Ytterdahl Niclas
Form 4
February 13, 2012

FORM 4

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

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

OMB APPROVAL	
OMB Number:	3235-0287
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(Print or Type Responses)

1. Name and Address of Reporting Person *
Ytterdahl Niclas

(Last) (First) (Middle)

C/O DOVER CORPORATION, 3005 HIGHLAND PARKWAY, SUITE 200

(Street)

DOWNERS GROVE, IL 60515

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
DOVER Corp [DOV]

3. Date of Earliest Transaction (Month/Day/Year)
02/09/2012

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

_____ Director _____ 10% Owner
__X__ Officer (give title below) _____ Other (specify below)
Senior Vice President

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amoun Underlying Securiti (Instr. 3 and 4)	
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amou or Numb of Sh
Stock Appreciation Right	$ 65.38	02/09/2012		A		15,142		02/09/2015	02/09/2022	Common Stock	15,1
Performance Shares	(1)	02/09/2012		A		1,032		(1)	(1)	Common Stock	1,0 (2

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Ytterdahl Niclas C/O DOVER CORPORATION 3005 HIGHLAND PARKWAY, SUITE 200 DOWNERS GROVE, IL 60515			Senior Vice President	

Signatures

/s/ Niclas Ytterdahl by Greg J. Felten, Attorney-in-fact	02/13/2012
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) Each performance share represents a contingent right to receive shares of Dover common stock, based on Dover's relative total shareholder return versus that of Dover's peer group over the three-year performance period ending 12/31/2014.

(2) Represents target grant amount. The actual number of shares that will be paid in respect of the performance share award may range from 0% to 200% of the target grant.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. 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. 20 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 21 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. 22 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 23 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 24 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. 25 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: PAYMENTS DUE BY PERIOD -- CONTRACTUAL OBLIGATIONS 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. 26 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 NATURAL GAS EQUIV. OIL (PER BBL) (PER MCF) (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 27 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 DAILY FLOOR DAILY CAP DAILY SWAP FLOOR VOLUME PRICE CAP VOLUME PRICE SWAP VOLUME PRICE PERIOD (BBL) (PER BBL) (BBL) (PER BBL) (BBL) (PER BBL) ------ ----------- --------- ---------- --------- ---------- --------- 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 DAILY FLOOR DAILY CAP DAILY SWAP FLOOR VOLUME PRICE CAP VOLUME PRICE SWAP VOLUME PRICE (MCF) (PER MCF) (MCF) (PER MCF) (MCF) (PER MCF) ------------ --------- ---------- --------- ---------- --------- 2002.......................... 5,000 $ 3.13 2,500 $ 8.05 5,000 $ 2.83 2003.......................... -- $ -- -- $ -- 2,500 $ 3.69 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: FAIR MARKET NOTIONAL VALUE AT SWAP AMOUNT LIBOR DECEMBER 31, 2001 (IN THOUSANDS) START DATE END DATE SWAP RATE (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 28 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. 29 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. 30 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. 31 ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA PAGE ---- 32 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. 33 ENCORE ACQUISITION COMPANY CONSOLIDATED BALANCE SHEETS DECEMBER 31, -------------------- 2001 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. 34 ENCORE ACQUISITION COMPANY CONSOLIDATED STATEMENTS OF OPERATIONS YEAR ENDED DECEMBER 31, ------------------------------------ 2001 2000 1999 ---------- ---------- ---------- (IN THOUSANDS EXCEPT PER SHARE DATA) Revenues: Oil... $105,768 $ 92,441 $30,454 Natural gas... 30,149 16,509 810 -------- -------- ------- Total revenues..................................... 135,917 108,950 31,264 Expenses: Production -- Direct lifting costs.................................... 25,139 18,669 8,408 Production, ad valorem, and severance taxes.............. 13,809 15,159 5,427 General and administrative (excluding non-cash stock based compensation)... 5,053 4,345 4,047 Non-cash stock based compensation.......................... 9,587 26,012 -- Depletion, depreciation, and amortization.................. 31,721 22,103 5,283 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 23,165 -------- -------- ------- Operating income.. 39,391 22,662 8,099 Other income (expenses): Interest.. (6,041) (10,490) (4,037) Other... 46 512 202 -------- -------- ------- Total other income (expenses)....................... (5,995) (9,978) (3,835) Income before income taxes................................ 33,396 12,684 4,264 Provision for income taxes (current)....................... (1,919) (7,272) -- Provision for income taxes (deferred)...................... (14,414) (7,547) (1,259) -------- -------- ------- Income (loss) before accounting change..................... 17,063 (2,135) 3,005 Cumulative effect of accounting change (net of income taxes of $541).. (884) -- -- -------- -------- ------- Net income (loss)................................... $ 16,179 $ (2,135) $ 3,005 ======== ======== ======= Income (loss) per common share before accounting change: Basic.. $ 0.59 $ (0.09) $ 0.13 Diluted.. 0.59 (0.09) 0.13 Income (loss) per common share after accounting change: Basic.. $ 0.56 $ (0.09) $ 0.13 Diluted.. 0.56 (0.09) 0.13 Weighted average common shares outstanding: Basic.. 28,718 22,806 22,687 Diluted.. 28,723 22,806 22,687 The accompanying notes are an integral part of these consolidated financial statements. 35 ENCORE ACQUISITION COMPANY CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY NOTES RETAINED CLASS A CLASS B RECEIVABLE EARNINGS COMMON COMMON COMMON PAID-IN OFFICERS/ (DEFICIT) STOCK STOCK STOCK CAPITAL 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 $ -- ======= ==== ==== ==== ======== ==== ACCUMULATED OTHER TREASURY COMPREHENSIVE STOCKHOLDERS' STOCK INCOME 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. 36 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. 37 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. 38 ENCORE ACQUISITION COMPANY NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED) 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. 39 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 40 ENCORE ACQUISITION COMPANY NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED) 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 41 ENCORE ACQUISITION COMPANY NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED) 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 42 ENCORE ACQUISITION COMPANY NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED) 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. 43 ENCORE ACQUISITION COMPANY NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED) 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 ======= ======= ====== 44 ENCORE ACQUISITION COMPANY NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED) 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. 45 ENCORE ACQUISITION COMPANY NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED) 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 46 ENCORE ACQUISITION COMPANY NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED) 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 ======= ======= ======= 47 ENCORE ACQUISITION COMPANY NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED) 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: WEIGHTED NUMBER OF AVERAGE OPTIONS 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 48 ENCORE ACQUISITION COMPANY NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED) 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 FAIR BOOK FAIR VALUE VALUE VALUE 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. 49 ENCORE ACQUISITION COMPANY NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED) The following tables summarize our open hedging positions as of December 31, 2001: OIL HEDGES AT DECEMBER 31, 2001 DAILY FLOOR DAILY CAP DAILY SWAP FLOOR VOLUME PRICE CAP VOLUME PRICE SWAP VOLUME PRICE PERIOD (BBL) (PER BBL) (BBL) (PER BBL) (BBL) (PER BBL) ------ ------------ --------- ---------- --------- ----------- --------- 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 DAILY FLOOR DAILY CAP DAILY SWAP FLOOR VOLUME PRICE CAP VOLUME PRICE SWAP VOLUME PRICE PERIOD (MCF) (PER MCF) (MCF) (PER MCF) (MCF) (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: FAIR MARKET NOTIONAL LIBOR VALUE AT SWAP AMOUNT START DATE END DATE SWAP RATE 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 50 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. 51 ENCORE ACQUISITION COMPANY NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED) 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. 52 ENCORE ACQUISITION COMPANY NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED) 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. 53 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: NATURAL OIL OIL GAS EQUIVALENT (MBBL) (MMCF) (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 54 ENCORE ACQUISITION COMPANY NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED) The change in proved reserves were as follows for the years ended: NATURAL OIL OIL GAS EQUIVALENT (MBBL) (MMCF) (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 ========== =========== ========== 55 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 ========= ======== ======== 56 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 57 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: Report of Independent Public Accountant.................... 33 Consolidated Balance Sheets as of December 31, 2001 and 2000.. 34 Consolidated Statements of Operations for the Years Ended December 31, 2001, 2000 and 1999........................... 35 Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2001, 2000, and 1999.............. 36 Consolidated Statements of Cash Flows for the Years Ended December 31, 2001, 2000 and 1999........................... 37 Notes to Consolidated Financial Statements................. 38 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. 58 (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. 99.1 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. 99.2 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. --------------- * 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. 59 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 sixth 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 6, 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 DATE --------- ---------------- ---- /s/ I. JON BRUMLEY Chairman of the Board, Chief December 6, 2002 --- Executive Officer, and Director I. Jon Brumley /s/ JON S. BRUMLEY President and Director December 6, 2002 --- Jon S. Brumley /s/ MORRIS B. SMITH Chief Financial Officer, December 6, 2002 --- Treasurer, Executive Vice Morris B. Smith President, Secretary and Principal Financial Officer /s/ ROBERT C. REEVES Vice President, Controller, and December 6, 2002 --- Principal Accounting Officer Robert C. Reeves /s/ ARNOLD L. CHAVKIN Director December 6, 2002 --- Arnold L. Chavkin /s/ HOWARD H. NEWMAN Director December 6, 2002 --- Howard H. Newman /s/ TED A. GARDNER Director December 6, 2002 --- Ted A. Gardner /s/ TED COLLINS, JR. Director December 6, 2002 --- Ted Collins, Jr. /s/ JAMES A. WINNE, III Director December 6, 2002 --- James A. Winne, III 60 CERTIFICATIONS I, I. Jon Brumley, certify that: 1. I have reviewed this annual report on Form 10-K/A of Encore Acquisition Company (the "Company"): 2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of circumstances under which such statements were made, not misleading with respect to the period covered by this annual report; 3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this annual report; 4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the Company and we have: a) designed such disclosure controls and procedures to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared; b) evaluated the effectiveness of the Company's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date; 5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation, to the Company's auditors and the audit committee of the Company's board of directors (or persons performing the equivalent function): a) all significant deficiencies in the design or operation of internal controls which could adversely affect the Company's ability to record, process, summarize and report financial data and have identified for the Company's auditors any material weaknesses in internal controls; and b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls; and 6. The Company's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses. Date: December 6, 2002 By: /s/ I. Jon Brumley ------------------------------------- I. Jon Brumley Chairman and Chief Executive Officer 61 I, Morris B. Smith, certify that: 1. I have reviewed this annual report on Form 10-K/A of Encore Acquisition Company (the "Company"): 2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of circumstances under which such statements were made, not misleading with respect to the period covered by this annual report; 3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this annual report; 4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the Company and we have: a) designed such disclosure controls and procedures to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared; b) evaluated the effectiveness of the Company's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date; 5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation, to the Company's auditors and the audit committee of the Company's board of directors (or persons performing the equivalent function): a) all significant deficiencies in the design or operation of internal controls which could adversely affect the Company's ability to record, process, summarize and report financial data and have identified for the Company's auditors any material weaknesses in internal controls; and b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls; and 6. The Company's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses. Date: December 6, 2002 By: /s/ Morris B. Smith ------------------------------------ Morris B. Smith Chief Financial Officer, Treasurer, Executive Vice President and Principal Financial Officer 62 INDEX TO EXHIBITS EXHIBIT NUMBER 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. 99.1 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. 99.2 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. --------------- * 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. 63