focus for HPAI, the Red River U4 zone, is the same zone where HPAI has been successfully implemented by other operators in adjacent areas and on our Pennel unit of the CCA. Response from HPAI investments is not expected until ten to eighteen months from the time of first injection. Our high-pressure air injection budget for 2004 is $34 million.

Expand Our Reserves, Production, and Drilling Inventory Through a Disciplined Acquisition Program. We will continue to pursue acquisitions of properties with similar upside potential to our current producing properties portfolio. Using the experience of our management team, we have developed and refined an acquisition program designed to increase our reserves and to complement our core properties, while providing upside potential. We have a staff of engineering and geoscience professionals who manage our core properties and use their experience and expertise to target 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. For the year ended 2003, we evaluated over $1 billion of potential acquisitions. We will continue to aggressively evaluate acquisition opportunities in 2004 with the same disciplined commitment to acquire assets that fit our portfolio and continue to create value for our shareholders.

Focus on Cost Control Through Efficient and Safe Operations. As of December 31, 2003, we operated properties representing approximately 84% of our proved reserves, which allows us to control capital allocation and expenses. Not only do we strive to efficiently operate our properties but we strive to safely operate our properties. The total recordable incident rate (TRIR) averaged 2.5 per 200,000 man hours for the industry in 2003. We are very proud to have a perfect TRIR of zero for our employees in 2003.

Challenges to Implementing Our Strategy. We face a number of challenges to implementing our strategy and achieving our goals. Our primary challenge is to generate superior rates of return on our investments in a volatile commodity pricing environment, while replenishing our drilling inventory. Changing commodity prices affect the rate of return on a property acquisition, internally generated cash flow, and, in turn, can affect our capital budget. In addition to the changing commodity price risk, we face strong competition from independents and major oil companies. For more information on the challenges to implementing our strategy and achieving our goals, please read Factors That May Affect Future Results and Financial Condition beginning on page 37.

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Business Activities

The following table sets forth the net production, proved reserves quantities, and PV-10 values of our properties:

Properties Principal Areas of Operations

	Net Production 2003				Proved Reserve Quantities at December 31, 2003			PV-10 at December 31, 2003	
	Oil (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent	Oil (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Amount(5)	Percent
								(In thousands)	
Cedar Creek Anticline(1)	4,723	1,206	4,924	61%	100,387	19,286	103,601	$ 614,428	60%
Permian Basin(2)	853	4,857	1,662	20%	11,067	68,138	22,424	230,223	23%
Rockies(3)	990	490	1,071	13%	6,123	2,983	6,620	62,263	6%
Mid Continent(4)	35	2,498	453	6%	155	48,543	8,245	114,160	11%
Total	6,601	9,051	8,110	100%	117,732	138,950	140,890	$ 1,021,074	100%

(1) Our CCA properties, which produce mainly from porous dolomites drilled on 40 to 80 acre spacing intervals, have longer reserve lives than our other properties because the low permeability level encountered within those producing intervals require a longer time to produce the reserves in place. This results in a lower production decline rate.

(2) Permian Basin includes the Central Permian, Indian Basin and Crockett properties.

(3) Rockies includes the Paradox Basin, Lodgepole and Bell Creek properties.

(4) Mid Continent includes the Elm Grove and Verden Properties.

(5) The pretax present value of estimated future revenues to be generated from the production of proved reserves, net of estimated production and future development costs; using prices and costs as of the date of estimation without future escalation; without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service, and depletion, depreciation, and amortization; and discounted using an annual discount rate of 10%. Giving effect to hedging transactions based on prices current at such dates, our PV-10 value would have been decreased by $23.8 million at December 31, 2003. The Standardized Measure at December 31, 2003 is $736.9 million. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes.

Operations

We act as operator of properties representing approximately 84% of our proved reserves at December 31, 2003. As operator, we are able to better control expenses, capital allocation, and the timing of exploitation and development activities of these properties. Our remaining properties are operated by third parties, and, as working interest owners in those properties, we are required to pay our share of the costs of operating, exploiting, and developing them. See Properties Nature of Our Ownership Interests on page 11. During the years ended December 31, 2003, 2002, and 2001 our approximate costs for development activities on non-operated properties were $5.4 million, $3.4 million, and $9.3 million, respectively. Because the properties purchased in our North Louisiana acquisition in 2003 are all non-operated, we expect our capital costs related to non-operated activities to increase in 2004.

Proved Reserves

Proved developed reserves are proved reserves that are expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on acreage yet to be drilled for which

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the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells where a relatively major expenditure is required to establish production. Proved undeveloped reserves include unrealized production response from fluid injection and other improved recovery techniques where such techniques have been proved effective by actual tests in the area and in the same reservoir.

The following table sets forth estimated period-end proved reserves for the periods indicated as estimated by Miller and Lents, Ltd., independent petroleum engineers (in thousands except per Bbl and per Mcf amounts):

	As of December 31,		
	2003	2002	2001
Oil (Bbls)			
Developed	92,377	93,945	71,639
Undeveloped	25,355	17,729	19,730
Total	117,732	111,674	91,369
Natural Gas (Mcf)			
Developed	104,767	82,217	69,941
Undeveloped	34,183	17,601	5,746
Total	138,950	99,818	75,687
Combined (BOE)			
Developed	109,838	107,648	83,296
Undeveloped	31,052	20,662	20,687
Total(1)	140,890	128,310	103,983
PV-10(2)			
Developed	$ 844,873	$732,823	$299,383
Undeveloped	176,201	132,281	60,979
Total	$1,021,074	$865,104	$360,362
Standardized Measure(3)	$ 736,939	$624,718	$284,309
Reserve price assumptions			
Oil ($/Bbl)	$ 32.55	$ 31.20	$ 19.84
Natural gas ($/Mcf)	5.83	4.79	2.57

(1) Volumetric reserves attributed to the net profits interests in our CCA properties were 20,623 MBOE, 16,262 MBOE, and 11,062 MBOE, respectively, at December 31, 2003, 2002, and 2001. See Properties Net Profits Interests on page 13. The volumes attributed to the net profits interests, which reduce our reserves on a BOE for BOE basis, will fluctuate from period to period primarily based on commodity prices and the level of planned development expenditures.

(2) The pretax present value of estimated future revenues to be generated from the production of proved reserves net of estimated future production and future development costs; using prices and costs as of the date of estimation without future escalation; without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service, and depletion, depreciation, and amortization; and discounted using an annual discount rate of 10%. Giving effect to hedging transactions based on prices current at such dates, our PV-10 value would have been $997.2 million at December 31, 2003, $860.6 million at December 31, 2002, and $364.4 million at December 31, 2001.

(3) Estimated future cash inflows to be generated from the production and sale of proved oil and natural gas reserves, net of estimated future production and development costs, and future income tax expenses discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of exploitation expenditures. The data in the above table represents estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly, and estimates of other engineers might differ materially from those shown above. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Results of drilling, testing, and production, after the date of the estimate, may justify revisions. Accordingly, reserve estimates may vary significantly from the quantities of oil and natural gas that are ultimately recovered.

Future prices received for production and future costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The PV-10 reserve value shown should not be construed as the current market value of the reserves. The 10% discount factor used to calculate present value, which is mandated by the Securities and Exchange Commission (SEC), is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate. For properties that we operate, future production expenses exclude our share of contractual overhead charges. In addition, the calculation of estimated future costs does not take into account the effect of various cash outlays, including, among other things, general and administrative costs and interest expense.

During the calendar year 2003, we filed estimates of oil and natural gas reserves at December 31, 2002 with the U.S. Department of Energy on Form EIA-23. As required for the EIA-23, this filing reflects only production that comes from our operated wells at year end, and is reported on a gross basis. These estimates come directly from our reserve report that is prepared by Miller and Lents, Ltd., who are independent petroleum engineers.

Production and Price History

The following table sets forth information regarding net production of oil and natural gas, certain price information, and average cost per BOE for each of the periods indicated:

	Year Ended December 31,		
	2003	**2002**	**2001**
Production:			
Oil (MBbls)	6,601	6,037	4,935
Natural gas (MMcf)	9,051	8,175	8,078
Combined (MBOE)	8,110	7,399	6,281
Average Daily Production:			
Oil (Bbls/d)	18,085	16,540	13,519
Natural gas (Mcf/d)	24,798	22,397	22,130
Combined (BOE/d)	22,218	20,273	17,208
Average Prices:			
Oil (per Bbl)	$ 26.72	$ 22.34	$ 21.43
Natural gas (per Mcf)	4.83	3.16	3.73
Combined (per BOE)	27.14	21.72	21.64

	Year Ended December 31,		
	2003	2002	2001
Average Costs per BOE:			
Lease operations expense	$4.67	$4.15	$4.00
Production, ad valorem, and severance taxes	2.71	2.12	2.20
General and administrative (excluding non-cash stock based compensation)	1.07	0.83	0.80
Depletion, depreciation, and amortization	4.13	4.67	5.05

Producing Wells

The following table sets forth information at December 31, 2003 relating to the producing wells in which we owned a working interest as of that date. We also held royalty interests in 2,546 producing wells as of that date. Wells are classified as oil or natural gas wells according to their predominant production stream. Gross wells are the total number of producing wells in which we have an interest, and net wells are determined by multiplying gross wells by our average working interest.

	Oil Wells			Natural Gas Wells		
	Gross Wells	Net Wells	Average Working Interest	Gross Wells	Net Wells	Average Working Interest
Cedar Creek Anticline	565	492	87%	31	8	25%
Permian Basin	1,171	213	18%	367	143	39%
Rockies	309	77	25%			
Mid Continent	65	3	5%	222	39	18%
Total	2,110(1)	785	37%	620(1)	190	31%

(1) Our total wells include 906 operated wells and 1,824 non-operated wells.

Acreage

The following table sets forth information at December 31, 2003 relating to acreage held by us. Developed acreage is assigned to producing 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. Our undeveloped acreage is concentrated in our CCA, Bell Creek, and Verden properties, which represent 75%, 7%, and 7% of our total undeveloped acreage, respectively. These leases expire at various dates ranging from January 2004 to July 2012, with leases representing $403,000 of cost set to expire in 2004 if not developed.

	Gross Acreage	Net Acreage
Developed acreage	211,219	138,981
Undeveloped acreage	73,896	56,903
Total	285,115	195,884

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Drilling Results

The following table sets forth information with respect to wells drilled during the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found, or economic value. We should continue to have good results from drilling because most of our exposure is to infill drilling. Productive wells are those that produce commercial quantities of hydrocarbons, exclusive of their capacity to produce a reasonable rate of return.

	Year Ended December 31,		
Development Wells	2003	2002	2001
Productive			
Gross	137.0	109.0	142.0
Net	103.0	95.3	105.6
Dry			
Gross	1.0	0.0	1.0
Net	0.7	0.0	1.0

Present Activities

As of December 31, 2003, we had a total of 3 gross (2.9 net) wells that had been spudded and were in varying stages of drilling operations. Also, there were 10 gross (9.8 net) wells that had reached total depth and were in varying stages of completion pending first production.

As of December 31, 2003, we are in the process of expanding the HPAI program to the entire north end of the Pennel Unit. Full field design has been completed and we are ordering necessary tubular, electrical, and compression equipment for the project.

We are in the process of completing the first phase of HPAI in the Little Beaver area on CCA. First injection began in the Little Beaver phase one during December 2003 and phase one and phase two should be completed during 2004.

Delivery Commitments and Marketing

Our oil and natural gas production is principally sold to end users, marketers, refiners, and other purchasers having access to nearby pipeline facilities consistent with industry practices. In areas where there is no practical access to pipelines, oil is trucked to storage facilities. Our marketing of oil and natural gas can be affected by factors beyond our control, the potential effects of which cannot be accurately predicted. For the fiscal year 2003, our largest purchasers included ConocoPhillips, Shell, and Eighty-Eight Oil, which respectively accounted for 28%, 26%, and 11% of total oil and natural gas sales. Management is of the opinion 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. The sale of approximately 50% of CCA oil is dependant on transportation to markets through the Butte pipeline to Guernsey, Wyoming. Any restrictions on the available capacity for us to transport oil in this pipeline could have a material adverse effect on our price we receive and our oil revenues.

Competition

We compete with major and independent oil and natural gas companies. Some of our competitors have substantially greater financial and other resources than we do. In addition, larger competitors may be able to absorb the burden of any changes in federal, state, provincial, and local laws and regulations more easily than we can, adversely affecting our competitive position. Our competitors may be able to pay more for productive oil and natural gas properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than we can. Further, these companies may enjoy technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to

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acquire additional properties in the future will depend upon our ability to conduct efficient operations, evaluate and select suitable properties, implement advanced technologies, and consummate transactions in this highly competitive environment.

Federal and State Regulations

Compliance with applicable federal and state regulations is often difficult and costly, and non-compliance may result in substantial penalties. The following are some specific regulations that may affect us. We cannot predict the impact of these or future legislative or regulatory initiatives.

Federal Regulation of Natural Gas. The interstate transportation and sale for resale of natural gas is subject to federal regulation, including transportation rates and various other matters, by the Federal Energy Regulatory Commission (FERC). Federal wellhead price controls on all domestic natural gas were terminated on January 1, 1992 and none of our natural gas sales are currently subject to FERC regulation. We cannot predict the impact of future government regulation on any natural gas operations.

Although FERC s regulations should generally facilitate the transportation of natural gas produced from our properties and the direct access to end-user markets, the future impact of these regulations on marketing our production or on our natural gas transportation business cannot be predicted. We do not believe, however, that we will be affected differently than competing producers and marketers.

Federal Regulation of Oil. Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. The net price received from the sale of these products is affected by market transportation costs. A significant part of our oil production is transported by pipeline. Under rules adopted by FERC effective January 1995, interstate oil pipelines can change rates based on an inflation index, though other rate mechanisms may be used in specific circumstances. The United States Court of Appeals upheld FERC s orders in 1996. These rules have had little effect on our oil transportation cost.

State Regulation. Oil and natural gas operations are subject to various types of regulation at the state and local levels. Such regulation includes requirements for drilling permits, the method of developing new fields, the spacing and operations of wells and waste prevention. The production rate may be regulated and the maximum daily production allowable from oil and natural gas wells may be established on a market demand or conservation basis. These regulations may limit production by well and the number of wells that can be drilled.

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 Bureau of Land Management, Minerals Management Service and other agencies.

Environmental Regulations. Various federal, state and local laws regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment, directly impact oil and natural gas exploration, development and production operations, and consequently may impact our operations and costs. Management believes that we are in substantial compliance with applicable environmental laws and regulations. To date, we have not expended any material amounts to comply with such regulations, and we do not currently anticipate that future compliance will have a materially adverse effect on our consolidated financial position or results of operations.

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 operations. Any of these problems could adversely affect our ability to conduct 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

We had 119 employees as of December 31, 2003, 50 of which are field personnel. None of the employees are represented by any union. We consider our relations with our employees to be good.

Principal Executive Office

Our principal executive offices are 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 items filed with the SEC pursuant to Section 13(a) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with the SEC. In addition, the public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 450 Fifth Street, NW, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC 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 officer and senior financial officers. The code of business conduct and ethics is available on our Internet website (www.encoreacq.com). 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 NYSE require us to disclose, we intend to disclose these events on our website.

The charters of our board of director committees are available on our website. Copies of the code of business conduct and ethics and board committee charters are also available in print upon written request to the 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.

Properties

Nature of Our Ownership Interests

We own interests in oil and natural gas properties located in Montana, North Dakota, Texas, New Mexico, Oklahoma, Utah, and Louisiana. Substantially all of our PV-10 reserve value at December 31, 2003 was attributable to working interests in oil and natural gas properties. A working interest in an oil and natural gas lease requires us to pay our proportionate share of the costs of drilling and production. The map on the following page depicts the location of our significant properties and the properties we plan to acquire from Cortez. For information on the pending acquisition of Cortez, see General Recent Acquisitions and Note 14. Subsequent Events (unaudited) to the consolidated financial statements.

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Cedar Creek Anticline Properties Montana and North Dakota

The CCA was purchased on June 1, 1999, and we have subsequently acquired additional working interests from various owners. Presently, we operate approximately 99.5% of the CCA properties with an average working interest of approximately 87%.

The CCA is a major structural feature of the Williston Basin in southeastern Montana and northwestern North Dakota. Our acreage is concentrated on the crest of the CCA, giving us access to the greatest accumulation of oil in the structure. Our holdings extend for approximately 70 continuous miles across five counties in two states. The gross producing interval on the CCA is approximately 2,000 feet thick, and ranges in depth from approximately 7,000 feet to 9,000 feet.

Since taking over operations, along with subsequent additional acquired interests, we have increased production by 75% on the CCA from 7,807 BOE per day (average for June 1999) to 13,655 BOE per day (average for the fourth quarter 2003). We have accomplished ongoing production growth through a combination of:

- additional acquisition of interests;
- detailed attention to the existing wellbores;
- the addition of strategically positioned new horizontal and vertical wellbores;
- the highly successful application of horizontal re-entry drilling in existing wellbores;
- waterflood enhancements;
- and implementation of our high-pressure air injection program.

In 2003, we drilled 78 gross wells on the CCA, of which 46 were horizontal re-entry wells that both reestablished production from non-producing wells, added additional barrels from existing producing wells and serve as injection wells for secondary and tertiary recovery projects. Including our HPAI project, we incurred $77.6 million of capital projects on the CCA during 2003. The average daily production from the CCA was 13,490 BOE per day for 2003.

Our outlook for sustained production growth on the CCA remains strong. We plan to continue the development of the reserve base through currently identified opportunities and future opportunities resulting from knowledge gained through continued study and the drilling and exploitation efforts ongoing on these properties. We believe that HPAI continues to be our most significant source of sustained production growth on the CCA.

The CCA represents 73% of our total proved reserves as of December 31, 2003. The CCA represents our most valuable asset today and in the foreseeable future. A large portion of our future success revolves around future exploitation and production from these properties.

High-Pressure Air Injection. High-pressure air injection is a tertiary recovery technique that involves utilizing compressors to inject air into oil and natural gas formations in order to displace remaining resident hydrocarbons and force them under pressure to a common lifting point for production.

In 2002 we initiated a HPAI pilot program that injects air into the Red River U4 zone in the Pennel area of the CCA. The Red River U4 zone is the same zone where high-pressure air injection has been successfully implemented by other operators in adjacent areas on the CCA. We have seen positive results from this pilot high-pressure air injection project at Pennel. Based on these results, we are in the process of expanding high pressure air injection to other areas in the CCA. We believe that high-pressure air injection technology can be applied throughout the CCA and that it may yield significant new reserves. We believe that the high-pressure air injection will generate a higher rate of return than other tertiary processes on the CCA.

The pilot project at Pennel continues to perform well with production uplift on target with our original projection. During the second half of 2003 we approved a $25 million project to expand HPAI to the entire north end of the Pennel Unit (Pennel Phase Two). Full field design has been completed and we are ordering necessary tubular, electrical, and compression equipment. The Pennel Phase Two expansion should be complete in early 2005.

In the Little Beaver area of the CCA we were able to arrange to purchase our high-pressure air compression services from an offset operator during 2003. This allowed us to implement a HPAI project in Little Beaver, on the south end of the CCA, in less than one year. First injection began in Little Beaver phase one during December 2003 and phase one and phase two should be completed during 2004. Our independent reserve engineers, Miller and Lents, Ltd., booked 12.2 million barrels of proved undeveloped oil reserves associated with high pressure air at year end 2003 related to the Little Beaver unit project. High-pressure air injection contributed to our FD&A cost during 2003.

We believe that much of our acreage in the CCA has potential opportunities for utilizing HPAI recovery techniques at economic rates of return. We continue to evaluate and perform engineering studies on these projects. Over the next several years we plan to implement these development projects initially in the Red River U4 zone of the CCA. Additionally, we have other zones in the CCA that currently produce oil and may provide additional HPAI opportunities. We believe these zones can be most economically evaluated for HPAI opportunities after initiating HPAI in the Red River U4 zone.

Net Profits Interests. A major portion of our acreage position in the CCA is subject to net profits interests (NPI) ranging from 1% to 50%. 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, but in general, net profits are determined after considering operating expense, overhead expense, interest expense, and drilling costs. The amounts of reserves and production calculated to be attributable to these net profits interests are deducted from our reserves and production data, and our revenues are reported net of NPI payments. The reserves and production that are attributed to the NPIs are calculated by dividing estimated future NPI payments (in the case of reserves) or prior period actual NPI payments (in the case of production) by the commodity prices current 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 NPIs and will have an inverse effect on our reported reserves and production. For the years ended December 31, 2003, 2002, and 2001, we reduced revenue for the payments of the net profits interests by $5.8 million, $2.0 million, and $2.8 million, respectively.

Permian Basin Properties Texas and New Mexico

Central Permian Andrews, Ector, and Pecos Counties, Texas

The Central Permian properties were purchased from Conoco on January 4, 2002. These properties are located in the Permian Basin near Midland, Texas, and include two major operated fields: East Cowden Grayburg Unit and Fuhrman-Nix; and two non-operated fields: North Cowden and Yates. The properties are 94% oil. Production from the Central Permian comes from multiple reservoirs including the San Andres, Grayburg, Glorieta, and Pennsylvanian zones at depths ranging from approximately 4,000 feet to 10,000 feet. We invested $12.2 million in the development drilling of 18 gross wells on the properties in 2003. Average daily production from the Central Permian properties was 2,410 BOE per day in 2003. We see these properties as an area of growth over the next several years.

Crockett Crockett County, Texas

The Crockett properties were purchased on March 30, 2000. We have acquired small additional working interests subsequent to the initial acquisition. The properties, located in the southern portion of the Permian Basin of West Texas consist primarily of three field groupings located near the town of Ozona, Texas. We operate approximately 34% of the Crockett properties, and we own a large interest in a significant number of the properties that we do not operate.

Production comes mainly from the Canyon and Strawn Formations. Both formations contain multiple pay intervals, and continued development opportunities remain on these properties. In 2003, an active development drilling program took place on our non-operated properties. In 2003, we invested approximately $3.7 million of development capital on the Crockett properties. Since acquiring these properties, we have increased production 18% from 8,700 Mcfe per day (average daily production for 2000) to 10,288 Mcfe per day (average daily production for 2003). We see these properties as an area of growth over the next couple of years.

Indian Basin Eddy County, New Mexico

The Indian Basin properties were purchased on August 24, 2000. We own varied non-operated working interests in these properties (primary area operators are Marathon and ChevronTexaco), whose production is 96% natural gas. Located in the western portion of the Permian Basin in southeastern New Mexico, these properties produce from multiple zones in the Pennsylvanian Formation. In 2003, we invested an insignificant amount of capital in the Indian Basin properties. The average daily production from the Indian Basin properties was 2,573 Mcfe per day for 2003.

Rocky Mountain Properties North Dakota, Montana, and Utah

Lodgepole Stark County, North Dakota

The Lodgepole properties were purchased on March 31, 2000. The properties consist of working and overriding royalty interests in several geographically concentrated fields. Approximately 95% of our interests are non-operated; the largest of which is the Eland Unit in which we own a 26% working interest.

The Lodgepole properties are located in the Williston Basin in western North Dakota near the town of Dickinson, approximately 120 miles from our CCA properties. The Lodgepole properties produce exclusively from the Mississippian-aged Lodgepole Formation, and the Eland Unit is the largest accumulation in the trend. The average production from the Lodgepole properties was 1,817 BOE per day for 2003. In 2003, we invested an insignificant amount of capital in the Lodgepole properties.

The Lodgepole properties produce from reefs with high permeability and thick oil columns. The prolific nature of these reservoirs makes future engineering estimates related to ultimate recovery of reserves inherently difficult to determine. If the properties performance varies significantly from the Miller and Lents, Ltd. estimates of reserves, then our future cash flows could be affected in 2004 and a few years beyond.

Bell Creek Powder River and Carter Counties, Montana

The Bell Creek properties, located in the Powder River Basin of southeastern-most Montana, were purchased on November 29, 2000. We operate the seven production units that comprise the Bell Creek properties, each with a 100% working interest. The shallow (less than 5,000 feet) Cretaceous-aged Muddy Sandstone reservoir produces 100% oil. We invested $0.5 million of capital in these properties in 2003. The average daily production from the Bell Creek properties was 314 BOE per day for 2003.

Paradox Basin San Juan County, Utah

The Paradox Basin properties, located in southeast Utah s Paradox Basin, were purchased on August 29, 2002. The properties are divided between two prolific oil producing units: the Ratherford Unit operated by ExxonMobil and the Aneth Unit operated by ChevronTexaco. The working interest and net revenue interest in the Ratherford Unit are 11.1% and 9.7%, respectively, and the working interest and the net revenue interest in the Aneth Unit are 13.4% and 11.4%, respectively. The average net production to us was approximately 804 BOE per day. We believe these properties have horizontal redevelopment, secondary development, and tertiary recovery potential. Our development capital was $0.5 million for 2003.

Mid Continent Properties Oklahoma and Louisiana

Elm Grove Bossier Parish, Louisiana

The Elm Grove properties were purchased on July 31, 2003 for $52.5 million before purchase price adjustments. Subsequent to the initial acquisition, we have purchased additional interests in the properties. The interests in the natural gas properties are located in the Elm Grove Field in Bossier Parish, Louisiana. The acquired properties include non-operated working interests ranging from 2% to 38% across 1,800 net acres in 15 sections. We did not own the properties for an entire year; but the properties averaged 8,255 Mcfe per day in the fourth quarter of 2003. At December 31, 2003, there were two wells currently being drilled and five wells waiting on completion. In 2003, we invested approximately $2.8 million of development capital on the Elm Grove properties. We believe these properties are an area of growth for us.

Verden Caddo and Grady Counties, Oklahoma

The Verden properties were purchased on August 24, 2000. We own various operated and non-operated interests in these properties. Located in the Anadarko Basin of central Oklahoma, production is primarily natural gas from the deep (below 15,000 feet) prolific Springer Sands. The development of these properties is driven primarily by other operators where we have a working interest in the properties and share our proportional drilling costs. Therefore, we do not control the timing of future development of the properties. During 2003, we invested $1.6 million of capital in the properties. The average daily production from the Verden properties was 4,088 Mcfe per day for 2003.

Title To Properties

We believe that our title to our oil and natural gas properties is good and defensible 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 profit interests, and other burdens under oil and natural gas leases;
- contractual obligations, including, in some cases, development obligations arising under operating agreements, farmout 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 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 indicated under Net Profits Interests above, a major portion of our acreage position in the CCA, our primary asset, is subject to net profits interests.

Item 3. *Legal Proceedings*

We are not currently a party to any material legal proceeding of which we are aware.

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

There were no matters submitted to stockholders during the quarter ended December 31, 2003.

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PART II

Item 5. ***Market for Registrant s Common Equity and Related Stockholder Matters***

Our common stock, $0.01 par value, is listed on the New York Stock Exchange under the symbol EAC . The following table sets forth quarterly high and low sales prices of our common stock for each quarterly period of 2003 and 2002:

	High	Low
2003		
Quarter ended December 31	$25.28	$19.60
Quarter ended September 30	22.15	17.80
Quarter ended June 30	20.01	17.00
Quarter ended March 31	19.35	16.63
2002		
Quarter ended December 31	$20.40	$13.51
Quarter ended September 30	17.55	15.00
Quarter ended June 30	17.35	14.60
Quarter ended March 31	15.00	12.40

On February 27, 2004, we had approximately 202 shareholders of record.

Recent Sale and Repurchase of Securities

On November 13, 2003, we priced a public offering of 8.0 million shares of our common stock at a price to the public of $20.25 per share. The underwriters also exercised their over-allotment option for an additional 1.06 million shares of common stock, at a price of $20.25 per share, on December 2, 2003, for a total of 9.06 million shares. We used all of the net proceeds to repurchase 6,866,643 shares of our common stock from J.P. Morgan and 2,193,357 shares from Warburg Pincus at a price of $19.3775 per share. The 9.06 million shares we purchased were retired upon repurchase. Our total shares outstanding did not change as a result of this offering. Net proceeds from the original offering and the over-allotment option totaled approximately $175.6 million, after deducting underwriting discounts and commissions and the estimated expenses of the offering. After giving effect to the repurchase, J.P. Morgan no longer beneficially owns any of our common stock and Warburg Pincus beneficially owns 24.5% of our common stock.

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 our Board of Directors after taking into account many factors, including our operating results, financial condition, current and anticipated cash needs, and plans for expansion. The declaration and payment of dividends is restricted by our existing credit agreement, the indenture governing our 8 3/8% notes, and any future dividends may also be restricted by future agreements with our lenders.

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Item 6. ***Selected Financial Data***

The following selected consolidated financial 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 (in thousands except per share and per unit data):

	Year Ended December 31,				
	2003	2002	2001	2000	1999
Consolidated Statements of Operations Data:					
Revenues(1):					
Oil	$ 176,351	$ 134,854	$ 105,768	$ 92,441	$ 30,454
Natural gas	43,745	25,838	30,149	16,509	810
Total revenues	$ 220,096	$ 160,692	$ 135,917	$ 108,950	$ 31,264
Net income (loss)	$ 63,641(2)	$ 37,685	$ 16,179(3)	$ (2,135)(4)	$ 3,005
Net income (loss) per common share:					
Basic	$ 2.11	$ 1.25	$ 0.56	$ (0.09)	$ 0.13
Diluted	2.10	1.25	0.56	(0.09)	0.13
Weighted average number of common shares outstanding:					
Basic	30,102	30,031	28,718	22,806	22,687
Diluted	30,333	30,161	28,723	22,806	22,687
Consolidated Statements of Cash Flows Data:					
Cash provided by (used by):					
Operating activities	$ 123,818	$ 91,509	$ 80,212	$ 44,508	$ 9,759
Investing activities	(153,747)	(159,316)	(89,583)	(99,236)	(201,701)
Financing activities	17,303	80,749	8,610	49,107	194,972
Production:					
Oil (Bbls)	6,601	6,037	4,935	3,961	1,796
Natural gas (Mcf)	9,051	8,175	8,078	4,303	180
Combined (BOE)	8,110	7,399	6,281	4,678	1,826
Average Sales Price:					
Oil ($/Bbl)	$ 26.72	$ 22.34	$ 21.43	$ 23.34	$ 16.96
Natural gas ($/Mcf)	4.83	3.16	3.73	3.84	4.50
Combined ($/BOE)	27.14	21.72	21.64	23.29	17.12
Costs per BOE:					
Lease operations	$ 4.67	$ 4.15	$ 4.00	$ 3.99	$ 4.60
Production and severance taxes	2.71	2.12	2.20	3.24	2.97
General and administrative (excluding non-cash stock based compensation)	1.07	0.83	0.80	0.93	2.22
Depletion, depreciation, and amortization	4.13	4.67	5.05	4.72	2.89
Reserves:					
Oil (Bbls)	117,732	111,674	91,369	78,910	69,299
Natural gas (Mcf)	138,950	99,818	75,687	72,970	10,940
Combined (BOE)	140,890	128,310	103,983	91,072	71,122

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	As of December 31,				
	2003	**2002**	**2001**	**2000**	**1999**
Consolidated Balance Sheet Data:					
Working capital	$ (52)	$ 12,489	$ 1,107	$ (15,275)	$ 5,126
Total assets	672,138	549,896	402,000	343,756	215,571
Total debt	179,000	166,000	79,107	162,045	99,250
Stockholders equity	358,975	296,266	269,302	147,811	102,422

(1) For the years ended December 31, 2003, 2002, 2001, 2000, and 1999 we reduced revenue for the payments of the net profits interests by $5.8 million, $2.0 million, $2.8 million, $11.5 million, and $4.4 million, respectively.

(2) Net income for the year ended December 31, 2003 includes a $0.9 million cumulative effect of accounting change, which affects its comparability with other periods presented. See pro forma amounts presented in Note 2. Summary of Significant Account Policies New Accounting Standards to the accompanying consolidated financial statements.

(3) Net income for the year ended December 31, 2001 includes $9.6 million of non-cash compensation expense, $4.3 million of bad debt expense, $1.6 million of impairment of oil and natural gas properties, and a $(0.9) million cumulative effect of accounting change, which affects its comparability with other periods presented.

(4) Net income for the year ended December 31, 2000 includes $26.0 million of non-cash compensation expense, which affects its comparability with other periods presented.

Item 7. *Management s Discussion and Analysis of Financial Condition and Results of Operations*

The following discussion and analysis of the consolidated financial condition and results of operations of Encore Acquisition Company should be read in conjunction with the historical financial information provided in the consolidated financial statements and accompanying notes, as well as the business and properties descriptions in Items 1 and 2 of this Report.

Overview

We engage in the acquisition, development, exploitation and production of onshore North American oil and natural gas reserves. We remain determined to execute our business strategy of maintaining an active low-risk development drilling program, maximizing existing reserves and production through high-pressure air injection projects, expanding our reserves and production through a disciplined acquisition program, and cost control through efficient and safe operations.

Our financial results and ability to generate cash depend upon many factors, particularly the price of oil and natural gas. Oil prices remained strong in 2003. The average oil price for the NYMEX futures market was $31.04 and $26.08 per barrel for 2003 and 2002, respectively. The average natural gas price for the NYMEX futures market was $5.50 and $3.36 per MMBTU for 2003 and 2002, respectively. Commodity prices are impacted by many factors that are outside of our control. It is very difficult for us to predict future commodity prices. For this reason, we attempt to mitigate the effect of commodity price risk by hedging.

In 2003, we were able to expand our Mid Continent area by acquiring a non-operated interest in natural gas properties in North Louisiana. We are optimistic both about how well this particular asset, Elm Grove, fits in our portfolio, and by the possibilities of additional acquisitions in the region. Elm Grove complements our existing asset base in many ways. We believe it contains a solid, predictable production base along with a large number of low risk infill drilling opportunities that are currently being exploited.

Also in 2003, we continued to see positive results from our initial high-pressure air injection project at our Pennel unit of the CCA, and have approved expanding it to other areas in the CCA. We began phase one of our second HPAI project in Little Beaver during December 2003 and phase one and phase two should be completed during 2004. Our independent reserve engineers, Miller and Lents, Ltd., booked 12.2 million barrels of proved undeveloped oil reserves associated with high pressure air at year end 2003 related to the Little Beaver unit project. High pressure air injection contributed to our FD&A cost of $7.42 per BOE during 2003. For the long term, we believe that high-pressure air injection technology can be applied throughout the Cedar Creek Anticline.

2003 Highlights

Our financial and operating results for the year ended December 31, 2003 included the following highlights:

Oil and natural gas reserves increased 10% to 140,890 MBOE. During 2003, we added 20.7 MMBOE at a FD&A cost of $7.42 per BOE, replacing 255% of the 8.1 MMBOE produced in 2003. Including revisions, the development program added 14.4 MMBOE (178% of our production) at a cost of $6.86 per BOE. Included in our reserve additions are 12.5 MMBOE of high-pressure air volumes. The 12.5 MMBOE represents the first reserves related to our high-pressure air injection program in the Cedar Creek Anticline of Montana and North Dakota. Our three year FD&A costs, including revisions, are $5.60 per BOE with a reserve replacement ratio of 329%. Oil reserves accounted for 84% of total proved reserves, and 78% of proved reserves are proved developed. Our reserve-to-production ratio is 17 years for total proved reserves and 14 years for proved developed reserves.

Production volumes for the year increased 10% to 8.1 MMBOE (22,218 BOE per day), compared with 2002 production of 7.4 MMBOE (20,273 BOE per day). Oil represented 81% and 82% of our total BOE production in 2003 and 2002, respectively. The increase in production is due to our continued successful development and exploitation program as well as the Elm Grove acquisition.

Net income for the full year of 2003 increased 69% to $63.6 million, or $2.10 per diluted share, on revenues of $220.1 million. Net income for the year ended December 31, 2003 includes a $0.9 million ($0.03 per diluted share) cumulative effect of accounting change resulting from the adoption of Statement of Financial Accounting Standards No. 143 Accounting for Asset Retirement Obligations on January 1, 2003. This compares to full year 2002 net income of $37.7 million, or $1.25 per diluted share, on revenues of $160.7 million. For 2003, cash flow from operations increased 35% to $123.8 million from $91.5 million for 2002. The increase in net income and cash flow from operations from 2002 was primarily a result of higher production and higher commodity prices throughout the year.

We improved our financial flexibility and liquidity by negotiating an increased borrowing base under the existing credit facility from $220 million to $270 million. At December 31, 2003, we had $29 million outstanding on the borrowing base and $241 million available for funding of future capital requirements.

We improved our ability to access capital markets with the filing of a $400 million universal shelf registration statement on Form S-3. We currently have $216 million availability remaining under the registration statement.

We expanded the liquidity and public ownership of our common stock by facilitating the sale of common stock by J.P. Morgan and Warburg Pincus. On November 13, 2003, we priced a public offering of 8.0 million shares of our common stock at a price to the public of $20.25 per share. The underwriters also exercised their over-allotment option for an additional 1.06 million shares of common stock, at a price of $20.25 per share, on December 2, 2003, for a total of 9.06 million shares. We used all of the net proceeds to repurchase 6,866,643 shares of our common stock from J.P. Morgan and 2,193,357 shares from Warburg Pincus at a price of $19.3775 per share. The 9.06 million shares we purchased were retired upon repurchase. Our total shares outstanding did not change as a result of this offering. Net proceeds from the original offering and the over-allotment option totaled approximately $175.6 million, after deducting underwriting discounts and commissions and the estimated expenses of the offering. After giving effect to the repurchase, J.P. Morgan

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no longer beneficially owns any of our common stock and Warburg Pincus beneficially owns 24.5% of our common stock.

High-pressure air injection was implemented in a second area on the CCA properties in the Little Beaver area. We were able to negotiate the purchase of high-pressure air compression services from an offset operator. This allowed us to implement a project in Little Beaver unit, on the south end of the Cedar Creek Anticline, in less than one year. First injection began in Little Beaver phase one during December 2003 and phase one and phase two should be completed during 2004. Our independent reserve engineers, Miller and Lents, Ltd., booked 12.2 million barrels of oil reserves associated with high pressure air at year end 2003 at Little Beaver. High pressure air injection contributed to our FD&A cost during 2003.

Results of Operations

Comparison of 2003 to 2002

Set forth below is our comparison of operations during the year ended December 31, 2003 with the year ended December 31, 2002.

Revenues and Production. For the year ended December 31, 2003, revenues increased $59.4 million. The following table illustrates the primary components of oil and natural gas revenue for the years ended December 31, 2003 and 2002, as well as each year s respective oil and natural gas volumes (dollars in thousands except per unit amounts):

	Year Ended December 31,					
	2003		2002		*Difference*	
	Revenue	$/Unit	Revenue	$/Unit	*Revenue*	*$/Unit*
Revenues:						
Oil wellhead	$190,203	$28.82	$141,119	$23.38	*$ 49,084*	*$ 5.44*
Oil hedges	(13,852)	(2.10)	(6,265)	(1.04)	*(7,587)*	*(1.06)*
Total Oil Revenues	$176,351	$26.72	$134,854	$22.34	*$ 41,497*	*$ 4.38*
Natural gas wellhead	$ 45,218	$ 5.00	$ 24,803	$ 3.03	*$ 20,415*	*$ 1.97*
Natural gas hedges	(1,473)	(0.17)	1,035	0.13	*(2,508)*	*(0.30)*
Total Natural Gas Revenues	$ 43,745	$ 4.83	$ 25,838	$ 3.16	*$ 17,907*	*$ 1.67*
Combined wellhead	$235,421	$29.03	$165,922	$22.42	*$ 69,499*	*$ 6.61*
Combined hedges	(15,325)	(1.89)	(5,230)	(0.70)	*(10,095)*	*(1.19)*
Total Combined Revenues	$220,096	$27.14	$160,692	$21.72	*$ 59,404*	*$ 5.42*

	Production	Average NYMEX $/Unit	Production	Average NYMEX $/Unit	*Production*	*Average NYMEX $/Unit*
Other data:						
Oil (MBbls)	6,601	$31.04	6,037	$26.08	*564*	*$4.96*
Natural Gas (MMcf)	9,051	5.50	8,175	3.36	*876*	*2.14*
Combined (MBOE)	8,110		7,399		*711*	

Oil revenues increased $41.5 million in 2003 over 2002 as production increased 564 MBbls and our average realized price increased $4.38 per Bbl. The increase in production resulted from our successful development drilling program and uplift from the HPAI program. Oil revenues were reduced by $13.9 million in 2003 due to our hedging program. The hedging per Bbl reduction to our wellhead oil price of $2.10 represented a $1.06 per Bbl greater reduction than in 2002. This compares favorably with the

$4.96 increase in the average NYMEX price from 2002 to 2003 as we were able to realize additional upside due to a higher average ceiling on our 2003 hedges compared to NYMEX than in 2002. In addition, our oil wellhead revenue was reduced by $5.6 million and $2.0 million in 2003 and 2002, respectively, for the net profits interests payments made to others related to our CCA properties.

Natural gas revenues increased in 2003 by $17.9 million due to a 65% increase in the net wellhead price received along with increased production of 876 MMcf. The increase in net wellhead price received of $1.97 per Mcf resulted as the average NYMEX price increased $2.14 per Mcf over the same period. The natural gas production increase resulted from the Elm Grove acquisition during 2003. Averaging 7,984 Mcfe per day since its acquisition on July 31, 2003, the Elm Grove properties added 3,345 Mcfe per day to our average daily production for the full year.

For 2004, we anticipate increased production related to our budgeted $93 million capital drilling program and $34 million in HPAI projects. We also have an additional $13 million budgeted for leasehold and other general capital expenditures. The total capital budget for 2004 is $140 million.

Prices received for oil and natural gas production are largely based on current market prices, which are beyond our control. We have based our 2004 forecasts on the assumptions of $23.50 per Bbl and $3.75 per Mcf NYMEX prices. For comparability and accountability, we take a constant approach to budgeting commodity prices. We presently analyze our inventory of capital projects on $23.50 per Bbl and $3.75 per Mcf NYMEX prices to ensure a good rate of return to our shareholders without the benefit of escalating future commodity prices. If NYMEX prices trend downward below our base deck, we may reevaluate our capital projects. At these assumed prices, we have forecasted net hedge contract payments of approximately $0.9 million for oil and net receipts of $4.5 million for natural gas. However, these amounts will change directly with any change in the market price of oil and natural gas and with any change in our outstanding hedge positions. Additionally, we have anticipated net profits interests payments of $1.7 million for oil and $0.03 million for natural gas. These payments are highly dependent on the level of drilling in the CCA and commodity prices, and thus, any change in the level of drilling or market fluctuation in commodity prices will have a direct impact on the amount of payments we are required to make. If commodity prices are significantly lower than our forecasted prices of $23.50 for oil and $3.75 for natural gas, we will not have sufficient internally generated cash flow to fund the budgeted $93 million drilling program, $34 million in HPAI projects, and $13 million leasehold and other capital for 2004. In this case, we would have to borrow money under our existing revolving credit facility, seek capital markets, or curtail the capital program. If drilling is curtailed or ended, future cash flows could be materially negatively impacted.

Lease Operations Expense. Lease operations expense for the year ended December 31, 2003 increased by $7.2 million as compared to 2002. The increase in total lease operations expense resulted from the increase in volumes as a result of our 2003 drilling program, the Elm Grove acquisition and HPAI program. See Revenues and Production above. On a per BOE basis, lease operations expense increased $0.52 primarily due to (1) full year results of our Paradox Basin properties, which had higher average per BOE lease operations expense of $9.04 for 2003 compared to our average of $4.67 per BOE, (2) the HPAI project on the CCA properties, and (3) lower production volumes from our Lodgepole properties, which have low operating costs.

For 2004, we anticipate an increase in total lease operations expense, as well as on a per BOE basis. We anticipate this increase due to a full year of production at our North Louisiana properties, as well as further implementation of the high-pressure air injection program. Also, the continued production decline of our Lodgepole properties, which have low per BOE operating costs, will continue to raise our lease operations expense on a per BOE basis. We have projected total lease operations expenses of approximately $46.5 million, or $5.56 per BOE, for 2004.

Production, Ad Valorem, and Severance Taxes. Production, ad valorem, and severance taxes for the year ended December 31, 2003 increased as compared to 2002 by approximately $6.4 million. The increase is a direct result of the increase in wellhead revenue. See Revenues and Production above. As a percentage of oil and natural gas revenues (excluding the effects of net profits and hedges), production, ad valorem, and severance taxes increased slightly from 9.3% to 9.4% from 2002 to 2003.

For 2004, total production, ad valorem, and severance taxes will depend in a large part on prevailing oil and natural gas prices. However, the production, ad valorem, and severance tax rate should remain relatively constant at an estimated 9.1% of wellhead revenues. However, if NYMEX prices continue to stay above $30 per barrel, we will temporarily lose production and severance tax incentives in Montana and North Dakota, which would cause our tax rates to increase in 2004.

Depletion, Depreciation, and Amortization (DD&A) Expense. Despite an increase in production, DD&A expense decreased by approximately $1.0 million in 2003. This decrease was due to the adoption of SFAS 143 on January 1, 2003, which resulted in a lower per BOE rate. As a result of the adoption of SFAS 143, we can no longer assume proceeds received for the salvage value of our equipment will offset plugging and abandonment costs, and thus are now required to deduct salvage value from the book value of equipment in calculating our depreciable base. This was the primary driver of the decrease in the average DD&A rate from $4.67 per BOE of production during 2002 to $4.13 per BOE in 2003.

We anticipate the total DD&A expense in 2004 will increase due to increased production resulting from the Elm Grove acquisition and our planned 2004 capital expenditures of $140 million. Assuming capital expenditures do not differ significantly from our budgeted amount, we expect our DD&A rate for 2004 to be approximately $4.60 per BOE. This per BOE increase from 2003 is primarily attributable to higher than historical FD&A costs for 2003. This rate could vary significantly based on actual capital expenditures, production rates, net profits interests, and any acquisition that closes in 2004. Additionally, changes in the market price for oil and natural gas could affect the level of our reserves. As the level of reserves change, the DD&A rate is inversely affected.

General and Administrative (G&A) Expense. G&A expense increased $2.5 million ($0.24 per BOE) to $8.7 million in 2003 (excluding non-cash stock based compensation of $0.6 million in 2003). The increase in G&A expense was a result of increased staffing levels used to manage our growing asset base and outside consulting services used in the evaluation of potential acquisitions.

We have forecast approximately $9.8 million for general and administrative expenses in 2004. This represents an increase of approximately $1.1 million from 2003. The increase is expected to result from the continued implementation of the HPAI projects, increased staffing, additional expenses related to compliance with the Sarbanes-Oxley Act of 2002 and the changes in listing requirements of The New York Stock Exchange.

Non-Cash Stock Based Compensation Expense. Non-cash stock based compensation expense increased from zero in 2002 to $0.6 million in 2003. This expense represents the amortization of deferred compensation, recorded in equity related to restricted stock granted under the 2000 Incentive Stock Plan. This amount is being amortized to expense over the vesting period of the restricted stock.

During 2002 and 2003, we issued 129,328 and 45,461 shares, respectively, of restricted stock to employees. Of these, 77,901 shares issued in 2002 and 45,461 shares issued in 2003 vest in equal installments on the third, fourth, and fifth anniversary of the date of the grant and depend only on continued employment for future issuance. These represent a fixed award per APB 25 and compensation expense will be recorded over the related service period. Of the remaining 51,427 shares issued in 2002, 34,464 remain outstanding at December 31, 2003. These were issued to two members of senior management and also vest in equal installments on the third, fourth, and fifth anniversary of the date of the grant. However, these shares not only depend on the passage of time and continued employment, but on certain performance measures for their future issuance. These represent a variable award under APB 25 and, thus, the full amount of compensation expense to be recorded for these shares will not be known until their eventual issuance.

Other Operating Expense. Other operating expense for the year ended December 31, 2003 increased as compared to 2002 by approximately $1.4 million. This amount primarily consists of 2003 severance payment obligations to former employees. The remaining amount relates to the inclusion of accretion

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expense on our SFAS 143 future abandonment liability; and the abandonment in undeveloped leasehold costs.

For 2004, we anticipate other operating expense to be approximately $2.9 million.

Interest Expense. Interest expense for the year ended December 31, 2003 increased $3.8 million over 2002 due primarily to an increase in our weighted average interest rate from period to period, as well as an increase in debt outstanding related to our credit facility. We incurred additional debt in 2003 to fund the North Louisiana acquisition. The weighted average interest rate, net of hedges, for 2003 was 9.6% compared to 8.2% for 2002. This higher weighted average interest rate is the result of the issuance of $150 million aggregate principal amount of 8 3/8% senior subordinated notes in June 2002, which was the primary component of our total indebtedness during 2003, while the revolving credit facility with a lower floating rate was the primary component during the first half of 2002. In conjunction with the issuance of 8 3/8% notes in June 2002, we entered into an interest rate swap, which swaps fixed rates to floating, with the intent of lowering our effective interest payments. As this transaction does not qualify for hedge accounting, changes in its fair market value, as well as settlements, are not recorded in interest expense, but in Derivative fair value (gain) loss on the Consolidated Statements of Operations. During 2003, a gain of $1.5 million related to this interest rate swap was recorded in Derivative fair value (gain) loss . See Note 11 to the accompanying consolidated financial statements.

The following table illustrates the components of interest expense for 2003 and 2002 (in thousands):

	2003	**2002**	*Difference*
8 3/8% senior subordinated notes	$12,563	$ 6,488	*$ 6,075*
Revolving credit facility	453	2,260	*(1,807)*
Hedge settlements		1,249	*(1,249)*
Hedge loss amortization	1,910	1,619	*291*
Debt issuance cost amortization	714	314	*400*
Fees and other	511	376	*135*
Total	$16,151	$12,306	*$ 3,845*

Derivative Fair Value Gain/Loss. The derivative fair value gain of $0.9 million in 2003 represents the ineffective portion of the mark-to-market loss on our derivative hedging instruments, settlements received on our fixed to floating interest rate swap, any commodity derivatives not designated as hedges, and changes in the mark-to-market value of our fixed to floating interest rate swap.

Currently, this line item on the Statement of Operations is primarily dependent on the futures price of oil, natural gas and LIBOR interest rates. This is due to the fact that the main components are the mark-to-market movement of and any settlements on our commodity derivative contracts not designated as hedges and our fixed to floating interest rate swap.

Income Tax Expense. Income tax expense for 2003 increased $13.5 million over 2002. This increase is due primarily to the $38.6 million increase in Income before Income Taxes from 2002 to 2003. Our effective income tax rate, prior to adjusting for Section 43 credits, remained at a constant 38% for both 2002 and 2003. However, during 2003, we generated $2.1 million in Section 43 credits, as compared to $1.1 million of Section 43 credits generated in 2002. This increase resulted in an effective income tax rate of 36.5% in 2003, a decrease of 1% from our 2002 effective rate of 37.5%.

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Comparison of 2002 to 2001

Set forth below is our comparison of operations during the year ended December 31, 2002 with the year ended December 31, 2001.

Revenues and Production. For the year ended December 31, 2002, revenues increased $24.8 million. The following table illustrates the primary components of oil and natural gas revenue for the years ended December 31, 2002 and 2001, as well as each year s respective oil and natural gas volumes (dollars in thousands except per unit amounts):

	Year Ended December 31,					
	2002		2001		*Difference*	
	Revenue	$/Unit	Revenue	$/Unit	*Revenue*	*$/Unit*
Revenues:						
Oil wellhead	$141,119	$23.38	$114,723	$23.25	*$26,396*	*$ 0.13*
Oil hedges	(6,265)	(1.04)	(8,955)	(1.82)	*2,690*	*0.78*
Total Oil Revenues	$134,854	$22.34	$105,768	$21.43	*$29,086*	*$ 0.91*
Natural gas wellhead	$ 24,803	$ 3.03	$ 34,014	$ 4.21	*$ (9,211)*	*$(1.18)*
Natural gas hedges	1,035	0.13	(3,865)	(0.48)	*4,900*	*0.61*
Total Natural Gas Revenues	$ 25,838	$ 3.16	$ 30,149	$ 3.73	*$ (4,311)*	*$(0.57)*

	Production	Average NYMEX $/Unit	Production	Average NYMEX $/Unit	*Production*	*Average NYMEX $/Unit*
Other data:						
Oil (MBbls)	6,037	$26.08	4,935	$25.92	*1,102*	*$ 0.16*
Gas (MMcf)	8,175	3.36	8,078	4.06	*97*	*(0.70)*
Combined (MBOE)	7,399		6,281		*1,118*	

Oil revenues increased $29.1 million in 2002 over 2001 primarily due to an increase in oil volumes, while the net wellhead price received remained relatively flat. Oil volumes increased 1,102 MBbls from 2001 to 2002 due to the Central Permian and Paradox Basin acquisitions, as well as increased production from our successful development drilling program. Wellhead oil revenues were reduced by $2.0 million and $2.7 million in 2002 and 2001, respectively, for the net profits interests payments held by others in the CCA. Total oil revenues were further increased by a decrease in hedge payments, which were $2.7 million lower.

Natural gas revenues decreased in 2002 by $4.3 million due to a 28% decrease in the net wellhead price received, from $4.21 in 2001 to $3.03 in 2002, with essentially flat production. This price decline is consistent with the NYMEX decline from $4.06 to $3.36 over the same period. We recovered a portion of the natural gas price decline through our hedges, which generated net receipts of $1.0 million in 2002 versus net payments of $3.9 million in 2001. These hedging receipts are a direct result of the decrease in the average NYMEX price for natural gas.

Lease Operations Expense. Lease operations expense for the year ended December 31, 2002 increased as compared to 2001 by $5.5 million. The increase in lease operations expenses resulted from the increase in volumes as a result of our 2002 Central Permian and Paradox Basin acquisitions and our successful drilling program. See Revenues and Production above. On a per BOE basis, lease operations expenses increased from $4.00 in 2001 to $4.15 in 2002 primarily due to higher per BOE lifting costs for our 2002 acquisitions.

Production, Ad Valorem, and Severance Taxes. Production, ad valorem, and severance taxes for the year ended December 31, 2002 increased as compared to 2001 by approximately $1.8 million. The increase is a direct result of the increase in wellhead revenue. See Revenues and Production above. As a

percentage of oil and natural gas revenues (excluding the effects of net profits and hedges), production, ad valorem, and severance taxes increased slightly from 9.1% to 9.3% from 2001 to 2002.

Depletion, Depreciation, and Amortization (DD&A) Expense. DD&A expense increased by approximately $2.8 million in 2002. This increase was due to a 1.1 MMBOE increase in production volumes, partially offset by a decrease in the DD&A rate per BOE. See Revenues and Production above. The average DD&A rate decreased from $5.05 per BOE of production during 2001 to $4.67 per BOE in 2002. The increase in volumes caused a $5.6 million increase in related DD&A expense, while the decrease in the DD&A rate caused a $2.8 million decrease. The decrease is attributable to upward reserve revisions due to higher prices.

General and Administrative (G&A) Expense. G&A expense increased $1.1 million in 2002 (excluding non-cash stock based compensation of $9.6 million in 2001). The increase in G&A resulted from the additional staff necessary after the Permian and Paradox Basin acquisitions to manage, expand, and exploit our growing asset base. On a per BOE basis, G&A expense remained relatively flat at $0.83 during 2002 as compared to $0.80 during 2001.

Other Operating Expense. Other operating expense for the year ended December 31, 2002 increased as compared to 2001 by approximately $1.1 million. This amount primarily consists of 2001 severance payment obligations to former employees, as well as transportation costs, namely pipeline fees paid to third parties, geological and geophysical expenses, and delay rentals. The increase is due to higher transportation costs and geological and geophysical expenses in 2002, which more than offset the lack of severance payments in 2002.

Interest Expense. Interest expense for the year ended December 31, 2002 increased $6.3 million over 2001. The increase in interest expense is primarily due to increased levels of debt, amortization of hedge loss (see below), and a higher weighted average interest rate in 2002 as compared to 2001. On June 25, 2002, we issued $150.0 million in 8 3/8% senior subordinated notes, and used most of the proceeds to repay all amounts outstanding under the previous credit facility and entered into a new revolving credit facility. See Capital Commitments, Capital Resources and Liquidity on page 31. For 2002, the weighted average debt balance was $149.7 million, compared with $89.3 million for 2001. Additionally, the weighted average interest rate, including hedges, in 2002 was 8.2%, while it was 6.8% in 2001. The higher weighted average interest rate is due to a higher fixed rate on the 8 3/8% notes as compared to the floating rate debt outstanding previously.

At the time the previous credit facility was terminated, we had three interest rate swaps outstanding, with a notional amount of $30.0 million each, which swapped LIBOR-based floating rates for fixed rates. According to the provisions of SFAS 133, these no longer qualified for hedge accounting. The unrealized loss of $3.8 million at June 25, 2002, which was recognized in accumulated other comprehensive income, is being amortized to interest expense over the original life of the swaps. We amortized $1.6 million of this loss to interest expense during 2002.

The following table illustrates the components of interest expense for 2002 and 2001 (in thousands):

	2002	2001	*Difference*
8 3/8% senior subordinated notes	$ 6,488	$	*$ 6,488*
Revolving credit facility	2,260	4,596	*(2,336)*
Burlington note		389	*(389)*
Hedge settlements	1,249	717	*532*
Hedge loss amortization	1,619		*1,619*
Debt issuance cost	314	120	*194*
Fees and other	376	219	*157*
Total	$ 12,306	$ 6,041	*$ 6,265*

Non-Cash Stock Based Compensation Expense. Non-cash stock based compensation expense decreased from $9.6 million for 2001 to zero in 2002. This non-cash stock based compensation expense is associated with the purchase by our management stockholders of Class A common stock under our management stock plan adopted in August 1998 and was recorded as compensation in accordance with variable plan accounting under Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees (APB 25). The $9.6 million of non-cash compensation expense recorded in the first quarter of 2001 represents the final amount of expense to be recorded related to the Class A common stock.

Derivative Fair Value Gain/Loss. The derivative fair value gain of $0.9 million in 2002 represents the ineffective portion of the mark-to-market loss on our derivative hedging instruments, as well as the mark-to-market loss on our two short puts outstanding at December 31, 2002 and our interest rate swap settlements subsequent to the issuance of the senior subordinated notes on June 25, 2002.

Bad Debt Expense. On December 2, 2001, Enron Corp. and certain subsidiaries, including Enron North America Corp. (Enron), each filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Bankruptcy Code. Prior to this date, we had entered into oil and natural gas hedging contracts with Enron, many of which were set to expire at December 31, 2001; however, others related to 2002 and 2003. As a result of the Chapter 11 bankruptcy declaration and pursuant to the terms of our contract with Enron, we terminated all outstanding oil and natural gas derivative contracts with Enron as of December 12, 2001. According to the terms of the contract, Enron is liable to us for the mark-to-market value of all contracts outstanding on that date, which totaled $6.6 million. Additionally, Enron failed to make timely payment of $0.4 million in 2001 hedge settlements. Both of these amounts remained outstanding as of December 31, 2001. Due to the uncertainty of future collection of any or all of the amounts owed to us by Enron, for the year ended December 31, 2001, we have recorded a charge to bad debt expense for the full amount of the receivable, $7.0 million, and recorded a related allowance on the receivable of $7.0 million.

At the time of termination, the market price of our commodity contracts with Enron exceeded their amortized cost on our balance sheet, giving rise to a gain. In accordance with the provisions of SFAS 133, this gain was recorded in other comprehensive income until such time as the original hedged production affected income. As a result, at December 31, 2001, we had $4.8 million in gross unrecognized gains in other comprehensive income that were reversed into earnings during 2002 and 2003. The following table illustrates the amortization of this amount to revenue (in thousands):

Period	Oil	Gas	Total
2002	$2,822	$1,594	$4,416
2003	401	18	419
Total	$3,223	$1,612	$4,835

Impairment of Oil and Natural Gas Properties. Throughout 2001, futures prices for oil and natural gas continued to decline from their December 31, 2000 levels. The SEC price case used for our 2000 reserve estimate was $26.80 per Bbl and $9.77 per Mcf dropping to $19.84 per Bbl and $2.57 per Mcf for the 2001 estimate. Although the SEC price case does not necessarily coincide with management s estimates of future prices, this indicated the need to assess our oil and natural gas properties for any possible impairment. Thus, we compared the undiscounted future cash flows for each of our oil and natural gas properties to their net book value, which indicated the need for an impairment charge on certain properties. We then compared the net book value 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 $2.6 million. Fair value was determined using estimates of future production volumes and estimates of future prices we might receive for these volumes discounted back to a present value using a rate commensurate with the risks inherent in the industry.

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We performed a similar review at December 31, 2002 and determined no impairment charge was necessary.

Description of Critical Accounting Estimates

Oil and Natural Gas Properties

Successful Efforts Method. We utilize the successful efforts method of accounting for our oil and natural gas properties as opposed to the full cost method. In general, we believe that the successful efforts method of accounting for oil and natural gas would not result in materially different operating results as we do not currently maintain an active exploratory drilling program. Under the successful efforts method, all development and acquisition costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of proved developed reserves or proved reserves, as applicable. Exploration expenses, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Costs of drilling exploratory wells are initially capitalized, but charged to expense if and when the well is determined to be unsuccessful. To date, our exploration efforts have been minimal. Expenditures for repairs and maintenance to sustain or increase production from the existing producing reservoir are charged to expense as incurred. Expenditures to recomplete a current well in a different or additional proven or unproven reservoir are capitalized pending determination that economic reserves have been added. If the recompletion is not successful, the expenditures are charged to expense. Expenditures for redrilling or directional drilling in a previously abandoned well are classified as drilling costs to a proven or unproven reservoir for determination of capital or expense. Significant tangible equipment added or replaced is capitalized. Expenditures to construct facilities or increase the productive capacity from existing reserves are capitalized. Internal costs directly associated with the development and exploitation of properties are capitalized as a cost of the property and are classified accordingly in our consolidated financial statements.

Oil and Natural Gas Reserves. Assumptions used by the independent reserve engineers in calculating reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. 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 will not remain constant. Actual production may not equal the estimated amounts used in the preparation of reserve projections. As these estimates change, the amount of calculated reserves change. Any change in reserves directly impacts our estimate of future cash flows from the property, as well as the property s fair value.

Impairment. Impairments of proved oil and natural gas properties are directly affected by our reserve estimates. We are required to assess the need for an impairment of capitalized costs of oil and natural gas properties and other long-lived assets whenever events or circumstances indicate that the carrying value of those assets 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 it is recognized to the extent that the carrying value exceeds fair value. Each part of this calculation is subject to a large degree of management judgment, including the determination of property s reserves, amount and timing of future cash flows, and fair value.

Depletion, Depreciation, and Amortization (DD&A). DD&A expense is directly affected by our reserve estimates. Any change in reserves directly impacts the amount of DD&A expense that we recognize in a given period. 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. Changes in future commodity prices would likely result in increases or decreases in estimated recoverable reserves. Additionally, the Miller & Lents, Ltd., our independent reserve engineers estimate our reserves once a year at December 31.

Net Profits Interests

A major portion of our acreage position in the Cedar Creek Anticline is subject to net profits interests (NPI) ranging from 1% to 50%. The holders of these net profits interests are entitled to receive a fixed percentage of the cash flow remaining after specified costs have been deducted from net revenues. The net profits calculations are contractually defined, but in general, net profits are determined after considering operating expense, overhead expense, interest expense, and drilling costs. The amounts of reserves and production calculated to be attributable to these net profits interests are deducted from our reserves and production data, and our revenues are reported net of NPI payments. The reserves and production that are attributed to the NPIs are calculated by dividing estimated future NPI payments (in the case of reserves) or prior period actual NPI payments (in the case of production) by the commodity prices current 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 NPIs and will have an inverse effect on our reported reserves and production. Based largely on higher commodity prices, we expect the net profit interest to be higher in the year 2004 and possibly beyond, which directly impacts our revenues, production, reserves, and earnings.

Revenue Recognition

Revenues are recognized for our share of jointly owned properties as oil and natural gas is produced and sold, net of royalties and net profits interest payments. Natural gas revenues are also reduced by any processing and other fees paid except for transportation costs paid to third parties which are recorded as expense. Revenues are recorded using the sales method of accounting whereby revenue is recognized as natural gas is sold by us rather than as our working interest share of production. Royalties, net profits interests, and severance taxes are paid 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, we estimate and record the expected sales volumes and values for those properties. We also do not recognize revenue for the production in tanks or pipelines that has not been delivered to the purchaser yet. Our net oil inventories in pipelines were 46,622 Bbls and 104,954 Bbls at December 31, 2003 and 2002, respectively. Natural gas imbalances under-delivered to us at December 31, 2003 and December 31, 2002, were 446,000 MMBTU and 510,000 MMBTU, respectively.

Income Taxes

Section 43 Credits. Section 43 of the Internal Revenue Code (Code) allows a 15 percent tax credit for certain enhanced oil recovery project costs incurred in the United States. We believe project costs incurred related to our HPAI tertiary recovery project on the CCA qualify under the provisions of the Code and, therefore, we have reduced income tax expense by 15 percent of project costs incurred to date. The tax basis for the properties (and related intangible drilling cost deductions and future depreciation deductions) is reduced by the amount of the enhanced oil recovery tax credit. In order to qualify for the credits a project must meet all of the following requirements:

1. The project involves the application of one or more qualified tertiary recovery methods that is reasonably expected to result in more than an insignificant increase in the amount of crude oil that ultimately will be recovered;

2. The project is located within the United States;

3. The first injection of liquids, gases, or other matter for the project occurs after December 31, 1990; and

4. The project is certified by a petroleum engineer.

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According to the Code, the costs that will qualify for the credit when paid or incurred in connection with a qualifying enhanced oil recovery project include:

1. *Tangible Property.* Any amount paid for tangible property that is an integral part of a qualified enhanced oil recovery project, and with respect to which depreciation is allowable.

2. *Intangible Drilling and Development Costs.* Intangible drilling cost with respect to which the taxpayer may make an intangible drilling costs deduction election under Code Sec. 263(c).

3. *Qualified Tertiary Injectant Expenses.* Any qualified tertiary injectant expenses for which a deduction is allowable under any Code section.

If our federal income tax returns are reviewed by the Internal Revenue Service (the IRS), the IRS could disagree with our decision and disallow a portion of the credit. While we believe our HPAI project qualifies for the tax credit and that our accounting and tracking of the costs related to project are accurate, should the IRS disagree with our position, we would be required to record additional income tax expense to the extent tax credits have been previously recognized.

Stock-based Compensation

Employee stock options and restricted stock awards are accounted for under the provisions of Accounting Principles Board Opinion No. 25 (APB 25), Accounting for Stock Issued to Employees. Accordingly, no compensation is recorded for stock options that are granted to employees or non-employee directors with an exercise price equal to or above the common stock price on the grant date. If compensation expense for the stock based awards had been determined using the provisions of SFAS 123, our net income and net income per share would have been adjusted to the pro forma amounts indicated below (in thousands, except per share amounts):

	Year Ended December 31,		
	2003	**2002**	**2001**
As Reported:			
Net income	$63,641	$37,685	$16,179
Non-cash stock based compensation (net of taxes)	381		9,587
Diluted net income per share	2.10	1.25	0.56
Pro Forma:			
Net income	$62,093	$36,408	$15,475
Non-cash stock based compensation (net of taxes)	1,929	1,277	10,291
Diluted net income per share	2.05	1.21	0.54

Hedging and Related Activities

We use various financial instruments for non-trading purposes to manage and reduce price volatility and other market risks associated with our crude 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 over-the-counter forward derivative contracts executed 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.

Effective January 1, 2001, we adopted Statement of Financial Accounting Standards No. 133 (SFAS 133), Accounting for Derivative Instruments and Hedging Activities. This standard requires us to recognize all of our derivative and hedging instruments in our statements of financial position as either assets or liabilities and measure them 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 does qualify for hedge accounting, depending on the nature of the hedge, changes in fair value can be offset against the change in fair value of the hedged item through earnings or recognized in 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 due to changes in the underlying items being hedged. In addition, all hedging relationships must be designated, documented, and reassessed periodically. Most of our derivative financial instruments qualify for hedge accounting. In accordance with the provisions of SFAS 133, cash flow hedges are marked-to-market through comprehensive income each quarter.

Currently, all of our derivative financial instruments that are designated as hedges are designated as cash flow hedges. These instruments hedge the exposure of variability in expected future cash flows that is attributable to a particular risk. The effective portion of the gain or loss on these derivative instruments is recorded in 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 gain or loss is recognized as Derivative fair value (gain) loss in the Consolidated Statements of Operations immediately. While management does not anticipate changing the designation of any of our current derivative contracts as hedges, factors beyond our control can preclude the use of hedge accounting. One example would be variability in the NYMEX price for oil or natural gas, upon which many of our commodity derivative contracts are based, that does not coincide with changes in the spot price for oil and natural gas that we are paid. Another example would be if the counterparty to a derivative contract was deemed no longer creditworthy and non-performance under the terms of the contract was likely. To the extent our derivative contracts are not designated as hedges, high earnings volatility can result, as any future changes in the market value of the contract would then be marked-to-market through earnings.

Capital Commitments, Capital Resources and Liquidity

Capital Commitments. Our primary needs for cash are as follows:

- Development and exploitation of our existing oil and natural gas properties
- High-pressure air injection programs on our CCA properties
- Acquisitions of oil and natural gas properties
- Leasehold and acreage costs
- Other general property and equipment
- Funding of necessary working capital
- Payment of contractual obligations

Development and Exploitation. Our capital expenditures for conventional development and exploitation during the years ended December 31, 2003 and 2002 totaled $86.1 million and $73.7 million, respectively.

For 2004, we expect to invest $93 million in development and exploitation. We have based our 2004 forecasts on the assumptions of $23.50 per Bbl and $3.75 per Mcf NYMEX prices. For comparability and accountability, we take a constant approach to budgeting commodity prices. We analyze our inventory of capital projects based on $23.50 per Bbl and $3.75 per Mcf NYMEX prices to ensure a rate of return to our shareholders without the benefit of escalating future commodity prices. If NYMEX prices trend downward below our base deck, we may reevaluate capital projects and may adjust the capital budgeted for development and exploitation investments accordingly.

High-Pressure Air Injection. Our capital expenditures for high-pressure air injection during the years ended December 31, 2003 and 2002 totaled $12.9 million and $6.6 million, respectively. In 2003, we began implementing our second HPAI program in the Little Beaver unit of the CCA and began injecting air in the reservoir in December 2003. We expect to have the Little Beaver unit fully implemented by the first quarter of 2004. The Little Beaver unit project was taken from concept to implementation in less than

9 months. We successfully negotiated a contract from a third party to supply the air compression services to Little Beaver, which reduced the up front capital requirements for the Little Beaver unit project. In 2002, we began a pilot program to begin injecting air into the Red River U4 reservoir in a portion of the Pennel Unit of the CCA. Because of positive results, we are planning to expand the project in the Pennel unit of the CCA with a $25.2 million expansion of the project which we expect to complete by early 2005. We believe that the HPAI program will generate a higher rate of return than other tertiary processes and can be applied throughout the CCA. The zone of our initial focus, the Red River U4 zone, is the same zone where HPAI has been successfully implemented by other operators in adjacent areas and on the Pennel unit of the CCA. Response from HPAI investments is not expected until ten to eighteen months from the time of first injection.

For 2004, we expect to invest $34 million in high-pressure air injection. We have based our 2004 forecasts on the assumptions of $23.50 per Bbl and $3.75 per Mcf NYMEX prices. See Development and Exploitation above regarding our approach to budgeting commodity prices.

Acquisitions. Our capital expenditures for oil and natural gas acquisitions during the years ended December 31, 2003 and 2002 totaled $54.6 million and $78.5 million, respectively. In 2003, we completed an acquisition of interests in natural gas properties in North Louisiana. The properties are located in the Elm Grove Field in Bossier Parish, Louisiana and are non-operated working interests ranging from 2% to 38% across 1,800 net acres in 15 sections. The production and reserves of the properties are substantially all natural gas. On January 1, 2002, we completed the Central Permian acquisition from Conoco for approximately $50.1 million. During the second quarter of 2002, we closed a second, follow-on acquisition of additional working interest for $8.3 million. The Central Permian properties increased our operational presence in West Texas. On August 29, 2002 we acquired an interest in oil and natural gas properties in southeast Utah s Paradox Basin.

We will continue to pursue acquisitions of properties with similar upside potential to our current producing properties portfolio. For the year ended 2003, we evaluated over $1 billion of potential acquisitions. We do not budget for acquisitions but we will continue to evaluate acquisition opportunities as they arise in 2004 with the same disciplined commitment to acquire assets that fit our portfolio and continue to create value.

Our current $140 million capital budget for 2004 does not include any funds for the development and exploitation of oil and natural gas properties that we may acquire during 2004. Our practice is to review our capital budget following a significant acquisition. We are currently undertaking such a review in connection with the Cortez transaction.

Leasehold and Acreage Costs. Our capital expenditures for leasehold and acreage costs during the years ended December 31, 2003 and 2002 totaled $0.1 million and $0.4 million, respectively.

For 2004, we expect to invest $12 million for leasehold and acreage costs. Compared to historical expenditures for leasehold and acreage, 2004 will be a significant increase in capital expenditures. We plan to actively pursue leases and acreage in our core areas that we are currently operating oil and natural gas properties. These investments are not expected to result in oil and natural gas production in 2004.

Other General Property and Equipment. Our capital expenditures for other general property and equipment during the years ended December 31, 2003 and 2002 totaled $1.5 million and $0.7 million, respectively. Capital expenditures for other general property and equipment include corporate leasehold improvements, computers, software, telecommunications equipment, field trucks, and field rental equipment.

For 2004, we expect to invest $0.8 million in other general property and equipment.

Working Capital. At December 31, 2003, our working capital was $(0.1) million while at December 31, 2002 working capital was $12.5 million, a decrease of $12.6 million. The decrease is primarily attributable to cash and cash equivalents. Excluding the decrease in cash of $12.6 million, working capital was essentially flat from 2002 to 2003. In order to minimize our interest expense, we use

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excess cash reserves to pay down any amounts outstanding under our revolving credit facility. However, at the end of 2002, due to the margin maintenance requirements with our commodity derivative counterparties and the high commodity price environment, we maintained cash reserves on hand to satisfy any margin calls as they arose. Thus, we held a much higher cash and cash equivalents balance at December 31, 2002 than would otherwise be held. This resulted in the decrease in working capital from December 31, 2002 to December 31, 2003. Currently, as of March 3, 2004, we have $4.5 million posted related to our derivatives margin account.

For 2004, we expect working capital to remain relatively flat to 2003. We anticipate cash reserves to be close to zero as we use any excess cash to fund capital obligations and any additional excess cash would be used to pay down our existing credit facility. We do not plan to pay cash dividends in the foreseeable future. The overall 2004 commodity prices for oil and natural gas will be the largest variable driving the different components of working capital. Our operating cash flow is determined in a large part by commodity prices. Assuming moderate to high commodity prices, our operating cash flow should remain positive for the foreseeable future. We have budgeted capital expenditures of approximately $140.0 million for 2004. The level of these and other future expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly, depending on available opportunities and market conditions. We plan to finance our ongoing expenditures using internally generated cash flow, available cash, and our existing credit agreement.

Contractual Obligations. The following table illustrates our contractual obligations and commercial commitments outstanding at December 31, 2003 (in thousands):

	Payments Due by Period				
Contractual Obligations and Commercial Commitments	**Total**	**2004**	**2005-2006**	**2007-2008**	**Thereafter**
8 3/8% Notes(1)	$256,782	$12,563	$25,125	$25,125	$193,969
Revolving Credit Facility(2)	28,593	637	27,956		
Derivative Obligations(3)	8,204	4,903	2,272	1,029	
Development Commitments(4)	50,793	48,923	1,270	600	
Operating Leases(5)	2,843	951	1,507	342	43
Totals	$347,215	$67,977	$58,130	$27,096	$194,012

(1) Amounts included in the table above include both principal and projected interest payments. See information presented in Note 6. Indebtedness to the accompanying consolidated financial statements for additional information regarding our long-term debt.

(2) Amounts included in the table above include both principal and projected interest payments. See Note 6. Indebtedness to the accompanying consolidated financial statements for additional information regarding our long-term debt. Giving effect to the Cortez acquisition, the pro-forma amount outstanding under our revolving credit facility as of December 31, 2003 would be approximately $152.0 million.

(3) Derivative obligations represent liabilities for derivatives that were valued as of December 31, 2003. The ultimate settlement amounts of the remaining portions of our derivative obligations are unknown because they are subject to continuing market risk. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Note 11. Financial Investments to the accompanying consolidated financial statements for additional information regarding our derivative obligations.

(4) Development commitments represent authorized purchases not placed to vendors, thus not accrued at year-end. These purchases are authorized and expected to be made during 2004 unless circumstances change. Above amounts also include minimum transmission payments for electricity.

(5) Operating leases represent office space and equipment obligations that have remaining non-cancelable lease terms in excess of one year. See Note 4. Commitments and Contingencies to the accompanying consolidated financial statements for additional information regarding our operating leases.

Investing Activities. Cash used by investing activities decreased by $5.6 million from 2002 to 2003. This was due to offsetting changes in its two primary components: acquisition of oil and natural gas properties, which decreased by $23.9 million; and development of oil and natural gas properties, which increased $18.7 million. Cash used for the acquisition of oil and natural gas properties varies year to year based on our success in acquiring oil and natural gas properties. Our bid price is a price we feel provides a certain level of return based on our expectation of future oil and natural gas prices, while providing potential for some upside realization. Success in the acquisition market is largely driven by competition in the marketplace and in the availability of properties for sale. During 2002, we were successful in completing two major property acquisitions, one comprised of properties in the Paradox Basin of Utah and one comprised of properties in the Permian Basin of West Texas at a combined cost of $78.6 million, while in 2003 we were successful in completing one major property acquisition of properties in the North Louisiana Salt Basin of Louisiana at a cost of $54.6 million. The increase in cash used in the development of oil and natural gas properties of $18.7 was the result of drilling 29 more gross wells (8.3 net) and the expansion of the HPAI project into the Little Beaver area of the CCA.

Capital Resources. Our primary capital resources are net cash provided by operating activities, and proceeds from financing activities which are used to fund our capital commitments. Our primary needs for cash include our high-pressure air injection program in the CCA, acquisitions of oil and natural gas properties, development and exploitation of our existing oil and natural gas properties, leasehold and acreage cost, funding of necessary working capital, and payment of contractual obligations.

Operating Activities. For 2003, cash provided by operating activities increased by $32.3 million. This increase resulted from the $26.0 increase in net income coupled with an increase in deferred taxes of $11.8 million, offset by decrease in changes in operating assets and liabilities from 2002 to 2003 of $6.4 million. The increase in net income was primarily due to increased production volumes and higher commodity prices compared to 2002.

Financing Activities. During 2003 proceeds from financing activities was $17.3 million, while it was $80.7 million in 2002. In 2003, we were able to close the initial Elm Grove acquisition and subsequent interests for $54.6 million and fund our $99.0 million capital drilling program with only a modest $13.0 million increase in our revolving credit facility. During 2002, however, we increased our debt by $88.0 million to fund two property acquisitions, Central Permian and Paradox Basin, and fund $80.3 million in development expenditures.

Additionally during 2003, on November 13, 2003, we priced a public offering of 8.0 million shares of our common stock at a price to the public of $20.25 per share. The underwriters also exercised their over-allotment option for an additional 1.06 million shares of common stock, at a price of $20.25 per share, on December 2, 2003, for a total of 9.06 million shares. We used all of the net proceeds to repurchase 6,866,643 shares of our common stock from J.P. Morgan and 2,193,357 shares from Warburg Pincus at a price of $19.3775 per share. The 9.06 million shares we purchased were retired upon repurchase. Our total shares outstanding did not change as a result of this offering. Net proceeds from the original offering and the over-allotment option totaled approximately $175.6 million, after deducting underwriting discounts and commissions and the estimated expenses of the offering. After giving effect to the repurchase, J.P. Morgan no longer beneficially owns any of our common stock and Warburg Pincus beneficially owns 24.5% of our common stock.

This compares to 2002 when on June 25, 2002, we sold $150 million of 8 3/8% Senior Subordinated Notes maturing on June 15, 2012 in a private placement pursuant to Rule 144A. We received net proceeds of $145.6 million from the sale of the 8 3/8% notes, after deducting debt issuance costs. The proceeds were used to repay and retire our prior credit facility ($143.0 million), to pay the fees and expenses related to the new revolving credit facility ($1.5 million), and to hold in reserve for the Paradox Basin acquisition ($1.1 million).

Liquidity. Our principal source of short-term liquidity is our revolving credit facility. We entered into the current revolving credit facility on June 25, 2002. Borrowings under the facility are secured by a first priority lien on our proved oil and natural gas reserves. Availability under the facility is determined through semi-annual borrowing base determinations and may be increased or decreased. The amount available under our credit facility increased in 2003 by $50.0 million to $270.0 million, with $29.0 million outstanding as of December 31, 2003. We expect the pending acquisition of Cortez will reduce the availability by $123.0 million. The maturity date of the new facility is June 25, 2006.

Amounts outstanding under the facility are subject to varying rates of interest based on the amount outstanding and our borrowing base. Based on our current $270.0 million borrowing base, our applicable interest rates are calculated as follows:

Amount Outstanding	Rate
$0 to $55,000,000	LIBOR + 1.000%
$55,000,001 to $110,000,000	LIBOR + 1.125%
$110,000,001 to $165,000,000	LIBOR + 1.250%
$165,000,001 to $198,000,000	LIBOR + 1.500%
$198,000,001 to $270,000,000	LIBOR + 1.750%

Our revolving credit facility and the indenture related to the 8 3/8% notes contain financial and other restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. The covenants under our revolving credit facility are similar but generally more restrictive than the covenants under the indenture. Our ability to borrow under our revolving credit facility is subject to financial covenants, including leverage, interest and fixed charge coverage ratios. Our revolving credit facility limits our ability to effect mergers, asset sales, and change of control events. These covenants also contain restrictions regarding our ability to incur additional indebtedness in the future. In some cases, our subsidiaries are subject to similar restrictions that may restrict their ability to make distributions to us. The indenture related to our 8 3/8% notes also contains limitations on our ability to effect mergers and change of control events, incur additional indebtedness, sell assets, declare and pay dividends or make other restricted payments, enter into transactions with affiliates and subject our assets to liens.

Based on current commodity conditions, we believe that our capital resources are adequate to meet the requirements of our business through 2005 and the foreseeable future. Based on our anticipated capital programs, we expect to invest our internally generated cash flow to replace production and enhance our development programs. During 2004, we have planned total capital expenditures of approximately $140 million, although we may need additional capital to pursue acquisitions or other capital projects. Our current capital budget does not include any funds for development and exploitation of oil and natural gas properties that we may acquire during 2004. Our practice is to review our capital budget following a significant transaction. We are currently undertaking such review in connection with the Cortez transaction.

Substantially all of our capital expenditures are discretionary and will be undertaken only if funds are available and the projected rates of return are satisfactory. Future cash flows are subject to a number of variables including the level of oil and natural gas production and prices. Operations and other capital resources may not provide cash in sufficient amounts to maintain planned levels of capital expenditures. Additionally, we are required to maintain margin amounts and/or letters of credits with the counterparties to our outstanding hedges if the mark-to-market value of our hedges reach a certain negative value. Although we did not have any margin deposits with our counterparties as of December 31, 2003, if commodity prices were to rise substantially, we would be required to post margin with one or more counterparties for expected future hedging settlements. Currently, as of March 3, 2004, we have $4.5 million posted related to our derivatives margin account.

Book Capitalization. At December 31, 2003, we had total assets of $672.1 million. Total capitalization was $538.0 million, of which 66.7% was represented by stockholders equity and 33.3% by senior debt.

Inflation and Changes in Prices

While the general level of inflation affects certain of our costs, factors unique to the petroleum industry result in independent price fluctuations. Historically, significant fluctuations have occurred in oil and natural gas prices. In addition, changing prices often cause costs of equipment and supplies to vary as industry activity levels increase and decrease to reflect perceptions of future price levels. Although it is difficult to estimate future prices of oil and natural gas, price fluctuations have had, and will continue to have, a material effect on us.

The following table indicates the average oil and natural gas prices received for the years ended December 31, 2003, 2002, and 2001. Average equivalent prices for 2003, 2002, and 2001 were decreased by $1.89, $0.70, and $2.04 per BOE, respectively, as a result of our hedging activities. Average prices per equivalent barrel indicate the composite impact of changes in oil and natural gas prices. Natural gas production is converted to oil equivalents at the conversion rate of six Mcf per Bbl.

	Oil ($/Bbl)	Natural Gas ($/Mcf)	Combined ($/BOE)
Net Price Realization with Hedges			
Year ended December 31, 2003	$26.72	$4.83	$27.14
Year ended December 31, 2002	22.34	3.16	21.72
Year ended December 31, 2001	21.43	3.73	21.64
Average Wellhead Price			
Year ended December 31, 2003	$28.82	$5.00	$29.03
Year ended December 31, 2002	23.38	3.03	22.42
Year ended December 31, 2001	23.25	4.21	23.68

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Our disclosure and analysis in this Report contains some forward-looking statements. Forward-looking statements give our current expectations or forecasts of future events. You can identify these statements by the fact that they do not relate strictly to historical or current facts. These statements may include words such as anticipate , estimate , expect , project , intend , plan , believe , should , and other wor of similar meaning in connection with any discussion of future operating or financial performance. In particular, these include, among other things, statements relating to:

expected capital expenditures and the focus of our capital program;

areas of future growth;

our drilling program;

future horizontal development, secondary development and tertiary recovery potential;

the implementation of our High-Pressure Air Program, the ability to expand the program to other parts of the CCA and the effects thereof;

the completion of current HPAI projects and the effects thereof;

anticipated prices for oil and natural gas;

projected revenues; FD&A costs; lifting costs; lease operations expenses; production, ad valorem and severance taxes; general and administrative expenses; taxes; and DD&A;

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

expected hedging positions and payments related to hedging contracts;

expectations regarding working capital, cash flow and anticipated liquidity;

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- the closing of the Cortez transaction and the benefits to be derived therefrom;
- projected borrowings under our credit facility; and
- marketing of oil and natural gas.

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 the subsection entitled Factors That May Affect Future Results and Financial Condition below and elsewhere in this Report and our other filings with the Securities and Exchange Commission. If one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. We undertake no responsibility to update for changes related to these or any other factors that may occur subsequent to this filing for any reason.

FACTORS THAT MAY AFFECT FUTURE RESULTS AND FINANCIAL CONDITION

You should read carefully the following factors and all other information contained in this Report. If any of the risks and uncertainties described below or elsewhere in this Report actually occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our common stock could decline, and an investor may lose all or part of his investment.

Risks Related to Our Business

Oil and natural gas prices are volatile and sustained periods of low prices could materially and adversely affect our financial condition and results of operations.

Historically, the markets for oil and natural gas have been volatile, and these markets are likely to continue to be volatile in the future. Our revenues, profitability and future growth depend substantially on prevailing oil and natural gas prices. Lower oil and natural gas prices may reduce the amount of oil and natural gas that we can economically produce. Prevailing oil and natural gas prices also affect the amount of internally generated cash flow available for repayment of indebtedness and capital expenditures. In addition, the amount we can borrow under our revolving credit facility is subject to periodic redetermination based in part on changing expectations of future oil and natural gas prices.

The factors that can cause oil and natural gas price volatility include:

- the supply of domestic and foreign oil and natural gas;
- the ability of members of the Organization of Petroleum Exporting Countries to agree upon and maintain oil prices and production levels;
- political instability or armed conflict in oil or natural gas producing regions;
- the level of consumer demand;
- weather conditions;
- the price and availability of alternative fuels;
- domestic and foreign governmental regulations and taxes;
- domestic political developments; and
- worldwide economic conditions.

The volatile nature of markets for oil and natural gas makes it difficult to reliably estimate future prices. Any decline in oil and natural gas prices adversely affects our financial condition. If oil or natural gas prices decline significantly for a sustained period of time, we may, among other things, be unable to meet our financial obligations, make planned expenditures or raise additional capital.

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Reserve estimates depend on many assumptions that may prove to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated.

Estimating quantities of proved oil and natural gas reserves is a complex process that requires interpretations of available technical data and numerous assumptions, including certain economic assumptions. Any significant inaccuracies in these interpretations or assumptions or changes in conditions could cause the quantities and net present value of our reserves to be overstated.

To prepare estimates of economically recoverable oil and natural gas reserves and future net cash flows, we must analyze many variable factors, such as historical production from the area compared with production rates from other producing areas. We must also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also involves economic assumptions relating to commodity prices, production costs, severance and excise taxes, capital expenditures and workover and remedial costs. Actual results most likely will vary from our estimates. Any significant variance could reduce the estimated quantities and present value of our reserves.

You should not assume that the present value of future net cash flows from our proved reserves referred to in this Report is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate.

The results of high pressure air injection techniques are uncertain.

We utilize high pressure air injection, or HPAI, techniques on some of our properties and plan to use the techniques in the future on a substantial portion of our properties, including our CCA properties. The additional production and reserves attributable to our use of the techniques, if any, are inherently difficult to predict. If our HPAI programs do not allow for the extraction of residual hydrocarbons in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected.

If oil and natural gas prices decrease, we may be required to take write downs.

We may be required to write down the carrying value of our oil and natural gas properties when future estimated oil and gas prices are low or if we have substantial downward adjustments to our estimated proved reserves or increases in our estimates of operating expenses or development costs. We capitalize the costs to acquire, find and develop our oil and natural gas properties under the successful efforts accounting method. The net capitalized costs of our oil and natural gas properties may not exceed their estimated fair value. If net capitalized costs of our oil and natural gas properties exceed their fair value, we must charge the amount of the excess to earnings. We review the carrying value of our properties quarterly, based on changes in expectations of future oil and natural gas prices, expenses and tax rates. Once incurred, a write down of oil and natural gas properties is not reversible at a later date even if oil or gas prices increase.

Our acquisition strategy subjects us to numerous risks that could adversely affect our results of operations.

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. Depending on conditions in the acquisition market, it may be difficult or impossible for us to identify properties for acquisition or we may not be able to make acquisitions on terms that we consider economically acceptable. Even if we are able to identify suitable acquisition opportunities, our acquisition strategy depends upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals.

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The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We are often not entitled to contractual indemnification for environmental liabilities and acquire properties on an as is basis.

Possible 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 operating results. 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. Competition for acquisitions is intense and may increase the cost of, or cause us to refrain from, completing acquisitions.

The failure to properly manage growth through acquisitions could adversely affect our results of operations.

Growing through acquisitions and managing that growth will require us to continue to invest in operational, financial and management information systems and to attract, retain, motivate and effectively manage our employees. Pursuing and integrating acquisitions involves a number of risks, including:

- diversion of management attention from existing operations;
- unexpected losses of key employees, customers and suppliers of the acquired business;
- conforming the financial, technological and management standards, processes, procedures and controls of the acquired business with those of our existing operations; and
- increasing the scope, geographic diversity and complexity of our operations.

The process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations.

A substantial portion of our producing properties is located in one geographic area.

We have extensive operations in the Williston Basin of Montana and North Dakota. As of December 31, 2003, our CCA properties in the Williston Basin represented approximately 73% of our proved reserves and 61% of our 2003 production. Any circumstance or event that negatively impacts production or marketing of oil and natural gas in the Williston Basin could materially reduce our earnings and cash flow.

Derivative instruments expose us to risks of financial loss in a variety of circumstances.

We use derivative instruments in an effort to reduce our exposure to fluctuations in the prices of oil and natural gas and to reduce our cash outflows related to interest. Our derivative instruments expose us to risks of financial loss in a variety of circumstances, including when:

- a counterparty to our derivative instruments is unable to satisfy its obligations;
- production is less than expected; or
- there is an adverse change in the expected differential between the underlying price in the derivative instrument and actual prices received for our production.

Derivative instruments may limit our ability to realize increased revenue from increases in the prices for oil and natural gas.

We adopted Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133), on January 1, 2001. SFAS 133 generally requires us to record each hedging transaction as an asset or liability measured at its fair value. Each quarter we must record changes in the fair value of our hedges, which could result in significant fluctuations in net income and stockholders equity from period to period.

Drilling oil and natural gas wells is a high-risk activity.

Drilling oil and natural gas wells, including development wells, involves numerous risks, including the risk that no commercially productive oil or natural gas reservoirs will be discovered. We often are uncertain as to the future cost or timing of drilling, completing and producing wells. We may not recover all or any portion of our investment in drilling oil and natural gas wells.

Our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including unexpected drilling conditions or miscalculations, title problems, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions, compliance with environmental and other governmental requirements and cost of, or shortages or delays in the availability of, drilling rigs and equipment.

The failure to replace our reserves could adversely affect our financial condition.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves generally decline when reserves are produced, unless we conduct successful exploitation or development activities or acquire properties containing proved reserves, or both. We may not be able to find, develop or acquire additional reserves on an economic basis.

Substantial capital is required to replace and grow reserves. If lower oil and natural gas prices or operating difficulties result in our cash flow from operations being less than expected or limit on our ability to borrow under our revolving credit facility, we may be unable to expend the capital necessary to find, develop or acquire new oil and natural gas reserves.

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

Other companies operate some of the properties in which we have an interest. 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 drilling or acquisition activities and lead to unexpected future costs.

Our business involves many operating risks that can cause substantial losses; insurance may be unavailable or inadequate to protect us against these risks.

Our operations are subject to hazards and risks inherent in drilling for, producing and transporting oil and natural gas, such as fires; natural disasters; explosions; formations with abnormal pressures; blowouts; collapses of wellbore, casing or other tubulars; failure of oilfield drilling and service tools; uncontrollable flows of oil, natural gas, formation water or drilling fluids; pressure forcing oil or natural gas out of the wellbore at a dangerous velocity coupled with the potential for fire or explosion; changes in below-ground pressure in a formation that cause surface collapse or cratering; pipeline ruptures or cement failures; environmental hazards, such as oil spills, natural gas leaks and discharges of toxic gases; and weather. If any of these events occur, we could incur substantial losses as a result of injury or loss of life; damage to and destruction of property, natural resources and equipment; pollution and other environmental damage; regulatory investigations and penalties; suspension of our operations; and repair and remediation costs.

We do not maintain insurance against the loss of oil or natural gas reserves as a result of operating hazards, nor do we maintain business interruption insurance. In addition, pollution and environmental risks generally are not fully insurable. We may experience losses for uninsurable or uninsured risks or losses in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could harm our financial condition and results of operations.

Terrorist activities and the potential for military and other actions could adversely affect our business.

The threat of terrorism and the impact of military and other action have caused instability in world financial markets and could lead to increased volatility in prices for oil and natural gas, all of which could adversely affect the markets for our operations. Future acts of terrorism could be directed against companies operating in the United States. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. These developments have subjected our operations to increased risk and, depending on their ultimate magnitude, could have a material adverse effect on our business.

Our development and exploitation 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 and exploitation projects. We intend to finance these capital expenditures through a combination of cash flow from operations and external financing arrangements. 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 drilling and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

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 and Chief Executive Officer, Jon S. Brumley, our President, and other key personnel. The loss of the services of Mr. I. Jon Brumley or Mr. Jon S. Brumley or other key personnel could adversely affect our business, and we do not have employment agreements with, and do not maintain key man insurance on the lives of, any of these persons. Our drilling 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 some other professionals is extremely intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

The marketability of our oil and natural gas production is dependent upon transportation facilities over which we have no control.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of pipelines, oil and natural gas gathering systems and processing facilities. Any significant change in market factors affecting these infrastructure facilities could harm our business. We deliver oil and natural gas through gathering systems and pipelines that we do not own. These facilities may not be available to us in the future.

Competition in the oil and natural gas industry is intense, and many of our competitors have greater financial, technological and other resources than we do.

We operate in the highly competitive areas of oil and natural gas acquisition, development, exploitation and production. The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. We face intense competition from independent, technology-driven companies as well as from both major and other independent oil and natural gas companies in each of the following areas:

- acquiring desirable producing properties or new leases for future exploration;
- marketing our oil and natural gas production;
- integrating new technologies; and
- acquiring the equipment and expertise necessary to develop and operate our properties.

Many of our competitors have financial, technological and other resources substantially greater than ours, which may adversely affect our ability to compete with these companies. These companies may be able to pay more for development prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Further, these companies may enjoy technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to develop and exploit our oil and natural gas properties and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, implement advanced technologies, evaluate and select suitable properties and consummate transactions in this highly competitive environment.

We are subject to complex federal, state and local laws and regulations that could adversely affect our business.

Exploration, development, production and sale of oil and natural gas in North America are subject to extensive federal, state, provincial and local laws and regulations, including complex tax and environmental laws and regulations. We may be required to make large expenditures to comply with applicable laws and regulations, which could adversely affect our results of operations and financial condition. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, spacing of wells, unitization and pooling of properties, environmental protection, reports concerning operations and taxation. Under these laws and regulations, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, reclamation costs, remediation and clean-up costs and other environmental damages.

We do not believe that full insurance coverage for all potential environmental damages is available at a reasonable cost, and we may need to expend significant financial and managerial resources to comply with environmental regulations and permitting requirements. We could incur substantial additional costs and liabilities in our oil and natural gas operations as a result of stricter environmental laws, regulations and enforcement policies.

Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Further, these laws and regulations could change in ways that substantially increase our costs. Any of these liabilities, penalties,

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suspensions, terminations or regulatory changes could make it more expensive for us to conduct our business or cause us to limit or curtail some of our operations.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

Hedging Policy. We have adopted a formal hedging policy. The purpose of our hedging program is to mitigate the negative effects of declining commodity prices on our business. The hedging policy is set by the President with input from the Chief Executive Officer and the Chief Financial Officer. We plan to continue in the normal course of business to hedge our exposure to fluctuating commodity prices. The volumes we have capped or swapped will not exceed 75% of our anticipated production from proved producing reserves. Under our hedging policy, we do not enter into derivatives for speculative purposes. However, not all of our derivatives qualify for hedge accounting and in some instances management has determined it is more cost effective not to designate certain derivatives as hedges.

Counterparties. Our counterparties to hedging contracts include: BNP Paribas; Deutsche Bank; Koch; Morgan Stanley; Mitsui & Co; Shell Trading; Credit Lyonnais; J. Aron & Company, a wholly-owned subsidiary of Goldman, Sachs & Co. At December 31, 2003 approximately 35%, 23%, 20%, and 16% of estimated oil production hedged is committed to Morgan Stanley, J. Aron & Company, Deutsche Bank, and Credit Lyonnais, respectively. Approximately 42%, 33%, and 25% of our hedged gas production is contracted with BNP Paribas, J. Aron & Company, and Morgan Stanley, respectively. Performance on all of J. Aron & Company s contracts with us is guaranteed by their parent, Goldman, Sachs & Co. We feel the credit-worthiness of our current counterparties is sound and we do not anticipate any non-performance of contractual obligations. As long as each counterparty maintains an investment grade credit rating, pursuant to our hedging contracts, no collateral is required.

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 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. First, the netting of the value of all trades reduces the requirements of daily collateral posting by us. Second, default by counterparty under one financial trade can trigger rights for us to terminate all financial trades with such counterparty. Third, netting of settlement amounts reduces our credit exposure to a given counterparty in the event of close-out.

Commodity Price Sensitivity. The tables in this section provide information about derivative financial instruments to which we were a party as of December 31, 2003 that are sensitive to changes in oil and natural gas commodity prices.

We hedge commodity price risk with swap contracts, put contracts, and collar contracts. 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. Collar contracts 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. Additionally, we occasionally we sell short put contracts with a strike price well below the floor price of the collar. These short put contracts do not qualify for hedge accounting under SFAS 133, and accordingly, the mark-to-market change in the value of these contracts is recorded as fair value gain/loss in the statements of operations. Thus, not all of our derivatives qualify for hedge accounting and in some instances management has determined it is more cost effective not to designate certain derivatives as hedges. The unrealized mark-to-market loss on our outstanding commodity derivatives at December 31, 2003 was approximately $(16.0) million. The fair market value of our oil derivative contracts was $(7.1) million and the fair market value of our natural gas derivative contracts was $(0.6) million.

Oil Derivative Contracts at December 31, 2003

Period	Daily Floor Volume (Bbls)	Floor Price (per Bbl)	Daily Cap Volume (Bbls)	Cap Price (per Bbl)	Daily Swap Volume (Bbls)	Swap Price (per Bbl)
Jan. - June 2004	17,000	$23.16	7,000	$29.06	500	$26.48
July - Dec. 2004	17,000	23.91	5,000	28.33	500	26.48
Jan. - June 2005	2,500	23.00	2,000	30.41	1,000	25.12
July - Dec. 2005	1,500	23.00	1,500	30.18	1,000	25.12
Jan. - Dec. 2006					2,000	25.03
Jan. - Dec. 2007					2,000	25.11

Natural Gas Derivative Contracts at December 31, 2003

Period	Daily Floor Volume (Mcf)	Floor Price (per Mcf)	Daily Cap Volume (Mcf)	Cap Price (per Mcf)	Daily Swap Volume (Mcf)	Swap Price (per Mcf)
Jan. - Dec. 2004	20,000	$4.07	7,500	$6.02	5,000	$5.01
Jan. - Dec. 2004					5,000	4.63

Subsequent to December 31, 2003, we entered into several additional oil and natural gas derivative contracts. The tables below summarize the terms of the contracts entered into from January 1, 2004 through March 4, 2004:

Additional Oil Derivative Contracts at March 4, 2004

Period	Daily Floor Volume (Bbls)	Floor Price (per Bbl)	Daily Cap Volume (Bbls)	Cap Price (per Bbl)	Daily Swap Volume (Bbls)	Swap Price (per Bbl)
July - Dec. 2004	1,000	$31.50	1,000	$34.56		
Jan. - Dec 2005	1,000	28.50	1,000	32.40		
Jan. - Dec 2006	1,000	27.50	1,000	29.88		

Additional Natural Gas Derivative Contracts at March 4, 2004

Period	Daily Floor Volume (Mcf)	Floor Price (per Mcf)	Daily Cap Volume (Mcf)	Cap Price (per Mcf)	Daily Swap Volume (Mcf)	Swap Price (per Mcf)
July - Dec. 2004					5,000	$5.65
Jan. - Dec 2005	5,000	$5.05	5,000	$5.97		
Jan. - Dec. 2006	5,000	4.85	5,000	5.68		

Interest Rate Sensitivity. At December 31, 2003, we had total long-term debt of $179.0 million. Of this amount, $150.0 million bears interest at a fixed rate of 8 3/8%. The remaining outstanding long-term debt balance of $29.0 million is under our credit agreement and is subject to floating market rates of interest. Borrowings under the credit agreement bear interest at a fluctuating rate that is linked to LIBOR. As of December 31, 2003, we had one outstanding interest rate swap. This swap does not qualify for hedge accounting as it swaps fixed interest rate for a floating interest rate tied to LIBOR. The following table summarizes the terms of this swap:

Interest Rate Derivative Contract at December 31, 2003

Notional Swap Amount	Start Date	End Date	Encore Pays	Encore Receives	Fair Market Value at December 31, 2003
(In thousands)					(In thousands)
$80,000	June 25, 2002	June 15, 2005	LIBOR + 3.89%	8.375%	$2,420

GLOSSARY OF OIL AND NATURAL GAS TERMS

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

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

Bcf. One billion cubic feet of natural gas at standard atmospheric conditions.

Bbl/ D. One stock tank barrel of oil or other liquid hydrocarbons per day.

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

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

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

Delay Rentals. Fees paid to the lessor of the 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 which are allocated or assignable to producing wells or wells capable of production.

Development Well. A well drilled within or in close proximity to an area of known production targeting existing reservoirs.

Exploratory Well. A well drilled to find and produce oil or natural gas in an unproved area or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

Finding, Development, and Acquisition (FD&A) Costs. Capital costs incurred in the finding, development, acquisition, exploitation, improved recovery, and revisions of proved oil and natural gas reserves, excluding non-cash asset retirement obligations.

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

High-Pressure Air Injection (HPAI). High-pressure air injection involves utilizing compressors to inject air into previously produced oil and natural gas formations in order to displace remaining resident hydrocarbons and force them under pressure to a common lifting point for production.

Horizontal Drilling. A drilling operation in which a portion of the 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. All direct and 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.

MBbl. One thousand barrels of oil or other liquid hydrocarbons.

MBOE. One thousand barrels of oil equivalent, calculated by converting gas to oil equivalent barrels at a ratio of six Mcf to one Bbl of oil.

Mcf. One thousand cubic feet of natural gas.

Mcf/ D. One thousand cubic feet of natural gas per day.

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

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

MMBtu. One million British thermal units. One British thermal unit is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.

MMcf. One million cubic feet of natural gas.

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

Net Production. Production that is owned by us less royalties and production due others.

NYMEX. New York Mercantile Exchange.

Oil. Crude oil or condensate.

Operating Income. Gross oil and natural gas revenue less applicable production taxes and lease operating expense.

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

Present Value of Future Net Revenues or Present Value or PV-10. The pretax present value of estimated future revenues to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depletion, depreciation, and amortization, and discounted using an annual discount rate of 10%.

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

Proved Reserves. The estimated quantities of oil, natural gas, and natural gas liquids 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 undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on acreage yet to be drilled for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells where a relatively major expenditure is required to establish production. Proved undeveloped reserves include unrealized production response from fluid injection and other improved recovery techniques where such techniques have been proved effective by actual tests in the area and in the same reservoir.

Reserve-To-Production Index or R/ P Index. An estimate expressed in years, of the total estimated proved reserves attributable to a producing property divided by production from the property for the 12 months preceding the date as of which the proved reserves were estimated.

Royalty. An interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but does not require the owner to pay any portion of the costs of drilling or operating the wells 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.

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

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Tertiary Recovery. An enhanced recovery operation that normally occurs after waterflooding in which chemicals or natural gasses are used as the injectant. HPAI is a form of tertiary recovery.

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 and natural gas lease that gives the owner of the interest 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 costs of drilling and production operations.

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Item 8. ***Financial Statements and Supplementary Data***

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REPORT OF INDEPENDENT AUDITORS

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

We have audited the accompanying consolidated balance sheets of Encore Acquisition Company and subsidiaries (the Company) as of December 31, 2003 and 2002, and the related consolidated statements of operations, stockholders equity, and cash flows for years then ended. 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. The financial statements of Encore Acquisition Company as of December 31, 2001, and for the year then ended were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those financial statements in their report dated March 1, 2002.

We conducted our audits in accordance with auditing standards generally accepted in the 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 and subsidiaries at December 31, 2003 and 2002, and the consolidated results of their operations and their cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States.

As explained in Note 2 to the consolidated financial statements, effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations.

/s/ ERNST & YOUNG LLP

Fort Worth, Texas
February 6, 2004

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REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Shareholders of Encore Acquisition Company:

We have audited the accompanying consolidated balance sheets of Encore Acquisition Company (a Delaware corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2001. 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 auditing standards generally accepted in the 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 financial statements referred to above present fairly, in all material respects, the financial position of Encore Acquisition Company and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As explained in Note 2 to the financial statements, effective January 1, 2001, the Company changed its method of accounting for derivatives.

ARTHUR ANDERSEN LLP

Dallas, Texas
March 1, 2002

Subsequent to the completion of the audit of the Company s 2001 financial statements, Arthur Andersen LLP was convicted of obstruction of justice charges relating to a federal investigation of Enron Corporation and ceased operations as a public accounting firm. Accordingly, the report of independent public accountants included above is a copy of a report previously issued by Arthur Andersen. Arthur Andersen has not reissued its report for inclusion in this document.

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ENCORE ACQUISITION COMPANY

CONSOLIDATED BALANCE SHEETS

	December 31, 2003	December 31, 2002
	(In thousands except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 431	$ 13,057
Accounts receivable (net of allowance of $0 and $7.0 million, respectively)	27,640	21,981
Inventory	6,019	5,032
Derivative assets	5,588	3,245
Deferred tax asset	3,592	4,833
Other current assets	1,673	1,317
Total current assets	44,943	49,465
Properties and equipment, at cost successful efforts method:		
Producing properties	739,288	581,012
Undeveloped properties	921	1,168
Accumulated depletion, depreciation, and amortization	(124,646)	(94,356)
	615,563	487,824
Other property and equipment	3,831	3,680
Accumulated depreciation	(2,586)	(1,917)
	1,245	1,763
Other assets	10,387	10,844
Total assets	$ 672,138	$ 549,896
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 10,668	$ 9,650
Accrued lease operations expense	2,507	2,373
Accrued development capital	9,302	4,500
Derivative liabilities	8,026	8,558
Production and severance taxes payable	5,365	4,822
Other current liabilities	9,127	7,073
Total current liabilities	44,995	36,976
Derivative liabilities	3,514	2,998
Future abandonment cost	5,341	
Deferred tax liability	80,313	47,656
Long-term debt	179,000	166,000

Total liabilities	313,163	253,630
Commitments and contingencies		
Stockholders equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none issued and outstanding		
Common stock, $.01 par value, 60,000,000 shares authorized, 30,335,693 and 30,162,955 issued and outstanding	303	302
Additional paid-in capital	253,865	251,231
Deferred compensation	(2,528)	(2,396)
Retained earnings	117,365	53,724
Accumulated other comprehensive income	(10,030)	(6,595)
Total stockholders equity	358,975	296,266
Total liabilities and stockholders equity	$ 672,138	$ 549,896

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

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ENCORE ACQUISITION COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2003	**2002**	**2001**
	(In thousands except per share data)		
Revenues:			
Oil	$176,351	$134,854	$105,768
Natural gas	43,745	25,838	30,149
Total revenues	220,096	160,692	135,917
Expenses:			
Production			
Lease operations	37,846	30,678	25,139
Production, ad valorem, and severance taxes	22,013	15,653	13,809
Depletion, depreciation, and amortization	33,530	34,550	31,721
General and administrative (excluding non-cash stock based compensation)	8,680	6,150	5,053
Non-cash stock based compensation	614		9,587
Derivative fair value (gain) loss	(885)	(900)	680
Bad debt expense			7,005
Impairment of oil and natural gas properties			2,598
Other operating expense	3,481	2,045	934
Total expenses	105,279	88,176	96,526
Operating income	114,817	72,516	39,391
Other income (expenses):			
Interest	(16,151)	(12,306)	(6,041)
Other	214	91	46
Total other income (expenses)	(15,937)	(12,215)	(5,995)
Income before income taxes and cumulative effect of accounting change	98,880	60,301	33,396
Current income tax benefit (provision)	(991)	745	(1,919)
Deferred income tax provision	(35,111)	(23,361)	(14,414)
Income before cumulative effect of accounting change	62,778	37,685	17,063
Cumulative effect of accounting change, net of income taxes	863		(884)
Net income	$ 63,641	$ 37,685	$ 16,179
Income before cumulative effect of accounting change per common share:			
Basic	$ 2.09	$ 1.25	$ 0.59
Diluted	2.07	1.25	0.59
Net income per common share:			
Basic	$ 2.11	$ 1.25	$ 0.56
Diluted	2.10	1.25	0.56

Weighted average common shares outstanding:			
Basic	30,102	30,031	28,718
Diluted	30,333	30,161	28,723

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

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ENCORE ACQUISITION COMPANY

CONSOLIDATED STATEMENT OF STOCKHOLDERS   EQUITY

	Class A Common Stock	Class B Common Stock	Common Stock	Additional Paid-In Capital	Notes Receivable Officers/ Employees	Treasury Stock	Deferred Compensation	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income	Total Stockholders Equity
					(In thousands except share data)					
Balance at December 31, 2000	$ 1	$ 3	$	$ 147,968	$ (21)	$	$	$ (140)	$	$ 147,811
Proceeds from initial public offering (net of offering costs of $1,568)			71	91,456						91,527
Non-cash stock based compensation				9,587						9,587
Recapitalization	(1)	(3)	229	(225)						
Repayment of notes receivable officers and employees					21					21
Components of comprehensive income:										
Net income								16,179		16,179
Change in deferred hedge gain/loss (net of income taxes of $12,226)									19,058	19,058
Cumulative effect of accounting change (net of income taxes of $9,121)									(14,881)	(14,881)
Total comprehensive income										20,356
Balance at December 31, 2001			300	248,786				16,039	4,177	269,302
Exercise of stock options				51						51
Issuance of restricted stock			2	2,394			(2,396)			
Components of comprehensive income:										
Net income								37,685		37,685
Change in deferred hedge gain/loss (Net of income taxes of $6,602)									(10,772)	(10,772)
Total comprehensive income										26,913
Balance at December 31, 2002			302	251,231			(2,396)	53,724	(6,595)	296,266
Exercise of stock options			1	1,974						1,975
			91	175,383						175,474

Issuance of Common Stock										
Purchase of Treasury Stock						(175,560)				(175,560)
Cancellation of Treasury Stock			(91)	(175,469)		175,560				
Deferred compensation:										
Issuance of restricted Common Stock				927			(927)			
Amortization of expense							614			614
Other changes				(181)			181			
Components of comprehensive income:										
Net income								63,641		63,641
Change in deferred hedge gain/loss (Net of income taxes of $2,105)									(3,435)	(3,435)
Total comprehensive income										60,206
Balance at December 31, 2003	$	$	$ 303	$ 253,865	$	$	$ (2,528)	$ 117,365	$ (10,030)	$ 358,975

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

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ENCORE ACQUISITION COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2003	**2002**	**2001**
		(In thousands)	
Operating activities			
Net income	$ 63,641	$ 37,685	$ 16,179
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation, and amortization	33,530	34,550	31,721
Deferred taxes	35,111	23,361	13,718
Non-cash stock based compensation	614		9,587
Cumulative effect of accounting change	(863)		884
Non-cash derivative fair value (gain) loss	(165)	(1,239)	680
Other non-cash	1,293	177	1,718
Loss on disposition of assets	322	254	165
Bad debt expense			7,005
Impairment of oil and natural gas properties			2,598
Changes in operating assets and liabilities:			
Accounts receivable	(5,602)	(5,695)	4,564
Other current assets	(8,592)	(3,161)	(2,258)
Other assets	(2,024)	2,177	(4,605)
Accounts payable and other current liabilities	6,553	3,400	(1,744)
Cash provided by operating activities	123,818	91,509	80,212
Investing activities			
Proceeds from disposition of assets	1,295	226	310
Purchases of other property and equipment	(1,464)	(680)	(1,091)
Acquisition of oil and natural gas properties	(54,601)	(78,549)	(1,622)
Development of oil and natural gas properties	(98,977)	(80,313)	(87,180)
Cash used by investing activities	(153,747)	(159,316)	(89,583)
Financing activities			
Proceeds from issuance of common stock	176,127		93,095
Purchase of treasury stock	(175,560)		
Offering costs paid	(653)		(1,568)
Proceeds from issuance of 8 3/8% note		150,000	
Payments for debt issuance costs	(125)	(6,195)	
Exercise of stock options	1,975	51	
Proceeds from notes receivable officers and employees			21
Proceeds from long-term debt	112,500	144,000	161,000
Payments on long-term debt	(99,500)	(206,000)	(227,500)
Cash overdrafts	2,539		
Payments on note payable		(1,107)	(16,438)
Cash provided by financing activities	17,303	80,749	8,610
Increase (decrease) in cash and cash equivalents	(12,626)	12,942	(761)
Cash and cash equivalents, beginning of period	13,057	115	876
Cash and cash equivalents, end of period	$ 431	$ 13,057	$ 115

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

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Formation of the Company and Basis of Presentation

Encore Acquisition Company (the Company), a Delaware Corporation, is an independent (non-integrated) oil and natural gas company in the United States. We were organized in April 1998 and are engaged in the acquisition, development, exploitation, and production of North American oil and natural gas reserves. Our oil and natural gas reserves are concentrated in fields located in the Williston Basin of Montana and North Dakota, the Permian Basin of Texas and New Mexico, the Anadarko Basin of Oklahoma, the Powder River Basin of Montana, the Paradox Basin of Utah, and the North Louisiana Salt Basin.

2. Summary of Significant Accounting Policies

Principles of Consolidation

Our consolidated financial statements include the accounts of all subsidiaries in which we hold a controlling interest. All material intercompany balances and transactions are eliminated.

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, cash accounts that are overdrawn are reclassified to current liabilities and any change in cash overdrafts is shown as a financing activity in the consolidated statements of cash flows.

Inventories

Inventories are comprised principally of materials and supplies, which are stated at the lower of cost (determined on an average basis) or market, and oil in pipelines. Oil produced at the lease which resides unsold in pipelines is carried at an amount equal to its operating costs to produce.

Oil and Natural Gas Properties

We utilize the successful efforts method of accounting for our oil and natural gas properties. Under this method, all development and acquisition costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of proved developed reserves or proved reserves, as applicable. Exploration expenses, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Costs of drilling exploratory wells are initially capitalized, but charged to expense if and when the well is determined to be unsuccessful. Expenditures for repairs and maintenance to sustain or increase production from the existing producing reservoir are charged to expense as incurred. Expenditures to recomplete a current well in a different or additional proven or unproven reservoir are capitalized pending determination that economic reserves have been added. If the recompletion is not successful, the expenditures are charged to expense. Expenditures for redrilling or directional drilling in a previously abandoned well are classified as drilling costs to a proven or unproven reservoir for determination of capital or expense. Significant tangible equipment added or replaced is capitalized. Expenditures to construct facilities or increase the productive capacity from existing reserves are capitalized. Internal costs directly associated with the development and exploitation of properties are capitalized as a cost of the property and are classified accordingly in the Company s consolidated financial statements. Natural gas volumes are converted to equivalent barrels at the rate of six Mcf to one barrel. See Note 2, New Accounting Standards, on page 58 for a discussion of Statement of Financial Accounting Standard No. 143, Accounting for Asset Retirement Obligations (SFAS 143), which the Company adopted as of January 1, 2003.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company is required to assess the need for an impairment of capitalized costs of oil and natural gas properties and other long-lived assets whenever events or circumstances indicate that the carrying value of those assets 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 it is recognized to the extent that the carrying value exceeds fair value. Any impairment charge incurred is expensed reduces our recorded basis in the asset.

The costs of retired, sold, or abandoned properties that constitute part of an amortization base are charged or credited, net of proceeds received, to the accumulated depletion, depreciation, and amortization reserve. Gains or losses from the disposal of other properties are recognized in the current period.

Additionally, the Company s independent reserve engineers estimate our reserves once a year at December 31. This results in a new DD&A rate which the Company uses for the preceding fourth quarter and, to the extent no other reserve estimates change materially, the subsequent three quarters of the following year.

Stock-based Compensation

Employee stock options and restricted stock awards are accounted for under the provisions of Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees (APB 25). Accordingly, no compensation is recorded for stock options that are granted to employees or non-employee directors with an exercise price equal to or above the common stock price on the grant date. However, expense is recorded related to restricted stock granted to employees. If compensation expense for the stock based awards had been determined using the provisions of Statement of Financial Accounting Standard No. 123, Accounting for Stock-Based Compensation (SFAS 123), the Company s net income and net income per share would have been adjusted to the pro forma amounts indicated below (in thousands, except per share amounts):

	Year Ended December 31,		
	2003	**2002**	**2001**
As Reported:			
Net income	$63,641	$37,685	$16,179
Non-cash stock based compensation (net of taxes)	381		9,587
Diluted net income per share	2.10	1.25	0.56
Pro Forma:			
Net income	$62,093	$36,408	$15,475
Non-cash stock based compensation (net of taxes)	1,929	1,277	10,291
Diluted net income per share	2.05	1.21	0.54

Segment Reporting

The Company has only one operating segment, the development and exploitation of oil and natural gas reserves. Additionally, all of our assets are located in the United States and all of our oil and natural gas revenues are derived from customers located in the United States.

For 2003, 28%, 26%, and 11% of total oil and natural gas production was sold to ConocoPhillips, Shell, and Eighty-Eight Oil, respectively. In 2002, ConAgra and Equiva Trading Company (a joint venture between Shell and Texaco) accounted for 16% and 10% of total oil and natural gas sales, respectively. For 2001, 25%, 17%, and 11% of total oil and natural gas production was sold to ConAgra, Equiva Trading Company and EOTT Energy Co., respectively.

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ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 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.

Revenue Recognition

Revenues are recognized for Encore s share of jointly owned properties as oil and natural gas is produced and sold, net of royalties and net profits interest payments. Revenues are also reduced by any processing and other fees paid 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 as natural gas is sold by the Company rather than as the Company s working interest share of production. Royalties, net profits interests, and severance taxes are paid 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, we estimate and record the expected sales volumes and values for those properties. The Company also does not recognize revenue for the production in tanks or pipelines that has not been delivered to the purchaser yet. Encore s net oil inventories in pipelines were 46,622 Bbls and 104,954 Bbls at December 31, 2003 and 2002, respectively. Natural gas imbalances under-delivered to Encore at December 31, 2003 and December 31, 2002, were 446,000 MMBTU and 510,000 MMBTU, respectively.

Shipping Costs

Shipping costs in the form of pipeline fees paid to third parties are incurred to move oil and natural gas production from certain properties to a different market location for ultimate sale. These costs are included in other operating expense in our statements of operations.

Hedging and Related Activities

We use 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 over-the-counter forward derivative contracts with large financial institutions.

Effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards No. 133 (SFAS 133), Accounting for Derivative Instruments and Hedging Activities . This standard requires us to recognize all of our derivative financial instruments in our consolidated balance sheets as either assets or liabilities and measure them 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 does qualify for hedge accounting, depending on the nature of the hedge, changes in fair value can be offset against the change in fair value of the hedged item through earnings or recognized in 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. The impact of adopting SFAS 133 on January 1, 2001 was to record the fair value of our derivatives as a reduction in assets of $1.1 million and as a

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ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

liability in the amount of $24.4 million. Additionally, we recorded a reduction in earnings as the cumulative effect of an accounting change of $0.9 million (net of taxes of $0.5 million) and a decrease to stockholders equity for other comprehensive income in the amount of $14.9 million (net of deferred taxes of $9.1 million).

Currently, all of our derivative financial instruments that are designated as hedges are designated as cash flow hedges. These instruments hedge the exposure of variability in expected future cash flows that is attributable to a particular risk. The effective portion of the mark-to-market gain or loss on these derivative instruments is recorded in 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 into earnings immediately.

Comprehensive Income

Comprehensive income includes net income and other comprehensive income, which includes, effective January 1, 2001, unrealized gains and losses on derivative financial instruments. Encore chooses to show yearly comprehensive income as part of its consolidated statement of stockholders equity.

Use of Estimates

Preparing financial statements in conformity with accounting principles generally accepted in the United States 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 reported. Actual results could differ materially from those estimates.

Estimates made in preparing these consolidated financial statements include the Company s estimated proved oil and natural gas reserve volumes used in calculating depletion, depreciation, and amortization expense; the estimated future cash flows and fair value of our properties used in determining the need for any impairment write-down; and the timing and amount of future abandonment costs used in calculating the Company s asset retirement obligations. See Note 4. Commitments and Contingencies Asset Retirement Obligations. Future changes in the assumptions used could have a significant impact on reported results in future periods.

New Accounting Standards

Statements of Financial Accounting Standards No. 141, Business Combinations (SFAS 141) and No. 142, Goodwill and Other Intangible Assets (SFAS 142) were issued in July 2001. SFAS 141 requires that all business combinations entered into subsequent to June 30, 2001 be accounted for under the purchase method of accounting and that certain acquired intangible assets in a business combination be recognized and reported as assets apart from goodwill. SFAS 142 requires that amortization of goodwill be replaced with periodic tests of the goodwill s impairment at least annually in accordance with the provisions of SFAS 142 and that intangible assets other than goodwill be amortized over their useful lives.

Currently, the Emerging Issues Task Force staff are engaged in discussions on the issue of whether SFAS 141 and SFAS 142 which were effective June 30, 2001, called for mineral rights held under a lease or other contractual arrangement to be classified on the balance sheet as intangible assets and accompanied by specific footnote disclosures. Historically, oil and gas companies, including Encore, have included these costs with all other oil and natural gas property costs in Property, Plant, and Equipment on the consolidated balance sheet.

In the event this interpretation is adopted, a substantial portion of the acquisition costs of oil and natural gas properties would be required to be classified on the balance sheet as an intangible asset. The

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ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Company believes this interpretation would not have a material effect on our results of operations for the periods presented or in the future as these intangible assets would be depleted using the units of production method in a manner consistent with the method currently used to calculate depletion, depreciation, and amortization expense on these assets.

At December 31, 2003, the Company had $0.9 million of undeveloped leasehold costs and $291.5 million of developed leasehold costs (net of accumulated depletion) that would be reclassified as Intangible developed and undeveloped leasehold costs if the Company were to apply the interpretation as currently discussed.

In August 2001, the FASB issued SFAS 143, which the Company adopted as of January 1, 2003. This statement requires us to record a liability in the period in which an asset retirement obligation (ARO) is incurred. Also, upon initial recognition of the liability, we must capitalize additional asset cost equal to the amount of the liability. In addition to any obligations that arise after the effective date of SFAS 143, upon initial adoption we must recognize (1) a liability for any existing AROs, (2) capitalized cost related to the liability, and (3) accumulated depletion, depreciation, and amortization on that capitalized cost.

The adoption of SFAS 143 resulted in a January 1, 2003 cumulative effect adjustment to record (i) a $4.0 million increase in the carrying values of proved properties, (ii) a $2.1 million decrease in accumulated depletion, depreciation, and amortization, and (iii) a $5.2 million increase in other non-current liabilities, and (iv) a gain of $0.9 million, net of tax, as a cumulative effect of accounting change on January 1, 2003. The Company does not include a market risk premium in its risk estimates as the effect would not be material.

The following table shows net income and basic and diluted net income per common share as reported, as well as pro forma amounts as if the Company had adopted SFAS 143 prior to January 1, 2001 (in thousands, except per common share amounts):

	Year Ended December 31,		
	2003	**2002**	**2001**
As Reported:			
Net income	$63,641	$37,685	$16,179
Basic net income per common share	2.11	1.25	0.56
Diluted net income per common share	2.10	1.25	0.56
Pro Forma:			
Net income	$62,778	$38,035	$16,549
Basic net income per common share	2.09	1.27	0.58
Diluted net income per common share	2.07	1.26	0.58

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets (SFAS 144), which is effective for financial statements issued for fiscal years beginning after December 15, 2001 and interim periods within those fiscal years. SFAS 144 requires that long-lived assets to be disposed of by sale be measured at the lower of the carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations. SFAS 144 broadens the reporting of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The Company adopted SFAS No. 144 effective January 1, 2002. The Company s adoption of this statement has not had a material effect on its financial position or results of operations.

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ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In April 2002, the FASB issued SFAS 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections. Under Statement 4, all gains and losses from extinguishment of debt were required to be aggregated and, if material, classified as an extraordinary item, net of related income tax effect. This Statement eliminates Statement 4 and, thus, the exception to applying Opinion 30 to all gains and losses related to extinguishments of debt. As a result, gains and losses from extinguishment of debt should be classified as extraordinary items only if they meet the criteria in Opinion 30. Applying the provisions of Opinion 30 will distinguish transactions that are part of an entity s recurring operations from those that are unusual or infrequent or that meet the criteria for classification as an extraordinary item. This statement is effective for Encore beginning January 1, 2003, at which time the extraordinary loss on extinguishment of debt of $0.9 million recorded in the second quarter of 2002 was reclassified to operating income.

In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure, an Amendment of FASB Statement No. 123 (SFAS 148). This Statement amends SFAS 123, to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this Statement amends the disclosure requirements of SFAS 123 to require prominent disclosures in both annual and interim financial statements. Certain of the disclosure modifications are required for fiscal years ending after December 15, 2002. SFAS 148 has not had any effect on the Company s financial position or results of operations. See additional required disclosures at Note 10. Employee Benefit Plans.

3. Acquisitions

2001 Acquisitions

During 2001, we made small miscellaneous acquisitions of undeveloped acreage. No material proved property acquisitions were made.

2002 Acquisitions

On January 4, 2002 we closed the purchase of our Central Permian properties. These properties were purchased from Conoco for approximately $50.1 million. The properties include two major operated fields: East Cowden Grayburg and Fuhrman-Nix; and two non-operated fields: North Cowden and Yates. During the second quarter of 2002, we closed a second follow-on acquisition of additional working interests in the East Cowden Field for $8.3 million.

On August 29, 2002, we completed an acquisition of interests in oil and natural gas properties in southeast Utah s Paradox Basin. The final purchase price after the exercise of preferential rights was $17.9 million ($16.7 million after closing adjustments). The properties are divided between two oil producing units: the Ratherford Unit operated by ExxonMobil and the Aneth Unit operated by Chevron Texaco.

2003 Acquisitions

On July 31, 2003, we closed the initial acquisition of the North Louisiana properties. Subsequently, we have purchased several smaller interests in these properties. The original purchase was effective June 1, 2003. The Company purchased interests in natural gas properties in North Louisiana (the Elm Grove acquisition) from a group of private sellers at a cost of $54.6 million. Beginning August 1, 2003, revenues and expenses from these properties have been included in the Company s Consolidated Statements of Operations and drilling costs have been included in Development of oil and natural gas properties in the Consolidated Statements of Cash Flows. From June 1, 2003 to July 31, 2003, revenues, expenses, and development capital of the properties were treated as adjustments to the purchase price. The properties are

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ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

located in the Elm Grove Field in Bossier Parish, Louisiana and are non-operated working interests ranging from 2% to 38% across 1,800 net acres in 15 sections.

These acquisitions have been accounted for as purchases. The operating results of the acquired properties have been included in our consolidated financial statements since the date of acquisition.

4. Commitments and Contingencies

Leases

We lease office space and equipment that have remaining non-cancelable lease terms in excess of one year. The following table summarizes by year our remaining non-cancelable future payments under operating leases as of December 31, 2003 (in thousands):

2004	$951
2005	987
2006	520
2007	171
2008	171
Thereafter	43

Our operating lease rental expense was approximately $1.5 million, $0.9 million, and $0.7 million in 2003, 2002, and 2001, respectively.

Asset Retirement Obligations

The Company s primary asset retirement obligations relate to future plugging and abandonment expenses on our oil and natural gas properties and related facilities disposal. As of December 31, 2003, the Company had $2.7 million held in an escrow account from which funds are released only for reimbursement of plugging and abandonment expenses on our Bell Creek property. This amount is included in Other assets in the accompanying Consolidated Balance Sheet. The following table summarizes the changes in the Company s future abandonment liability recorded in Future abandonment cost on the Company s Consolidated Balance Sheet from the liability initially recorded upon adoption of SFAS 143 on January 1, 2003 through December 31, 2003 (in thousands):

	Year Ended December 31, 2003
Future abandonment liability at January 1, 2003	$4,791
Acquisition of Elm Grove properties	337
Wells Drilled	83
Accretion expense	272
Plugging and abandonment costs incurred	(100)
Revision of estimates	(42)
Future abandonment liability at December 31, 2003	$5,341

The pro-forma asset retirement obligation as of December 31, 2001 and 2000 would have been $4.1 million and $4.2 million, respectively, had the Company adopted SFAS 143 prior to January 1, 2001.

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ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Accounts Payable and Accrued Liabilities

Other current liabilities were as follows at December 31 (in thousands):

	2003	2002
Cash overdrafts	$2,681	$
Oil and natural gas revenue payable	1,176	4,108
Net profits payable	589	237
Interest	563	595
Other	4,118	2,133
Total	$9,127	$7,073

6. Indebtedness

The following table details the Company s indebtedness at December 31 (in thousands):

	2003	2002
Revolving Credit Facility	$ 29,000	$ 16,000
8 3/8% Notes	150,000	150,000
Total	$179,000	$166,000

Prior to restructuring our debt on June 25, 2002 (see below), the Company s operating subsidiary maintained a credit agreement with a group of banks that matured in May 2004. The Company guaranteed the subsidiary s obligations under the credit agreement and pledged the stock and other equity interests of its subsidiaries to secure the guaranty.

On June 25, 2002, the Company sold $150 million of 8 3/8% Senior Subordinated Notes maturing on June 15, 2012 (the Notes). The offering was made through a private placement pursuant to Rule 144A. Subsequently, the Company filed a registration statement on Form S-4/A, which was declared effective on December 6, 2002. The Company received net proceeds of $145.6 million from the sale of the Notes, after deducting debt issuance costs. The proceeds were used to repay and retire the Company s prior credit facility ($143.0 million), to pay the fees and expenses related to a new revolving credit facility ($1.5 million), and to hold in reserve for the Paradox Basin acquisition ($1.1 million).

All of the Company s subsidiaries are currently subsidiary guarantors of the Notes. Since (i) each subsidiary guarantor is 100% owned by the Company, (ii) the Company has no assets or operations that are independent of its subsidiaries, (iii) the subsidiary guarantees are full and unconditional and joint and several and (iv) all of the Company s subsidiaries are subsidiary guarantors, the Company has not included the financial statements of each subsidiary in this report. The subsidiary guarantors may without restriction transfer funds to the Company in the form of cash dividends, loans and advances.

Concurrently with the issuance of the Notes, the Company also entered into a new revolving credit facility (the Facility) on June 25, 2002. Borrowings under the Facility are secured by a first priority lien on the Company s proved oil and natural gas reserves. Availability under the Facility is determined through semi-annual borrowing base determinations and may be increased or decreased. The amount available under the

Facility at December 31, 2003 was $270.0 million, with $29.0 million outstanding as of December 31, 2003. The maturity date of the Facility is June 25, 2006.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Amounts outstanding under the Facility are subject to varying rates of interest based on the amount outstanding and the Company s borrowing base. Based on our current $270.0 million borrowing base, our applicable interest rates are calculated as follows:

Amount Outstanding	Rate
$0 to $55,000,000	LIBOR + 1.000%
$55,000,001 to $110,000,000	LIBOR + 1.125%
$110,000,001 to $165,000,000	LIBOR + 1.250%
$165,000,001 to $198,000,000	LIBOR + 1.500%
$198,000,001 to $270,000,000	LIBOR + 1.750%

During 2003 and 2002, the weighted average interest rate under the Facility was 9.6% and 8.2%, respectively.

Additionally, under the Facility, the Company is subject to certain affirmative, negative, and financial covenants. These include limitations on incurrence of additional debt, restrictions on asset dispositions and restricted payments, maintenance of a 1.0 to 1.0 current ratio, and maintenance of an EBITDA, as defined, to interest expense ratio of at least 2.5 to 1.0. As of December 31, 2003, the Company was in compliance with all covenants.

The following table illustrates the Company s long-term debt maturities at December 31, 2003 (in thousands):

	Payments Due by Period				
	Total	2004	2005 - 2006	2007 - 2008	Thereafter
8 3/8% Notes	$150,000	$	$	$	$150,000
Revolving credit facility	29,000		29,000		
Totals	$179,000	$	$29,000	$	$150,000

Consolidated cash payments for interest were $16.2 million, $13.2 million, and $6.4 million, respectively, for 2003, 2002, and 2001.

7. Taxes

Income Taxes

The components of the Company s total income tax expense including amounts related to items shown net of income taxes on the statements of operations were attributed to the following items (in thousands):

	Year Ended December 31,		
	2003	2002	2001
Taxes related to:			
Income before cumulative effect of accounting change	$36,102	$22,616	$16,333
Cumulative effect of accounting change	529		541

Total tax expense	$36,631	$22,616	$16,874

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ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The components of the income tax provision related to income/ loss before cumulative effect of accounting change and extraordinary loss are as follows (in thousands):

	Year Ended December 31,		
	2003	2002	2001
Federal:			
Current	$ 991	$ (745)	$ 1,919
Deferred	32,145	21,552	13,125
Total federal	33,136	20,807	15,044
State:			
Current			
Deferred	2,966	1,809	1,289
Total state	2,966	1,809	1,289
Income tax provision	$36,102	$22,616	$16,333

Reconciliation of income tax expense with tax at the Federal statutory rate is as follows (in thousands):

	Year Ended December 31,		
	2003	2002	2001
Income before income taxes	$98,880	$60,301	$33,396
Tax at statutory rate	$34,608	$21,105	$11,689
State income taxes, net of federal benefit	2,966	1,809	1,289
Non-cash stock based compensation			3,355
Section 29 & 43 credits	(1,322)	(632)	
Other	(150)	334	
Income tax provision	$36,102	$22,616	$16,333

The major components of the net current deferred tax asset and net long-term deferred tax liability are as follows at December 31 (in thousands):

	December 31,	
	2003	2002

Current:		
Assets:		
Allowance for bad debt	$	$ 984
Unrealized hedge loss in other comprehensive income	4,626	3,883
Other		65
Total current deferred tax assets	4,626	4,932
Liabilities:		
Derivative fair value loss	(881)	(99)
Other	(153)	
Total current deferred tax liabilities	(1,034)	(99)
Net current deferred tax asset	$ 3,592	$4,833

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	December 31,	
	2003	**2002**
Long-term:		
Assets:		
Alternative minimum tax	$ 1,972	$ 1,312
Unrealized hedge loss in other comprehensive income	1,453	159
Section 43 credits	1,062	1,019
Other	251	14
Total long-term deferred tax assets	4,738	2,504
Liabilities:		
Book basis of oil and natural gas properties in excess of tax basis	(85,051)	(50,160)
Net long-term deferred tax liability	$ (80,313)	$ (47,656)

Cash income tax payments in the amount of $1.5 million were made in 2003 and in 2001. No cash income tax payments were made in 2002.

Taxes Other than Income Taxes

Taxes other than income taxes were comprised of the following (in thousands):

	Year Ended December 31,		
	2003	**2002**	**2001**
Production and severance	$ 19,999	$ 14,397	$ 13,303
Property and ad valorem	2,014	1,256	506
Franchise, payroll and other taxes	677	383	316
Total	$ 22,690	$ 16,036	$ 14,125

8. Stockholders Equity

Public Offerings of Common Stock

On March 8, 2001, the Company priced its shares to be issued in its initial public offering (IPO) and began trading on the New York Stock Exchange the following day under the ticker symbol EAC . Immediately prior to Encore s IPO, all of the outstanding shares of Class A and Class B stock held by management and institutional investors were converted into 2,630,203 and 20,249,758 shares, respectively, of a single class of common stock. Through the IPO, the Company sold an additional 7,150,000 shares of common stock to the public at the offering price of $14.00 per share, resulting in total outstanding shares of 30,029,961. The Company received $91.5 million in net proceeds after deducting the underwriter s discounts and commissions and related offering expenses. The proceeds received from the IPO were used to pay down debt outstanding under our credit facility.

On November 13, 2003, the Company priced a public offering of 8.0 million shares of Encore s common stock at a price to the public of $20.25 per share. The underwriters also exercised their over-allotment option for an additional 1.06 million shares of common stock, at a price of $20.25 per share, on December 2, 2003, for a total of 9.06 million shares. The Company used all of the net proceeds to repurchase 6,866,643 shares of Encore s common stock from J.P. Morgan Partners (SBIC), LLC (J.P. Morgan) and 2,193,357 shares from Warburg Pincus Equity Partners L.P. (Warburg Pincus) at a price of $19.3775 per share. The 9.06 million shares the Company purchased were retired upon

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ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

repurchase. Encore s total shares outstanding did not change as a result of this offering. Net proceeds from the original offering and the over-allotment option totaled approximately $175.6 million, after deducting underwriting discounts and commissions and the estimated expenses of the offering. After giving effect to the repurchase, J.P. Morgan no longer beneficially owns any of Encore s common stock and Warburg Pincus beneficially owns 24.5% of Encore s common stock.

Common Stock Option Exercises

During the years ended December 31, 2003 and 2002, employees of the Company exercised 145,727 and 3,666 options, respectively. The Company received proceeds from the option exercises of $2.0 million and $0.1 million in the years ended December 31, 2003 and 2002, respectively, related to these option exercises.

Preferred Stock

The Company has authorized a class of undesignated preferred stock consisting of 5,000,000 shares, none of which are issued and outstanding. The Board of Directors has not determined the rights and privileges of holders of such preferred stock and we have no current plans to issue any shares of preferred stock.

Non-Cash Stock Based Compensation Expense on Class A Stock

The Company followed variable plan accounting for the Class A stock sold to management. Accordingly, compensation expense was based on the excess of the estimated fair value of the Class A stock over the amount paid by the shareholders. Compensation expense was adjusted in each reporting period based on the most recent fair value estimates until the measurement date occurred. Compensation expense was recorded over the expected service period of the Class A stock, which was based on a vesting schedule. The Class A stock vested 25% upon issuance and an additional 15% per year for the following five years. Prior to September 1, 2000, the Company estimated the fair value of our Class A common stock based on discounted cash flow estimates of our oil and natural gas properties. Beginning on September 1, 2000, we estimated the fair value of the Class A stock based on 90% of the estimated offering price in the Company s IPO. The measurement date occurred on March 8, 2001, the date of the IPO, as after this date the Class A shareholders were no longer required to make future capital contributions. Total compensation expense on the Class A shares using the IPO price of $14.00 per share was $35.6 million. Based on the estimated fair values and vesting at the end of each period, the Company recorded $9.6 million of compensation expense for 2001 and $26.0 million in 2000. The $9.6 million recorded in 2001 represented the final compensation expense to be recorded related to the Class A shares.

9. Earnings Per Share (EPS)

Under Statement of Financial Accounting Standards No. 128, the Company must report basic EPS, which excludes the effect of potentially dilutive securities, and diluted EPS, which includes the effect of all potentially dilutive securities. EPS for the periods presented is based on weighted average common shares outstanding for the period.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table reflects EPS data for the years ended December 31 (in thousands, except per share data):

	Year Ended December 31,		
	2003	2002	2001
Numerator:			
Income before cumulative effect of accounting change	$62,778	$37,685	$17,063
Cumulative effect of accounting change	863		(884)
Net income	$63,641	$37,685	$16,179
Denominator:			
Denominator for basic earnings per share weighted average shares outstanding	30,102	30,031	28,718
Effect of dilutive options and dilutive restricted stock(a)	231	130	5
Denominator for diluted earnings per share	30,333	30,161	28,723
Basic income per common share before accounting change	$ 2.09	$ 1.25	$ 0.59
Cumulative effect of accounting change, net of tax	0.02		(0.03)
Basic income per common share after accounting change	$ 2.11	$ 1.25	$ 0.56
Diluted income per common share before accounting change	$ 2.07	$ 1.25	$ 0.59
Cumulative effect of accounting change, net of tax	0.03		(0.03)
Diluted income per common share after accounting change	$ 2.10	$ 1.25	$ 0.56

(a) There were no antidilutive options or antidilutive restricted stock outstanding for the year ended December 31, 2003 and December 31, 2001. Options to purchase 272,177 shares of common stock were outstanding but not included in the above calculation of 2002 diluted earnings per share because their effect would be antidilutive. Additionally, the Company issued 129,328 shares of restricted stock at the end of 2002 which are not included in the calculation of 2002 diluted earnings per share because their effect on the shares outstanding would be nominal.

10. Employee Benefit Plans

401(k) plan

We make contributions to the Encore Acquisition Company 401(k) Plan, which is a voluntary and contributory plan for eligible employees. Our contributions, which are based on a percentage of matching employee contributions, totaled $0.5 million in 2003, $0.5 million in 2002, and $0.4 million in 2001. The Company s 401(k) plan does not currently allow employees to invest in securities of the Company.

Incentive Stock Plans

During 2000, the Company s Board of Directors approved the 2000 Incentive Stock Plan (the Plan). The purpose of the Plan is to attract, motivate, and retain selected employees of the Company and to provide the Company with the ability to provide incentives more directly linked to the profitability of the business and increases in shareholder value. All directors and full-time regular employees of the Company and its subsidiaries and affiliates are eligible to be granted awards under the Plan. The total number of shares of common stock reserved and available for distribution pursuant to the Plan is 1.8 million. The Plan provides for the granting of incentive stock options, non-qualified stock options, and restricted stock at the discretion of the Company s Board of Directors.

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ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

All options granted under the Plan have a strike price equal to the market price on the date of grant. Additionally, all have a ten-year life and vest equally over a two or three-year period. The following table summarizes the changes in the number of outstanding options and their related weighted average strike prices during 2003, 2002, and 2001:

	Year Ended December 31, 2003		Year Ended December 31, 2002		Year Ended December 31, 2001	
	Number of Options	Weighted Average Strike Price	Number of Options	Weighted Average Strike Price	Number of Options	Weighted Average Strike Price
Outstanding at beginning of year	1,178,511	$ 14.62	847,500	$ 13.44		$
Granted(a)	49,792	19.45	378,177	17.21	940,000	13.49
Forfeited	(119,622)	16.11	(43,500)	14.24	(92,500)	14.00
Exercised	(145,727)	13.43	(3,666)	14.00		
Outstanding at end of year	962,954	14.86	1,178,511	14.62	847,500	13.44
Exercisable at end of year	581,610	13.95	324,278	13.31		

(a) During 2003 and 2002, 15,000 and none of the options granted, respectively, were granted to non-employee directors. The weighted average fair value of individual options granted in 2003 and 2002 was $6.38 and $6.91, respectively.

Additional information about common stock options outstanding and exercisable at December 31, 2003 is as follows:

	Options Outstanding		
Range of Strike Prices per Share	Number of Options	Weighted Average Life (Years)	Weighted Average Strike Price
$12.49 to $14.00	682,667	7.5	$ 13.37
$14.01 to $20.41	280,287	9.0	18.50

Under the Plan during 2003 and 2002, the Company issued 45,461 and 129,328 shares, respectively, of restricted common stock to employees. Of these, 45,461 shares issued in 2003 and 77,901 shares issued in 2002 vest in equal installments over a five year period evenly in years three, four, and five and depend only on continued employment for future issuance. These represent a fixed award per APB 25 and compensation expense is being recorded over the related five-year service period. Of the remaining 51,427 shares issued in 2002, only 34,464 remain outstanding at December 31, 2003. These were issued to two members of senior management and also vest in equal installments over a five year period evenly in years three, four, and five. However, these shares not only depend on the passage of time and continued employment, but on certain performance measures for their future issuance. These represent a variable award under APB 25, and thus, the full amount of compensation expense to be recorded for these shares will not be known until their eventual issuance as it is dependent on the price of the Company s common stock on that date. The closing stock price on the date of grant in 2002 was $18.60 and was $24.65 on December 31, 2003.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

SFAS 123 disclosures

Under SFAS 123, the fair value of each stock option grant is estimated on the date of grant using the Black-Scholes option-pricing model. See Stock-based Compensation in Note 2. The following amounts represent weighted average values used in the model to calculate the fair value of the options granted during 2003, 2002, and 2001:

	Year Ended December 31, 2003	Year Ended December 31, 2002	Year Ended December 31, 2001
Risk free interest rate	3.0%	3.4%	4.4%
Expected life	4 years	4 years	4 years
Expected volatility	36.5%	46.7%	28.9%
Expected dividend yield	0.0%	0.0%	0.0%

11. Financial Instruments

The following table sets forth the book value and estimated fair value of the Company s financial instruments (in thousands):

	December 31, 2003		December 31, 2002	
	Book Value	Fair Value	Book Value	Fair Value
Cash and cash equivalents	$ 431	$ 431	$ 13,057	$ 13,057
Accounts receivable, net	27,640	27,640	21,981	21,981
Accounts payable	(10,668)	(10,668)	(9,650)	(9,650)
8 3/8% Notes	(150,000)	(162,750)	(150,000)	(161,000)
Revolving credit facility	(29,000)	(29,000)	(16,000)	(16,000)
Commodity derivative contracts	(7,768)	(7,768)	(5,047)	(5,047)
Interest rate swaps	2,420	2,420	(1,325)	(1,325)
Plugging bond	589	643	554	633

The book value of cash and cash equivalents approximates fair value because of the short maturity of these instruments. The fair value of our 8 3/8% bonds was determined using their open market quote as of December 31, 2003. The difference between book value and fair value represents the premium on that date. The book value of the Facility approximates the fair value as the interest rate is variable. The plugging bond is classified as held to maturity and therefore is recorded at amortized cost, which at December 31, 2003 is less than fair value. Commodity contracts and interest rate swaps are marked to market each quarter in accordance with the provisions of SFAS 133.

Commodity Derivatives

The Company hedges commodity price risk with swap contracts, put contracts, and collar contracts and hedges interest rate risk with swap contracts. Swap contracts provide a fixed price for a notional amount of volume. Put contracts provide a fixed floor price on a notional amount of volume while allowing full price participation if the relevant index price closes above the floor price. Collar contracts provide floor price for a notional amount of volume while allowing some additional price participation if the relevant index price closes above the floor price. Additionally, we occasionally sell put contracts with a strike price well below the floor price of the collar. These short put contracts do not qualify for hedge accounting under SFAS 133, and accordingly, the mark-to-market change in the value of these contracts is recorded as fair value gain/loss in the statement of operations.

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ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company has several oil and natural gas put contracts in place at December 31, 2003 which the Company did not designate as cash flow hedges, and thus they are also marked to market through earnings each quarter. Some instances management has determined it is more cost effective to not designate certain derivatives as hedges. At December 31, 2003, we had oil put contracts of 1,500 Bbls per day in the first half of 2004, 2,500 Bbls of oil put contracts in the second half of 2004, and natural gas put contracts of 5,000 Mcf per day for 2004 that were not designated as cash flow hedges. The fair value of these contracts at December 31, 2003 was $0.9 million.

In order to more effectively hedge the cash flows received on our oil and natural gas production, the Company enters into financial instruments whereby we swap certain per Bbl or per Mcf floating market indices for a fixed amount. These market indices are a component of the price the Company is paid on its actual production and by fixing this component of our marketing price, we are able to realize a net price with a more consistent differential to NYMEX. Since NYMEX is the basis of all our derivative oil hedging contracts and some of our natural gas contracts, a more consistent differential results in more effective hedges. However, management has elected not to use hedge accounting for certain of these contracts. Instead, we mark these contracts to market each quarter through Derivative fair value (gain) loss in the Consolidated Statements of Operations. Thus, as these contracts do not change the Company s overall hedged volumes, average prices presented in the table below are exclusive of any effect of these non-hedge instruments. As of December 31, 2003, the mark-to-market value of these contracts is $0.1 million.

The following tables summarize our open commodity derivative positions designated as cash flow hedges as of December 31, 2003:

Oil Hedges at December 31, 2003

Period	Daily Floor Volume (Bbls)	Floor Price (per Bbl)	Daily Cap Volume (Bbls)	Cap Price (per Bbl)	Daily Swap Volume (Bbls)	Swap Price (per Bbl)	Fair Market Value (In thousands)
Jan. June 2004	15,500	$22.98	7,000	$29.06	500	$26.48	$(3,679)
July Dec. 2004	14,500	23.72	5,000	28.33	500	26.48	(1,203)
Jan. June 2005	2,500	23.00	2,000	30.41	1,000	25.12	(421)
July Dec. 2005	1,500	23.00	1,500	30.18	1,000	25.12	(509)
Jan. Dec. 2006					2,000	25.03	(1,139)
Jan. Dec. 2007					2,000	25.11	(1,029)

Natural Gas Hedges at December 31, 2003

Period	Daily Floor Volume (Mcf)	Floor Price (per cf)	Daily Cap Volume (Mcf)	Cap Price (per Mcf)	Daily Swap Volume (Mcf)	Swap Price (per Mcf)	Fair Market Value (In thousands)
Jan. Dec. 2004	15,000	$4.02	7,500	$6.03	5,000	$5.01	$(477)
Jan. Dec. 2005					5,000	4.63	(311)

As a result of all of our hedging transactions for oil and natural gas we recognized a pre-tax reduction in revenues of approximately $15.3 million, $5.2 million, and $12.8 million in 2003, 2002, and 2001, respectively. Based on the fair value of our hedges at December 31, 2003, our unrealized pre-tax loss recorded in other comprehensive income related to outstanding hedges is $13.9 million for oil and $2.1 million for natural gas. Of the total deferred hedge loss at December 31, 2003 related to commodity contracts, $12.1 million relates to 2004 contracts, and $1.7 million, $1.2 million, $1.0 million relate to 2005, 2006, and 2007 contracts, respectively.

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ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Interest Rate Derivatives

As discussed in Note 6. Indebtedness, in conjunction with the sale of the Notes, the Company repaid all amounts outstanding under its previous credit facility on June 25, 2002, and terminated the prior revolving credit facility on that date. At the time, the Company had three interest rate swaps outstanding, with a notional amount of $30 million each, which swapped LIBOR based floating rates for fixed rates. According to the provisions of SFAS 133, these no longer qualified for hedge accounting. Their unrealized loss of $3.8 million through June 25, 2002 was recognized in accumulated other comprehensive income, and is being amortized to interest expense over the original life of the swaps as follows (in thousands):

Year	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
2002	$	$ (59)	$ (806)	$ (754)	$ (1,619)
2003	(654)	(544)	(414)	(297)	(1,909)
2004	(212)	(153)	(109)	(72)	(546)
2005	(40)	72	85	60	177
2006	22	24	29	33	108
2007	38	1			39
Total					$ (3,750)

During the third quarter of 2002, the Company cash settled one of three interest rate swaps discussed above and during the first quarter of 2003, the Company cash settled the remaining two. This resulted in a gain of $0.6 million in 2003 and a loss of $0.4 million in 2002, which was included in Derivative fair value (gain) loss in the Statements of Operations.

The following table summarizes the Company s only remaining interest rate swap contract at December 31, 2003:

Contract Expiration	Notional Amount	Encore Pays	Encore Receives	Fair Market Value (In thousands)
June 2005	$ 80,000,000	LIBOR + 3.89%	8.375%	$ 2,420

As a result of our hedging transactions for interest, we recognized in interest expense a pre-tax loss of approximately $1.9 million, $1.6 million, and $0.7 million in 2003, 2002, and 2001, respectively. Additionally, $1.5 million gain was recognized in Derivative fair value (gain) loss in 2003 for settlements and changes in fair value of our current interest rate swap, which does not qualify for hedge accounting.

The actual gains or losses we realize from our derivative transactions may vary significantly from the deferred loss amount recorded in equity at December 31, 2003 due to fluctuation of prices in the commodities markets and/or fluctuations in the floating LIBOR interest rate.

Counterparty Risk

The Company s counterparties to hedging contracts include: Paribas BNP; Deutsche Bank; Koch; Morgan Stanley; Mitsui & Co; Shell Trading; Credit Lyonnais; J. Aron & Company, a wholly-owned subsidiary of Goldman, Sachs & Co. Approximately 35%, 23%, 20%, and 16% of estimated oil production hedged is committed to Morgan Stanley, J. Aron & Company, Deutsche Bank, and Credit Lyonnais, respectively. Approximately 42%, 33%, and 25% of our hedged gas production is contracted with BNP Paribas, J. Aron & Company, and Morgan Stanley, respectively. Performance on all of J. Aron & Company s contracts with the Company is guaranteed by their parent Goldman, Sachs & Co. We feel the credit-worthiness of our current counterparties is sound and we do not anticipate any non-performance of

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

contractual obligations. However, as long as each counterparty maintains an investment grade credit rating, pursuant to our hedging contracts, no collateral is required.

In order to mitigate the credit risk of financial instruments, the Company enters into master netting agreements with significant counterparties. The master netting agreement is a standardized, bilateral contract between the Company and a given counterparty. Instead of treating each financial transaction between the Company and its counterparty separately, the master netting agreement enables the Company and its counterparty to aggregate all financial trades and treat them as a single agreement. This arrangement benefits the Company in three ways. First, the netting of the value of all trades reduces the requirements of daily collateral posting by the Company. Second, default by a counterparty under one financial trade can trigger rights for the Company to terminate all financial trades with such counterparty. Third, netting of settlement amounts reduces the Company s credit exposure to a given counterparty in the event of close-out.

12. Termination of Enron Hedges

On December 2, 2001, Enron Corp. and certain subsidiaries, including Enron North America Corp. (Enron), each filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Bankruptcy Code. Prior to this date, the Company had entered into oil and natural gas hedging contracts with Enron, many of which were set to expire at December 31, 2001; however, others related to 2002 and 2003. As a result of the Chapter 11 bankruptcy declaration and pursuant to the terms of the Company s contract with Enron, we terminated all outstanding oil and natural gas derivative contracts with Enron as of December 12, 2001. According to the terms of the contract, Enron is liable to the Company for the mark-to-market value of all contracts outstanding on that date, which totaled $6.6 million. Additionally, Enron failed to make timely payment of $0.4 million in 2001 hedge settlements. Both of these amounts remained outstanding as of December 31, 2001. Due to the uncertainty of future collection of any or all of the amounts owed to the Company by Enron, the Company recorded an allowance for the full amount of the receivable of $7.0 million.

At the time of termination, the market price of our commodity contracts with Enron exceeded their amortized cost on our balance sheet, giving rise to a gain. In accordance with the provisions of SFAS 133, this gain was recorded in other comprehensive income and was reversed into earnings during 2003 and 2002. The following table illustrates the amortization of this amount to revenue by year (in thousands):

Period	Oil Revenue	Natural Gas Revenue	Total
2002	$2,822	$1,594	$4,416
2003	401	18	419
Total	$3,223	$1,612	$4,835

During the first quarter of 2003, due to continued uncertainty of any ultimate collection and continuing legal fees, the Company sold its entire Enron receivable to a third party for $0.5 million. As the receivable was fully reserved, this amount was recorded as a gain in 2003 and included in Other operating expense in the Consolidated Statements of Operations. The Company no longer has any claims outstanding against Enron and accordingly has eliminated the previously recorded $7.0 million receivable and related allowance from the accompanying consolidated balance sheet as of December 31, 2003.

The Company actively evaluates the credit exposure related to its derivatives and receivables, and considers its history with the debtor, how long the amount has been outstanding, potential offsets to the amount owed, and general economic conditions. Other than the Enron loss, the Company has not become aware of any conditions which warrant an allowance or write-off of a receivable or derivative position.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Impairment of Long-Lived Assets

Throughout 2001, futures prices for oil and natural gas continued to decline from their December 31, 2000 levels. The SEC price case used for our 2000 reserve estimate was $26.80 per Bbl and $9.77 per Mcf dropping to $19.84 per Bbl and $2.57 per Mcf for the 2001 estimate. Although the SEC price case does not necessarily coincide with management s estimates of future prices, this indicated the need to assess our oil and natural gas properties for any possible impairment. Thus, we compared the undiscounted future cash flows for each of our oil and natural gas properties to their net book value, which indicated the need for an impairment charge on certain properties. We then compared the net book value 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 $2.6 million. Fair value was determined using estimates of future production volumes and estimates of future prices we might receive for these volumes discounted back to a present value using a rate commensurate with the risks inherent in the industry. We performed a similar review at December 31, 2003 and 2002, and determined no impairment charge was necessary.

14. Subsequent Events (unaudited)

On March 2, 2004, the Company entered into a stock purchase agreement to acquire all of the outstanding common stock of Cortez Oil & Gas, Inc., a privately held, independent oil and gas company (Cortez), for total consideration of approximately $123.0 million. The Company intends to fund the acquisition initially with bank debt under the Company s existing credit facility. The acquired oil and natural gas assets from Cortez are in the same areas as our producing properties located in the CCA of Montana, the Permian Basin of West Texas and Southeastern New Mexico, and in our Mid Continent area, including the Anadarko and Arkoma Basins of Oklahoma, and the Barnett Shale north of Fort Worth, Texas. We expect to close the transaction in the second quarter of 2004, however, the closing is subject in some respects to the Company s due diligence review and other closing conditions, and there can be no assurance that the closing will occur as expected.

In connection with the Cortez acquisition, we entered into several oil and natural gas hedges subsequent to December 31, 2003. The table below shows the terms of these contracts as of March 4, 2004:

Additional Oil Derivative Contracts at March 4, 2004

Period	Daily Floor Volume (Bbls)	Floor Price (per Bbl)	Daily Cap Volume (Bbls)	Cap Price (per Bbl)	Daily Swap Volume (Bbls)	Swap Price (per Bbl)
July Dec. 2004	1,000	$31.50	1,000	$34.56		
Jan. Dec 2005	1,000	28.50	1,000	32.40		
Jan. Dec 2006	1,000	27.50	1,000	29.88		

Additional Natural Gas Derivative Contracts at March 4, 2004

Period	Daily Floor Volume (Mcf)	Floor Price (per Mcf)	Daily Cap Volume (Mcf)	Cap Price (per Mcf)	Daily Swap Volume (Mcf)	Swap Price (per Mcf)
July Dec. 2004					5,000	$5.65
Jan. Dec. 2005	5,000	$5.05	5,000	$5.97		
Jan. Dec. 2006	5,000	4.85	5,000	5.68		

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SUPPLEMENTAL INFORMATION

Capitalized Costs Relating to Oil and Gas Producing Activities

The capitalized cost of oil and natural gas properties at December 31, 2003 and 2002 are as follows (in thousands):

Properties and equipment, at cost successful efforts method:		
Producing properties	$ 739,288	$581,012
Undeveloped properties	921	1,168
Accumulated depletion, depreciation, and amortization	(124,646)	(94,356)
	$ 615,563	$487,824

Costs Incurred Relating to Oil and Gas Producing Activities

The following table summarizes costs incurred related to oil and natural gas properties:

	Year Ended December 31,		
	2003	2002	2001
	(In thousands)		
Acquisitions			
Producing properties	$ 54,484	$ 78,158	$ 1,471
Undeveloped properties	117	391	151
Asset retirement obligations(1)	337		
Development			
Drilling and exploitation	98,977	80,313	87,180
Asset retirement obligations(1)	83		
Total	$153,998	$158,862	$88,802

(1) The Company adopted SFAS 143 on January 1, 2003 which requires us to capitalize additional asset cost equal to the amount of our discounted asset retirement obligation assumed in a property purchase or incurred in the drilling of new wells. Had the Company adopted SFAS 143 prior to January 1, 2001, the Company s acquisition cost incurred on a pro-forma basis would have been increased by $0.7 million and zero for the years ended December 31, 2002 and 2001, respectively. The effect on the Company s development cost incurred on a pro-forma basis would have been insignificant.

Oil & Natural Gas Producing Activities (unaudited)

The estimates of the Company s proved oil and natural gas reserves, which are located entirely within the United States, were prepared in accordance with guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board. Proved oil and natural gas reserve quantities are based on estimates prepared by Miller and Lents, Ltd., who are independent petroleum engineers.

Future prices received for production and future production costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. There can be no assurance that the proved reserves will be developed within the periods assumed or that prices and costs will remain constant. Actual production may not equal the estimated amounts used in the preparation of reserve projections. In accordance with the Securities and Exchange Commission s guidelines, the Company s estimates of future net cash flows from the properties and the representative value thereof are made using oil and natural gas prices in effect as of the dates of such estimates and are held constant throughout the life of the properties. Average prices used in estimating net cash flows at December 31, 2003, 2002, and 2001 were $32.55, $31.20, and

$19.84 per barrel, respectively, for oil and $5.83, $4.79, and $2.57 per Mcf, respectively, for natural gas. The net profits interest on our Cedar Creek Anticline properties has been

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deducted from future cash inflows in the calculation of Standardized Measure. The Company s reserve and production quantities have been reduced by the amounts attributable to the net profits interest. In addition, net future cash inflows have not been adjusted for hedge positions outstanding at the end of the year. The future cash flows are reduced by estimated production costs and development costs, which are based on year-end economic conditions and held constant throughout the life of the properties, and by the estimated effect of future income taxes. Future income taxes are based on statutory income tax rates in effect at year end, the Company s tax basis in its proved oil and natural gas properties, and the effect of net operating loss, alternative minimum tax and Section 43 credits, and other carry forwards.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures. 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 any exact way, and estimates of other engineers might differ materially from those included in this Annual Report on Form 10-K. The accuracy of any reserve estimate is a function of the quality of available data and engineering, and estimates may justify revisions. Accordingly, reserve estimates are often materially different from the quantities of oil and natural gas that are ultimately recovered. Reserve estimates are integral to management s analysis of impairments of oil and natural gas properties and the calculation of depletion, depreciation, and amortization on these properties.

Estimated net quantities of proved oil and natural gas reserves of the Company were as follows:

	Oil (MBbl)	Natural Gas (MMcf)	Oil Equivalent (MBOE)
December 31, 2003			
Proved reserves	117,732	138,950	140,890
Proved developed reserves	92,377	104,767	109,838
December 31, 2002			
Proved reserves	111,674	99,818	128,310
Proved developed reserves	93,945	82,217	107,648
December 31, 2001			
Proved reserves	91,369	75,687	103,983
Proved developed reserves	71,639	69,941	83,296

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The change in proved reserves were as follows for the years ended:

	Oil (MBbl)	Natural Gas (MMcf)	Oil Equivalent (MBOE)
Balance, December 31, 2000	78,910	72,970	91,072
Acquisitions of minerals-in-place			
Extensions and discoveries	19,266	14,063	21,610
Revisions of estimates	(1,872)	(3,268)	(2,418)
Production	(4,935)	(8,078)	(6,281)
Balance, December 31, 2001	91,369	75,687	103,983
Acquisitions of minerals-in-place	14,555	5,434	15,461
Extensions and discoveries	9,605	23,643	13,546
Revisions of estimates	2,182	3,229	2,719
Production	(6,037)	(8,175)	(7,399)
Balance, December 31, 2002	111,674	99,818	128,310
Acquisitions of minerals-in-place	13	37,464	6,257
Extensions and discoveries	3,957	7,354	5,182
Improved recovery	12,773	(178)	12,744
Revisions of estimates	(4,084)	3,543	(3,493)
Production	(6,601)	(9,051)	(8,110)
Balance, December 31, 2003	117,732	138,950	140,890

The Standardized Measure of discounted estimated future net cash flows and changes therein related to proved oil and natural gas reserves (in thousands) is as follows at:

	December 31,		
	2003	2002	2001
Net future cash inflows	$ 4,245,574	$ 3,648,515	$ 1,770,384
Future production costs	(1,683,810)	(1,448,110)	(794,139)
Future development costs	(81,076)	(63,194)	(67,652)
Future income tax expense	(716,869)	(623,987)	(215,568)
Future net cash flows	1,763,819	1,513,224	693,025
10% annual discount	(1,026,880)	(888,506)	(408,716)
Standardized measure of discounted estimated future net cash flows	$ 736,939	$ 624,718	$ 284,309

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Primary changes in the Standardized Measure of discounted estimated future net cash flows (in thousands) are as follows for the year ended:

	Year Ended December 31,		
	2003	2002	2001
Standardized measure, beginning of year	$ 624,718	$ 284,309	$ 599,276
Net change in sales prices and production costs	81,964	305,097	(334,809)
Acquisitions of minerals-in-place	91,654	131,370	
Extensions, discoveries, and improved recovery	103,780	135,897	71,090
Revisions of quantity estimates	(25,650)	18,216	(18,244)
Sales, net of production costs	(151,955)	(114,361)	(96,969)
Development costs incurred during the year	98,977	80,313	87,179
Accretion of discount	86,511	36,036	70,636
Change in estimated future development costs	(116,859)	(44,285)	(51,238)
Net change in income taxes	(52,992)	(164,334)	31,028
Change in timing and other	(3,209)	(43,540)	(73,640)
Standardized measure, end of year	$ 736,939	$ 624,718	$ 284,309

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Selected Quarterly Financial Data

The following table sets forth selected quarterly financial data for the years ended December 31, 2003 and 2002:

	Quarter			
	First	Second	Third	Fourth
	(In thousands, except per share data)			
2003				
Revenues	$55,787	$51,243	$55,724	$57,342
Operating Income	$31,377	$26,679	$28,789	$27,972
Income before accounting change	$17,115	$14,233	$15,768	$15,662
Cumulative effect of accounting change, net of tax of $329	863			
Net income	$17,978	$14,233	$15,768	$15,662
Basic income per common share:				
Before accounting change	$ 0.57	$ 0.47	$ 0.52	$ 0.51
Accounting change, net of tax	0.03			
After accounting change	$ 0.60	$ 0.47	$ 0.52	$ 0.51
Diluted income per common share:				
Before accounting change	$ 0.57	$ 0.47	$ 0.52	$ 0.51
Accounting change, net of tax	0.02			
After accounting change	$ 0.59	$ 0.47	$ 0.52	$ 0.51
2002				
Revenues	$32,297	$37,807	$43,502	$47,086
Operating Income	$12,929	$16,951	$19,789	$22,846
Net income	$ 7,110	$ 9,126	$10,113	$11,336
Basic income per common share:	$ 0.24	$ 0.30	$ 0.34	$ 0.38
Diluted income per common share:	$ 0.24	$ 0.30	$ 0.33	$ 0.38

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Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

On April 1, 2002, we dismissed Arthur Andersen LLP as our independent accountants effective as of that date. The decision to dismiss Arthur Andersen LLP was recommended by the Audit Committee of the Board of Directors and was approved by the Board of Directors on April 1, 2002.

Arthur Andersen s report on the Company s consolidated financial statements for the fiscal year ended December 31, 2001 did not contain an adverse opinion or disclaimer of opinion and was not qualified or modified as to uncertainty or audit scope. Arthur Andersen LLP included in its opinion explanatory language related to the Company s change in its method of accounting for derivatives as a result of the Company s adoption of Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities. During 2001 and the period from January 1, 2002 through the date of Arthur Andersen LLP s termination, there were no disagreements between us and Arthur Andersen LLP on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, that, if not resolved to the satisfaction of Arthur Andersen LLP, pursuant to Item 304(a)(1) of Regulation S-K, would have caused it to make reference to the subject matter of the disagreements in its report.

As required under the regulations of the SEC, we provided Arthur Andersen LLP with a copy of our disclosure in connection with this matter and requested Arthur Andersen LLP to furnish us with a letter addressed to the SEC stating whether it agreed with our statements and, if not, stating the respects in which it did not agree. Arthur Andersen LLP s letter was filed as Exhibit 16.1 to our Current Report on Form 8-K filed with the SEC on April 5, 2002.

Effective April 11, 2002, we engaged Ernst & Young LLP, as our new independent accountants for the fiscal year ending December 31, 2002. The decision to appoint Ernst & Young LLP was recommended by the Audit Committee of the Board of Directors and was approved by the Board of Directors on April 1, 2002.

There have been no disagreements with our independent accountants on our accounting or financial reporting that would require our independent accountants to qualify or disclaim their report on our consolidated financial statements, or otherwise require disclosure in this Form 10-K.

Item 9A. ***Controls and Procedures***

Our Chief Executive Officer and our Chief Financial Officer (our principal executive officer and principal financial officer, respectively) have concluded, based on their evaluation as of the end of the period covered by this annual report on Form 10-K, that our disclosure controls and procedures are effective to ensure that information required to be disclosed by us in the reports filed or submitted by us under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and include controls and procedures designed to ensure that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. There were no changes in our internal control over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART III

Item 10. ***Directors and Executive Officers of the Registrant***

The information required in response to this item is set forth in the Company s definitive proxy statement for the annual meeting of stockholders to be held on April 29, 2004 and is incorporated herein by reference.

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We have adopted a Code of Business Conduct and Ethics covering our directors, officers, and employees, which is available free of charge on our Internet website (www.encoreacq.com).

Item 11. ***Executive Compensation***

The information required in response to this item is set forth in the Company s definitive proxy statement for the annual meeting of stockholders to be held on April 29, 2004 and is incorporated herein by reference.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information required in response to this item is set forth in the Company s definitive proxy statement for the annual meeting of stockholders to be held on April 29, 2004 and is incorporated herein by reference.

Item 13. ***Certain Relationships and Related Transactions***

The information required in response to this item is set forth in the Company s definitive proxy statement for the annual meeting of stockholders to be held on April 29, 2004 and is incorporated herein by reference.

Item 14. ***Principal Accountant Fees and Services***

The information required in response to this item is set forth in the Company s definitive proxy statement for the annual meeting of stockholders to be held on April 29, 2004 and is incorporated herein by reference.

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PART IV

Item 15. ***Exhibits, Financial Statement Schedules, and Reports on Form 8-K***

(a) The following documents are filed as a part of this Report at page 48:

1. *Financial Statements:*

2. *Financial Statement Schedules:*

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the financial statements or the notes to the consolidated financial statements.

(b) *Reports on Form 8-K*

We filed the following reports on Form 8-K during the quarter ended December 31, 2003:

1. On November 4, 2003, we filed a Form 8-K to furnish certain earnings-related information under Items 7 and 12.

2. On November 7, 2003, we filed a Form 8-K to furnish information under Items 7 and 9 regarding the appointment of Roy W. Jageman as our Chief Financial Officer.

3. On November 10, 2003, we filed a Form 8-K to furnish information under Items 7 and 9 regarding a public offering of up to 9.2 million shares of our common stock and the use of proceeds therefrom.

4. On November 14, 2003, we filed an Item 5 and Item 7 Form 8-K to disclose the execution of an underwriting agreement with respect to the public offering of up to 9.2 million shares of our common stock and the execution of a stock purchase agreement with respect to the repurchase of up to 9.2 million shares of our common stock from J.P. Morgan Partners (SBIC), LLC and Warburg, Pincus Equity Partners L.P.

5. On November 20, 2003, we filed a Form 8-K to furnish information under Items 7 and 9 regarding the closing of a public offering of 8.0 million shares of our common stock and the use of proceeds therefrom.

6. On December 3, 2003, we filed a Form 8-K to furnish information under Items 7 and 9 regarding the sale of 1,060,000 shares of our common stock pursuant the exercise of the underwriters over-allotment option and the use of proceeds therefrom.

(c) *Exhibits*

See Exhibits to Index on the following page for a description of the exhibits filed as a part of this report.

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INDEX TO EXHIBITS

Exhibit No.	Description
3.1	Second Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001, filed with the SEC on November 7, 2001).
3.2	Second Amended and Restated Bylaws of the Company (incorporated by reference to the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001, filed with the SEC on November 7, 2001).
4.1	Specimen certificate of the Company (incorporated by referenced to Exhibit 4.1 to Registration Statement on Form S-1, Registration No. 333-47540, filed with the SEC on December 15, 2000).
4.2	Indenture, dated as of June 25, 2002, among the Company, subsidiary guarantors party thereto and Wells Fargo Bank, N.A. (incorporated by reference to Exhibit 4.1 to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2002, filed with the SEC on August 9, 2002).
4.3	Form of 8 3/8% Senior Subordinated Note to Cede & Co. or its registered assigns, dated January 16, 2003.
10.1+	2000 Incentive Stock Plan (incorporated by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001, filed with the SEC on November 14, 2002).
10.2+	Employee Severance Protection Plan (incorporated by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2003, filed with the SEC on May 8, 2003).
10.3+	Form of Restricted Stock Award Executive (incorporated by reference to Exhibit 10.2 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2003, filed with the SEC on May 8, 2003).
10.4	Credit Agreement, dated June 25, 2002 (the Credit Agreement), among the Company, Encore Operating, L.P., Fleet National Bank, a national banking association, as Administrative Agent, Wachovia Bank, N.A., as Syndication Agent, Fortis Capital Corp., as Documentary Agent and the financial institutions listed therein (incorporated by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2002, filed with the SEC on August 9, 2002).
10.5*	First Amendment to Credit Agreement dated October 31, 2002.
10.6*	Second Amendment to Credit Agreement dated October 21, 2003.
10.7	Registration Rights Agreement, dated August 18, 1998, by and among the Company and the other parties thereto (incorporated by reference to Exhibit 4.2 to the Company s Registration Statement on Form S-1 (File No. 333-47540), filed with the SEC on October 6, 2000).
10.8*+	Severance Agreement, dated December 18, 2003, between the Company and Morris B. Smith.
10.9*	Stock Purchase Agreement dated March 2, 2004 by and among Cortez Oil & Gas, Inc., HRM Resources, Inc., the Security Holders of Cortez Oil & Gas, Inc., and Encore Acquisition Company.
16.1	Current Report on Form 8-K, filed with the SEC on April 5, 2002, regarding the dismissal of independent auditor.
21.1*	Subsidiaries of the Company.
23.1*	Consent of Ernst & Young LLP
23.2*	Consent of Miller and Lents, Ltd.
24.1*	Power of Attorney (included on the signature page of this report).
31.1*	Rule 13a-14(a)/15d-14(a) Certification (Principal Executive Officer)
31.2*	Rule 13a-14(a)/15d-14(a) Certification (Principal Executive Officer)

Exhibit No.	Description
32.1*	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

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

Copies of the above exhibits not contained herein are available at the cost of reproduction to any security holder upon written request to the Assistant Treasurer, Encore Acquisition Company, 777 Main Street, Suite 1400, Fort Worth, Texas 76102.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 11th day of March, 2004.

ENCORE ACQUISITION COMPANY

By: /s/ I. JON BRUMLEY

I. Jon Brumley
Chief Executive Officer

KNOW ALL MEN BY THESE PRESENTS, that each individual whose signature appears below constitutes and appoints I. Jon Brumley and Roy W. Jageman, and each of them, his true and lawful attorneys-in-fact and agents with full power of substitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments (including post-effective amendments) to this report, and to file the same, with all exhibits thereto, and all documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or his or their substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant in the capacities indicated on March 11, 2004.

Signature	Title or Capacity
/s/ I. JON BRUMLEY I. Jon Brumley	Chairman of the Board, Chief Executive Officer, and Director (Principal Executive Officer)
/s/ JON S. BRUMLEY Jon S. Brumley	President and Director
/s/ ROY W. JAGEMAN Roy W. Jageman	Chief Financial Officer, Treasurer, Executive Vice President and Corporate Secretary (Principal Financial Officer)
/s/ ROBERT C. REEVES Robert C. Reeves	Vice President, Controller and Assistant Corporate Secretary (Principal Accounting Officer)
/s/ ARNOLD L. CHAVKIN Arnold L. Chavkin	Director
/s/ HOWARD H. NEWMAN Howard H. Newman	Director

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Signature	Title or Capacity
/s/ TED A. GARDNER Ted A. Gardner	Director
/s/ TED COLLINS, JR. Ted Collins, Jr.	Director
/s/ JAMES A. WINNE, III James A. Winne, III	Director