ENCORE ACQUISITION CO
Form 10-K/A
December 05, 2002

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

FORM 10-K/A
AMENDMENT NO. 1

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2001

COMMISSION FILE NO. 1-16295

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

DELAWARE (State or other jurisdiction of incorporation or organization)	75-2759650 (I.R.S. Employer Identification Number)
777 MAIN STREET, SUITE 1400, FT. WORTH, TEXAS (Address of principal executive offices)	76102 (Zip code)

REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE:
(817) 877-9955

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

TITLE OF EACH CLASS	NAME OF EACH EXCHANGE ON WHICH REGISTERED
Common Stock	New York Stock Exchange

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 [X] No [ ]

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. [ ]

Aggregate market value of the voting stock held by non-affiliates of the Registrant as of March 1, 2002......	$397,296,000
Number of shares of Common Stock, $0.01 par value, outstanding as of March 1, 2002..........................	30,029,961

ENCORE ACQUISITION COMPANY
2001 ANNUAL REPORT ON FORM 10-K
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This Amendment No. 1 on Form 10-K/A amends Items 1 and 2, Item 6, Item 7, and the unaudited supplemental information of Item 8 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001 as filed by the Company on March 17, 2002, and is being filed to revise production and reserve disclosures by reducing volumes by amounts attributable to the financial net profits interests burdening the Company's Cedar Creek Anticline properties, to reclass a portion of proved developed reserves to proved undeveloped reserves associated with projected future response from waterfloods at the Company's Cedar Creek Anticline properties, to add certain enhanced disclosures relative to Management's Discussion and Analysis of Other Operating Expense for 2001, to clarify the basis of presentation for certain pro forma amounts in Management's Discussion and Analysis of operating results of the Company during 2000 and to revise certain selected quarterly financial data disclosures in Item 8.

Parts I and II of this annual report on Form 10-K (the "Report") contain forward-looking statements that involve risks and uncertainties that are made pursuant to the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995. 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 26, under the caption "Glossary of Oil and Natural Gas Terms." In addition, all production and reserve volumes disclosed represent amounts net to Encore.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

GENERAL

Organized as a Delaware corporation in 1998, Encore Acquisition Company (together with our subsidiaries, "we", "Encore", or the "Company") is a rapidly growing independent energy company engaged in the acquisition, development, and exploitation of onshore North American oil and natural gas reserves.

Since inception, the Company has maintained an acquisition process, refined by senior management, to seek and acquire high quality assets with potential for upside through low-risk development drilling projects.

Our rapid growth has come primarily from the acquisition of producing oil and natural gas properties. We have been successful in purchasing six major packages of producing properties since inception in April 1998. The Company has acquired producing properties in the Williston, Permian, Anadarko, and Powder River Basins. All our producing assets reside onshore in the continental lower 48 United States. See "-- Properties". Since our inception, we have invested $350.8 million in acquiring producing oil and natural gas properties including our last acquisition that closed in January 2002. We have invested another $122.5 million for development and exploitation of these properties.

The Cedar Creek Anticline ("CCA"), in the Williston Basin of Montana and North Dakota, represents 89% of our total proved reserves as of December 31, 2001. The CCA represents the Company's most valuable asset today and in the foreseeable future. A large portion of the Company's future success revolves around future exploitation and production from the property.

The Company strives to acquire long-lived quality assets with upside from low-risk development drilling opportunities. In 2001, all of our reserve growth was achieved organically by the drill bit by harvesting a portion of the Company's extensive inventory of drilling projects. In 2001, we drilled 108 gross operated wells and participated in drilling another 35 gross non-operated wells for a total of 143 gross wells for the year. On a net basis, the Company drilled 95 net operated wells and participated in 12 non-operated wells for a total of 107 net wells in 2001. We invested $87.2 million to drill and complete the 107 net wells for 2001 or approximately $815,000 net per well. The drilling program added 21.6 million BOE for 2001 at an average cost of $4.04 per BOE.

The Company's estimated proved reserves at December 31, 2001 were 91.4 MMBls of oil and 75.7 Bcf of natural gas, or 104.0 MMBOE. The proved developed reserves were 83.3 million BOE, or 80% of total proved

reserves at December 31, 2001. Our Reserve-to-Production ratio averaged 16.6 years based upon December 31, 2001 proved reserves and the prior 12 months' production. Prevailing prices as of December 31, 2001 were $19.84 per Bbl of oil and $2.57 per Mcf of natural gas. Proved oil and natural gas reserve quantities are based on estimates prepared by Miller and Lents, Ltd., who are independent petroleum engineers.

Production from our properties averaged 13,521 Bbls/D of oil and 22,132 Mcf/D of natural gas, or 17,208 BOE/D, for the 2001 fiscal year. The direct lifting costs for our properties averaged $4.00 per BOE for the year. Production, severance, and ad valorem taxes were $2.20 per BOE.

On January 4, 2002, the Company closed the purchase of the sixth producing property package since inception. These Central Permian properties were purchased from Conoco for approximately $50 million and were not a part of the Company's 2001 reserve or production base. The properties include two major operated fields: East Cowden Grayburg and Fuhrman-Nix; and two non-operated fields: North Cowden and Yates. We believe that we will be able to exploit significant opportunities in these fields to increase production through development drilling and waterflood enhancements. See "-- Properties -- Permian and Anadarko Properties -- Central Permian".

STRATEGY

Our strategy is to grow our reserves and production through selective acquisitions and low-risk development drilling. We intend to maximize internally generated cash flow and shareholder value by continuing our low-risk development program on our existing properties and by acquiring properties with similar upside potential to our current producing properties portfolio. We believe that we are more likely to acquire properties during periods of low acquisition values and will vigorously pursue development activities during periods of high acquisition values. However, we believe that additional growth will come both from acquisitions and development projects.

Secondary and tertiary recovery is the third leg to our growth strategy. 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 secondary recovery projects revolve around the successful implementation and further enhancements of waterfloods on the Company's quality asset base. The tertiary recovery project for the Company revolves around an initial High-Pressure Air Injection ("HPAI") project on the Company's CCA asset in Montana.

To execute our strategy, we intend to:

- pursue an active low-risk development and exploitation program on existing properties;

- control costs through efficient operations of existing properties; and

- continue our successful acquisition program.

Development of Existing Properties. Our properties generally have long reserve lives and reasonably stable and predictable reservoir production characteristics. The R/P Index for our proved reserves at December 31, 2001 was 16.6 years based on the prior 12 months' production. However, the R/P Index for our proved reserves at December 31, 2001 for our Cedar Creek Anticline properties, which represented 89% of our total proved reserves, was 22.5 years based on the prior 12 months' production at December 31, 2001. Our Cedar Creek Anticline properties, which produce mainly from tight porous dolomites drilled on 40 to 80 acre spacing intervals, have longer reserve lives than our other properties because the low permeability level encountered in the CCA with those producing intervals requires a longer time to produce the reserves in place, resulting in a lower production decline rate.

The inventory of potential development drilling locations or major recompletion opportunities on our existing properties is sufficient to sustain the same level of capital investment for approximately four years. Longer term, we believe that there is significant value to be created through our High-Pressure Air Injection project in the CCA. See "-- Present Activities -- Cedar Creek Anticline High-Pressure Air Injection Pilot Program".

Efficient Operations. We operate properties representing 86% of the PV-10 value of our proved reserves, which allows us to control capital allocation and expenses. For the year ended December 31, 2001, our lease operating expenses consisted of direct lifting costs of $4.00 per BOE produced and production, ad valorem, and severance tax payments of $2.20 per BOE produced. Our general and administrative costs, excluding non-cash stock based compensation expense, averaged $0.80 per BOE produced in 2001.

Continued Successful Acquisition Program. The Company, using the experience of our senior management team, has developed and refined an acquisition program designed to increase our reserves and to complement our core properties. We have a staff of engineering and geoscience professionals who manage our core properties and use their experience and expertise to target 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. Through December 31, 2001, the Company has completed five acquisitions, at a total initial acquisition cost of $301 million, representing 86.1 MMBOE of proved reserves. In addition, in the fourth quarter of 2001, we entered into a purchase agreement with Conoco to acquire several operated and non-operated properties in the Permian Basin of Texas for $55 million. The acquisition closed in January 2002 with a final purchase price of $50 million after closing adjustments and exercise of preferential rights.

Challenges to Implementing Our Strategy. We face a number of challenges in implementing our strategy and achieving our goals. Our primary challenge is the ability to acquire quality producing properties with attractive rates of return, especially in a changing commodity price environment. In addition, we face strong competition for capital, expenses, and acquisitions from independents and major oil companies.

BUSINESS ACTIVITIES

The following table sets forth the net production, proved reserves quantities, and PV-10 values of our principal properties as of December 31, 2001:

PROPERTIES -- PRINCIPAL AREAS OF OPERATIONS

	NET PRODUCTION FOR THE YEAR 2001				PROVED RESERVE QUANTITIES AT DECEMBER 31, 2001		
	OIL (MBBLS)	NATURAL GAS (MMCF)	TOTAL (MBOE)	PERCENT	OIL (MBBLS)	NATURAL GAS (MMCF)	TOTAL (MBOE)
Cedar Creek Anticline....	3,944	969	4,105	65%	89,313	18,960	92,472
Crockett County..........	20	4,011	689	11	103	38,824	6,574
Lodgepole................	778	449	853	14	1,277	628	1,382
Indian Basin/Verden......	53	2,649	494	8	153	17,275	3,032
Bell Creek...............	140	--	140	2	523	--	523
Total..................	4,935	8,078	6,281	100%	91,369	75,687	103,983

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(1) 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 depreciation, depletion 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 increased by $3.8 million at December 31, 2001. The Standardized Measure at December 31, 2001 is $284.3 million. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes.

During 2002, we plan to invest approximately $81 million to exploit and develop existing core properties. This is in addition to the $50 million paid for the Permian Basin acquisition, and will support a four-rig, 110 well drilling program in the Cedar Creek Anticline, the High-Pressure Air Injection program, waterflood improvements, workovers, and recompletions. If attractive opportunities arise during that period, we will acquire additional producing oil and natural gas properties.

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OPERATIONS

We act as operator of properties representing approximately 86% of our PV-10 reserve value at December 31, 2001. As operator, we are able to 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 exploiting and developing them. See "-- Properties -- Nature of Our Ownership Interests". During the years ended December 31, 2001, 2000, and 1999 our approximate costs for development activities on non-operated properties were $9.3 million, $0.3 million, and $0.9 million, respectively.

PROVED RESERVES

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 unit amounts):

	HISTORICAL		
	DECEMBER 31, 2001	DECEMBER 31, 2000	DECEMBER 31, 1999
Oil (Bbls)			
Developed	71,639	66,363	59,134
Undeveloped	19,730	12,547	10,165
Total	91,369	78,910	69,299
Natural Gas (Mcf)			
Developed	69,941	66,337	8,896
Undeveloped	5,746	6,633	2,044
Total	75,687	72,970	10,940
Total (BOE)(1)	103,983	91,072	71,122
PV-10(2)			
Developed	$299,383	$630,429	$287,439
Undeveloped	60,979	75,928	35,813
Total	$360,362	$706,357	$323,252
Standardized Measure(3)	$284,309	$599,276	$272,955
Reserve price assumptions			
Oil ($/Bbl)	$ 19.84	$ 26.80	$ 25.60
Natural gas ($/Mcf)	2.57	9.77	2.31

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(1) Volumetric reserves attributed to the net profits interests in our Cedar Creek Anticline properties were 11,062 BOE, 11,730 BOE and 10,178 BOE, respectively, at December 31, 2001, 2000 and 1999. See "-- Net Profits Interests" on page 10. The volumes attributed to the NPIs, which reduce our reserves on a BOE for BOE basis, will fluctuate from period to period 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 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 $364.4 million at December 31, 2001, $689.6 million at December 31, 2000, and $318.3 million at December 31, 1999.

(3) 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.

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 many factors, which include oil and natural gas pricing assumptions, the quality of available data, 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 is mandated by the SEC. The present value is materially affected by assumptions as to timing of future production, which may prove to be inaccurate. For properties that we operate, expenses exclude our share of overhead charges. In addition, the calculation of estimated future net revenues 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 2001, the Company filed estimates of oil and natural gas reserves at December 31, 2000 with the U.S. Department of Energy on Form EIA-23. This estimate was based on an internal reserve study and reflected more reserves than those set forth in the table above. This reduction resulted from a reassessment of some of our proved undeveloped reserves as a result of additional drilling.

PRODUCTION AND PRICE HISTORY

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

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999(1)
PRODUCTION DATA:			
Oil (MBbls)	4,935	3,961	1,796
Natural gas (MMcf)	8,078	4,303	180
Combined volumes (MBOE)	6,281	4,678	1,826
AVERAGE PRICES:			
Oil (per Bbl)	$21.43	$23.34	$16.96
Natural gas (per Mcf)	3.73	3.84	4.50
Combined volumes (per BOE)	21.64	23.29	17.12
AVERAGE COSTS (PER BOE):			
Lease Operating Expenses:			
Direct lifting costs	$ 4.00	$ 3.99	$ 4.60
Production, ad valorem, and severance taxes	2.20	3.24	2.97
Depletion, depreciation, and amortization	5.05	4.72	2.89

General and administrative (excluding non-cash stock based compensation)	0.80	0.93	2.22

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(1) In the year ended December 31, 1999, the Company commenced production June 1, 1999.

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PRODUCING WELLS

The following table sets forth information at December 31, 2001 relating to the producing wells in which we owned a working interest as of that date. We also held royalty interests in 650 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	503	440	87%	8	2	30%
Crockett County	--	--	--	314	127	40%
Lodgepole	25	6	24%	--	--	--
Indian Basin/Verden	87	10	11%	80	12	15%
Bell Creek	47	47	100%	--	--	--
Total	662(1)	503	76%	402(1)	141	35%

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(1) Our total wells include 699 operated wells and 365 non-operated wells.

ACREAGE

The following table sets forth information at December 31, 2001 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.

	GROSS ACREAGE	NET ACREAGE
Developed acreage	170,144	118,630
Undeveloped acreage	57,101	42,527

Total	227,245	161,157

DRILLING RESULTS

The following table sets forth information with respect to wells drilled during the periods indicated. However, 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	2001	2000	1999
Productive			
Gross	142.0	50.0	10.0
Net	105.6	37.2	8.3
Dry			
Gross	1.0	3.0	--
Net	1.0	1.1	--

PRESENT ACTIVITIES

As of December 31, 2001, the Company had a total of six gross (4.8 net) wells that were in varying stages of drilling operations. Also, there were eight gross (6.2 net) wells that had reached total depth and were in varying stages of completion pending first production. Upgrades to facilities allowing for additional waterflood operations at North Pine in the Cedar Creek Anticline were also underway, as part of the ongoing North Pine waterflood reactivation program.

CEDAR CREEK ANTICLINE HIGH-PRESSURE AIR INJECTION PILOT PROGRAM

In addition to the conventional development operations planned for 2002, design and fabrication of compressors and facilities is underway for implementation of Phase I of the High-Pressure Air Injection program ("HPAI program") in the Pennel Unit on the Cedar Creek Anticline properties. As the name suggests, High-Pressure Air Injection involves utilizing specialized 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. The capital outlay for the initial two projects is approximately $5.0 million. The new compressors for the HPAI program will be in place and operational by summer 2002 and an initial indication of success should occur by the end of the first quarter of 2003. Peak response will not occur until much later in the future.

We believe that High-Pressure Air Injection, if proven effective and feasible, would be the most useful tertiary recovery technique applicable to the Cedar Creek Anticline, with economics comparable to, if not better than, current reserve acquisition values. For example, if successful, production could increase from 25% to 100% over the existing 360 barrels of oil per day currently produced on the properties involved in the initial pilot program. This would yield a rate of return in excess of 20% based on a $20.00 per barrel oil price.

If the projects are successful, the High-Pressure Air Injection will be significantly expanded and added to other applicable areas of the field in the second half of 2004. If this new High-Pressure technology proves successful and can be applied throughout the Cedar Creek Anticline, we believe operations of this type ultimately have the potential to yield significant new reserves.

Readers and investors should note that this is a pilot program to test the efficacy of a relatively novel tertiary recovery technology and the results are highly prospective. While management is enthusiastic about the program, the success of the program, as well as the amount of additional production and reserves attributable to the program, if any, cannot be predicted with certainty at this time.

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. 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 2001, our largest purchasers included ConAgra, Equiva Trading Company (a joint venture between Shell and Texaco) and EOTT Energy Co., which respectively accounted for 25%, 17%, 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 its ability to market our oil and natural gas production. As of March 1, 2002, we no longer market our oil with EOTT Energy Co. and have substituted Eighty Eight Oil, LLC. as the purchaser.

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 acquire additional properties in the future will depend upon our ability to conduct efficient operations, to evaluate and select suitable properties, implement advanced technologies, and to 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 the Company. 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 charged 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. Encore 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 the Company's properties and the direct access to end-user markets, the future impact of these regulations on marketing Encore's production or on its gas transportation business cannot be predicted. We, however, do not believe 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 the Company's 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 Encore is in substantial compliance with applicable environmental laws and regulations. To date, we have not expended any material amounts to comply with such regulations, and management does not currently anticipate that future compliance will have a materially adverse effect on the consolidated financial position or results of operations of Encore.

Rules and Regulations Resulting from Enron's Bankruptcy. Rules and Regulations governing publicly traded companies often change as a result of the current and economic and political environment. With the financial collapse of Enron Corp., regulatory changes are expected that may affect the industry and Encore. We cannot predict the changes to be implemented, or whether or not such changes will adversely affect the Company.

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 which 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. For certain risks, we may not obtain insurance 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.

Because of significant losses suffered by the insurance industry over the last few years, we are anticipating significantly higher insurance premiums related to all areas of our business in 2002 and years beyond.

EMPLOYEES OF THE COMPANY

The Company had 92 employees as of December 31, 2001, of which, 40 are field personnel. None of the employees are represented by any union. The Company considers its relations with its employees to be good.

PROPERTIES

NATURE OF OUR OWNERSHIP INTERESTS

We own interests in oil and natural gas properties located in Montana, North Dakota, Texas, New Mexico, and Oklahoma. Substantially all of our PV-10 reserve value at December 31, 2001 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.

NET PROFITS INTERESTS

A major portion of our acreage 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 deducted from 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

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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.

Cedar Creek Anticline -- Montana and North Dakota

The Cedar Creek Anticline was purchased on June 1, 1999, and we have subsequently acquired additional working interests from various owners. Presently, we operate approximately 99% of the 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. The Company's 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, the Company has increased production 58% on the CCA from 7,807 BOE per day (average June, 1999) to 12,299 BOE per day (average 4Q 2001). We have accomplished this ongoing production growth through a combination of additional acquisition of interests, detailed attention to the existing wellbores, the addition of strategically positioned new wellbores, and the highly successful application of horizontal re-entry drilling. In 2001, we drilled 102 gross wells on the CCA, representing $73.0 million of cost. Of these, 60 were horizontal re-entry wells which both reestablished production from non-producing wells, and added additional barrels from existing producing wells. The average daily production from the CCA was 11,247 BOE per day for 2001.

Our outlook for sustained production growth on the CCA remains strong. The Company plans to continue the development of the reserve base through currently identified opportunities and those that result from the knowledge gained through continued study and the drilling and exploitation efforts ongoing on these properties.

The CCA represents 89% of our total proved reserves as of December 31, 2001. The CCA represents the Company's most valuable asset today and in the foreseeable future. A large portion of the Company's future success revolves around future exploitation and production from the property.

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 98% of our interests are non-operated; the largest of which is the Eland Unit in which the Company owns 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 Eland Unit is the largest accumulation in the trend. The average production from the Lodgepole properties was 2,337 BOE per day for 2001.

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. Since acquiring the properties in March 2000, the properties have outperformed engineering forecasts. We do not believe that this trend will continue in the future. In 2002, we are predicting the properties to go on a steep decline in production. If the properties performance varies significantly from the Miller and Lents, Ltd. estimates of reserves, then our future cash flows could be affected in 2002 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 Montana, were purchased on November 29, 2000. The Company operates 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. The average daily production from the Bell Creek properties was 383 BOE per day for 2001.

PERMIAN AND ANADARKO BASIN PROPERTIES

Crockett -- Crockett County, Texas

The Crockett properties were purchased on March 30, 2000. The Company has 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. The Company operates approximately 52% 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 prolific Canyon and Strawn Formations. Both formations contain multiple pay intervals, and continued development opportunities remain on these properties. In 2001 we invested approximately $8.0 million drilling on the Crockett properties, and have increased production 30% from 8,700 Mcfe per day (average daily 2000) to 11,322 Mcfe per day (average daily 2001). The Crockett properties are the Company's most significant producers of natural gas.

Indian Basin -- Eddy County, New Mexico

The Indian Basin properties were purchased on August 24, 2000. The Company owns varied non-operated working interests in these properties (primary area operators are Marathon and Chevron), whose production is 97% 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. The average daily production from the Indian Basin properties was 4,476 Mcfe per day for 2001.

Verden -- Caddo and Grady Counties, Oklahoma

The Verden properties were purchased on August 24, 2000. The Company owns 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. We have participated in the drilling of four new wells in this area, and average daily production from the Verden properties was 3,654 Mcfe per day for 2001.

Central Permian -- Andrews, Ector, and Pecos Counties, Texas

The Central Permian properties were purchased from Conoco on January 4, 2002 and were not a part of the Company's 2001 reserve or production base. These properties are all 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 97% oil and the average daily production from the properties on January 1, 2002 was approximately 1,690 BOE per day. All of these fields contain multiple producing intervals. We believe that we will be able to exploit significant opportunities in the fields that we have identified which include development drilling and waterflood enhancements. Together with our existing Permian Basin properties, the Central Permian properties further focus our operational presence in this area of established production and growth potential.

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 the Company's acreage position in the Cedar Creek Anticline, our primary asset, is subject to a net profits interests.

ITEM 3. LEGAL PROCEEDINGS

The Company is 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 the Company's stockholders during the fourth quarter ended December 31, 2001.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

The Company's Common Stock, $0.01 par value, is listed on the New York Stock Exchange and trades under the symbol "EAC". The following table sets forth quarterly high and low closing sales prices of the Company's Common Stock for each quarter of 2001, since our initial public offering ("IPO") on March 8, 2001:

2001	HIGH	LOW
Quarter ended March 31	$14.55	$11.19
Quarter ended June 30	17.56	11.25
Quarter ended September 30	15.20	11.69
Quarter ended December 31	14.73	12.30

On March 1, 2002, the Company had approximately 1,250 shareholders of record.

DIVIDENDS

No dividends have been declared or paid on the Company's 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, 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 since inception 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,			PERIOD FROM INCEPTION (APRIL 22, 1998 THROUGH DECEMBER 31,
	2001	2000	1999	1998
CONSOLIDATED STATEMENT OF OPERATIONS DATA:				
Revenues(1):				
Oil	$105,768	$ 92,441	$ 30,454	$ --
Natural gas	30,149	16,509	810	--
Total revenues	$135,917	$108,950	$ 31,264	$ --
Net income (loss)	$ 16,179(2)	$ (2,135)(3)	$ 3,005	$(1,010)
Net income (loss) per common share:				
Basic	$ 0.56	$ (0.09)	$ 0.13	$ (0.08)
Diluted	0.56	(0.09)	0.13	(0.08)
Weighted average number of common				

shares outstanding:				
Basic	28,718	22,806	22,687	12,002
Diluted	28,723	22,806	22,687	12,002
CONSOLIDATED STATEMENT OF CASH FLOWS DATA:				
Cash provided by (used by):				
Operating activities	$ 80,212	$ 44,508	$ 9,759	$ (949)
Investing activities	(89,583)	(99,236)	(201,701)	(289)
Financing activities	8,610	49,107	194,972	4,705
PRODUCTION:				
Oil (Bbls)	4.935	3,961	1,796	--
Natural gas (Mcf)	8,078	4,303	180	--
Combined (BOE)	6,281	4,678	1,826	--
AVERAGE SALES PRICE:				
Oil ($/Bbl)	$ 21.43	$ 23.34	$ 16.96	$ --
Natural gas ($/Mcf)	3.73	3.84	4.50	--
Combined ($/BOE)	21.64	23.29	17.12	--
COSTS PER BOE:				
Direct lifting costs	$ 4.00	$ 3.99	$ 4.60	$ --
Production and severance taxes	2.20	3.24	2.97	--
General and administrative (excluding non-cash stock based compensation)	0.80	0.93	2.22	--
Depletion, depreciation, and amortization	5.05	4.72	2.89	--
RESERVES:				
Oil (Bbls)	91,369	78,910	69,299	--
Natural gas (Mcf)	75,687	72,970	10,940	--
Combined (BOE)	103,983	91,072	71,122	--

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	AT DECEMBER 31,			
	2001	2000	1999	1998
CONSOLIDATED BALANCE SHEET DATA:				
Total assets	$402,000	$343,756	$215,571	$3,751
Current liabilities	$ 27,441	$ 41,532	$ 12,640	$ 56
Other long-term liabilities	27,257	8,806	1,259	--
Long-term debt	78,000	145,607	99,250	--
Stockholders' equity	269,302	147,811	102,422	3,695
Total liabilities and equity	$402,000	$343,756	$215,571	$3,751

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(1) For the years ended December 31, 2001, 2000, and 1999, the Company reduced revenue for the payments to holders of the net profits interests by $2.8 million, $11.5 million, and $4.4 million, respectively.

(2) 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 gas properties, and a $0.9 million

cumulative effect of accounting change, which affects its comparability with other periods presented.

(3) 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

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", and other words and terms of similar meaning in connection with any discussion of future operating or financial performance. In particular, these include, among other things, statements relating to:

- amount, nature, and timing of capital expenditures;

- drilling of wells;

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

- increases in proved reserves;

- operating costs and other expenses;

- cash flow and anticipated liquidity;

- prospect exploitation and property acquisitions; and

- marketing of oil and natural gas.

Any or all of our forward-looking statements in this Report may turn out to be wrong. They can be affected by inaccurate assumptions we might make or by known or unknown risks and uncertainties. Many factors mentioned in our discussion in this Report would be important in determining future results. Actual future results may vary materially. Factors that could cause our results to differ materially from the results discussed in the forward-looking statements include the following:

- the risks associated with operating in one or two major geographic areas;

- the risks associated with drilling of oil and natural gas wells in our exploitation efforts;

- our ability to find, acquire, market, develop, and produce new properties;

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- oil and natural gas price volatility;

- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of exploitation expenditures;

- operating hazards attendant to the oil and natural gas business;

- drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or underperformance of significant wells;
- climatic conditions;
- availability and cost of material and equipment;
- actions or inactions of third-party operators of our properties;
- our ability to find and retain skilled personnel;
- availability of capital;
- the strength and financial resources of our competitors;
- regulatory developments;
- environmental risks; and
- general economic conditions.

When you consider these forward-looking statements, you should keep in mind these risk factors and the other cautionary statements in this Report.

DESCRIPTION OF CRITICAL ACCOUNTING POLICIES

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 financial statements. Natural gas volumes are converted to equivalent barrels at the rate of six Mcf to one barrel.

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 recorded in accumulated depletion, depreciation, and amortization ("DD&A") to reduce our recorded basis in the asset. Each part of this calculation is subject to a large degree of management judgment, including the determination of property's reserves, future cash flows, and fair value.

Management's assumptions used in calculating oil and natural gas reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. Any change could cause impairment expense to be recorded, reducing our net income and our basis in the related asset. 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. There can be no assurance that the proved reserves will be developed within the periods estimated or that prices and costs will 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. Additionally, as management's views related to future prices change, this changes the calculation of future net cash flows and also affects fair value estimates. Changes in either of these amounts will directly impact the calculation of impairment.

DD&A expense is also directly affected by the Company's reserve estimates. Any change in reserves directly impacts the amount of DD&A expense the Company recognizes in a given period. Assuming no other changes, such as an increase in depreciable base, as the Company's 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.

NET PROFITS INTERESTS

A major portion of our acreage 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 deducted from 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.

BAD DEBT EXPENSE

The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectibility. The Company historically has not required collateral or other performance guarantees from creditworthy counterparties. Many of our receivables are from joint interest owners on property of which we are the operator. Thus, we may have the ability to withhold future revenue disbursements to cover any non-payment of joint interest billings. Our oil and natural gas receivables quickly turnover, usually one month for oil and two months for gas; thus, signaling any problem accounts in a timely manner. Counterparties to our derivative commodity and interest rate contracts are routinely reviewed for creditworthiness to determine the realizability of any related derivative assets we might carry on our books. This review of receivables and counterparties is heavily dependent on the judgment of management. If it is determined that the carrying value of a receivable or financial instrument might not be recoverable, we record an allowance to the extent we believe the receivable or asset is not recoverable. The determination as to what extent a receivable or asset might be impaired is also heavily dependent on the judgment of management. As more information becomes known related to a particular counterparty or customer, management will continually reassess previous judgments and any resulting change in the related allowance could have a material positive or negative effect on our financial position and results of operations in the period of the change.

HEDGING AND RELATED ACTIVITIES

We use various financial instruments for non-trading purposes in the normal course of our business to manage and reduce price volatility and other market risks associated with our crude oil and natural gas production. This activity is referred to as hedging. 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.

Prior to January 1, 2001, these agreements were accounted for as hedges using the deferral method of accounting. Unrealized gains and losses were generally not recognized until the physical production required by the contracts was delivered. At the time of delivery, the resulting gains and losses were recognized as an adjustment to oil and natural gas revenues. The cash flows related to any recognized gains or losses associated with these hedges were reported as cash flows from operations. If the hedge was terminated prior to maturity, gains or losses were deferred and included in income in the same period as the physical production required by the contracts was delivered.

We also use derivative instruments in the form of interest rate swaps, which hedge our risk related to interest rate fluctuation. Prior to January 1, 2001, these agreements were accounted for as hedges using the accrual method of accounting. The differences to be paid or received on swaps designated as hedges were included in interest expense during the period to which the payment or receipt related. The cash flows related to recognized gains or losses associated with these hedges were reported as cash flows from operations.

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 and hedging 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 due to changes in the underlying items being hedged. In addition, all hedging relationships must be designated, documented, and reassessed periodically. Most of the Company's derivative financial instruments qualify for hedge accounting. The only exceptions at December 31, 2001 are two written oil put contracts representing 1,500 Bbls/D for 2002 sold to finance the purchase of oil collar contracts. Additionally, another oil put contract representing 500 Bbls/D was written in February 2002 to finance the purchase of another oil collar contract. According to the provisions of SFAS 133, these are marked-to-market through earnings each quarter. If oil prices were to change dramatically and cause a material increase or decrease in the market value of these contracts, the change would be recognized in earnings immediately.

Currently, all of the Company's derivative financial instruments that qualify for hedge accounting 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 into earnings immediately. While management does not anticipate changing the destination of any of our current derivative contracts as hedges, factors beyond our control could 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 no longer deemed creditworthy and non-performance under the terms of the contract was likely, (See "Bad Debt Expense" for discussion of management judgments as it relates to asset realizability). If any of our contracts

no longer qualify for hedge accounting, this could potentially induce high earnings volatility, as any future changes in the market value of the contract would then be marked-to-market through earnings.

COMPARISON OF 2001 TO 2000

Set forth below is our comparison of operations during the year ended December 31, 2001 with the year ended December 31, 2000.

Revenues and Production. For the year ended December 31, 2001, revenues increased $27.0 million. The following table illustrates the primary components of oil and natural gas revenue for the years ended December 31, 2001 and 2000, as well as each year's respective oil and natural gas volumes (in thousands except per unit amounts):

	YEAR ENDED DECEMBER 31,					
	2001		2000		DIFFERENCE	
REVENUES:	REVENUE	$/UNIT	REVENUE	$/UNIT	REVENUE	$/BBL
Oil wellhead..................	$114,723	$23.25	$112,300	$28.35	$ 2,423	$(5.10)
Oil hedges....................	(8,955)	(1.82)	(19,859)	(5.01)	10,904	3.19
Total Oil Revenues..........	$105,768	$21.43	$ 92,441	$23.34	$13,327	$(1.91)
Natural gas wellhead..........	$ 34,014	$4.21	$ 19,687	$4.58	$14,327	$(0.37)
Natural gas hedges............	(3,865)	(0.48)	(3,178)	(0.74)	(687)	0.26

Total Gas Revenues..........	$ 30,149	$3.73	$ 16,509	$3.84	$13,640	$(0.11)

OTHER DATA:	PRODUCTION	NYMEX $/UNIT	PRODUCTION	NYMEX $/UNIT	PRODUCTION	NYMEX $/UNIT
Oil (Bbls)....................	4,935	$25.92	3,961	$30.13	974	$(4.21)
Natural gas (Mcf).............	8,078	4.06	4,303	3.60	3,775	0.46
Combined (BOE)................	6,281		4,678		1,603	

Oil revenues increased $13.3 million from 2000 to 2001. As illustrated above, this was due to an increase in oil volumes offset by a decrease in net price per barrel. Oil volumes increased 974 MBbls from 2000 to 2001 due to a full year of production from the acquisitions completed during 2000, as well as increased production from the Company's successful development drilling program. This increase in production added $2.4 million in wellhead revenue despite a decrease of $5.10 per barrel in the wellhead price received. The decrease in wellhead price resulted primarily from a decrease in the overall market price for oil in 2001 as reflected in the $4.21 per Bbl decrease in the average NYMEX price from 2000 to 2001. Oil revenues were reduced by $2.7 million and $11.2 million in 2001 and 2000, respectively, for the net profits interests payments held by others in the CCA. The decrease in net profits interests payments in 2001 was due to increased capital activity, which reduces the net profits interests payments. The decrease in wellhead oil revenues was offset by a decrease in payments made for hedging, which decreased $10.9 million. The Company's hedging activities are not a component of the expenses deducted in calculating net profits interest payments. The decrease in hedging payments is a direct result of the decrease in the average NYMEX price for oil.

Natural gas revenues increased from 2000 to 2001 by $13.6 million due to a 3,775 MMcf increase in production, while net price received decreased by $0.11. The increase in volumes is due to a full year of production for the acquisitions completed in 2000, as well as increased production in the CCA and Crockett County properties due to successful development drilling. Wellhead price received decreased $0.37 per Mcf, while the average NYMEX price increased $0.46 per Mcf. This is the result of higher prices received in relation to NYMEX for natural gas in the CCA versus the price discount received in the Indian Basin/Verden areas. Hedging payments decreased $0.26 per Mcf due to different hedges being in effect during 2001 than 2000.

For 2002 the increased production related to our anticipated $81 million capital drilling program and the Permian Basin acquisition, which together we forecast to add an average of 2,542 BOE per day for the year.

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This should help counteract the sharp decline curve we expect on our Lodgepole property. Unless changes are made to our planned drilling activities, another acquisition is made, or Lodgepole performs differently than expected, production should average approximately 19,750 BOE/D for 2002.

Prices received for oil and natural gas production is largely based on current market prices, which are beyond our control. During 2001, prices were trending downward. The average NYMEX prices of $25.92 per Bbl and $4.06 per Mcf in 2001 were significantly higher than the 12-month forward strip prices at

December 31, 2001 of $20.47 per Bbl and $2.81 per Mcf. We feel that oil prices will rebound somewhat in 2002 from their December 31, 2001 projected levels. Thus, we have based our 2002 forecasts on the assumptions of $22.50 per Bbl and $2.75 per Mcf NYMEX prices. At these assumed prices, we have forecasted hedging payments of approximately $3.4 million for oil and receipts of $0.5 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 payments of $0.4 million for oil and $0.01 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 $22.50 for oil and $2.75 for natural gas, the Company will not be able to fund the budgeted $81 million drilling program for 2002 through internally generated cash flows. In this case, the Company would have to borrow money, seek additional equity, or curtail the capital program. If drilling is curtailed or ended, future cash flows will be materially negatively impacted.

Direct lifting costs. Direct lifting costs of the Company for the year ended December 31, 2001 increased as compared to 2000 by $6.5 million. The increase in direct lifting costs resulted from the increase in volumes related to the full year effect of our 2000 acquisitions and our successful drilling program, as well as an increase in direct lifting costs per BOE. See "-- Revenues and Production". On a per BOE basis, direct lifting costs increased from $3.99 in 2000 to $4.00 in 2001 due to higher workover and contract labor costs in the CCA resulting from to the relatively harsh winter and the increased cost for services. Additionally, the Company incurred $1.0 million related to workovers in Bell Creek, which was acquired in December 2000.

For 2002 we anticipate an increase in total direct lifting costs, as well as on a per BOE basis. The overall increase in total is directly related to our Permian Basin acquisition, which closed on January 4, 2002, as well as an increase in insurance rates on our wells caused by industry wide insurance losses sustained in 2001. On a per BOE basis, we anticipate higher direct lifting costs primarily from higher per BOE costs associated with our Permian Basin acquisition. We have projected total direct lifting costs of approximately $30.5 million or $4.16 per BOE for 2002.

Production, ad valorem, and severance taxes. Production, ad valorem, and severance taxes for the year ended December 31, 2001 decreased as compared to 2000 by approximately $1.4 million. As a percentage of oil and natural gas revenues (excluding the effects of hedges), production, ad valorem, and severance taxes decreased from 10.6% to 9.1% from 2000 to 2001. This decrease was the result of a higher production, ad valorem, and severance tax rate in Montana associated with our CCA asset versus the lower tax rates in Texas, North Dakota, New Mexico, and Oklahoma associated with our Crockett County, Lodgepole, and Indian Basin/Verden assets. Thus, as the percentage of revenue from Crockett County, Lodgepole, and Indian Basin/ Verden increased in 2001, the total production, ad valorem, and severance tax rate for all areas declined.

For 2002 we believe total production, ad valorem, and severance taxes will increase overall due to the Permian Basin acquisition. However, the production, ad valorem, and severance tax rate should remain relatively constant at an estimated 9.6% of wellhead revenues.

Depletion, depreciation, and amortization ("DD&A") expense. DD&A expense increased by approximately $9.6 million from 2000 to 2001. This increase was due to a 1.6 MMBOE increase in production volumes, as well as an increase in the DD&A rate per BOE. See "-- Revenues and Production". The average DD&A rate increased from $4.72 per BOE of production during 2000 to $5.05 per BOE in 2001. The increase in volumes caused a $6.4 million increase in related DD&A expense, while the increased DD&A rate caused a $3.2 million increase. The higher rate in 2001 is attributable to higher per BOE acquisition costs associated

with the Crockett County, Lodgepole, Indian Basin/Verden, and Bell Creek acquisitions completed in 2000 as compared to the original rate associated with the Cedar Creek Anticline.

We anticipate the total DD&A expense in 2002 to increase due to increased production resulting from the $50 million Permian Basin acquisition and our planned 2002 capital expenditures of $81 million. Assuming capital expenditures that do not differ significantly from our budgeted amount, our DD&A rate for 2002 should approximate $4.85 per BOE. This decrease from 2001 primarily reflects a decrease in anticipated production from some of our higher per BOE rate properties. This rate could vary significantly based on actual capital expenditures, production rates, and any acquisition that closes in 2002. 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 $0.7 million from 2000 to 2001 (excluding non-cash stock based compensation of $9.6 million and $26.0 million in 2001 and 2000, respectively). The increase in G&A resulted from the additional staff and lease space necessary for the Crockett County, Lodgepole, Indian Basin/Verden, and Bell Creek acquisitions completed in 2000. During 2001, the Company leased an additional floor at the corporate headquarters and incurred additional costs related to being a publicly traded company. On a per BOE basis, G&A expense fell to $0.80 during 2001 from $0.93 during 2000. This reduction resulted as fixed costs were spread over a greater amount of production in 2001 as compared to 2000.

We have forecasted approximately $6.0 -- $6.5 million for general and administrative expenses in 2002. This represents a modest increase from 2001. The increase will result from hiring additional staff necessary after the Permian Basin acquisition and hiring additional staff necessary to evaluate potential acquisitions in a year that we expect to see many quality oil and natural gas properties on the market.

Other Operating Expense. The Company recorded $0.9 million of other operating expense in 2001 with no similar amount in 2000. This amount primarily consists of severance payments made during 2001 or accrued at December 31, 2001 to former employees of the Company, as well as transportation costs, namely pipeline fees paid to third parties. Additionally, geological and geophysical and delay rentals are recorded on this line in the income statement.

For 2002, we anticipate other operating expense to be approximately $0.5 to $1.0 million.

Interest expense. Interest expense for the year ended December 31, 2001 decreased $4.4 million from 2000 to 2001. The decrease in interest expense resulted primarily from the pay down of debt in conjunction with the Company's initial public offering. In addition, the weighted average interest rate, including hedges, for 2001 was 6.8% compared to 7.4% for 2000. The following table illustrates the components of interest expense for 2001 and 2000 (in thousands):

	2001	2000	DIFFERENCE

Facility	$4,596	$ 9,693	$(5,097)
Burlington note	389	763	(374)
Hedges	717	(86)	803
Fees	339	120	219
Total	$6,041	$10,490	$(4,449)

Non-cash stock based compensation expense. Non-cash stock based compensation expense decreased from $26.0 million for 2000 to $9.6 million for 2001. 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 2001 non-cash compensation expense was recorded in the first quarter of 2001 and represents the final amount of expense to be recorded related to the Class A stock.

The Company does not expect to incur any additional expense associated with non-cash stock based compensation related to the Company's employees.

Derivative fair value loss. The derivative fair value loss of $0.7 million in 2001 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, 2001. See "Item 7A. Quantitative and Qualitative Disclosures about Market Risk -- Commodity Price Sensitivity". These amounts are now being recorded as required by Statement of Financial Accounting Standards 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"). See "Description of Critical Accounting Policies". No similar amounts were recorded in 2000 as we adopted SFAS 133 effective January 1, 2001.

Currently this line item on the income statement is primarily dependent on the futures price of oil. This is due to the fact that, currently, the main component is the mark-to-market movement of our two short oil puts. The unrealized loss related to these two written option contracts at December 31, 2001 that has been recognized in earnings was $0.7 million. Additionally, we wrote another put contract representing 500 Bbls/D of oil in February 2002 to finance the purchase of another oil collar contract. Since these contracts move in conjunction with the futures price of oil, if the price of oil moves down, we will recognize a loss and if it moves up we will recognize a gain. As the market price of oil continually changes, we cannot reliably estimate the mark-to-market value of these puts in the future.

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, 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 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. Any ultimate recovery on the Enron receivable will be recognized in earnings when management believes recovery of the asset is probable.

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. According to the provisions of SFAS 133, this gain must be recorded in other comprehensive income until such time as the original hedged production affects income. As a result, at December 31, 2001, we had $4.8 million in gross unrecognized gains in other comprehensive income that will be reversed into earnings during 2002 and 2003. The following table illustrates the future 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 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 our Bell Creek properties. We then compared

the net book value of the Bell Creek properties to their estimated fair value, which resulted in a write-down of the value of proved oil and 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.

Future impairment charges could result based on changes in the Company's estimated reserves, management's estimate of future prices, or management's fair value estimate of our properties. If oil and natural gas prices were to decrease in the future, our reserves could be negatively impacted and/or management's estimate of either future cash flows or fair value of our properties could change. Any of these results could indicate the need for additional impairment charges.

COMPARISON OF 2000 TO 1999

Set forth below is our comparison of operations during the year ended December 31, 2000 with the year ended December 31, 1999. In reading the comparison, the 2000 period included twelve months of operations while the 1999 period included only seven months of operating activities. Accordingly, operations in the two accounting periods are not directly comparable.

Revenues. Oil and natural gas revenues of the Company for 2000 increased as compared to 1999 by $77.7 million, from $31.3 million to $109.0 million. This increase resulted from the additional five months of production from the CCA properties acquired in June 1999, as well as the Crockett County and Lodgepole acquisitions completed in April 2000. The Indian Basin/Verden acquisition includes four months of production for 2000. The Bell Creek acquisition accounted for one month of production for 2000. During the fourth quarter of 2000, an unusually severe winter storm briefly disrupted our operation of the CCA properties. The disruption in operations resulted in a loss of production of approximately 30 MBOE or $0.8 million of associated revenue. Also, the Indian Basin gas plant was off-line for one-time modifications in the fourth quarter of 2000. That disruption in operations resulted in loss of production of 20 MBOE or $0.6 million of revenue. Hedging transactions had the effect of reducing oil and natural gas revenues by $23.0 million, or $4.92 per BOE, during 2000 and decreasing oil and natural gas revenues by $4.4 million, or $2.42 per BOE, during 1999. Net profits interest payments had the effect of reducing oil and natural gas revenues by $11.5 million during 2000 and decreasing oil and natural gas revenues by $4.4 million during 1999.

Direct lifting costs. Direct lifting costs of the Company for the year ended December 31, 2000 increased as compared to 1999 by $10.3 million, from $8.4 million to $18.7 million. The increase in direct lifting costs resulted from the CCA acquisition completed in June 1999, as well as the Crockett County, Lodgepole, Indian Basin/Verden and Bell Creek acquisitions completed in 2000. On a per BOE basis, direct lifting costs decreased from $4.60 to $3.99, primarily as a result of lower lifting costs associated with our Lodgepole acquisition in April 2000. Because of the winter storm in the fourth quarter of 2000 at our CCA properties, direct lifting costs included $0.6 million, or $0.13 per BOE for the year, of expenses associated with repairing equipment and bringing production back on line.

Production, ad valorem, and severance taxes. Production, ad valorem, and severance taxes for the year ended December 31, 2000 increased as compared to 1999 by approximately $9.8 million, from $5.4 million to $15.2 million. The increase in production, ad valorem, and severance taxes resulted from the CCA acquisition completed in June 1999, as well as the Crockett County, Lodgepole, Indian Basin/Verden and Bell Creek acquisitions completed in 2000. As a percent of oil and natural gas revenues (excluding the effects of hedges), production, ad valorem, and severance taxes decreased from 13.5% to 10.6%. The decrease in production, ad valorem, and severance taxes as a percent of revenue was a result of the higher production, ad valorem, and severance tax rate in Montana associated with our CCA asset versus the tax rates in Texas and North Dakota associated with our Crockett County and Lodgepole assets, respectively.

Depletion, depreciation and amortization ("DD&A") expense. DD&A expense increased by approximately $16.8 million, during 2000 from $5.3 million to $22.1 million as compared to 1999. The increase in DD&A resulted from the CCA acquisition completed in June 1999, as well as the Crockett County, Lodgepole, Indian Basin/Verden and Bell Creek acquisitions completed in 2000. The average DD&A rate of $4.72 per BOE of production during 2000 represents an increase of $1.83 per BOE from the $2.89 per BOE

recorded in 1999. The increase was attributable to higher per BOE acquisition costs associated with the Crockett County, Lodgepole, Indian Basin/Verden and Bell Creek acquisitions completed in 2000.

General and administrative ("G&A") expense. G&A expense increased $0.3 million during 2000, from $4.0 million to $4.3 million (excluding non-cash stock based compensation of $26.0 million) as compared to 1999. The increase in G&A resulted from the additional staff and lease space necessary for the CCA acquisition completed in June 1999, as well as the Crockett County, Lodgepole, Indian Basin/Verden and Bell Creek acquisitions completed in 2000. On a per BOE basis, G&A expense fell to $0.93 during 2000 from $2.22 during 1999.

Non-cash stock based compensation expense. The Company has recorded $26.0 million of non-cash stock based compensation associated with the purchase by our management stockholders of Class A common stock under our management stock plan adopted in August 1998. This amount represents the vested portion of the shares purchased and is recorded as compensation, based on 90% of the anticipated price per share associated with our initial public offering, calculated in accordance with variable plan accounting under APB 25.

Interest expense. Interest expense for the year ended December 31, 2000 was $10.5 million compared to $4.0 million for the year ended December 31, 1999. The increase in interest expense resulted from the additional borrowing necessary under the Company's credit agreement for the CCA acquisition completed in June 1999, as well as the Crockett County acquisition completed in April 2000, the Indian Basin/Verden acquisition completed in August 2000 and the Bell Creek acquisition completed in November 2000. Additional interest expense during the first nine months of 2000 resulted from a seller financed note from Burlington Resources Oil & Gas. The note requires monthly principal payments and 4% interest on the outstanding principal paid at maturity of the note in January 2002.

LIQUIDITY AND CAPITAL RESOURCES

Principal uses of capital have been for the acquisition and development of oil and natural gas properties.

During the year ended December 31, 2001, net cash provided by operations was $80.2 million, an increase of $35.7 million compared to 2000. We anticipate that our capital expenditures will total approximately $81.0 million for 2002 not including the $50 million Permian Basin acquisition that closed in January 2002. 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 development and acquisition expenditures using internally generated cash flow, available cash, and our existing credit agreement.

At December 31, 2001, the Company had total assets of $402.0 million. Total capitalization was $348.4 million, of which 77.3% was represented by stockholders' equity and 22.7% by senior debt.

The Company's operating subsidiary currently maintains a credit agreement with a group of banks that matures in May 2004. The Company has guaranteed the subsidiary's obligations under the credit agreement and has pledged the stock and other equity interests of its subsidiaries to secure the guaranty. Borrowings under the credit agreement totaled $78.0 million as of December 31, 2001. The borrowing base, as established in the credit agreement, was $180.0 million as of December 31, 2001. During 2001, the weighted average interest rate under the facility was 5.7%. The remaining borrowing base available under the credit agreement at December 31, 2001, was $102.0 million. We pay certain fees based on the unused portion of the borrowing base. We financed the $50 million Permian Basin acquisition, which closed on January 4, 2002, with available borrowings under the credit agreement. Amounts outstanding under the credit agreement at February 28, 2002 were $130.0 million, which gave us remaining borrowing capacity of $50 million as of that date.

The borrowing base is to be redetermined each June 1. The Company and the bank syndicate each have the ability to request one additional borrowing base redetermination per year. If amounts outstanding ever exceed the borrowing base, the Company must reduce the amounts outstanding to the redetermined borrowing base within six months.

The credit agreement contains a number of negative and financial covenants. We were in compliance with all of them as of December 31, 2001. The most important of these covenants are:

- a prohibition against incurring debt in excess of $6.0 million, except for borrowings under the credit agreement and the seller financing note described below;

- a prohibition against paying dividends or purchasing or redeeming capital stock;

- a restriction on creating liens on the Company's assets;

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

- restrictions on investments, transactions with affiliates, changing the Company's principal business and incurring funding obligations under ERISA;

- a provision limiting oil and natural gas hedging transactions to a volume not exceeding 75% of anticipated production from proved reserves; and

- a requirement that we maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0.

The Company issued a $35.2 million note payable to Burlington Resources in connection with the Lodgepole acquisition in North Dakota. The note required monthly principal payments over the 22 month period ending January 31, 2002. The note bore monthly compounded interest at the rate of 4% per annum on the outstanding principal plus accrued interest and was payable at maturity in January 2002. Principal payments through December 31, 2001 and 2000 totaled $34.1 million and $17.7 million, respectively. The remaining principal balance of $1.1 million was paid in January 2002, along with accrued interest, which at December 31, 2001 totaled $1.3 million.

Based on current commodity conditions, the Company believes that its capital resources are adequate to meet the requirements of its business through 2003. Based on our anticipated capital investment programs, we expect to invest our internally generated cash flow to replace production and enhance our waterflood programs. Additional capital may be required to pursue acquisitions and longer-term capital projects, such as our proposed high pressure air injection tertiary recovery project in the CCA, to increase our reserve base. Substantially all of these 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.

The following table illustrates the Company's contractual obligations outstanding at December 31, 2001:

CONTRACTUAL OBLIGATIONS	PAYMENTS DUE BY PERIOD TOTAL	2002	2003 -- 2004	2005 -- 2006	THEREAFTER
Long-term debt	$78,000	$ --	$78,000	$ --	$ --
Note payable	1,107	1,107	--	--	--
Operating leases	4,686	885	1,910	1,507	384
Totals	$83,793	$1,992	$79,910	$1,507	$384

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.

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The following table indicates the average oil and natural gas prices received for the years ended December 31, 2001, 2000, and 1999. Average equivalent prices for 2001, 2000, and 1999 were decreased by $2.04, $4.92, and $2.42 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 (PER BBL)	NATURAL GAS (PER MCF)	EQUIV. OIL (PER BOE)
NET PRICE REALIZATION WITH HEDGES			
Year ended December 31, 2001	$21.43	$3.73	$21.64
Year ended December 31, 2000	23.34	3.84	23.29
Year ended December 31, 1999	16.96	4.50	17.12
AVERAGE WELLHEAD PRICE			
Year ended December 31, 2001	$23.25	$4.21	$23.68
Year ended December 31, 2000	28.35	4.58	28.21
Year ended December 31, 1999	19.42	4.50	19.54

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 Executive Vice President of Business Development with input from the Chief Executive Officer and the Chief Financial Officer. Trades are executed by the Executive Vice President of Business Development. The Treasury Department handles the administration functions, which entail tracking existing trades, confirming new trades, and conducting monthly settlements. Our Accounting Department records the transactions in the financial statements. We plan to continue in the normal course of business to hedge our exposure to fluctuating commodity prices. These arrangements will not exceed 75% of anticipated production from proved producing reserves. Currently, for the first six months of 2002, we have approximately 32% of our oil production placed in floors, 16% capped, and 16% in swap agreements and for the last six months of 2002, we have approximately 25% of our estimated oil production in floors, 16% capped, and 13% in swap agreements. In addition, for 2002, we have approximately 24% of our estimated natural gas placed in floors, 12% capped, and 12% in swap agreements and for 2003 we have approximately 14% of our estimated natural gas production in swap agreements. Our hedging policy does not permit us to engage in hedging transactions for speculation for our own account.

Counterparties. The Company's counterparties to hedging contracts include Bank of America, a commercial bank, J. Aron, a wholly-owned subsidiary of Goldman, Sachs & Co. and a commodities trading firm, and CIBC World Markets ("CIBC"), the marketing arm of the Canadian Imperial Bank of Commerce. As of December 31, 2001, approximately 67%, 20%, and 13% of hedged oil production is committed to J. Aron, Bank of America, and CIBC, respectively. All of our hedged natural gas production is contracted with J. Aron. Performance on all of J. Aron's contracts with the Company is guaranteed by their parent Goldman, Sachs & Co. As of December 12, 2001, we have terminated all of our oil and natural gas contracts with Enron North America Corp. See "Item 6. Comparison of 2001 to 2000 -- Bad Debt Expense". We feel the credit-worthiness of our current counterparties is sound and do not anticipate any non-performance of contractual obligations. However, as long as a counterparty maintains an investment grade credit rating, pursuant to our hedging contracts, no collateral is required.

Commodity price sensitivity. The tables in this section provide information about derivative financial instruments to which we were a party as of December 31, 2001 that are sensitive to changes in oil and natural gas commodity prices. No instrument provides the option to roll the contract forward rather than make or take delivery.

The Company hedges 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 finance the purchase of collar contracts through the short sale of 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 income statement. At December 31, 2001, we had two such contracts in place representing 1,500 Bbls/D with a strike price of $20.00 per barrel. Additionally, we sold another put contract short representing 500 Bbls/D of oil in February 2002 to finance the purchase of an oil collar contract. The unrealized mark-to-market gain on our outstanding commodity derivatives at December 31, 2001 was approximately $3.8 million. The fair market value of our oil hedging contracts was $2.8 million and the fair market value of our gas hedging contracts was $1.7 million. At December 31, 2001, the fair value liability of the Company's two written put contracts was $1.1 million.

OIL HEDGES AT DECEMBER 31, 2001

PERIOD	DAILY FLOOR VOLUME (BBL)	FLOOR PRICE (PER BBL)	DAILY CAP VOLUME (BBL)	CAP PRICE (PER BBL)	DAILY SWAP VOLUME (BBL)
Jan.-June 2002..................	5,000	$23.14	2,500	$26.31	2,500
July-Dec. 2002..................	4,000	$22.93	2,500	$26.31	2,000

NATURAL GAS HEDGES AT DECEMBER 31, 2001

	DAILY FLOOR VOLUME (MCF)	FLOOR PRICE (PER MCF)	DAILY CAP VOLUME (MCF)	CAP PRICE (PER MCF)	DAILY SWAP VOLUME (MCF)
2002...........................	5,000	$ 3.13	2,500	$ 8.05	5,000
2003...........................	--	$ --	--	$ --	2,500

Since December 31, 2001, the Company has entered into several additional oil collar contracts representing 3,000 Bbls/D of 2003 production. The weighted average floor price of these contracts is $19.17 per Bbl and the weighted average cap price is $25.33 per Bbl.

Interest rate sensitivity. At December 31, 2001, the Company had total debt of $79.1 million. Of this amount, $1.1 million bears interest at a fixed rate of 4%. The remaining outstanding debt balance of $78.0 million is under our credit agreement, which is subject to floating market rates of interest. Borrowings under the credit agreement bear interest at a fluctuating rate that is linked to LIBOR or the prime rate, at our option. Any increase in these rates can have an adverse impact on the Company's results of operations and cash flow. We have entered into interest rate swap agreements to hedge the impact of interest rate changes on a portion of our floating rate debt. As of December 31, 2001, we had interest rate swaps as follows:

NOTIONAL SWAP AMOUNT (IN THOUSANDS)	START DATE	END DATE	LIBOR SWAP RATE	FAIR MARKET VALUE AT DECEMBER 31, 2001 (IN THOUSANDS)
$30,000	December 19, 2000	March 31, 2005	6.72%	$(2,184)
$30,000	November 19, 2001	November 21, 2005	4.24%	$ 374

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:

Acquisition and Development Costs. Capital costs incurred in the acquisition, development, exploitation, and revisions of proved oil and natural gas reserves.

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.

Direct lifting costs. All direct 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.

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.

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

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.

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.

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.

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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 the Company 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. Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

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.

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

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.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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.

ENCORE ACQUISITION COMPANY

CONSOLIDATED BALANCE SHEETS

	DECEMBER 31, 2001	DECEMBER 31, 2000
	(IN THOUSANDS EXCEPT SHARE DATA)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 115	$ 876
Accounts receivable (net of allowance of $7.0 million at December 31, 2001)	16,286	21,210
Derivative assets	7,030	--
Other current assets	5,117	4,171
Total current assets	28,548	26,257

Properties and equipment, at cost -- successful efforts method:		
Producing properties	422,542	333,892
Undeveloped properties	776	624
Accumulated depletion, depreciation, and amortization	(60,548)	(26,868)
	362,770	307,648
Other property and equipment	3,001	1,910
Accumulated depletion, depreciation, and amortization	(1,253)	(621)
	1,748	1,289
Other assets	8,934	8,562
Total assets	$402,000	$343,756
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 10,793	$ 8,840
Derivative liabilities	3,525	--
Current portion of note payable	1,107	16,438
Other current liabilities	12,016	16,254
Total current liabilities	27,441	41,532
Derivative liabilities	1,288	--
Long-term debt	78,000	144,500
Note payable	--	1,107
Deferred income taxes	25,969	8,806
Total liabilities	132,698	195,945
Commitments and contingencies	--	--
Stockholders' equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none issued and outstanding	--	--
Class A common stock, $.01 par value, 75,000 shares authorized, none and 73,725 issued and outstanding	--	1
Class B common stock, $.01 par value, 300,000 shares authorized, none and 294,901 issued and outstanding	--	3
Common stock, $.01 par value, 60,000,000 shares authorized, 30,029,961 and none issued and outstanding	300	--
Additional paid-in capital	248,786	147,968
Notes receivable -- officers and employees	--	(21)
Retained earnings (deficit)	16,039	(140)
Accumulated other comprehensive income	4,177	--
Total stockholders' equity	269,302	147,811
Total liabilities and stockholders' equity	$402,000	$343,756

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

ENCORE ACQUISITION COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
	(IN THOUSANDS EXCEPT PER SHARE DAT		
Revenues:			
Oil	$105,768	$ 92,441	$30,45
Natural gas	30,149	16,509	81
Total revenues	135,917	108,950	31,26
Expenses:			
Production --			
Direct lifting costs	25,139	18,669	8,40
Production, ad valorem, and severance taxes	13,809	15,159	5,42
General and administrative (excluding non-cash stock based compensation)	5,053	4,345	4,04
Non-cash stock based compensation	9,587	26,012	-
Depletion, depreciation, and amortization	31,721	22,103	5,28
Derivative fair value loss	680	--	-
Bad debt expense	7,005	--	-
Impairment of oil and gas properties	2,598	--	-
Other operating expense	934	--	-
Total expenses	96,526	86,288	23,16
Operating income	39,391	22,662	8,09
Other income (expenses):			
Interest	(6,041)	(10,490)	(4,03
Other	46	512	20
Total other income (expenses)	(5,995)	(9,978)	(3,83
Income before income taxes	33,396	12,684	4,26
Provision for income taxes (current)	(1,919)	(7,272)	-
Provision for income taxes (deferred)	(14,414)	(7,547)	(1,25
Income (loss) before accounting change	17,063	(2,135)	3,00
Cumulative effect of accounting change (net of income taxes of $541)	(884)	--	-
Net income (loss)	$ 16,179	$ (2,135)	$ 3,00
Income (loss) per common share before accounting change:			
Basic	$ 0.59	$ (0.09)	$ 0.1
Diluted	0.59	(0.09)	0.1
Income (loss) per common share after accounting change:			
Basic	$ 0.56	$ (0.09)	$ 0.1
Diluted	0.56	(0.09)	0.1
Weighted average common shares outstanding:			
Basic	28,718	22,806	22,68
Diluted	28,723	22,806	22,68

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

ENCORE ACQUISITION COMPANY
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

	RETAINED EARNINGS (DEFICIT)	CLASS A COMMON STOCK	CLASS B COMMON STOCK	COMMON STOCK	PAID-IN CAPITAL	NOTES RECEIVABLE OFFICERS/ EMPLOYEES
	(IN THOUSANDS EXCEPT SHARE DATA)					
BALANCE AT DECEMBER 31, 1998	$(1,010)	$ 1	$ 3	$ --	$ 4,701	$ --
Issuance of 2,503 shares of A common stock and 101 of B common stock and capital calls	--	--	--	--	95,738	--
Offering costs	--	--	--	--	(16)	--
Net income (loss)	3,005	--	--	--	--	--
BALANCE AT DECEMBER 31, 1999	1,995	1	3	--	100,423	--
Issuance of 1,203 shares of A common stock and 49 shares of B common stock and capital call	--	--	--	--	21,533	--
Purchase of 3,177 shares of A common stock and 102 shares of B common stock	--	--	--	--	--	--
Issuance of 3,177 shares of A common stock held in treasury and 102 shares of B common stock held in treasury	--	--	--	--	--	--
Non-cash stock based compensation	--	--	--	--	26,012	--
Notes receivable -- officers and employees	--	--	--	--	--	(21)
Net income (loss)	(2,135)	--	--	--	--	--
BALANCE AT DECEMBER 31, 2000	(140)	1	3	--	147,968	(21)
Proceeds from initial public offering (net of offering costs of $1,568)	--	--	--	71	91,456	--
Non-cash stock based compensation	--	--	--	--	9,587	--
Recapitalization	--	(1)	(3)	229	(225)	--
Repayment of notes receivable -- officers and employees	--	--	--	--	--	21
Components of comprehensive income:						
Net income	16,179	--	--	--	--	--
Change in deferred hedge gain/loss (net of income taxes of $12,226)	--	--	--	--	--	--
Cumulative effect of accounting change (net of						

income taxes of $9,121)	--	--	--	--	--	--
Total comprehensive income						
BALANCE AT DECEMBER 31, 2001	$16,039	$ --	$ --	$300	$248,786	$ --

	TREASURY STOCK	ACCUMULATED OTHER COMPREHENSIVE INCOME	STOCKHOLDERS' EQUITY
	(IN THOUSANDS EXCEPT SHARE DATA)		
BALANCE AT DECEMBER 31, 1998	$ --	$ --	$ 3,695
Issuance of 2,503 shares of A common stock and 101 of B common stock and capital calls	--	--	95,738
Offering costs	--	--	(16)
Net income (loss)	--	--	3,005
BALANCE AT DECEMBER 31, 1999	--	--	102,422
Issuance of 1,203 shares of A common stock and 49 shares of B common stock and capital call	--	--	21,533
Purchase of 3,177 shares of A common stock and 102 shares of B common stock	(95)	--	(95)
Issuance of 3,177 shares of A common stock held in treasury and 102 shares of B common stock held in treasury	95	--	95
Non-cash stock based compensation	--	--	26,012
Notes receivable -- officers and employees	--	--	(21)
Net income (loss)	--	--	(2,135)
BALANCE AT DECEMBER 31, 2000	--	--	147,811
Proceeds from initial public offering (net of offering costs of $1,568)	--	--	91,527
Non-cash stock based compensation	--	--	9,587
Recapitalization	--	--	--
Repayment of notes receivable -- officers and employees	--	--	21
Components of comprehensive income:			
Net income	--	--	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	$ --	$ 4,177	$269,302

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,		
	2001	2000	1999
	(IN THOUSANDS)		
Operating activities			
Net income (loss)	$ 16,179	$ (2,135)	$ 3,005
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, and amortization	31,721	22,103	5,283
Deferred taxes	13,718	7,547	1,259
Non-cash stock based compensation	9,587	26,012	--
Non-cash cumulative accounting change	884	--	--
Non-cash derivative fair value loss	680	--	--
Other non-cash charges	1,718	88	97
Loss on disposition of assets	165	--	--
Bad debt expense	7,005	--	--
Impairment of oil and gas properties	2,598	--	--
Changes in operating assets and liabilities:			
Accounts receivable	4,564	(11,315)	(9,894)
Other current assets	(2,258)	(2,797)	(1,367)
Other assets	(4,605)	(7,449)	(1,208)
Accounts payable and other current liabilities	(1,744)	12,454	12,584
Cash provided by operating activities	80,212	44,508	9,759
Investing activities			
Proceeds from disposition of assets	310	--	--
Purchases of other property and equipment	(1,091)	(606)	(1,015)
Acquisition of oil and gas properties	(1,622)	(70,151)	(193,803)
Development of oil and gas properties	(87,180)	(28,479)	(6,883)
Cash used by investing activities	(89,583)	(99,236)	(201,701)
Financing activities			
Proceeds from capital calls	--	21,510	95,738
Issuance of treasury stock	--	95	--
Repurchase of common stock	--	(95)	--
Proceeds from initial public offering	93,095	--	--

Offering costs paid	(1,568)	--	(16)
Proceeds from notes receivable -- officers and employees	21	2	--
Proceeds from long-term debt	161,000	118,000	100,250
Payments on long-term debt	(227,500)	(72,750)	(1,000)
Payments on note payable	(16,438)	(17,655)	--
Cash provided by financing activities	8,610	49,107	194,972
Increase (decrease) in cash and cash equivalents	(761)	(5,621)	3,030
Cash and cash equivalents, beginning of period	876	6,497	3,467
Cash and cash equivalents, end of period	$ 115	$ 876	$ 6,497
Supplemental disclosure of non-cash investing and financing activities:			
Note payable issued for purchase of oil and gas properties	$ --	$ 35,200	$ --
Notes received from officers and employees in connection with capital calls	$ --	$ 23	$ --

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, and the Powder River Basin of Montana.

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.

INVENTORIES

Inventories are comprised principally of materials and supplies, and are stated at the lower of cost (determined on an average basis) or market.

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 financial statements. Natural gas volumes are converted to equivalent barrels at the rate of six Mcf to one barrel.

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 recorded in accumulated depletion, depreciation, and amortization ("DD&A") to reduce 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.

STOCK-BASED COMPENSATION

Employee stock options 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. Additionally, in accordance with Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation", we have disclosed in Note 10 the pro forma effect on net income and net income per share of recording stock-based compensation using the estimated fair value of option awards on the grant date.

SEGMENT REPORTING

In accordance with Statement of Financial Accounting Standards No. 131, "Disclosures about Segments of an Enterprise and Related Information", we have identified 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 2001, ConAgra, Equiva Trading Company (a joint venture between Shell and Texaco) and EOTT Energy Co., accounted for 25%, 17%, and 11% of total oil and natural gas sales, respectively. For 2000, our largest purchasers included Equiva Trading Company and EOTT Energy Co, which accounted for 56% and 11% of total oil and natural gas sales, respectively. As of March 1, 2002, we no longer market our oil with EOTT Energy Co. and have substituted Eighty Eight Oil, LLC. as the purchaser.

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. State franchise taxes are calculated on a stand-alone basis.

REVENUE RECOGNITION

Revenues are recognized from jointly owned properties as oil and natural gas is produced and sold, net of royalties. Revenues from natural gas production are recorded using the sales method, net of royalties. Under this method, revenue is recognized based on the cash received rather than our proportionate share of natural gas produced. Natural gas imbalances at December 31, 2001 were 483,000 MMbtu, and 556,000 MMbtu at December 31, 2000. Revenues are stated net of any net profits interests held by others. The reduction in revenue from net profits interest totaled $2.8 million, $11.5 million, and $4.4 million in 2001, 2000, and 1999, 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 on our income statement.

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ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

HEDGING AND RELATED ACTIVITIES

We use various financial instruments for non-trading purposes in the normal course of our business to manage and reduce price volatility and other market risks associated with our crude oil and natural gas production. This activity is referred to as hedging. 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.

Prior to January 1, 2001, these agreements were accounted for as hedges using the deferral method of accounting. Unrealized gains and losses were generally not recognized until the physical production required by the contracts was delivered. At the time of delivery, the resulting gains and losses were recognized as an adjustment to oil and natural gas revenues. The cash flows related to any recognized gains or losses associated with these hedges were reported as cash flows from operations. If the hedge was terminated prior to maturity, gains or losses were deferred and included in income in the same period as the physical production required by the contracts was delivered.

We also use derivative instruments in the form of interest rate swaps, which hedge our risk related to interest rate fluctuation. Prior to January 1, 2001, these agreements were accounted for as hedges using the accrual method of accounting. The differences to be paid or received on swaps designated as hedges were included in interest expense during the period to which the payment or receipt related. The cash flows related to recognized gains or losses associated with these hedges were reported as cash flows from operations.

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 and hedging 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 due to changes in the underlying item being hedged. 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 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 taxes of $9.1 million).

Currently, all of our derivative financial instruments that qualify for hedge accounting 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 into earnings immediately.

USE OF ESTIMATES

Preparing financial statements in conformity with accounting principles generally accepted in the United States requires management to make certain estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements

and the reported amounts of revenues and expenses during the reporting period. Actual results could differ materially from those estimates.

Estimates with regard to these financial statements include the estimate of proved oil and natural gas reserve volumes and the estimated future development, dismantlement, and abandonment costs used in determining amortization provisions. In addition, significant estimates are required for our assessment of impairment of long-lived assets. Future changes in the assumptions used could have a significant impact on whether impairment provisions are required in future periods.

COMPREHENSIVE INCOME

During 1998, The Company adopted Statement of Financial Accounting Standards No. 130 ("SFAS 130"), "Reporting Comprehensive Income," which establishes standards for reporting and display of comprehensive income and its components in a full set of general purpose financial statements. Comprehensive income includes net income and other comprehensive income, which includes, but is not limited to, unrealized gains and losses on marketable securities, foreign currency translation adjustments, minimum pension liability adjustments, and effective January 1, 2001, unrealized gains and losses on derivative financial instruments. For the years ended December 31, 2000 and 1999, comprehensive income and net income were equal and thus, SFAS 130 had no effect on our financial statements.

With the adoption of SFAS 133 on January 1, 2001, the Company began recording deferred hedge gains and losses on our derivative financial instruments as other comprehensive income. For the year ended December 31, 2001, comprehensive income totaled $20.4 million, while net income totaled $16.2 million. The difference between net income and comprehensive income is the result of recording a $14.9 million deferred hedge loss as a cumulative change in accounting, as well as a $19.1 million deferred hedge gain for the year ended December 31, 2001. The deferred hedge gain for 2001 resulted from a reduction in the market price of oil and natural gas during the year. At December 31, 2001, the Company had $4.2 million in deferred hedge gains, net of tax, in accumulated other comprehensive income, shown as a component of equity on the balance sheet.

3. OIL AND NATURAL GAS PROPERTIES

The cost of oil and natural gas properties at December 31, 2001 includes $0.8 million of undeveloped leasehold costs. Such properties are held for development or resale. The following table sets forth costs incurred related to oil and natural gas properties:

	2001	2000	1999
		(IN THOUSANDS)	
Proved Property Acquisition Costs	$ 1,622	$105,351	$193,626
Development Costs	87,180	28,479	7,060
Total	$88,802	$133,830	$200,686

1999 ACQUISITIONS

During June 1999, we purchased from Shell Western E&P Inc. their interests in approximately 475 oil and natural gas properties (450 operated, 25 non-operated) in the Cedar Creek Anticline located in Southeastern Montana and Southwestern North Dakota for $172.0 million ($170.5 million of proved properties and $1.5 million of inventory and other equipment).

The acquisition has been accounted for as a purchase. The operating results of the Shell Western properties have been included in our consolidated financial statements since the date of acquisition. During July and October 1999, we purchased additional working interests within the Cedar Creek Anticline properties

from various working interest owners for $22.2 million. These acquisitions were also accounted for as a purchase and included in our consolidated financial statements since the date of acquisition.

2000 ACQUISITIONS

On February 23, 2000, the Company executed a purchase and sale agreement to acquire working interests in 278 wells located in Crockett County, Texas (approximately 130 wells operated, 148 non-operated) for $43 million. The transaction closed on March 30, 2000.

On March 6, 2000, the Company executed a purchase and sale agreement to acquire working interests in 25 wells, (23 non-operated, two operated) located in Stark County, North Dakota for $35.2 million. The transaction closed on March 31, 2000.

The Company executed a purchase and sale agreement to acquire working interests in 161 wells located in Oklahoma and New Mexico (approximately seven wells operated, 154 non-operated) for $25.4 million. The transaction closed on August 24, 2000 with an effective date of April 1, 2000.

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.

Unaudited pro forma information, as if the acquisitions were consummated on January 1, 1999, is as follows (in thousands):

SUMMARY PRO FORMA DATA

	FOR THE YEAR ENDED DECEMBER 31,	
	2000	1999
Revenue	$129,537	$86,379
Net income	3,047	8,421
Earnings per share	0.13	0.37

2001 ACQUISITIONS

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

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 our remaining non-cancelable future payments under operating leases as of December 31, 2001 (in thousands):

2002	$885
2003	959
2004	951
2005	987
2006	520
Thereafter	384

Our operating lease rental expense was approximately $0.7 million, $0.3 million, and $0.3 million in 2001, 2000, and 1999, respectively.

5. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities were as follows at December 31 (in thousands):

	2001	2000
Accounts payable trade	$10,716	$ 7,389
Hedge settlements payable	77	1,451
Oil and natural gas revenue payable	3,284	4,296
Property and production taxes	2,581	4,490
Net proceeds payable	80	466
Interest	1,451	1,769
Direct lifting costs	2,097	1,220
Current income taxes payable	--	3,272
Drilling costs	1,100	--
Other	1,423	741
Total	$22,809	$25,094

6. INDEBTEDNESS

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

	2001	2000

Credit Agreement	$78,000	$144,500
Note payable	1,107	17,545
Total	79,107	162,045
Less: Current portion of note payable	1,107	16,438
Long-term debt, net of current portion	$78,000	$145,607

The Company's operating subsidiary currently maintains a credit agreement with a group of banks that matures in May 2004. All amounts outstanding under the credit agreement are payable upon maturity in May 2004. The Company has guaranteed the subsidiary's obligations under the credit agreement and has pledged the stock and other equity interests of its subsidiaries to secure the guaranty. Borrowings under the credit agreement totaled $78.0 million and $144.5 million as of December 31, 2001 and 2000. The borrowing base, as established in the credit agreement, was $180.0 million as of December 31, 2001 and 2000. During 2001 and 2000, the weighted average interest rate under the facility was 5.7% and 7.8%, respectively. The remaining borrowing base available under the credit agreement at December 31, 2001, was $102.0 million. The Company pays certain fees based on the unused portion of the borrowing base.

The borrowing base is to be redetermined each June 1. The Company and the bank syndicate each have the ability to request one additional borrowing base redetermination per year. If amounts outstanding ever exceed the borrowing base, the Company must reduce the amounts outstanding to the redetermined borrowing base within six months.

The credit agreement contains a number of negative and financial covenants. The Company was in compliance with all of them as of December 31, 2001. The most important of these covenants are:

- a prohibition against incurring debt in excess of $6.0 million, except for borrowings under the credit agreement and the seller financing note described below;

- a prohibition against paying dividends or purchasing or redeeming capital stock;

- a restriction on creating liens on the Company's assets;

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

- restrictions on investments, transactions with affiliates, changing the Company's principal business, and incurring funding obligations under ERISA;

- a provision limiting oil and natural gas hedging transactions to a volume not exceeding 75% of anticipated production from proved reserves; and

- a requirement that the Company maintain a ratio of consolidated current assets to consolidated current liabilities as defined in the agreement, of not less than 1.0 to 1.0.

The Company issued a $35.2 million note payable to the seller in connection with the Lodgepole acquisition in North Dakota. The note requires monthly principal payments over the 22 month period ending January 31, 2002. The note bears monthly compounded interest at the rate of 4% per annum on the outstanding principal plus accrued interest and is payable at maturity in January 2002. Principal payments through December 31, 2001 totaled $34.1 million. The remaining amount payable at December 31, 2001 totals $1.1 million, which along with accrued interest of $1.3 million, was paid in January 2002.

Consolidated cash payments for interest were $6.4 million, $10.2 million, and $3.4 million, respectively, for 2001, 2000, and 1999.

7. TAXES

INCOME TAXES

The components of the income tax expense are as follows (in thousands):

	DECEMBER 31,		
	2001	2000	1999
Federal:			
Current	$ 1,919	$ 6,292	$ --
Deferred	13,125	7,547	1,038
Total federal	15,044	13,839	1,038
State:			
Current	--	980	--
Deferred	1,289	--	221
Total state	1,289	980	221
Income tax expense	$16,333	$14,819	$1,259

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

	DECEMBER 31,		
	2001	2000	1999
Income before income taxes	$33,396	$12,684	$4,264
Tax at statutory rate	$11,689	$ 4,439	$1,450
State income taxes, net of federal benefit	1,289	980	190

Non-cash stock based compensation	3,355	9,104	--
Valuation allowance	--	--	(342)
Other	--	296	(39)
Income tax expense	$16,333	$14,819	$1,259

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):

	2001	2000
CURRENT:		
Assets:		
Allowance for bad debt	$ 2,662	$ --
Derivative fair value loss	258	--
Total current deferred tax assets	2,920	--
Liabilities:		
Unrealized hedge gain in other comprehensive income	(2,899)	--
Net current deferred tax asset	$ 21	$ --
LONG-TERM:		
Assets:		
Alternative minimum tax	$ 1,919	$ --
Net operating loss carryforwards	4,298	--
Unrealized hedge loss in other comprehensive income	339	--
Other	92	11
Total long-term deferred tax assets	6,648	11
Liabilities:		
Book basis of oil and natural gas properties in excess of tax basis	(32,617)	(8,817)
Net long-term deferred tax liability	$(25,969)	$(8,806)

Cash income tax payments in the amount of $1.5 million and $4.0 million were made in 2001 and 2000, respectively. No cash income tax payments were made in 1999. Our net operating loss carryforward is scheduled to expire in 2021.

TAXES OTHER THAN INCOME TAXES

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

	DECEMBER 31, 2001	2000	1999
Production and severance	$13,303	$14,616	$5,139
Property and ad valorem	506	543	288
Payroll and other	316	210	143
Total	$14,125	$15,369	$5,570

8. STOCKHOLDERS' EQUITY

COMMON STOCK

On August 18, 1998, the Company entered into a Stock Purchase Agreement and a Stockholders' Agreement (collectively the "Agreements"), with members of our management ("Management") and non-management investors (the "Investors"). Under the terms of the Agreements, 294,901 shares of Class B Common Stock, par value $0.01 per share (the "Class B") and 73,725 shares of Class A Common Stock, par value $0.01 per share ("Class A") were authorized to be issued for a total amount of committed consideration to be invested in the Company of $298 million by Management and the Investors.

At December 31, 2000 and 1999, 294,901 and 294,852 shares of Class B and 73,725 and 72,522 shares of Class A were issued and outstanding. The total Management capital commitment for Class A and Class B shares was approximately $8 million.

During 2000, an additional 4,380 shares of Class A common stock were sold to employees of the Company.

During 2000 and 1999, capital calls totaling $21.5 million and $95.7 million, respectively were initiated in order to fund the acquisitions of oil and natural gas properties.

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.

PREFERRED STOCK

The Company has authorized a class of undesignated preferred stock consisting of 1,000 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 follows variable plan accounting for the Class A stock sold to management. Accordingly, compensation expense is 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 vests 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 gas properties. Beginning on September 1, 2000, we estimated the fair value of its 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, $26.0 million in 2000, and none in 1999. The $9.6 million recorded in the first quarter of 2001 represented the final compensation expense to be recorded related to the Class A shares.

9. EARNINGS (LOSS) PER SHARE ("EPS")

Under Statement of Financial Accounting Standards 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.

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

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
NUMERATOR:			
Income (loss) before accounting change	$17,063	$(2,135)	$ 3,005
Net income (loss)	$16,179	$(2,135)	$ 3,005
DENOMINATOR:			
Denominator for basic earnings per share -- weighted average shares outstanding	28,718	22,806	22,687
Effect of dilutive securities:			
Dilutive options	5	--	--
Denominator for diluted earnings per share	28,723	22,806	22,687
Basic income (loss) per common share before accounting change	$ 0.59	$ (0.09)	$ 0.13
Cumulative effect of accounting change, net of tax	(0.03)	--	--

Basic income (loss) per common share after accounting change	$ 0.56	$ (0.09)	$ 0.13
Diluted income (loss) per common share before accounting change	$ 0.59	$ (0.09)	$ 0.13
Cumulative effect of accounting change, net of tax	(0.03)	--	--
Diluted income (loss) per common share after accounting change	$ 0.56	$ (0.09)	$ 0.13

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 $0.4 million in 2001, $0.3 million in 2000, and $0.1 million in 1999. 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 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 reserved and available for distribution pursuant to the plan is 1.8 million shares. 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. Pursuant to the plan, during 2001, 936,000 incentive and non-qualified stock options were granted to employees and 4,000 incentive stock options were granted to non-employee directors. All options were granted with a strike price equal to the market price on the date of grant. The options have a ten-year life and vest equally over a two or three-year period. The following table summarizes the number of options and their related weighted average strike prices for 2001:

	NUMBER OF OPTIONS	WEIGHTED AVERAGE STRIKE PRICE
Outstanding at December 31, 2000	--	$ --
Granted during 2001	940,000	13.49
Forfeited during 2001	(92,500)	14.00
Outstanding at December 31, 2001(a)	847,500	13.44

(a) Due to the one-year minimum vesting requirement, none of the options outstanding at December 31, 2001 were exercisable. The options outstanding December 31, 2001 had strike prices ranging from $12.49 to $14.00 and had a weighted average remaining life of 9.4 years.

SFAS 123 DISCLOSURES

The Company follows the provisions of APB 25 in accounting for its stock based compensation. Accordingly, no compensation expense has been recognized for its stock option awards. If compensation expense for the stock option awards had been determined using the provisions of 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, 2001
Net income	$15,475
Basic net income per share	0.54
Diluted net income per share	0.54

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. The following amounts represent weighted average values used in the model to calculate the fair value of the options granted during 2001:

	YEAR ENDED DECEMBER 31, 2001
Risk free interest rate	4.4%
Expected life	4 years
Expected volatility	28.9%
Expected dividend yield	0.0%

11. FINANCIAL INSTRUMENTS

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

	DECEMBER 31, 2001	DECEMBER 31, 2000

	BOOK VALUE	FAIR VALUE	BOOK VALUE	FAIR VALUE
Cash and cash equivalents.............	$ 115	$ 115	$ 876	$ 876
Senior debt...........................	(78,000)	(78,000)	(144,500)	(144,500)
Long-term commodity contracts.........	7,463	7,463	4,723	(18,812)
Interest rate swaps...................	(1,813)	(1,813)	--	(1,010)
Note payable..........................	(1,107)	(1,107)	(17,545)	(17,545)

The book value of cash and cash equivalents approximates fair value because of the short maturity of these instruments. The fair value of senior debt is presented at face value given its floating rate structure. Since the note payable is payable on demand if called by the issuer, fair value approximates book value.

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 sales volume. Put contracts provide a fixed floor price on a notional amount of sales 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 sales volume while allowing some additional price participation if the relevant index price closes above the floor price. A swaption is an option to enter into a swap in the future. However, no swaptions were outstanding at December 31, 2001. Additionally, we occasionally finance the purchase of collar contracts through the short sale of 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 income statement. At December 31, 2001, we had two such contracts in place representing 1,500 Bbls/D in 2002 with a strike price of $20.00 per barrel.

The following tables summarize our open hedging positions as of December 31, 2001:

OIL HEDGES AT DECEMBER 31, 2001

PERIOD	DAILY FLOOR VOLUME (BBL)	FLOOR PRICE (PER BBL)	DAILY CAP VOLUME (BBL)	CAP PRICE (PER BBL)	DAILY SWAP VOLUME (BBL)	SWAP PRICE (PER BB
Jan. - June 2002......	5,000	$23.14	2,500	$26.31	2,500	$18.43
July - Dec. 2002......	4,000	22.93	2,500	26.31	2,000	17.97

NATURAL GAS HEDGES AT DECEMBER 31, 2001

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
2002.................	5,000	$3.13	2,500	$8.05	5,000	$2.83
2003.................	--	--	--	--	2,500	3.69

For the first six months of 2002, we have approximately 32% of our oil production placed in floors, 16% capped, and 16% in swap agreements and for the last six months of 2002, we have approximately 25% in floors, 16% capped, and 13% in swap agreements. In addition, for 2002, we have approximately 24% of our estimated natural gas placed in floors, 12% capped, and 12% in swap agreements and for 2003 we have approximately 14% in swap agreements.

As a result of all of our hedging transactions for oil and natural gas we recognized a pre-tax loss in earnings of approximately $12.8 million, $23.0 million, and $4.4 million in 2001, 2000, and 1999, respectively. Based on the fair value of our hedges at December 31, 2001, our unrealized pre-tax gain recorded in other comprehensive income related to outstanding hedges is $2.4 million for oil and $1.4 million for natural gas. These amounts will be reclassified to earnings as the related production affects earnings, which for oil is in 2002 and for gas is $1.0 million in 2002 and $0.4 million in 2003. The actual gains or losses we realize from our commodity hedge transactions may vary significantly from these amounts due to the fluctuation of prices in the commodity markets. In order to calculate the unrealized gain or loss, the relevant variables are (1) the type of commodity, (2) the delivery price, and (3) the delivery location. We do not take into account the time value of money because of the short-term nature of our hedging instruments. These calculations may be used to analyze the gains and losses we might realize on our financial hedging contracts and do not reflect the effects of price changes on our actual physical commodity sales.

INTEREST RATE DERIVATIVES

The Company has entered into interest rate swap agreements to hedge the impact of interest rate changes on a portion of its floating rate debt. As of December 31, 2001, we had interest swaps as follows:

NOTIONAL SWAP AMOUNT	START DATE	END DATE	LIBOR SWAP RATE	FAIR MARKET VALUE AT DECEMBER 31, 2001
(IN THOUSANDS)				(IN THOUSANDS)
$30,000	December 19, 2000	March 31, 2005	6.72%	$(2,184)
$30,000	November 19, 2001	November 21, 2005	4.24%	$ 374

As a result of our hedging transactions for interest we recognized in interest expense a pre-tax loss of approximately $0.7 million, $0.1 million, and $0.1 million in 2001, 2000, and 1999, respectively. Based on the fair value of our interest rate swaps at December 31, 2001, our pre-tax unrealized loss recorded in other comprehensive income related to these swaps was $1.9 million. This amount will be reclassified to interest expense as the related interest payments become due. For 2002, $0.6 million will be reclassified with the

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

remainder over the remaining terms of the swaps. The actual gains or losses we realize from our interest rate swaps may vary significantly from these amounts due to the fluctuation of the LIBOR interest rate. We do not take into account the time value of money because of the short-term nature of our hedging instruments.

COUNTERPARTY RISK

The Company's counterparties to hedging contracts include: Bank of America, a commercial bank; J. Aron, a wholly-owned subsidiary of Goldman, Sachs & Co. and a commodities trading firm; and CIBC World Markets ("CIBC"), the marketing arm of the Canadian Imperial Bank of Commerce. As of December 31, 2001, approximately 67%, 20%, and 13% of oil production hedged is committed to J. Aron, Bank of America, and CIBC, respectively. All of our hedged gas production is contracted with J. Aron. Performance on all of J. Aron'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 do not anticipate any non-performance of contractual obligations. However, as long as each counterparty maintains an investment grade credit rating, pursuant to our hedging contracts, no collateral is required.

12. NEW ACCOUNTING STANDARDS

In June 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 141, Business Combinations. This statement supercedes APB Opinion No. 16, Business Combinations and FASB No. 38, Accounting for Preacquisition Contingencies of Purchased Enterprises and applies to all business combinations initiated after June 30, 2001. This statement eliminates the pooling method of accounting for a business combination and requires the use of purchase accounting. We feel this statement will not have a material impact on our financial statements.

In June 2001, the FASB issued Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets. This statement is effective for years beginning after December 15, 2001. This statement addresses financial accounting and reporting for acquired goodwill and other intangible assets and supercedes APB Opinion No. 17, Intangible Assets. This statement also addresses how goodwill and other intangibles should be accounted for after they have been initially recognized in the financial statements. We feel this statement will not have a material impact on our financial statements.

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 143 ("SFAS 143"), Accounting for Asset Retirement Obligations, which the Company will be required to adopt 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. We are currently reviewing the provisions of the statement and assessing their impact on our financial statements. We do not currently know the effect, if any, the adoption of SFAS 143 will have on our financial statements.

In November 2001, the FASB issued Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived

Assets, which supercedes FASB Statement No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of ("SFAS 121"). This statement is effective for years beginning after December 15, 2001. This statement retains the fundamental provisions of SFAS 121 related to the recognition and measurement of the impairment of long-lived assets to be held and used. However, it provides additional guidance on estimating future cash flows and amends the rules related to assets to be disposed of and held for sale. We feel this statement will not have a material impact on our financial statements.

13. 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 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. Any ultimate recovery on the Enron receivable will be recognized in earnings when management believes recovery of the asset to be probable.

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. According to the provisions of SFAS 133, this gain must be recorded in other comprehensive income until such time as the original hedged production affects income. As a result, at December 31, 2001, the Company had $4.8 million in gross unrecognized gains in other comprehensive income that will be reversed into earnings during 2002 and 2003. The following table illustrates the future 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

14. 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 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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15. SUBSEQUENT EVENT

In January 2002, the Company completed the acquisition of interest in oil and natural gas properties in the Permian Basin from Conoco. The final purchase price after closing adjustments and preferential rights were exercised was $50 million. The acquisition was funded with bank financing under the Company's existing credit facility. The two principal operated properties are the East Cowden Grayburg and Fuhrman Nix fields; the non-operated properties are primarily in North Cowden and Yates. Preferential rights were exercised on non-operated properties in the Yates field. We estimate that the proved reserves are approximately 9.2 million barrels.

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ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

UNAUDITED SUPPLEMENTAL INFORMATION

OIL & NATURAL GAS PRODUCING ACTIVITIES

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 indicated 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, 2001, 2000, and 1999 were $19.84, $26.80, and $25.60 per barrel for oil and $2.57, $9.77, and $2.31 per Mcf for natural gas respectively. The net profits interest on our Cedar Creek Anticline properties has been deducted from future cash inflows in the calculation of standardized measure. The Company's reserve and production quantities have been reduced by 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 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 shown below. 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 depreciation, depletion, 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, 2001			
Proved reserves	91,369	75,687	103,983
Proved developed reserves	71,639	69,941	83,296
December 31, 2000			
Proved reserves	78,910	72,970	91,072
Proved developed reserves	66,363	66,337	77,419
December 31, 1999			
Proved reserves	69,299	10,940	71,122
Proved developed reserves	59,134	8,896	60,616

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

	OIL (MBBL)	NATURAL GAS (MMCF)	OIL EQUIVALENT (MBOE)
Balance, December 31, 1998	--	--	--
Acquisitions of minerals-in-place	69,630	10,833	71,435
Extensions and discoveries	1,465	287	1,513

Revisions of estimates	--	--	--
Production	(1,796)	(180)	(1,826)
Balance, December 31, 1999	69,299	10,940	71,122
Acquisitions of minerals-in-place	4,162	63,136	14,685
Extensions and discoveries	8,237	1,733	8,526
Revisions of estimates	1,173	1,464	1,417
Production	(3,961)	(4,303)	(4,678)
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

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,		
	2001	2000	1999
Net future cash inflows	$1,770,384	$ 2,611,633	$1,650,403
Future production costs	(794,139)	(998,660)	(755,249)
Future development costs	(67,652)	(45,583)	(31,561)
Future income tax expense	(215,568)	(377,789)	(258,114)
Future net cash flows	693,025	1,189,601	605,479
10% annual discount	(408,716)	(590,325)	(332,524)
Standardized measure of discounted estimated future net cash flows	$ 284,309	$ 599,276	$ 272,955

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ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

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,		
	2001	2000	1999
Standardized measure, beginning of year	$ 599,276	$272,955	$ --

Net change in sales price, net of production costs	(334,809)	19,764	--
Extensions and discoveries	71,090	75,236	9,304
Development costs incurred during the year	87,179	26,508	--
Revisions of quantity estimates	(18,244)	9,822	--
Accretion of discount	70,636	32,325	--
Change in future development costs	(51,238)	(18,667)	--
Acquisitions of minerals-in-place	--	336,601	349,869
Sales, net of production costs	(96,969)	(75,122)	(17,786)
Change in timing and other	(73,640)	(23,362)	(18,135)
Net change in income taxes	31,028	(56,784)	(50,297)
Standardized measure, end of year	$ 284,309	$599,276	$272,955

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

SELECTED QUARTERLY FINANCIAL DATA

The following table sets forth selected quarterly financial data for the years ended December 31, 2001 and 2000:

	QUARTER			
	FIRST	SECOND	THIRD	FOURTH
	(IN THOUSANDS, EXCEPT PER SHARE DATA)			
2001				
Revenues	$36,221	$34,608	$34,539	$30,549
Operating Income	$ 7,081	$15,781	$14,655	$ 1,874
Income (loss) before accounting change	$ (793)	$ 9,061	$ 8,423	$ 372
Cumulative effect of accounting change, net of tax	(884)	--	--	--
Net income (loss)	$(1,677)	$ 9,061	$ 8,423	$ 372
Basic income (loss) per common share:				
Before accounting change	$ (0.03)	$ 0.30	$ 0.28	$ 0.01
Cumulative effect of accounting change, net of tax	(0.04)	--	--	--
After accounting change	$ (0.07)	$ 0.30	$ 0.28	$ 0.01
Diluted income (loss) per common share:				
Before accounting change	$ (0.03)	$ 0.30	$ 0.28	$ 0.01
Cumulative effect of accounting change, net of tax	(0.04)	--	--	--
After accounting change	$ (0.07)	$ 0.30	$ 0.28	$ 0.01
2000				
Revenues	$17,227	$26,593	$31,091	$34,039
Operating Income	$ 4,325	$ 1,378	$ 3,300	$13,659
Net income (loss)	$ 514	$(4,803)	$(4,068)	$ 6,222
Basic income (loss) per common share	$ 0.02	$ (0.21)	$ (0.18)	$ 0.27
Diluted income (loss) per common share	$ 0.02	$ (0.21)	$ (0.18)	$ 0.27

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

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 23, 2002 and is incorporated herein by reference.

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 23, 2002 and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

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 23, 2002 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 23, 2002 and is incorporated herein by reference.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) The following documents are filed as a part of this Report at page 32:

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

The Company filed the following reports on Form 8-K during the quarter ended December 31, 2001 and through March 30, 2002:

On November 16, 2001, the Company filed a report on Form 8-K to disclose the acquisition of oil and natural gas properties located in the Permian Basin of West Texas.

On November 30, 2001, the Company filed a report on Form 8-K to disclose the resignation of Kenneth Hersh from the Board of Directors, effective November 31, 2001, and the election of Jon S. Brumley to the Board, effective November 31, 2001.

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(c) Exhibits

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

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)
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)
10.1*	2000 Incentive Stock Plan (incorporated by reference to the Company's Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001)
10.2	Credit Agreement dated as of May 7, 1999, by and among Encore Operating, L.P., Encore Acquisition Partners, Inc., and a syndicate of banks led by NationsBank, N.A. First Union National Bank and BankBoston, N.A. (incorporated by reference to the Company's registration statement on Form S-1, Registration Statement No. 333-47450, filed on March 8, 2001)
10.3	Letter Agreement effective as of August 24, 2000, amending the Credit Agreement (incorporated by reference to the Company's registration statement on Form S-1 Registration Statement No. 333-47450, filed on March 8, 2001)
21.1	Subsidiaries of the Company
23.1**	Consent of Arthur Andersen LLP
23.2***	Consent of Miller and Lents, Ltd.

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* Compensatory plan

** Omitted pursuant to rule 437a

*** Amended exhibit filed herewith

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 amended report to be signed on its behalf by the undersigned, thereunto duly authorized, on the fifth day of December, 2002.

ENCORE ACQUISITION COMPANY

By /s/ I. JON BRUMLEY

I. Jon Brumley,
Chairman of the Board, President,
Chief Executive Officer, and Director

Date: December 5, 2002

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 and in the capacities and on the dates indicated.

SIGNATURE	TITLE OR CAPACITY	DAT
/s/ I. JON BRUMLEY I. Jon Brumley	Chairman of the Board, Chief Executive Officer, and Director	December
/s/ JON S. BRUMLEY Jon S. Brumley	President and Director	December
/s/ MORRIS B. SMITH Morris B. Smith	Chief Financial Officer, Treasurer, Executive Vice President, Secretary and Principal Financial Officer	December
/s/ ROBERT C. REEVES Robert C. Reeves	Vice President, Controller, and Principal Accounting Officer	December
/s/ ARNOLD L. CHAVKIN Arnold L. Chavkin	Director	December

/s/ HOWARD H. NEWMAN Howard H. Newman	Director	December
/s/ TED A. GARDNER Ted A. Gardner	Director	December
/s/ TED COLLINS, JR. Ted Collins, Jr.	Director	December
/s/ JAMES A. WINNE, III James A. Winne, III	Director	December

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INDEX TO EXHIBITS

EXHIBIT NUMBER	DESCRIPTION
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