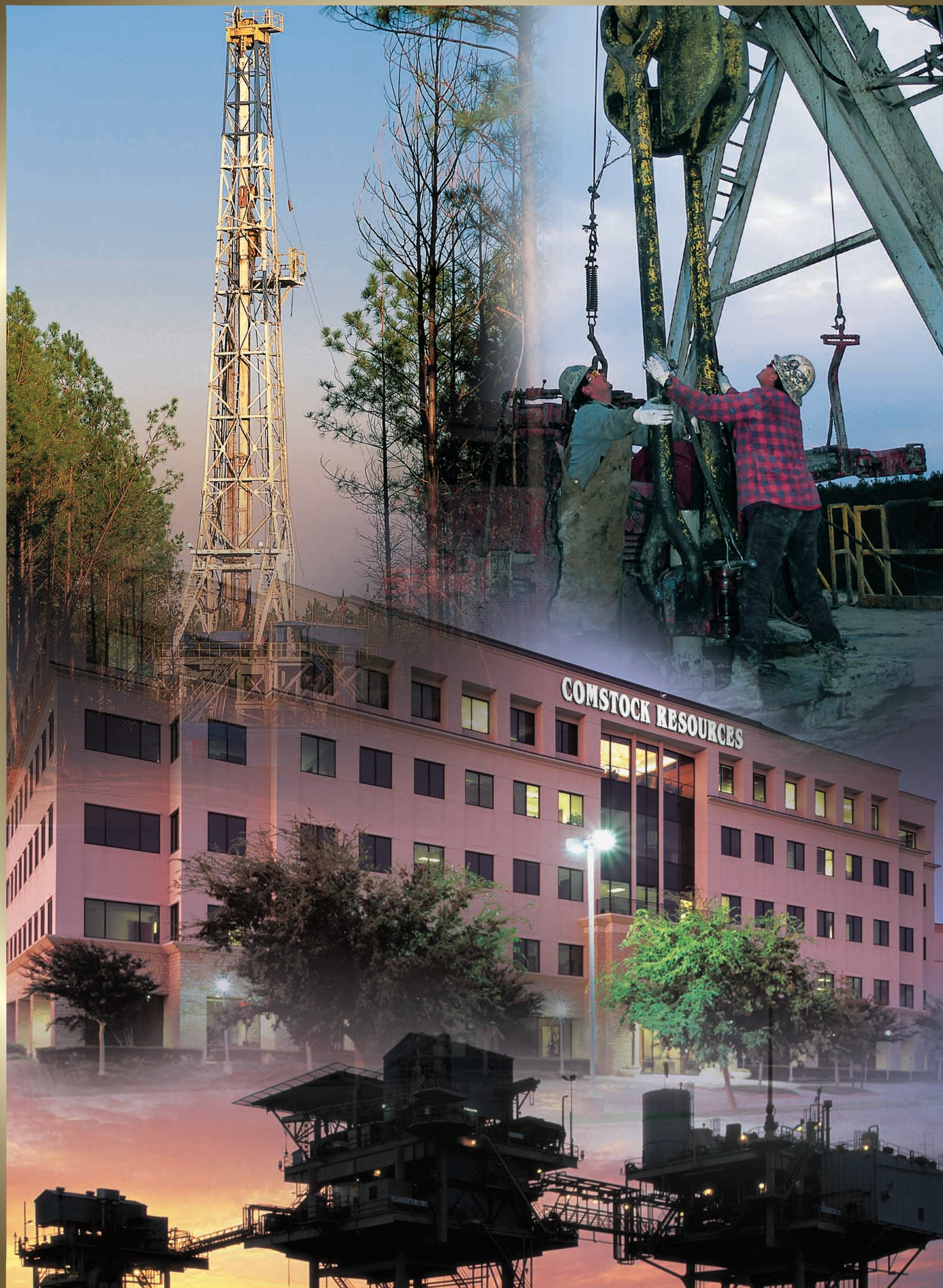
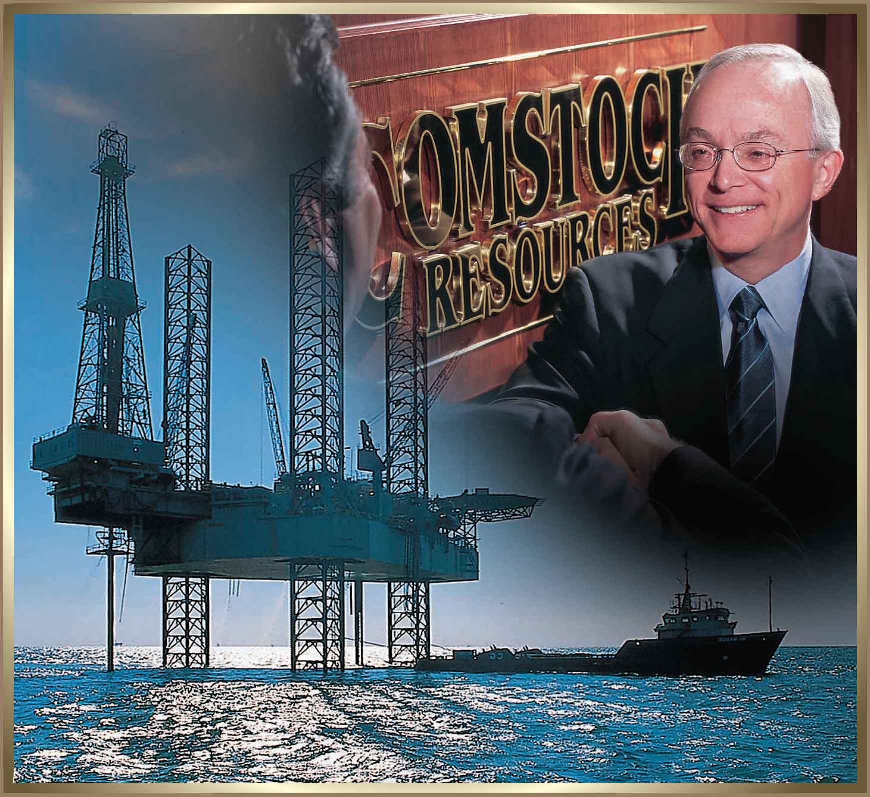


COMSTOCK RESOURCES ANNUAL REPORT

Region	2003 Reserves (Bcfe)		2003 Production (Bcfe)	
Gulf of Mexico	216.1	35%	14.9	34%
East Texas / North Louisiana	174.7	28%	11.2	26%
Southeast Texas	127.0	21%	12.0	27%
South Texas	47.1	8%	3.6	8%
Other Regions	52.0	8%	2.3	5%
	616.9		44.0	

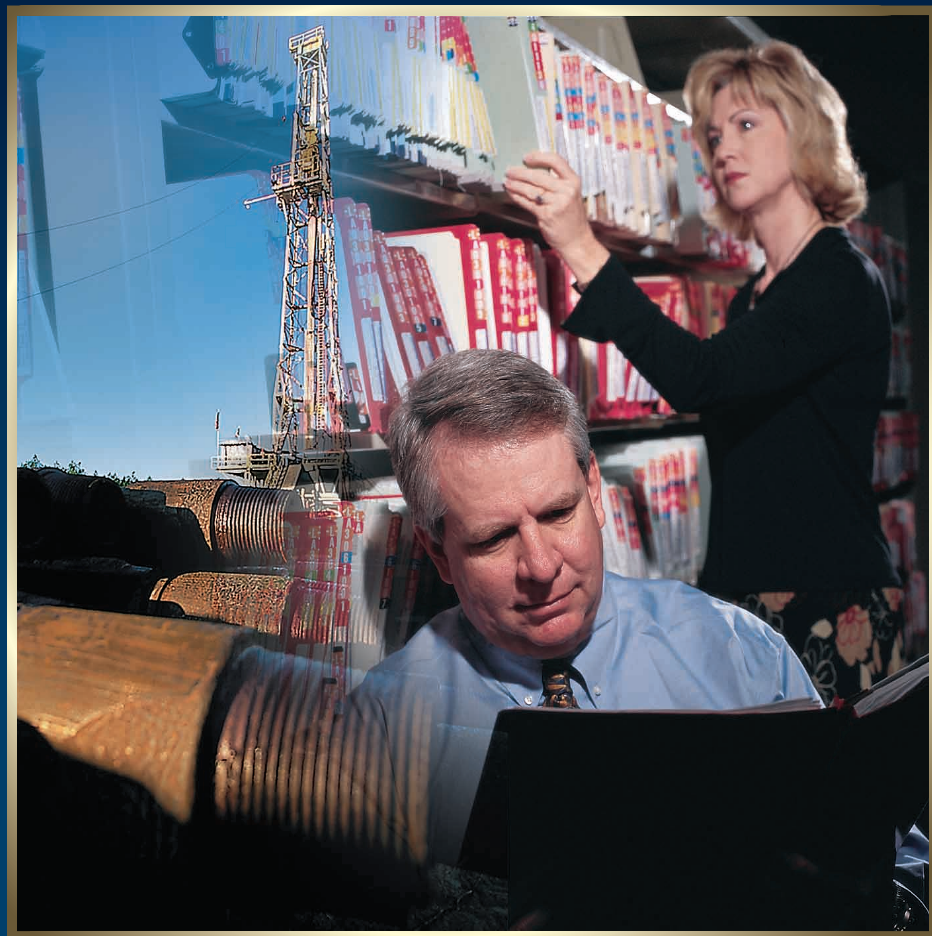
Comstock Resources, Inc. is a growing independent energy company engaged in the acquisition, development, production and exploration of oil and natural gas properties. Our operations are primarily focused in Texas, Louisiana and the Gulf of Mexico.



(in thousands except per share data)	1999	2000	2001	2002	2003
Financial Highlights					
Oil and gas sales	$ 88,833	$168,084	$166,118	$142,085	$235,102
Net income (loss) (a)	$ (3,283)	$ 40,973	$ 34,506	$ 12,577	$ 53,267
Per common share (a)	(21¢)	$ 1.20	$ 1.00	37¢	$ 1.51
Cash flow from operations	$ 42,371	$111,814	$107,698	$ 79,316	$151,955
Total assets	$433,956	$489,082	$680,769	$711,053	$760,956
Total debt	$254,131	$234,101	$372,464	$366,272	$306,623
Stockholders' equity	$106,512	$161,375	$195,668	$208,427	$289,656

(a) From continuing operations and before cumulative effect of accounting change in accounting principle.

Operational Highlights	1999	2000	2001	2002	2003
Capital expenditures	$ 34,981	$ 83,911	$252,551	$ 83,381	$ 92,930
Net producing wells	274.0	271.9	453.5	485.0	502.0
Natural gas production (MMcf per day)	64.6	73.4	76.3	90.9	94.0
Oil production (Barrels per day)	5,745	4,907	4,137	3,570	4,424
Proved gas reserves (MMcf)	258,121	297,835	462,085	488,784	501,778
Proved oil reserves (MBbls)	19,467	17,451	17,348	20,849	19,189



Oil and Gas Sales
$ in millions

Cash Flow from Operations
$ in millions

Earnings
$ in millons

TO OUR STOCKHOLDERS:

We reported the highest net income of any year in our corporate history in 2003.

Comstock had an outstanding year in 2003. We were able to set new corporate high records in 2003 for revenues, net income, cash flow and production. Our revenues soared to $235 million and our production reached 44 billion cubic feet equivalent of natural gas ("Bcfe"). We made a profit of $53 million and generated operating cash flow of $152 million. Strong natural gas prices and our successful exploration program were the primary drivers of our successful year in 2003. Our drilling program allowed us to increase our production and grow our oil and natural gas reserve base in 2003. We drilled 53 wells and achieved an 85% overall success rate with 45 of the wells drilled in 2003 being successful. Our 2003 drilling program combined with our acquisition activities replaced 108% of our 2003 production and increased our proved oil and natural gas reserves by 3%. In addition to achieving this growth in 2003, we were also able to greatly improve our balance sheet. We paid down $60 million of our long-term debt with our free cash flow and lowered our debt to total capitalization from 62% at the end of 2002 to 51% at the end of 2003.

FINANCIAL RESULTS

Our financial results exemplified the successful year we had in 2003. Strong natural gas prices and higher oil and natural gas production resulting from our successful drilling activities, combined to deliver exceptional financial results. In 2003, our oil and gas sales totaled $235 million, a new corporate high and an increase of 65% over 2002's sales of $142 million. We generated operating cash flow of $152 million in 2003, another corporate high record and a 92% increase from cash flow of $79 million for 2002. We reported the highest net income of any year in our corporate history in 2003 with a profit of $53 million. This

compares to an $11 million profit from continuing operations in 2002. For 2003, our earnings per share were $1.51 as compared to 37¢ per share in 2002. Our oil and natural gas production increased by 7% in 2003 to 44 Bcfe of natural gas, as compared to 2002's production of 41 Bcfe. Our average oil price in 2003 was $30.70 per barrel, a 23% increase from 2002's average oil price of $24.95 per barrel. The higher natural gas prices in 2003 were the major factors leading to the record revenues and profits. We averaged $5.41 per thousand cubic feet ("Mcf") for our natural gas production in 2003, a 64% increase from our average natural gas price of $3.30 per Mcf in 2002. Our costs were also up in 2003 from 2002. Our oil and gas operating costs per unit of production increased to $1.04 per thousand cubic feet equivalent of natural gas ("Mcfe") produced as compared to 82¢ in 2002. Higher severance and ad valorem taxes resulting from the higher oil and natural gas prices combined with higher fixed operating costs in the Gulf of Mexico account for the increase. Our general and administrative costs

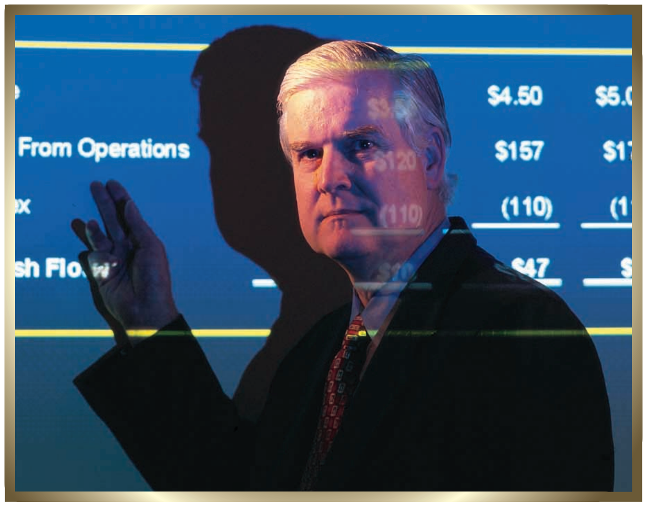

Total Assets
$ in millions
$680.8
$711.1
$761.0
01
02
03


Total Debt
$ in millions
$372.5
$366.3
$306.6
01
02
03


Stockholders' Equity
$ in millions
$195.7
$208.4
$289.7
01
02
03

During 2003, we were able to reduce our long-term debt by $60 million with our operating cash flow.

per Mcfe produced in 2003 was 16¢, which was 4¢ higher than 2002 costs of 12¢ per Mcfe. Our increased investment in our technical staff including opening an office in Houston to oversee our offshore operations are the reasons for the higher costs. Our depreciation, depletion and amortization per Mcfe produced increased 8¢ in 2003 to $1.37 from $1.29 in 2002. The higher rate results from the increase in production from some of our higher cost properties, especially in the Gulf of Mexico.



BALANCE SHEET

At the beginning of 2003, we stated that one of our goals was to improve our balance sheet. We believe that we made significant progress toward achieving that goal last year. During 2003, we were able to reduce our long-term debt by $60 million with our operating cash flow. We generated $152 million in operating cash flow in 2003 and spent $93 million on capital expenditures. The conversion of our preferred stock also contributed to our improved capital structure. The conversion of the preferred stock increased our equity by $17 million and saves us $1.7 million per year in dividend payments. Our record setting profits of $53 million accounted for the balance of the increase in stockholders' equity, which grew to $290 million at the end of 2003. Debt as a percent of our total book capitalization has fallen from 62% at the end of 2002 to 51%.

DEBT RESTRUCTURING

On February 25, 2004, we completed a series of transactions to restructure our long-term debt to take advantage of the current low interest rate environment. We repurchased 89% of our $11\frac{1}{4}$% bonds through a tender offer. We plan to repurchase the remaining $11\frac{1}{4}$% bonds on May 1, 2004 when the bonds are first callable. We entered into a new four year $400 million bank credit facility with a borrowing base of $300 million. We also closed on the public offering of $6\frac{7}{8}$% bonds which mature in 2012. The restructuring more than doubled the average maturities of our debt from 2.4 years to 5.9 years. More importantly, the restructuring lowered our interest expense by $10.8 million or 36% on a pro forma basis. Also on a pro forma basis, our interest expense per Mcfe produced in 2003 decreased by 25¢ from 68¢ per Mcfe to 43¢ per Mcfe.

DRILLING RESULTS

Our drilling program was the primary contributor to our reserve and production growth in 2003. We had great success with the drill bit in 2003. We spent $63 million to drill 53 wells (35 development wells and 18 exploratory wells). We spent an additional $28 million on acquiring exploratory acreage and seismic data, conducting recompletions and workovers on our existing wells, installing new production facilities for our properties, and to acquire additional interests in the Ship Shoal 113 Unit. Forty-five of the 53 wells drilled in 2003, were completed as producing wells

Development and Exploration Expenditures
$ in millions

Production
million cubic feet equivalent/day

Oil and Natural Gas Reserves
billion cubic feet equivalent

Our drilling program was the primary contributor to our reserve and production growth in 2003.

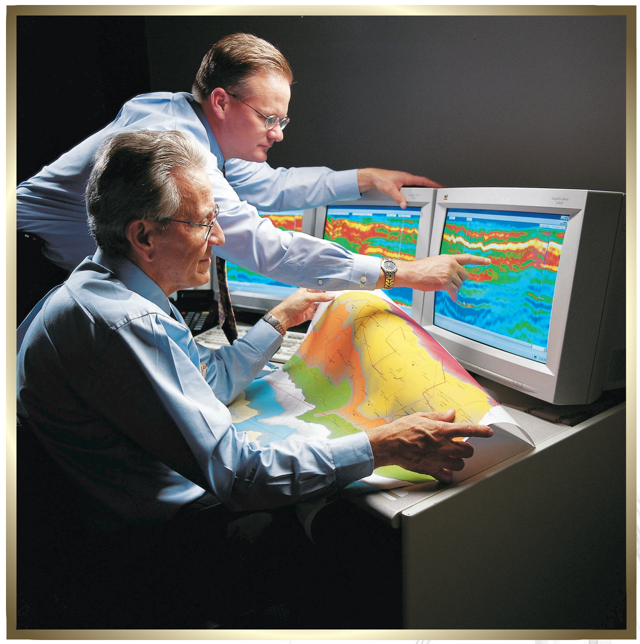
for a drilling success rate of 85%. Of the eighteen exploratory wells drilled last year, fourteen resulted in discoveries for a 78% drilling success rate. The drilling activity in 2003 added 52 Bcfe of new proved oil and natural gas reserves.

EAST TEXAS / NORTH LOUISIANA REGION

At the end of 2003, we had 175 Bcfe of our reserves (28%) in our East Texas / North Louisiana region. Our production from this region averaged 30.6 million cubic feet equivalent of natural gas ("Mmcfe") per day in 2003, which was 25% of our total production. Due to our limited reinvestment in this region in 2003, our production declined 11% from 2002's average production rate of 34.2 MMcfe per day. We spent $6 million in this region and drilled five wells in 2003. Four of these wells were successful development wells and one was an unsuccessful exploratory test drilled in North Louisiana. The successful wells have been tested at a per well average rate of 1.7 MMcfe per day. We have similar plans for this region in 2004 and have budgeted to spend $7 million this year to drill six development wells.

SOUTHEAST TEXAS REGION

In our Southeast Texas region we have 127 Bcfe of our reserves which is 21% of our total reserves. This region accounts for 27% of our daily production at 32.8 MMcfe per day which has increased 11% from 2002's production of 29.5 MMcfe per day. We drilled three wells in 2003 to continue to delineate our Hamman discovery which was made in 2002. The Collins #2 well and the Hamman #3 well were successful, while the Hamman #2 is not expected to be commercial. The successful wells have been tested at a per well average rate of 6.9 MMcfe per day. We are in the



process of obtaining 75 square miles of 3-D seismic over our Ross and Robin prospect areas. We have budgeted to spend $20 million in this region in 2004 to drill six wells including a well to test our high impact Robin prospect.

SOUTH TEXAS REGION

We have 47 Bcfe of our reserves (8%) in our South Texas region and about 8% of our production or 9.9 MMcfe per day. Production from this region is up 41% from 2002's production which averaged 7.0 MMcfe per day. In 2003, we spent $15 million for drilling in our South Texas region and had good results. We drilled 13 wells. Nine of the 13 wells were successful and were tested at an average per well rate of 7.4 MMcfe per day. In 2004, we have budgeted $15 million in South Texas to drill 15 wells. We will continue to develop the Ball Ranch and test several of our 3 D seismic defined exploration prospects in this region.

Our recently completed debt restructuring will substantially reduce our future interest expense and make us more profitable.

GULF OF MEXICO REGION

We have 216 Bcfe of our reserves (35%) in the state and federal waters in the Gulf of Mexico. This region accounts for 34% of our daily production at 40.7 MMcfe per day which is up 21% over 2002's production of 33.6 MMcfe per day. We spent a total of $60 million last year in our Gulf of Mexico drilling program. All of the wells we drilled were successful. Only five of these wells have been completed and were tested at an average per well of 5.6 MMcfe per day. We were able to extend our successful exploration program in 2003 with three deeper Gulf of Mexico shelf wells drilled at South Pelto Blocks 22 and 25. At this time we have 19 wells in the Gulf of Mexico that are awaiting completion or connection to production facilities. We believe that these wells will add almost 39 MMcfe to our net daily production level. We expect most of this production to be online in the second and third quarters of 2004. For 2004, we have budgeted $67 million to drill 24 wells in the Gulf of Mexico including five deeper shelf wells.

OUTLOOK FOR 2004

We have budgeted to spend $110 million for development and exploration activities in 2004. We plan to drill 28 development wells and 33 exploratory wells for a total of 61 wells. Exploration related projects will represent approximately two-thirds of the total amount budgeted in 2004. Our exploration program will revolve around our extensive inventory of drilling prospects in our Gulf of Mexico, Southeast Texas and South Texas regions. We expect our production to continue to increase in 2004 as we are able to connect to sales the offshore discoveries that we have made in 2003. These projects are expected to come on line at various times in 2004 and should have a significant impact

on our production starting in the second quarter. Our recently completed debt restructuring will substantially reduce our future interest expense and make us more profitable. And lastly, with continued strong natural gas prices into 2004, we should be able to continue to generate substantial cash flow in excess of our capital expenditures which will allow us to pay down more of our debt and continue to improve our balance sheet.

The directors and management of Comstock want to thank our stockholders for their continued support.

M. Jay Allison
Chairman and President

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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2003

or

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

Commission file no. 0-16741

Comstock Resources, Inc.

(Exact name of registrant as specified in its charter)

NEVADA	**94-1667468**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification Number)*

5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034
(Address of principal executive offices including zip code)

(972) 668-8800
(Registrant's telephone number and area code)

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

Common Stock, $.50 Par Value	**New York Stock Exchange**
Preferred Stock Purchase Rights	**New York Stock Exchange**
(Title of class)	*(Name of exchange on which registered)*

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes ☑ No ☐

As of March 12, 2004, there were 34,678,862 shares of common stock outstanding.

The aggregate market value of the voting common equity held by non-affiliates of the Registrant computed by reference to the price at which the common equity was last sold as of the last business day of the Registrant's most recently completed second fiscal quarter was $449,953,613.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy statement for the 2004 annual meeting of stockholders — Part III

COMSTOCK RESOURCES, INC.

ANNUAL REPORT ON FORM 10-K
For the Fiscal Year Ended December 31, 2003

CONTENTS

FORWARD-LOOKING STATEMENTS

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included in this report, including without limitation, statements under "Business and Properties" and "Management's Discussion and Analysis of Financial Condition and Results of Operations' regarding budgeted capital expenditures, increases in oil and natural gas production, our financial position, oil and natural gas reserve estimates, business strategy and other plans and objectives for future operations, are forward-looking statements. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. Furthermore, the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates made by different engineers often vary from one another. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revisions of such estimate and such revision, if significant, would change the schedule of any further production and development drilling. Accordingly, reserve estimates are generally different from the quantities of oil and gas that are ultimately recovered. Should one or more of these risks or uncertainties occur, or should underlying assumptions prove incorrect, our actual results and plans for 2004 and beyond could differ materially from those expressed in forward-looking statements. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by such factors.

DEFINITIONS

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and this report. Natural gas equivalents and crude oil equivalents are determined using the ratio of six Mcf to one barrel. All references to "us," "our," "we" or "Comstock" mean the registrant, Comstock Resources, Inc. and where applicable, its consolidated subsidiaries.

"Bbl" means a barrel of 42 U.S. gallons of oil.

"Bcf" means one billion cubic feet of natural gas.

"Bcfe" means one billion cubic feet of natural gas equivalent.

"Btu" means British thermal unit, which is the quantity of heat required to raise the temperature of one pound of water from 58.5 to 59.5 degrees Fahrenheit.

"Cash Margin per Mcfe" means the equivalent price per Mcfe less oil and gas operating expenses per Mcfe and general and administrative expenses per Mcfe.

"Completion" means the installation of permanent equipment for the production of oil or gas.

"Condensate" means a hydrocarbon mixture that becomes liquid and separates from natural gas when the gas is produced and is similar to crude oil.

"Development well" means a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

"Dry hole" means a well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"Exploratory well" means a well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new productive reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

"Gross" when used with respect to acres or wells, production or reserves refers to the total acres or wells in which we or another specified person has a working interest.

"MBbls" means one thousand barrels of oil.

"MBbls/d" means one thousand barrels of oil per day.

"Mcf" means one thousand cubic feet of natural gas.

"Mcfe" means thousand cubic feet of natural gas equivalent.

"MMBbls" means one million barrels of oil.

"MMcf" means one million cubic feet of natural gas.

"MMcf/d" means one million cubic feet of natural gas per day.

"MMcfe/d" means one million cubic feet of natural gas equivalent per day.

"MMcfe" means one million cubic feet of natural gas equivalent.

"Net" when used with respect to acres or wells, refers to gross acres of wells multiplied, in each case, by the percentage working interest owned by us.

"Net production" means production we own less royalties and production due others.

"Oil" means crude oil or condensate.

"Operator" means the individual or company responsible for the exploration, development, and production of an oil or gas well or lease.

"Present Value of Proved Reserves" means the present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with the Securities and Exchange Commission guidelines, 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 non-property related expenses such as general and administrative expenses, debt service, future income tax expense and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

"Proved developed reserves" means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery will be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

"Proved reserves" means the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

"Proved undeveloped reserves" means 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. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

"Recompletion" means the completion for production of an existing well bore in another formation from which the well has been previously completed.

"Reserve life" means the calculation derived by dividing year-end reserves by total production in that year.

"Reserve replacement" means the calculation derived by dividing additions to reserves from acquisitions, extensions, discoveries and revisions of previous estimates in a year by total production in that year.

"Royalty" means an interest in an oil and 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 generally 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.

"3-D seismic" means an advanced technology method of detecting accumulations of hydrocarbons identified by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

"Working interest" means an interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to the owners of royalties. For example, the owner of a 100% working interest in a lease burdened only by a landowner's royalty of 12.5% would be required to pay 100% of the costs of a well but would be entitled to retain 87.5% of the production.

"Workover" means operations on a producing well to restore or increase production.

PART I

Items 1. and 2. *Business and Properties*

We are an independent energy company engaged in the acquisition, development, production and exploration of oil and natural gas properties. Our oil and natural gas operations are concentrated in the Gulf of Mexico, East Texas/North Louisiana, Southeast Texas and South Texas regions. In addition, we have properties in the Illinois Basin region in Kentucky and in the Mid-Continent regions located in the Texas panhandle, Oklahoma and Kansas. Our oil and natural gas properties are estimated to have proved reserves of 616.9 Bcfe with an estimated Present Value of Proved Reserves of $1.7 billion as of December 31, 2003. Our proved oil and natural gas reserve base is 81% natural gas and 67% proved developed on a Bcfe basis as of December 31, 2003. We replaced 108% of our production of 44.0 Bcfe in 2003 through our exploration, development and acquisition activities. We were also able to reduce our long-term debt by $60.0 million from $366.0 million as of December 31, 2002 to $306.0 million as of December 31, 2003.

Our proved reserves at December 31, 2003 and our 2003 average daily production are summarized below:

	Reserves at December 31, 2003				2003 Daily Production			
	Oil (MMBbls)	Gas (Bcf)	Total (Bcfe)	% of Total	Oil (MBbls/d)	Gas (MMcf/d)	Total (MMcfe/d)	% of Total
Gulf of Mexico	14.7	127.7	216.1	35.0	3.2	21.8	40.7	33.8
East Texas/North Louisiana	0.9	169.3	174.7	28.3	0.2	29.2	30.6	25.4
Southeast Texas	2.9	109.8	127.0	20.6	0.7	28.4	32.8	27.2
South Texas	0.4	44.8	47.1	7.6	0.1	9.0	9.9	8.2
Other Regions	0.3	50.2	52.0	8.5	0.2	5.6	6.6	5.4
Total	19.2	501.8	616.9	100.0	4.4	94.0	120.6	100.0

Strengths

High Quality Properties. Our operations are focused in four geographically concentrated areas, the Gulf of Mexico, East Texas/North Louisiana, Southeast Texas and South Texas regions, which account for approximately 35%, 28%, 21% and 8% of our proved reserves, respectively. We have high price realizations relative to benchmark prices for natural gas and crude oil production. We also have favorable operating costs which results in us having high cash margins. Finally, our properties have an average reserve life of approximately 14 years and have extensive development and exploration potential.

Successful Exploration and Development Program. In 2003, we spent $46.8 million on the exploitation and development of our oil and natural gas properties for development drilling, recompletions, workovers, abandonment and production facilities. Overall, we drilled 35 development wells, 22.0 net to us, with a 89% success rate. We also had a successful exploratory drilling program in 2003, spending a total of $34.8 million to drill 18 wells, 7.4 net to us, with a 78% success rate. We spent an additional $5.1 million in acquiring new acreage and seismic data in 2003 to support our exploration program.

Successful Acquisitions. We have had significant growth over the years as a result of acquisitions. Since 1991, we have added 725.9 Bcfe of proved oil and natural gas reserves from 30 acquisitions at an average cost of $0.83 per Mcfe. Our application of strict economic and reserve risk criteria have enabled us to successfully evaluate and integrate acquisitions.

Efficient Operator. We operate 61% of our proved oil and natural gas reserve base as of December 31, 2003. This allows us to control operating costs, the timing and plans for future development, the level of drilling and lifting costs and the marketing of production. As an operator, we receive reimbursements for overhead from other working interest owners, which reduces our general and administrative expenses.

High Price Realizations. The majority of our wells are located in areas which can access attractive natural gas and crude oil markets. In addition, our natural gas production has a relatively high Btu content of approximately 1.07 Btu. Our crude oil production has a favorable API gravity of approximately 40 degrees.

Due to these factors, we have relatively high price realizations compared to benchmark prices. In 2003, our average natural gas price was $5.41 per Mcf, which represented a $0.02 premium to the 2003 NYMEX average monthly settlement price. Also in 2003, our average crude oil price was $30.70 per barrel, which represented a $1.69 barrel premium to the average monthly West Texas Intermediate crude oil price for 2003 posted by Koch Industries, Inc.

High Cash Margins. As a result of our quality properties, higher price realizations and efficient operations, we have higher cash margins than most of our competitors. Consequently, our oil and natural gas reserves have a higher value per Mcfe than reserves that generate lower cash margins.

Business Strategy

Exploit Existing Reserves. We seek to maximize the value of our oil and natural gas properties by increasing production and recoverable reserves through active workover, recompletion and exploitation activities. We utilize advanced industry technology, including 3-D seismic data, improved logging tools, and formation stimulation techniques. During 2003, we spent approximately $28.3 million to drill 35 development wells, 22.0 net to us, of which 31 wells, 19.2 net to us, were successful, representing a success rate of 89 %. In addition, we spent approximately $18.5 million for new production facilities, leasehold costs and for recompletion, abandonment and workover activities. For 2004, we have budgeted $37.0 million for development drilling and for recompletion, abandonment and workover activities.

Pursue Exploration Opportunities. We conduct exploration activities to grow our reserve base and to replace our production each year. In 2003, we spent approximately $34.8 million to drill 18 exploratory wells, 7.4 net to us, of which 14 wells, 5.3 net to us, were successful, representing a success rate of 78%. We also spent $5.1 million in acquiring new acreage and seismic data in 2003 to support our exploration program. We have budgeted $73.0 million in 2004 for exploration activities which will be focused primarily in the Gulf of Mexico, Southeast Texas and South Texas regions.

Maintain Low Cost Structure. We seek to increase cash flow by carefully controlling operating costs and general and administrative expenses. Our average oil and gas operating costs per Mcfe were $1.04 in 2003 and our general and administrative expenses per Mcfe averaged only $0.16 in 2003.

Acquire High Quality Properties at Attractive Costs. We have a successful track record of increasing our oil and natural gas reserves through opportunistic acquisitions. Since 1991, we have added 725.9 Bcfe of proved oil and natural gas reserves from 30 acquisitions at a total cost of $603.1 million, or $0.83 per Mcfe. The acquisitions were acquired at an average of 60% of their Present Value of Proved Reserves in the year the acquisitions were completed. We apply strict economic and reserve risk criteria in evaluating acquisitions. We target properties in our core operating areas with established production and low operating costs that also have potential opportunities to increase production and reserves through exploration and exploitation activities.

Maintain Flexible Capital Expenditure Budget. The timing of most of our capital expenditures is discretionary because we have not made any significant long-term capital expenditure commitments. Consequently, we have a significant degree of flexibility to adjust the level of such expenditures according to market conditions. We anticipate spending approximately $110.0 million on development and exploration projects in 2004. We intend to primarily use operating cash flow to fund our drilling expenditures in 2004. We may also make additional property acquisitions in 2004 that would require additional sources of funding. Such sources may include borrowings under our bank credit facility or sales of our equity or debt securities.

Primary Operating Areas

Our activities are concentrated in four primary operating areas: Gulf of Mexico, East Texas/North Louisiana, Southeast Texas and South Texas. The following table summarizes the estimated proved oil and natural gas reserves for our 20 largest fields as of December 31, 2003:

	Net Oil (MBbls)	Net Gas (MMcf)	MMcfe	%	Present Value of Proved Reserves (In thousands)	%
Gulf of Mexico						
Ship Shoal	8,550	53,604	104,903		$ 326,843	
South Timbalier/South Pelto	3,517	58,822	79,925		298,024	
Main Pass	1,531	1,556	10,739		27,560	
Vermilion/South Marsh Island	—	9,354	9,354		40,623	
East White Point	693	1,560	5,717		12,585	
Other	444	2,756	5,423		16,168	
	14,735	127,652	216,061	35.0	721,803	42.2
East Texas/North Louisiana						
Gilmer	232	53,734	55,125		132,524	
Beckville	110	44,357	45,014		101,395	
Logansport	37	16,885	17,105		47,469	
Waskom	196	12,181	13,356		33,234	
Blocker	36	10,215	10,431		21,911	
Longwood	84	7,016	7,521		22,424	
Box Church	3	6,064	6,079		14,686	
Lisbon	51	4,205	4,508		13,703	
Other	150	14,630	15,532		40,319	
	899	169,287	174,671	28.3	427,665	25.0
Southeast Texas						
Double A Wells	2,674	100,848	116,894		318,778	
Sugar Creek	85	8,150	8,659		18,474	
Other	120	764	1,482		4,500	
	2,879	109,762	127,035	20.6	341,752	20.0
South Texas						
J. C. Martin	—	16,148	16,148		40,999	
North Markham	178	12,506	13,573		41,065	
Lopeno	15	4,591	4,683		9,143	
Other	198	11,541	12,728		31,758	
	391	44,786	47,132	7.6	122,965	7.2
Illinois Basin						
New Albany Shale Gas	—	32,029	32,029	5.2	48,749	2.9
Mid-Continent						
Glick	8	5,079	5,128		11,039	
Other	98	10,642	11,230		27,159	
	106	15,721	16,358	2.7	38,198	2.2
Other Areas	179	2,541	3,623	0.6	7,943	0.5
Total	19,189	501,778	616,909	100.0	$1,709,075	100.0

Gulf of Mexico

Our Gulf of Mexico operating region includes properties located offshore of Louisiana and Texas, in state and federal waters of the Gulf of Mexico. We own interests in 98 producing wells, 50.1 net to us, in ten field areas, the largest of which are the Ship Shoal area (Ship Shoal Blocks 66, 67, 68, 69, 92, 93, 99, 107, 109, 110, 112, 113, 114, 117, 118, 119, 120, 135 and 146 and South Pelto Block 1), the South Timbalier/South Pelto area (South Timbalier Blocks 9, 11, 15, 16, 30, 34, 50, 52 and South Pelto Blocks 5, 15, 22 and 25) and the Main Pass Area (Main Pass Blocks 21,41,43, 55 and 58). In addition, we have 13 wells, 5.3 net to us, that have been drilled and are awaiting connection to production facilities in the Gulf of Mexico. We have 216.1 Bcfe of oil and natural gas reserves in the Gulf of Mexico region which represents 35% of our reserve base. We operate 40 of the wells that we own in this region. Production from the region averaged 21.8 MMcf of natural gas per day and 3,151 barrels of oil per day during 2003. We spent $14.2 million in this region in 2003 drilling seven development wells, 3.4 net to us, and $25.8 million drilling eleven exploratory wells, 4.0 net to us. We also spent $14.0 million for production facilities, recompletions, abandonment and workovers and $1.7 million on acquiring exploration acreage and seismic data. In 2004, we plan to spend $67.0 million for development and exploration activities in this region.

Ship Shoal. The Ship Shoal area is located in Louisiana state waters and in federal waters, offshore of Terrebonne Parish. In this area, oil and natural gas are produced from numerous Miocene sands occurring at depths from 5,800 to 13,500 feet, and in water depths from 10 to 60 feet. We own interests in 46 wells in this area, 31.2 net to us, in Ship Shoal Blocks 66, 67, 68, 69, 92, 93, 99, 107, 109, 110, 112, 113, 114, 117, 118, 119, 120, 135 and 146 and in South Pelto Block 1. We operate 32 of these wells. Our properties in the Ship Shoal area have estimated proved reserves of 104.9 Bcfe, which is 17% of our total reserves. Production from the Ship Shoal area net to our interest averaged 8.4 MMcf of natural gas per day and 2,145 barrels of oil per day during 2003. In 2003, we drilled eight wells, 3.9 net to us, at Ship Shoal.

South Timbalier/South Pelto. We own interests in 22 producing wells, 6.7 net to us, in Louisiana state waters and in federal waters in the South Timbalier/South Pelto area located offshore of Terrebonne and Lafourche Parishes in water depths ranging from 20 to 60 feet. We have estimated proved reserves totaling 79.9 Bcfe attributable to this area which is 13% of our total reserves. Production attributable to our interest averaged 11.1 MMcf of natural gas per day and 472 barrels of oil per day in 2003. These wells produce from numerous sands of Pliocene to Upper Miocene age, at depths ranging from 2,000 to 12,000 feet as well as the geopressured Miocene section at depths below 18,000 feet. We drilled six wells, 1.8 net to us, in the South Timbalier/South Pelto area in 2003.

Main Pass. Main Pass Block 21 is located in Louisiana state waters, offshore of Plaquemines Parish in water with a depth of approximately 12 feet. Our wells in this area produce from multiple Miocene sands at depths that range from 4,400 to 7,700 feet. We are the operator and own interests in six wells, 5.6 net to us, at Main Pass Block 21. We also own nonoperated interests in eight producing wells, 1.2 net to us, at Main Pass Blocks 41, 43, 55 and 58 in federal waters with an average depth of 50 feet. Proved reserves for the total Main Pass area were 10.7 Bcfe, which is 2% of our total reserves at December 31, 2003. Production attributable to our interest from the Main Pass Area was approximately 1.0 Mmcf of natural gas per day and 468 barrels of oil per day in 2003.

East Texas/North Louisiana

Approximately 28% or 174.7 Bcfe of our proved reserves are located in East Texas and North Louisiana where we own interests in 422 producing wells, 232.3 net to us, in 21 field areas. We operate 243 of these wells. The largest of our fields in this region are the Gilmer, Beckville, Logansport and Waskom fields. Production from this region averaged 29.2 MMcf of natural gas per day and 237 barrels of oil per day during 2003. Most of the reserves in this area produce from the Cretaceous aged Travis Peak/Hosston formation and the Jurassic aged Cotton Valley formation. The total thickness of these formations range from 2,000 to 4,000 feet of sand, shale and limestone sequences in the East Texas Basin and the North Louisiana Salt Basin, at depths ranging from 6,000 to 12,000 feet. In 2003, we spent $3.6 million drilling five wells, 2.4 net to us, and $1.9 million on workovers and recompletions in this region. We have budgeted approximately $7.0 million in 2004 for development activities in this region.

Gilmer. We own interests in 72 natural gas wells, 27.4 net to us, in the Gilmer field in Upshur County in East Texas. These wells produce primarily from the Cotton Valley Lime formation at a depth of approximately 11,500 to 12,000 feet. Proved reserves attributable to our interests in the Gilmer field are 55.1 Bcfe which represents 9% of our total reserve base. During 2003, production attributable to our interest from this field averaged 9.6 MMcf of natural gas per day and 110 barrels of oil per day.

Beckville. Our properties in the Beckville field, located in Panola and Rusk Counties, Texas, have proved reserves of 45.0 Bcfe which represents approximately 7% of our total reserves. We operate 72 wells in this field and own interests in thee additional wells for a total of 75 wells, 55.3 net to us. During 2003, production attributable to our interest from this field averaged 6.3 MMcf of natural gas per day and eight barrels of oil per day. The Beckville field produces from the Cotton Valley formation at depths ranging from 9,000 to 10,000 feet.

Logansport. The Logansport field produces from multiple sands in the Hosston formation at an average depth of 8,000 feet and is located in DeSoto Parish, Louisiana. Our proved reserves of 17.1 Bcfe in the Logansport field represent approximately 3% of our total reserves. We own interests in 81 wells, 40.2 net to us, and operate 50 of these wells. During 2003, net daily production attributable to our interest from this field averaged 3.1 MMcf of natural gas and twelve barrels of oil.

Waskom. The Waskom field, located in Harrison and Panola Counties in Texas, represents approximately 2% (13.4 Bcfe) of our proved reserves as of December 31, 2003. We own interests in 52 wells in this field, 26.0 net to us, and operate 28 wells in this field. During 2003, net daily production attributable to our interest averaged 0.9 MMcf of natural gas and 16 barrels of oil. The Waskom field produces from the Cotton Valley formation at depths ranging from 9,000 to 10,000 feet.

Southeast Texas

Approximately 21% or 127.0 Bcfe of our proved reserves are located in Southeast Texas, where we own interests in 88 producing wells, 50.9 net to us, and operate 61 of these wells. Net daily production rates from the area averaged 28.4 MMcf of natural gas and 738 barrels of oil during 2003. We spent $8.0 million in the Southeast Texas region in 2003 drilling three wells, 1.7 net to us, and for other development activity. In 2004, we plan to spend $20.0 million for development and exploration activities in this region. Substantially all of the reserves in this region are in the Double A Wells field area in Polk County, Texas.

Double A Wells. The Double A Wells field is our largest field area with total estimated proved reserves of 116.9 Bcfe, which is 19% of our total reserves. We own interests in and operate 59 producing wells, 29.7 net to us, in this field in Polk County, Texas. Net daily production from Double A Wells area averaged 27.3 MMcf of natural gas and 701 barrels of oil during 2003. These wells typically produce from the Woodbine formation at an average depth of 14,300 feet. In 1999, we began a redevelopment program in this field based on our interpretation of 3-D seismic data and drilled 19 successful wells from 1999 to 2001. In 2002, we found additional productive Woodbine sands to the south with two successful exploratory wells. In 2003, we drilled two additional delineation wells to further extend the discovery made in 2002. We are currently in the process of acquiring new 3-D seismic data to continue our exploration efforts.

South Texas

Approximately 8%, or 47.1 Bcfe, of our proved reserves are located in South Texas, where we own interests in 263 producing wells, 59.6 net to us. We own interests in eleven fields in the region, the largest of which are the J.C. Martin and the North Markham fields. Net daily production rates from the area averaged 9.0 MMcf of natural gas and 149 barrels of oil during 2003. We spent $13.1 million in this region in 2003 to drill 13 wells, 4.5 net to us, and for other development activity. In 2004, we plan to spend approximately $15.0 million primarily for development and exploration activity in this region.

J.C. Martin. Our largest field in South Texas is the J.C. Martin field which is located in the structurally complex and highly prolific Wilcox Lobo trend in Zapata County, Texas on the Mexico border. We own interests in 81 wells in this field, 13.0 net to us, with proved reserves of 16.1 Bcfe or 3% of our total reserves.

During 2003, net daily production attributable to our interest from this field averaged 4.3 MMcf of natural gas. This field produces primarily from Eocene Wilcox Lobo sands at depths ranging from 7,000 to 9,000 feet. The Lobo section is characterized by geopressured, multiple pay sands occurring in a highly faulted area.

North Markham. The North Markham/North Bay City field is located in Matagorda County, Texas. We own interests in and operate 19 producing wells, 19.0 net to us, in the Ohio-Sun Unit. We purchased these interests in December 2002 and are in the process of redeveloping this field. The field's estimated proved reserves of 13.6 Bcfe represent 2% of our total reserves. The field's active wells produce from more than twenty reservoirs of Oligocene Frio age at depths ranging from 6,500 to 9,000 feet. During 2003, net daily production attributable to our interests from this field averaged 67 barrels of oil per day.

Acquisition Activities

Acquisition Strategy. We have concentrated our acquisition activity in the Gulf of Mexico, East Texas/ North Louisiana, Southeast Texas and South Texas regions. Using a strategy that capitalizes on our knowledge of and experience in these regions, we seek to selectively pursue acquisition opportunities where we can evaluate the assets to be acquired in detail prior to completion of the transaction. We evaluate a large number of prospective properties according to certain internal criteria, including established production and the properties' future development and exploration potential, low operating costs and the ability for us to obtain operating control.

Major Property Acquisitions. As a result of our acquisitions, we have added 725.9 Bcfe of proved oil and natural gas reserves since 1991.

Our largest acquisitions are the following:

DevX Energy Acquisition. In December 2001, we completed the acquisition of DevX Energy, Inc. ("DevX") by acquiring 100% of the common stock of DevX for $92.6 million. The total purchase price including debt and other liabilities assumed in the acquisition was $160.8 million. As a result of the acquisition of DevX, we acquired interests in 600 producing oil and natural gas wells located onshore primarily in East and South Texas, Kentucky, Oklahoma and Kansas. Major fields acquired in the acquisition include the Gilmer field in East Texas and the J.C. Martin, Ball Ranch and Lopeno fields in South Texas. We also acquired interests in the New Albany Shale Gas field in Kentucky, the Glick field in Kansas and the N.E. Moorewood field in Oklahoma in this transaction. DevX's properties had 1.2 MMBbls of oil reserves and 156.5 Bcf of natural gas reserves at the time of the acquisition.

Bois d' Arc Acquisition. In December 1997, we acquired working interests in certain producing offshore Louisiana oil and gas properties as well as interests in undeveloped offshore oil and natural gas leases for approximately $200.9 million from Bois d' Arc Resources and certain of its affiliates and working interest partners. We acquired interests in 43 wells, 29.6 net to us, and eight separate production complexes located in the Gulf of Mexico offshore of Plaquemines and Terrebonne Parishes, Louisiana. The acquisition included interests in the Louisiana state and federal offshore areas of Main Pass Block 21, Ship Shoal Blocks 66, 67, 68 and 69 and South Pelto Block 1. The net proved reserves acquired in this acquisition were estimated at 14.3 MMBbls of oil and 29.4 Bcf of natural gas.

Black Stone Acquisition. In May 1996, we acquired 100% of the capital stock of Black Stone Oil Company and interests in producing and undeveloped oil and gas properties located in Southeast Texas for $100.4 million. We acquired interests in 19 wells, 7.7 net to us, that were located in the Double A Wells field in Polk County, Texas and became the operator of most of the wells in the field. The net proved reserves acquired in this acquisition were estimated at 5.9 MMBbls of oil and 100.4 Bcf of natural gas.

Sonat Acquisition. In July 1995, we purchased interests in certain producing oil and gas properties located in East Texas and North Louisiana from Sonat Inc. for $48.1 million. We acquired interests in 319 producing wells, 188.0 net to us. The acquisition included interests in the Beckville, Logansport, Waskom, and Longwood fields. The net proved reserves acquired in this acquisition were estimated at 0.8 MMBbls of oil and 104.7 Bcf of natural gas.

Oil and Natural Gas Reserves

The following table sets forth our estimated proved oil and natural gas reserves and the Present Value of Proved Reserves as of December 31, 2003:

	Oil (MBbls)	Gas (MMcf)	Total (MMcfe)	Present Value of Proved Reserves (000's)
Proved Developed Producing	6,180	215,680	252,757	$ 651,416
Proved Developed Non-producing	7,026	116,988	159,147	460,674
Proved Undeveloped	5,983	169,110	205,005	596,985
Total Proved	19,189	501,778	616,909	$1,709,075
Standardized Measure of Discounted Future Net Cash Flows(1)				$1,197,665

(1) The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to our proved oil and natural gas reserves after income tax discounted at 10%.

There are numerous uncertainties inherent in estimating oil and natural gas reserves and their values, including many factors beyond the control of the producer. The reserve data set forth above represents estimates only. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary. In addition, estimates of reserves are subject to revision based on the results of drilling, testing and production subsequent to the date of such estimates. Accordingly, reserve estimates are often different from the quantities of oil and gas reserves that are ultimately recovered.

In general, the volume of production from oil and natural gas properties decline as reserves are depleted. Except to the extent we acquire properties containing proved reserves or conduct successful exploration and development activities, our proved reserves will decline as reserves are produced. Our future oil and natural gas production is highly dependent upon the level of success in acquiring or finding additional reserves.

The Present Value of Proved Reserves was determined based on the market prices for oil and natural gas on December 31, 2003. The market price for our oil production on December 31, 2003, after basis adjustments, was $31.19 per barrel as compared to $30.07 per barrel on December 31, 2002. The market price received for our natural gas production on December 31, 2003, after basis adjustments, was $6.44 per Mcf as compared to $5.04 per Mcf on December 31, 2002.

Comstock did not provide estimates of total proved oil and natural gas reserves during the years ended December 31, 2001, 2002 or 2003 to any federal authority or agency, other than the SEC.

Drilling Activity Summary

During the three-year period ended December 31, 2003, we drilled development and exploratory wells as set forth in the table below.

	Year Ended December 31,					
	2001		2002		2003	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Oil	2	.7	—	—	—	—
Gas	29	16.3	26	10.7	31	19.2
Dry	4	1.8	1	1.0	4	2.8
	35	18.8	27	11.7	35	22.0
Exploratory Wells:						
Oil	1	.3	2	.8	1	.3
Gas	13	4.5	13	4.5	13	5.0
Dry	3	1.1	5	2.3	4	2.1
	17	5.9	20	7.6	18	7.4
Total Wells	52	24.7	47	19.3	53	29.4

Wells drilled in 2003 that are presented above exclude four pilot wells, 1.8 net to us, drilled in New Mexico to test a potential coalbed methane project. These wells are still being evaluated.

In 2004 to the date of this report, we have drilled seven development wells, 3.5 net to us, and two exploratory wells, 0.8 net to us. All of the development wells were successful. Both of the exploratory wells were dry holes. As of the date of this report, we have three development wells, 1.4 net to us, and one exploratory well, 0.2 net to us, that are in the process of drilling.

Producing Well Summary

The following table sets forth the gross and net producing oil and natural gas wells in which we owned an interest at December 31, 2003:

	Oil		Gas	
	Gross	Net	Gross	Net
Kansas	—	—	12	4.5
Kentucky	—	—	91	81.4
Louisiana	7	2.4	175	78.9
Mississippi	1	.1	1	.2
Offshore Gulf of Mexico	43	24.8	46	21.9
Oklahoma	3	.5	130	15.8
Texas	69	43.9	558	225.4
Wyoming	—	—	30	2.2
Total Wells	123	71.7	1,043	430.3

We operate 463 of the 1,166 producing wells presented in the above table. As of December 31, 2003, we owned interests in 12 gross wells containing multiple completions.

Acreage

The following table summarizes our developed and undeveloped leasehold acreage at December 31, 2003. We have excluded acreage in which our interest is limited to a royalty or overriding royalty interest.

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Colorado	320	80	—	—
Kansas	6,400	4,064	—	—
Kentucky	15,725	12,624	7,402	6,954
Louisiana	74,710	55,045	6,745	1,095
Mississippi	1,360	210	—	—
New Mexico	—	—	156,005	68,642
Offshore Gulf of Mexico	113,001	56,219	141,310	55,339
Oklahoma	37,440	5,336	—	—
Texas	223,720	139,310	64,649	31,396
Wyoming	13,440	927	—	—
Total	486,116	273,815	376,111	163,426

Title to our oil and natural gas properties is subject to royalty, overriding royalty, carried and other similar interests and contractual arrangements customary in the oil and gas industry, liens incident to operating agreements and for current taxes not yet due and other minor encumbrances. All of our oil and natural gas properties are pledged as collateral under our bank credit facility. As is customary in the oil and gas industry, we are generally able to retain our ownership interest in undeveloped acreage by production of existing wells, by drilling activity which establishes commercial reserves sufficient to maintain the lease or by payment of delay rentals.

Markets and Customers

The market for oil and natural gas produced by us depends on factors beyond our control, including the extent of domestic production and imports of oil and natural gas, the proximity and capacity of natural gas pipelines and other transportation facilities, demand for oil and natural gas, the marketing of competitive fuels and the effects of state and federal regulation. The oil and gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

All of our oil production is sold at the well site at prices tied to the spot oil markets. Substantially all of our natural gas production is sold either on the spot natural gas market under short-term contracts at prevailing spot market prices, or under long-term contracts based on current spot market prices. Our most significant purchaser in 2003 was Shell Trading Company. Substantially all of our Gulf of Mexico and Double A Wells field oil production in 2003 was sold to Shell. Oil sales in 2003 to Shell accounted for approximately 18% of our total 2003 oil and gas sales. BP Energy Company is our most significant natural gas purchaser. Total natural gas sales in 2003 to BP Energy Company accounted for approximately 14% of our total 2003 oil and gas sales. Our natural gas sales to Houston Pipe Line Company, a subsidiary of American Electric Power Company, Inc., accounted for approximately 10% of our total 2003 oil and gas sales.

Competition

The oil and gas industry is highly competitive. Competitors include major oil companies, other independent energy companies and individual producers and operators, many of which have financial resources, personnel and facilities substantially greater than we do. We face intense competition for the acquisition of oil and natural gas properties.

Regulation

Our operations are regulated by certain federal and state agencies. In particular, oil and natural gas production and related operations are or have been subject to price controls, taxes and other laws relating to the oil and natural gas industry. We cannot predict how existing laws and regulations may be interpreted by enforcement agencies or court rulings, whether additional laws and regulations will be adopted, or the effect such changes may have on our business or financial condition.

Our sales of natural gas are not regulated and are made at market prices. However, the Federal Energy Regulatory Commission regulates interstate and certain intrastate natural gas transportation rates and service conditions, which affect the marketing of natural gas produced by us, as well as the revenues received by us for sales of such production. Since the mid-1980s, the Federal Energy Regulatory Commission has issued a series of orders, culminating in Order Nos. 636, 636-A and 636-B, that have significantly altered the marketing and transportation of natural gas. These regulations mandated a fundamental restructuring of interstate pipeline sales and transportation service, including the unbundling by interstate pipelines of the sales, transportation, storage and other components of the city-gate sales services such pipelines previously performed. One of the Federal Energy Regulatory Commission purposes in issuing these regulations was to increase competition within all phases of the natural gas industry. Generally, these regulatory orders have eliminated or substantially reduced the interstate pipelines' traditional role as wholesalers of natural gas and have substantially increased competition and volatility in natural gas markets.

Our sales of oil and natural gas liquids are not regulated and are made at market prices. The price we receive from the sale of these products is affected by the cost of transporting the products to market.

Our oil and natural gas exploration, production and related operations are subject to extensive rules and regulations promulgated by federal, state and local agencies. Failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on the oil and gas industry increases our cost of doing business and affects our profitability. Because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws.

Most of the states in which we operate require permits for drilling operations, drilling bonds and the filing of reports concerning operations and impose other requirements relating to the exploration and production of oil and gas. These states also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and gas wells and the regulation of spacing, plugging and abandonment of such wells. The statutes and regulations of certain states limit the rate at which oil and gas can be produced from our properties.

We are required to comply with various federal and state regulations regarding plugging and abandonment of oil and natural gas wells. Our financial statements include a reserve for the estimated costs of plugging and abandoning our wells.

Environmental Regulation. Various federal, state and local laws and regulations governing the discharge of materials into the environment, or otherwise relating to the protection of the environment, health and safety, affect our operations and costs. These laws and regulations sometimes require governmental authorization before conducting certain activities, limit or prohibit other activities because of protected areas or species, create the possibility of substantial liabilities for pollution related to our operations or properties and provide penalties for noncompliance. In particular, our drilling and production operations, our activities in connection with storage and transportation of crude oil and other liquid hydrocarbons and our use of facilities for treating, processing or otherwise handling hydrocarbons and related exploration and production wastes are subject to stringent environmental regulation. As with the industry in general, compliance with existing and anticipated regulations increases our overall cost of business. While these regulations affect our capital expenditures and earnings, we believe that such regulations do not affect our competitive position in the industry because our competitors are similarly affected by environmental regulatory programs. Environmental regulations have historically been subject to frequent change and, therefore, we cannot predict with certainty the future costs or other future impacts of environmental regulations on our future operations. A discharge of hydrocarbons or hazardous substances into the environment could subject us to substantial expense, including the cost to comply with applicable regulations that require a response to the discharge, such as containment or cleanup, claims by neighboring landowners or other third parties for personal injury, property damage or their response costs and penalties assessed, or other claims sought, by regulatory agencies for response cost or for natural resource damages.

The following are examples of some environmental laws that potentially impact us and our operations.

Water. The Oil Pollution Act was enacted in 1990 and amends provisions of the Federal Water Pollution Control Act of 1972 and other statutes as they pertain to the prevention of and response to major oil spills. The Oil Pollution Act subjects owners of facilities to strict, joint and potentially unlimited liability for removal costs and certain other consequences of an oil spill along shorelines or that enters navigable waters. In the event of an oil spill into such waters, substantial liabilities could be imposed upon us. Recent regulations developed under the Oil Pollution Act require companies that own offshore facilities, including us, to demonstrate oil spill financial responsibility for removal costs and damage caused by oil discharge. States in which we operate have also enacted similar laws. Regulations are currently being developed under the Oil Pollution Act and similar state laws that may also impose additional regulatory burdens upon us.

The Federal Water Pollution Control Act imposes restrictions and strict controls regarding the discharge of produced waters, other oil and gas wastes, any form of pollutant, and, in some instances, storm water runoff, into waters of the United States. The Federal Water Pollution Control Act provides for civil, criminal and administrative penalties for any unauthorized discharges and, along with the Oil Pollution Act, imposes substantial potential liability for the costs of removal, remediation or damages resulting from an unauthorized discharge. State laws for the control of water pollution also provide civil, criminal and administrative penalties and liabilities in the case of an unauthorized discharge into state waters. The cost of compliance with the Oil Pollution Act and the Federal Water Pollution Control Act have not historically been material to our operations, but there can be no assurance that changes in federal, state or local water pollution control programs will not materially adversely affect us in the future. Although no assurances can be given, we believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition or results of operations.

Air Emissions. The Federal Clean Air Act and comparable state programs require many industrial operations in the United States to incur capital expenditures in order to meet air emissions control standards developed by the United States Environmental Protection Agency and state environmental agencies. Although no assurances can be given, we believe that compliance with the Clean Air Act and comparable state laws will not have a material adverse effect on our financial condition or results of operations.

Solid Waste. We generate non-hazardous solid wastes that are subject to the requirements of the Federal Resource Conservation and Recovery Act and comparable state statutes. The EPA and the states in which we operate are considering the adoption of stricter disposal standards for the type of non-hazardous wastes generated by us. The Resource Conservation and Recovery Act also governs the generation, management, and disposal of hazardous wastes. At present, we are not required to comply with a substantial portion of the requirements under this law because our operations generate minimal quantities of hazardous wastes. However, it is possible that additional wastes, which could include wastes currently generated during our operations, could in the future be designated as "hazardous wastes." Hazardous wastes are subject to more rigorous and costly disposal and management requirements than are non-hazardous wastes. Such changes in the regulations may result in additional capital expenditures or operating expenses by us.

Superfund. The Comprehensive Environmental Response, Compensation, and Liability Act also known as "Superfund", imposes liability, without regard to fault or the legality of the original act, on certain classes of persons in connection with the release of a "hazardous substance" into the environment. These persons include the current owner or operator of any site where a release historically occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Superfund also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. In the course of our ordinary operations, we may have managed substances that may fall within Superfund's definition of a "hazardous substance". Therefore, we may be jointly and severally liable under the Superfund for all or part of the costs required to clean up sites where we disposed of or arranged for the disposal of these substances. This potential liability extends to properties that we previously owned or operated, as well as to properties owned and operated by others at which disposal of our hazardous substances occurred.

We currently own or lease numerous properties that for many years have been used for the exploration and production of oil and gas. Although we believe we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released by us on or under the properties owned or leased by us. In addition, many of these properties have been previously owned or operated by third parties who may have disposed of or released hydrocarbons or other wastes at these properties. Under Superfund and analogous state laws, we could be subject to certain liabilities and obligations, such as being required to remove or remediate previously disposed wastes, including wastes disposed of or released by prior owners or operators, to clean up contaminated property, including contaminated groundwater, or to perform remedial plugging operations to prevent future contamination.

Office and Operations Facilities

Our executive offices are located at 5300 Town and Country Blvd., Suite 500 in Frisco, Texas 75034 and our telephone number is (972) 668-8800.

We make available free of charge on our website our annual report on Form 10-K, our quarterly reports on Form 10-Q, our current reports on Form 8-K, and amendments to these reports, as soon as reasonably practicable after we file such material with, or furnish it to, the SEC. The Internet address of our website is *www.comstockresources.com,* and such website contains additional information about us; however, such information does not constitute part of this Annual Report on Form 10-K.

We lease office space in Frisco, Texas covering 20,046 square feet at a monthly rate of $34,706, which increases to $39,717 beginning June 2004. The lease expires on May 31, 2006. In addition to our leased office space in Frisco, Texas, we lease 2,329 square feet of office space in Houston, Texas at a monthly rate of $3,299. This lease expires on March 31, 2007. We also own production offices and pipe yard facilities near Marshall and Livingston, Texas, Logansport, Louisiana and Guston, Kentucky.

Employees

As of December 31, 2003, we had 68 employees and utilized contract employees for certain of our field operations. We consider our employee relations to be satisfactory.

Directors, Executive Officers and Other Management

The following table sets forth certain information concerning our executive officers and directors.

Name	Age	Position with Company
M. Jay Allison	48	President, Chief Executive Officer and Chairman of the Board of Directors
Roland O. Burns	43	Senior Vice President, Chief Financial Officer, Secretary, Treasurer and Director
Mack D. Good	53	Vice President of Operations
Stephen E. Neukom	54	Vice President of Marketing
Richard G. Powers	49	Vice President of Land
Daniel K. Presley	43	Vice President of Accounting and Controller
Michael W. Taylor	50	Vice President of Corporate Development
David K. Lockett	49	Director
Cecil E. Martin, Jr.	62	Director
David W. Sledge	47	Director

Executive Officers.

M. Jay Allison has been one of our directors since 1987, and our President and Chief Executive Officer since 1988. Mr. Allison was elected chairman of the board of directors in 1997. From 1987 to 1988, Mr. Allison served as our vice president and secretary. From 1981 to 1987, he was a practicing oil and gas attorney with the firm of Lynch, Chappell & Alsup in Midland, Texas. In 1983, Mr. Allison co-founded a private independent oil and gas company, Midwood Petroleum, Inc., which was active in the acquisition and development of oil and gas properties from 1983 to 1987. He received B.B.A., M.S. and J.D. degrees from Baylor University in 1978, 1980 and 1981, respectively. Mr. Allison currently serves on the Board of Regents for Baylor University.

Roland O. Burns has been our senior vice president since 1994, chief financial officer and treasurer since 1990 and our secretary since 1991. Mr. Burns was elected one of our directors in June 1999. From 1982 to 1990, Mr. Burns was employed by the public accounting firm, Arthur Andersen LLP. During his tenure with Arthur Andersen LLP, Mr. Burns worked primarily in the firm's oil and gas audit practice. Mr. Burns received B.A. and M.A. degrees from the University of Mississippi in 1982 and is a Certified Public Accountant.

Mack D. Good was appointed our vice president of operations in March 1999. From August 1997 until his promotion, Mr. Good served as our district engineer for the East Texas/North Louisiana region. From 1983 until July 1997, Mr. Good was with Enserch Exploration, Inc. serving in various operations management and engineering positions. Mr. Good received a B.S. of Biology/Chemistry from Oklahoma State University in 1975 and a B.S. of Petroleum Engineering from the University of Tulsa in 1983. He is a Registered Professional Engineer in the State of Texas.

Stephen E. Neukom has been our vice president of marketing since December 1997 and has served as our manager of crude oil and natural gas marketing since December 1996. From October 1994 to 1996, Mr. Neukom served as vice president of Comstock Natural Gas, Inc., our former wholly owned gas marketing subsidiary. Prior to joining us, Mr. Neukom was senior vice president of Victoria Gas Corporation from 1987 to 1994. Mr. Neukom received a B.B.A. degree from the University of Texas in 1972.

Richard G. Powers joined us as Land Manager in October 1994 and has been our vice president of land since December 1997. Mr. Powers has over 20 years of experience as a petroleum landman. Prior to joining us, Mr. Powers was employed for 10 years as land manager for Bridge Oil (U.S.A.), Inc. and its predecessor Pinoak Petroleum, Inc. Mr. Powers received a B.B.A. degree in 1976 from Texas Christian University.

Daniel K. Presley has been our vice president of accounting since December 1997 and has been with us since December 1989, serving as controller since 1991. Prior to joining us, Mr. Presley had six years of experience with several independent oil and gas companies including AmBrit Energy, Inc. Prior thereto, Mr. Presley spent two and one-half years with B.D.O. Seidman, a public accounting firm. Mr. Presley has a B.B.A. from Texas A & M University.

Michael W. Taylor has been our vice president of corporate development since December 1997 and has served us in various capacities since September 1994. Mr. Taylor has 28 years of experience in the oil and gas business. For 15 years prior to joining us, he had been an independent oil and gas producer and petroleum consultant. Before that time, he worked in various engineering and executive capacities for a major oil company, a small independent producer and an international oil and gas consulting company. Mr. Taylor is a Registered Professional Engineer in the State of Texas and he received a B.S. degree in Petroleum Engineering from Texas A & M University in 1974.

Outside Directors.

David K. Lockett was appointed to our board of directors in 2001. Mr. Lockett is currently a vice president of Dell Computer Corp. and heads up Dell's Small and Medium Business group. Mr. Lockett has been employed by Dell Computer Corp. for the last ten years and has spent the past twenty five years in the technology industry. Mr. Lockett received a B.B.A. degree from Texas A&M University in 1976.

Cecil E. Martin, Jr. has been one of our directors since 1988. Mr. Martin has been an independent commercial real estate developer since 1991. From 1973 to 1991, he served as Chairman of a public accounting firm in Richmond, Virginia. Mr. Martin holds a B.B.A. degree from Old Dominion University and is a Certified Public Accountant.

David W. Sledge was elected to our board of directors in 1996. Since 1996, he has been investing in oil and gas exploration activities. Mr. Sledge served as President of Gene Sledge Drilling Corporation, a privately held contract drilling company based in Midland, Texas until its sale in October 1996. Mr. Sledge served Gene Sledge Drilling Corporation in various capacities from 1979 to 1996. Mr. Sledge is a past director of the International Association of Drilling Contractors and is a past chairman of the Permian Basin chapter of this association. He received a B.B.A. degree from Baylor University in 1979.

Item 3. *Legal Proceedings*

We are not a party to any legal proceedings which management believes will have a material adverse effect on our consolidated results of operations or financial condition.

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

No matters were submitted to a vote of our security holders during the fourth quarter of 2003.

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Our common stock is listed for trading on the New York Stock Exchange under the symbol "CRK." The following table sets forth, on a per share basis for the periods indicated, the high and low sales prices by calendar quarter for the periods indicated as reported by the New York Stock Exchange.

	High	Low
2002 —		
First Quarter	$ 7.95	$ 5.70
Second Quarter	9.47	6.65
Third Quarter	8.10	5.50
Fourth Quarter	9.74	6.61
2003 —		
First Quarter	$10.65	$ 8.95
Second Quarter	14.50	9.40
Third Quarter	15.20	12.10
Fourth Quarter	19.94	13.30

As of March 12, 2004, we had 34,678,862 shares of common stock outstanding, which were held by 414 holders of record and approximately 9,300 beneficial owners who maintain their shares in "street name" accounts.

We have never paid cash dividends on our common stock. We presently intend to retain any earnings for the operation and expansion of our business and we do not anticipate paying cash dividends in the foreseeable future. Any future determination as to the payment of dividends will depend upon the results of our operations, capital requirements, our financial condition and such other factors as our board of directors may deem relevant. In addition, we are limited under our bank credit facility and by the terms of the indenture for our senior notes from paying or declaring cash dividends.

The following table summarizes securities issuable and authorized by the stockholders under certain equity compensation plans:

	Number of Securities to be Issued Upon Exercise of Outstanding Options	Weighted Average Exercise Price of Outstanding Options	Number of Securities Authorized for Future Issuance Under Equity Compensation Plans
Equity compensation plans approved by stockholders	3,549,250	$8.83	318,082[(1)]

(1) Plus 1% of the outstanding shares of common stock each year beginning on January 1, 2004.

Item 6. *Selected Financial Data*

The historical financial data presented in the table below as of and for each of the years in the five-year period ended December 31, 2003 are derived from our consolidated financial statements. The financial results are not necessarily indicative of our future operations or future financial results. The data presented below should be read in conjunction with our consolidated financial statements and the notes thereto and "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Statement of Operations Data:

	Year Ended December 31,				
	1999	2000	2001	2002	2003
	(In thousands, except per share data)				
Oil and gas sales	$ 88,833	$168,084	$166,118	$142,085	$235,102
Operating expenses:					
Oil and gas operating(1)	23,117	29,277	31,855	33,499	45,746
Exploration	2,248	3,505	6,611	5,479	4,410
Depreciation, depletion and amortization	43,970	43,264	47,429	53,155	61,169
Impairment	—	—	1,400	—	4,255
General and administrative, net	2,399	3,537	4,351	5,113	7,006
Total operating expenses	71,734	79,583	91,646	97,246	122,586
Income from operations	17,099	88,501	74,472	44,839	112,516
Other income (expenses):					
Interest income	134	230	196	62	73
Interest expense	(24,192)	(25,819)	(22,098)	(31,252)	(29,860)
Gain (loss) from derivatives	—	—	243	(2,326)	(3)
Other income	1,907	122	272	8,027	223
	(22,151)	(25,467)	(21,387)	(25,489)	(29,567)
Income (loss) from continuing operations before income taxes expense	(5,052)	63,034	53,085	19,350	82,949
Income tax benefit (expense)	1,769	(22,061)	(18,579)	(6,773)	(29,682)
Net income (loss) from continuing operations	(3,283)	40,973	34,506	12,577	53,267
Discontinued operations including loss on disposal, net of income taxes	197	227	396	(1,072)	—
Cumulative effect of change in accounting principle	—	—	—	—	675
Net income (loss)	(3,086)	41,200	34,902	11,505	53,942
Preferred stock dividends	(1,853)	(2,471)	(1,604)	(1,604)	(573)
Net income (loss) attributable to common stock	$ (4,939)	$ 38,729	$ 33,298	$ 9,901	$ 53,369
Basic net income (loss) per share:					
From continuing operations	$ (0.21)	$ 1.46	$ 1.13	$ 0.38	$ 1.65
Discontinued operations	0.01	0.01	0.02	(0.04)	—
Cumulative effect of change in accounting principle	—	—	—	—	0.02
	$ (0.20)	$ 1.47	$ 1.15	$ 0.34	$ 1.67
Diluted net income (loss) per share:					
From continuing operations		$ 1.20	$ 1.00	$ 0.37	$ 1.51
Discontinued operations		—	0.01	(0.03)	—
Cumulative effect of change in accounting principle		—	—	—	0.02
		$ 1.20	$ 1.01	$ 0.34	$ 1.53
Weighted average shares outstanding:					
Basic	24,601	26,290	29,030	28,764	31,964
Diluted		34,219	34,552	33,901	35,275

(1) Includes lease operating costs and production and ad valorem taxes.

	As of December 31,				
	1999	2000	2001	2002	2003
			(In thousands)		
Balance Sheet Data:					
Cash and cash equivalents	$ 7,648	$ 7,105	$ 6,122	$ 1,682	$ 5,343
Property and equipment, net	394,497	434,065	636,274	664,208	698,686
Total assets	433,956	489,082	680,769	711,053	760,956
Total debt	254,131	234,101	372,464	366,272	306,623
Redeemable convertible preferred stock	30,000	17,573	17,573	17,573	—
Stockholders' equity	106,512	161,735	195,668	208,427	289,656

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

Results of Operations

Our operating data for the last three years is summarized below:

	Year Ended December 31,		
	2001	2002	2003
Net Production Data:			
Oil (MBbls)	1,510	1,303	1,615
Natural gas (MMcf)	27,859	33,171	34,320
Natural gas equivalent (MMcfe)	36,918	40,986	44,009
Average Sales Price:			
Oil (MBbls)	$ 25.46	$ 24.95	$ 30.70
Natural gas (MMcf)	4.58	3.30	5.41
Average equivalent price (per Mcfe)	4.50	3.47	5.34
Expenses ($ per Mcfe):			
Oil and gas operating(1)	$ 0.86	$ 0.82	$ 1.04
General and administrative	0.12	0.12	0.16
Depreciation, depletion and amortization(2)	1.28	1.29	1.37
Cash Margin ($ per Mcfe)(3)	$ 3.52	$ 2.53	$ 4.14

(1) Includes lease operating costs and production and ad valorem taxes.

(2) Represents depreciation, depletion and amortization of oil and gas properties only.

(3) Represents average equivalent price per Mcfe less oil and gas operating expenses per Mcfe and general and administrative expenses per Mcfe. Cash margin per Mcfe is presented because management believes it to be useful to investors in analyzing our operations.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Our oil and gas sales increased $93.0 million or 65% in 2003 to $235.1 million from $142.1 million in 2002. The increase in sales was mostly due to higher natural gas and crude oil prices and increased oil and natural gas production in 2003. Our average natural gas price increased by 64% and our average oil price increased by 23%. On an equivalent unit basis, our average price received for our production in 2003 was $5.34 per Mcfe, which was 54% higher than our average price in 2002 of $3.47 per Mcfe. The higher prices were accompanied by a 7% increase in our production. Our natural gas production increased by 3% while our oil production increased by 24%. The production increases are primarily related to new production resulting from wells drilled in our 2002 and 2003 drilling programs.

Our oil and gas operating expenses, including production taxes, increased $12.2 million (37%) to $45.7 million in 2003 from $33.5 million in 2002. Oil and gas operating expenses per equivalent Mcf produced increased $0.22 (27%) to $1.04 in 2003 from $0.82 in 2002. The increase in operating expenses is primarily related to the 7% increase in production and higher production and ad valorem taxes resulting from the significantly higher oil and gas prices in 2003.

In 2003, we had $4.4 million in exploration expense, which primarily related to the write-off of exploratory dry holes, impairment of certain of our exploratory leasehold and the acquisition of seismic data. Exploration expense for 2002 was $5.5 million, which related to the write-off of exploratory dry holes.

Our depreciation, depletion and amortization increased $8.0 million (15%) to $61.2 million in 2003 from $53.2 million in 2002. The increase is attributable to our higher production in 2003. Our depreciation, depletion and amortization per equivalent Mcf produced also increased to $1.37 in 2003 from $1.29 in 2002.

In 2003, we had a $4.3 million impairment of our oil and gas properties which primarily relates to some minor valued fields where an impairment was indicated based on estimated future cash flows attributable to the fields' estimated proved oil and natural gas reserves.

General and administrative expenses, which are reported net of overhead reimbursements, of $7.0 million for 2003 were 37% higher than general and administrative expenses of $5.1 million for 2002. The increase was due primarily to the opening of an offshore operations office in Houston, Texas as well as an increase in the number of employees and higher compensation paid to our employees in 2003.

Interest expense decreased $1.4 million (4%) to $29.9 million for 2003 from $31.3 million in 2002. The decrease was due to a reduction in the average borrowings outstanding under our credit facility of $119.7 million during 2003 as compared to an average of $172.0 million outstanding in 2002. The average interest rate on the outstanding borrowings under the credit facility also decreased to 3.0% in 2003 as compared to 3.6% in 2002.

Our other income in 2003 was $0.2 million as compared to $8.0 million in 2002. Included in other income in 2002 was $7.7 million related to refunds of severance taxes paid in prior years.

For 2003, we reported net income of $53.4 million, after deducting preferred stock dividends of $0.6 million. These results compared to net income from continuing operations in 2002 of $11.0 million, after deducting preferred stock dividends of $1.6 million. Our income from continuing operations per share for 2003 was $1.53 on diluted weighted average shares outstanding of 35.3 million as compared to net income from continuing operations per share of $0.37 for 2002 on diluted weighted average shares outstanding of 33.9 million.

Net income for 2003 included $0.7 million in income ($0.02 per share) related to the cumulative effect of a change in our accounting for future abandonment cost for our oil and gas properties.

In 2002, we sold certain marginal oil and gas properties. The operating results of these properties in 2002 including the loss on disposal of $1.1 million ($0.04 per share) have been reflected as discontinued operations.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Our oil and gas sales decreased $24.0 million or 14% in 2002 to $142.1 million from $166.1 million in 2001. The decrease in sales is mostly due to the lower natural gas prices in 2002. Our average natural gas price decreased by 28% and our average oil price decreased by 2%. On an equivalent unit basis, our average price received for our production in 2002 was $3.47 per Mcfe, which was 23% lower than our average price in 2001 of $4.50 per Mcfe. Our average natural gas price in 2002 was $0.04 higher as a result of gains from hedging activities. Without the hedging gains, our natural gas price would have averaged $3.26 in 2002. The lower prices were partially offset by an 11% increase in production. Our natural gas production was up 19% while our oil production fell by 14%. The natural gas production increase is related to our acquisition of DevX Energy, Inc. which we completed in December 2001. The oil production decrease was due to normal depletion of our oil properties.

Our oil and gas operating expenses, which includes production taxes, increased $1.6 million or 5%, to $33.5 million in 2002 from $31.9 million in 2001. The increase is due to the higher production level in 2002. Our oil and gas operating expenses per equivalent Mcf produced decreased by $0.04 to $0.82 in 2002 from

$0.86 for 2001. The decrease in per unit lifting costs is primarily related to lower production taxes resulting from the lower oil and natural gas prices in 2002.

In 2002, we had $5.5 million in exploration expense, which primarily related to the write-off of exploratory dry holes. Exploration expense for 2001 was $6.6 million which related to the write-off of dry holes and the expensing of $2.4 million in advances made by us to our joint venture partner for seismic data acquisition.

Our depreciation, depletion and amortization increased $5.7 million (12%) to $53.2 million in 2002 from $47.4 million in 2001. The increase is attributable to our higher production level in 2002. Our depreciation, depletion and amortization per equivalent Mcf produced increased to $1.29 in 2002 from $1.28 in 2001.

Our general and administrative expenses, which are reported net of overhead reimbursements that we receive, increased $762,000 or 18%, to $5.1 million in 2002 from $4.4 million in 2001. The increase was primarily due to an increase in the number of employees and higher compensation paid to our employees in 2002.

Our interest expense increased $9.2 million or 41% to $31.3 million in 2002 from $22.1 million for 2001. The increase is due to the higher debt level we had as a result of the acquisition of DevX Energy, Inc. in December 2001. In addition, in March 2002 we issued an additional $75.0 million of our 11¼% Senior Notes which refinanced amounts that were borrowed under our bank credit facility. In 2002, we averaged $172.0 million outstanding under our bank credit facility at a weighted average interest of 3.6%. In 2001, our average outstanding balance was $65.2 million under the bank credit facility with a weighted average interest rate of 5.6%.

Our other income in 2002 increased to $8.0 million from $272,000 in 2001. Included in other income in 2002 was $7.7 million related to refunds of severance taxes paid in prior years.

For 2002, we reported net income from continuing operations of $11.0 million, after deducting preferred stock dividends of $1.6 million. These results compared to net income in 2001 of $32.9 million, after deducting preferred stock dividends of $1.6 million. Our income from continuing operations per share for 2002 was $0.37 on diluted weighted average shares outstanding of 33.9 million as compared to net income from continuing operations per share of $1.00 for 2001 on diluted weighted average shares outstanding of 34.6 million.

In 2002, we sold certain marginal oil and gas properties. The operating results of these properties in 2002 including the loss on disposal of $1.1 million ($0.04 per share) have been reflected as discontinued operations.

Liquidity and Capital Resources

Funding for our activities has historically been provided by our operating cash flow, debt or equity financings or asset dispositions. In 2003, our net cash flow provided by operating activities totaled $153.8 million. Our other primary funding source in 2003 was borrowings of $23.4 million.

Our primary needs for capital, in addition to funding our ongoing operations, relate to the acquisition, development and exploration of our oil and gas properties and the repayment of our debt. In 2003, we incurred capital expenditures of $92.9 million for development, exploration and acquisition activities. We also repaid $83.1 million of our debt.

Our annual capital expenditure activity is summarized in the following table:

	Year Ended December 31,		
	2001	2002	2003
		(In thousands)	
Acquisitions of proved oil and gas properties	$160,794	$ 11,435	$ 4,805
Acquisitions of unproved oil and gas properties	7,113	4,268	4,447
Developmental leasehold costs	974	98	481
Workovers and recompletions	5,563	7,414	12,836
Offshore production facilities	907	4,867	5,227
Development drilling	43,646	22,893	28,254
Exploratory drilling	33,382	31,074	34,829
Other	172	1,332	2,051
Total	$252,551	$ 83,381	$ 92,930

The timing of most of our capital expenditures is discretionary because we have no material long-term capital expenditure commitments. Consequently, we have a significant degree of flexibility to adjust the level of our capital expenditures as circumstances warrant. We spent $91.6 million, $70.6 million and $86.1 million on development and exploration activities in 2001, 2002 and 2003, respectively. We have budgeted approximately $110.0 million for development and exploration projects in 2004. We expect to use internally generated cash flow to fund development and exploration activity. Our operating cash flow is highly dependent on oil and natural gas prices, especially natural gas prices.

We spent $160.8 million, $11.4 million and $4.8 million on acquisition activities in 2001, 2002 and 2003, respectively. We do not have a specific acquisition budget for 2004 since the timing and size of acquisitions are not predictable. We intend to use borrowings under our bank credit facility, or other debt or equity financings to the extent available, to finance significant acquisitions. The availability and attractiveness of these sources of financing will depend upon a number of factors, some of which will relate to our financial condition and performance and some of which will be beyond our control, such as prevailing interest rates, oil and natural gas prices and other market conditions.

The following table summarizes our aggregate liabilities and commitments by year of maturity:

	2004	2005	2006	2007	Total
			(In thousands)		
Bank credit facility	$ —	$ 86,000	$ —	$ —	$ 86,000
11¼% Senior notes	—	—	—	220,000	220,000
Other debt	623	—	—	—	623
Operating leases	491	516	238	10	1,255
	$ 1,114	$ 86,516	$ 238	$220,010	$307,878

At December 31, 2003, we had a $350.0 million revolving credit facility with Toronto Dominion (Texas), Inc. as administrative agent. The bank credit facility was a three year revolving credit line with a borrowing base of $260.0 million at December 31, 2003. Indebtedness under the bank credit facility was secured by substantially all of our assets. All of our subsidiaries were guarantors of this indebtedness. Interest charged on the revolving credit line was based on the utilization of the borrowing base, at our option at either (i) LIBOR plus 1.5% to 2.375% or (ii) the corporate base rate (generally the federal funds rate plus 0.5%) plus 0.5% to 1.375%. The credit facility would have matured on January 2, 2005 and contained covenants that, among other things, restricted our ability to pay cash dividends, limited the amount of our consolidated debt and limited our ability to make certain loans and investments. Financial covenants included the maintenance of a current ratio, maintenance of tangible net worth and maintenance of an interest coverage ratio.

At December 31, 2003, we had $220.0 million of aggregate principal amount of 11¼% senior notes outstanding which are due in 2007 (the "1999 Notes"). These notes are unsecured obligations of Comstock and are guaranteed by all of our subsidiaries.

Pursuant to a tender offer, we repurchased $197.7 million in principal amount of the 1999 Notes for $212.2 million plus accrued interest on February 25, 2004. We intend to redeem the remaining $22.3 million in principal amount of the 1999 Notes on May 1, 2004 when the notes are first callable at a price of 105.625 of par value. The total amount required to repurchase the remaining outstanding 1999 Notes is $23.6 million. The early extinguishment of the 1999 Notes will result in a pretax loss of $19.8 million in 2004.

In connection with the repurchase of the 1999 Notes, we sold $175.0 million of senior notes in an underwritten public offering. The new senior notes are due on March 1, 2012 and bear interest at 6⅞% which is payable semiannually on March 1 and September 1, commencing September 1, 2004. The notes are unsecured obligations of Comstock and are currently guaranteed by all of our subsidiaries.

On February 25, 2004, we also entered into a new $400.0 million bank credit facility with Bank of Montreal, as the administrative agent. The new credit facility is a four year revolving credit commitment that matures on February 25, 2008. Borrowings under the new credit facility are limited to a borrowing base that will be set at $300.0 million upon the retirement of all of the 1999 Notes. Borrowings under the new credit facility were used to refinance amounts outstanding under our prior bank credit facility and to fund the repurchase of the 1999 Notes.

Indebtedness under the new credit facility is secured by substantially all of our assets and is guaranteed by all of our subsidiaries. The new credit facility is subject to borrowing base availability, which will be redetermined semiannually based on the banks' estimates of the future net cash flows of our oil and natural gas properties. The borrowing base may be affected by the performance of our properties and changes in oil and natural gas prices. The determination of the borrowing base will be at the sole discretion of the administrative agent and the bank group. Borrowings under the new credit facility bear interest, based on the utilization of the of the borrowing base, at our option at either (1) LIBOR plus 1.25% to 1.75% or (2) the base rate (which is the higher of the prime rate or the federal funds rate) plus 0% to 0.5%. A commitment fee of 0.375% is payable on the unused borrowing base. The new credit facility contains covenants that, among other things, restrict the payment of cash dividends, limit the amount of consolidated debt we may incur and limit our ability to make certain loans and investments. The only financial covenants are the maintenance of a current ratio and maintenance of a minimum tangible net worth.

We believe that our cash flow from operations and available borrowings under the new bank credit facility will be sufficient to fund our operations and future growth as contemplated under our current business plan. However, if our plans or assumptions change or if our assumptions prove to be inaccurate, we may be required to seek additional capital. We cannot provide any assurance that we will be able to obtain such capital, or if such capital is available, that we will be able to obtain it on acceptable terms.

Federal Taxation

At December 31, 2003, we had federal income tax net operating loss carryforwards of approximately $45.5 million. We have established a $23.0 million valuation allowance against part of the net operating loss carryforwards acquired from DevX due to a "change in control" limitation which will prevent us from fully realizing these carryforwards. The carryforwards expire from 2017 through 2021. The value of these carryforwards depends on our ability to generate future taxable income in order to utilize these carryforwards.

Critical Accounting Policies

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and use assumptions that can affect the reported amounts of assets, liabilities, revenues or expenses. We are also required to select among alternative acceptable accounting policies. There are two generally acceptable methods for accounting for oil and gas producing activities. The full cost method allows the capitalization of all costs associated with finding oil and gas reserves, including certain general and administrative expenses. The successful efforts method allows only for the capitalization of costs associated with developing proven oil and gas properties as well as exploration costs associated with successful exploration projects. Costs related to exploration that are not successful are expensed when it is determined that commercially productive oil and gas reserves were not found. We have elected to use the successful efforts method to account for our oil and gas activities and we do not capitalize any of our general and administrative expenses.

The determination of depreciation, depletion and amortization expense as well as impairments that are recognized on our oil and gas properties are highly dependent on the estimates of the proved oil and natural gas reserves attributable to our properties. There are numerous uncertainties inherent in estimating oil and natural gas reserves and their values, including many factors beyond our control. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary. In addition, estimates of reserves are subject to revision based on the results of drilling, testing and production subsequent to the date of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and gas reserves that are ultimately recovered. The estimates of our proved oil and gas reserves used in preparation of our financial statements were determined by an independent petroleum engineering consulting firm and were prepared in accordance with the rules promulgated by the SEC and the Financial Accounting Standards Board (the "FASB"). The determination of impairment of our oil and gas reserves is based on the oil and gas reserve estimates using projected future oil and natural gas prices that we have determined to be reasonable. The projected prices that we employ represent our long-term oil and natural gas price forecast and may be higher or lower than the December 31, 2003 market prices for crude oil and natural gas. For the impairment review of our oil and gas properties that we conducted as of December 31, 2003, we used oil and natural gas prices that were based on the current futures market. We used oil prices of $30.67, $27.44, and $26.43 per barrel for 2004, 2005 and 2006, respectively, and escalated prices by 3% each year thereafter to a maximum price of $40.00 per barrel. For natural gas, we used prices of $5.44, $5.29, and $4.99 per Mcf for 2004, 2005 and 2006, respectively, and escalated prices by 3% each year thereafter to a maximum price of $5.20 per Mcf. To the extent we had used lower prices in our impairment review, an impairment could have been indicated on certain of our oil and gas properties.

New Accounting Standards

We adopted Statement of Financial Accounting Standards No. 143 ("SFAS 143") "Accounting for Asset Retirement Obligations," on January 1, 2003. This statement requires us to record a liability in the period in which an asset retirement obligation ("ARO") is incurred, in an amount equal to the discounted estimated fair value of the obligation that is capitalized. Thereafter, each quarter, this liability is accreted up to the final retirement cost. The adoption of SFAS 143 on January 1, 2003 resulted in a cumulative effect adjustment to record (i) a $3.7 million decrease in the carrying value of our oil and gas properties, (ii) a $3.3 million decrease in accumulated depletion, depreciation and amortization, (iii) a $1.5 million decrease in reserve for future abandonment, and (iv) a gain of $675,000, net of income taxes, which was reflected as the cumulative effect of a change in accounting principle.

On January 1, 2003, we adopted the provisions of Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections" ("SFAS 145"). Prior to SFAS 145, gains or losses on the early extinguishment of debt were required to be classified in a company's statements of operations as extraordinary gains or losses, net of associated income taxes, after the determination of income or loss from continuing operations. SFAS 145 requires, except in the case of events or transactions of a highly unusual and infrequent nature, that gains or losses from the early extinguishment of debt be classified as components of a company's income or loss from continuing operations. The adoption of the provisions of SFAS 145 did not affect our financial position or reported financial results. Under our the provisions of SFAS 145, gains or losses from the early extinguishment of debt will be recognized in the Consolidated Statements of Operations as components of other income or other expense and will be included in the determination of the income (loss) from continuing operations of those periods.

We also adopted Statement of Financial Accounting Standards No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" ("SFAS 146"), in 2003. This statement establishes accounting and reporting standards that are effective for exit or disposal activities beginning after December 31, 2002 which require that a liability be recognized for an exit or disposal activity when that liability is incurred. The adoption of SFAS 146 had no effect on our financial statements.

In December 2002, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 148, "Accounting for Stock-Based Compensation — Transition and Disclosure, an amendment of FASB Statement No. 123". This statement amends Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" ("SFAS 123"), to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS 123 to require prominent disclosures in both annual and interim financial statements. Certain of the disclosure modifications are included in the notes to our financial statements.

In January 2003, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirement for Guarantees, including Indirect Guarantees of Indebtedness of Others" ("FIN 45"). FIN 45 requires an entity to recognize a liability for the obligations it has undertaken in issuing a guarantee. This liability would be recorded at the inception of a guarantee and would be measured at fair value. Certain guarantees are excluded from the measurement and disclosure provisions while certain other guarantees are excluded from the measurement provisions of the interpretation. The adoption of the statement in 2003 had no effect on our financial statements.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities" ("FIN 46"), which was modified in December 2003. FIN 46 requires an entity to consolidate a variable interest entity if it is designated as the primary beneficiary of that entity even if the entity does not have a majority of voting interests. A variable interest entity is generally defined as an entity whose equity is unable to finance its activities or where the owners of the entity lack the risk and rewards of ownership. We are not the primary beneficiary of any variable interest entities, and accordingly, the adoption of FIN 46 is not expected to have a material effect on our financial statements when adopted.

We have been made aware of an issue that has arisen in the industry regarding the application of certain provisions of Statement of Financial Accounting Standards No. 141, "Business Combinations" ("SFAS 141"), and Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" ("SFAS 142"), to companies in the extractive industries, including oil and gas exploration and production companies. The issue is whether the provisions of SFAS 141 and SFAS 142 require companies to classify costs associated with mineral rights, including both proved and unproved lease acquisition costs, as intangible assets on the balance sheet, apart from other capitalized oil and gas property costs. Historically, we have included oil and gas lease acquisition costs as a component of oil and gas properties. Also under consideration is whether SFAS 142 requires companies to provide additional disclosures prescribed by SFAS 142 for intangible assets for costs associated with mineral rights. In the event it is determined that costs associated with mineral rights are required to be classified as intangible assets, a substantial portion of our capitalized oil and gas property costs would be separately classified on our balance sheet as intangible assets. The reclassification of these amounts would not affect the method in which such costs are amortized or the manner in which we assess impairment of capitalized costs. As a result, net income would not be affected by the reclassification if it were to occur. As of December 31, 2003, we had $380.6 million in capitalized leasehold costs, net of accumulated depletion.

Related Party Transactions

In recent years, we have not entered into any material transactions with our officers or directors apart from the compensation they are provided for their services. We also have not entered into any business transactions with our significant stockholders or any other related parties.

Item 7A. ***Quantitative and Qualitative Disclosure About Market Risks***

Oil and Natural Gas Prices

Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for crude oil, the foreign supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse affect on our ability to obtain capital for our exploration and development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations and capital resources. Based on our oil and natural gas production in 2003, a $1.00 change in the price per barrel of oil would have resulted in a change in our cash flow for such period by approximately $1.6 million and a $1.00 change in the price per Mcf of natural gas would have changed our cash flow by approximately $33.0 million.

We periodically use derivative transactions with respect to a portion of our oil and natural gas production to mitigate our exposure to price changes. During 2003, we did not hedge any of our oil and natural gas production. While the use of these derivative arrangements limits the downside risk of price declines, such use may also limit any benefits which may be derived from price increases. We use swaps, floors and collars to hedge oil and natural gas prices. Swaps are settled monthly based on differences between the prices specified in the instruments and the settlement prices of futures contracts quoted on the New York Mercantile Exchange. Generally, when the applicable settlement price is less than the price specified in the contract, we receive a settlement from the counterparty based on the difference multiplied by the volume hedge. Similarly, when the applicable settlement price exceeds the price specified in the contract, we pay the counterparty based on the difference. We generally receive a settlement from the counterparty for floors when the applicable settlement price is less than the price specified in the contract, which is based on the difference multiplied by the volumes hedged. For collars, we generally receive a settlement from the counterparty when the settlement price is below the floor and pay a settlement to the counterparty when the settlement price exceeds the cap. No settlement occurs when the settlement price falls between the floor and the cap.

Interest Rates

At December 31, 2003, we had long-term debt of $306.0 million. Of this amount, $220.0 million bears interest at a fixed rate of 11¼%. The fair market value of the fixed rate debt as of December 31, 2003 was $234.6 million based on the market price of 1.07% of the face amount. At December 31, 2003, we had $86.0 million outstanding under our bank credit facility, which was subject to floating market rates of interest. Borrowings under the bank credit facility bear interest at a fluctuating rate that is tied to LIBOR or the corporate base rate, at our option. Any increases in these interest rates can have an adverse impact on our results of operations and cash flow. Based on borrowings outstanding at December 31, 2003, a 100 basis point change in interest rates would change our interest expense on our variable rate debt by approximately $0.9 million. From January 1, 2003 to December 31, 2003, we had an interest rate swap in place which fixed our LIBOR rate on $25.0 million of our floating rate debt at 1.7%. As a result of this interest rate swap, we realized a loss of $108,000 in 2003. We had no interest rate derivatives outstanding at December 31, 2003.

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

Our consolidated financial statements are included on pages F-1 to F-29 of this report.

We have prepared these financial statements in conformity with generally accepted accounting principles. We are responsible for the fairness and reliability of the financial statements and other financial data included in this report. In the preparation of the financial statements, it is necessary for us to make informed estimates and judgments based on currently available information on the effects of certain events and transactions.

We maintain accounting and other controls which we believe provide reasonable assurances that our financial records are reliable, our assets are safeguarded, and that transactions are properly recorded in accordance with management's authorizations. However, limitations exist in any system of internal controls based upon the recognition that the cost of the system should not exceed benefits derived therefrom.

Our independent public accountants, Ernst & Young LLP, are engaged to audit our financial statements and to express an opinion thereon. Their audit is conducted in accordance with auditing standards generally accepted in the United States to enable them to report whether the financial statements present fairly, in all material respects, our financial position and results of operations in accordance with accounting principles generally accepted in the United States.

The audit committee of our board of directors is composed of three directors who are not our employees. This committee meets periodically with our independent public accountants and management. Our independent public accountants have full and free access to the audit committee to meet, with and without management being present, to discuss the results of their audits and the quality of our financial reporting.

Item 9. *Changes in and Disagreements With Accountants On Accounting and Financial Disclosure*

On May 16, 2003, our audit committee engaged Ernst & Young LLP as our independent public accountants for fiscal 2003 and dismissed KPMG LLP. There were no disagreements with KPMG LLP on matters of accounting principles or practices, financial statement disclosure or auditing scope and procedure, which disagreements if not resolved to the satisfaction of KPMG LLP would have caused it to make reference to the subject matter of the disagreements in connection with its report.

KPMG LLP's reports on our consolidated financial statements for the past two years did not contain an adverse opinion or disclaimer of opinion, nor were they qualified or modified as to uncertainty, audit scope or accounting principles.

Item 9A. *Controls and Procedures*

Our principal executive officer and principal financial officer have evaluated, as required by Rule 13a-15(b) promulgated under the Securities Exchange Act of 1934, our disclosure controls and procedures, as defined in Rule 13a-15(e), as of December 31, 2003. Based on that evaluation, our principal executive officer and principal financial officer concluded that the design and operation of our disclosure controls and procedures are effective in ensuring that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

There has not been any change in our internal control over financial reporting, as defined in Rule 13a-15(f), that occurred during the last fiscal quarter of 2003 that has materially affected or is reasonably likely to materially affect, our internal control over financial reporting.

PART III

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

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2003.

Item 11. ***Executive Compensation***

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2003.

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

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2003.

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

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2003.

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

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2003.

PART IV

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

(a) *Financial Statements:*

1. The following consolidated financial statements are included on Pages F-1 to F-29 of this report.

2. All financial statement schedules are omitted because they are not applicable, or are immaterial or the required information is presented in the consolidated financial statements or the related notes.

(b) *Reports on Form 8-K:*

Form 8-K and 8-K/A Reports filed subsequent to September 30, 2003 are as follows:

Filing Date	Item	Description
November 5, 2003	7 & 12	Operating results for the three months and nine months ended September 30, 2003.
November 7, 2003	7 & 12	Operating results for the three months and nine months ended September 30, 2003.
January 28, 2004	7 & 12	Oil and gas reserves for the fiscal year ended December 31, 2003.
February 5, 2004	7 & 12	Drilling results for the fiscal year ended December 31, 2003 and capital expenditure budget for 2004.
February 17, 2004	7 & 12	Operating results for the three months and year ended December 31, 2003.
February 24, 2004	5 & 7	Tender offer for 11¼% Senior Notes due 2007 and sale of 6⅞% Senior Notes due 2002.

(c) *Exhibits:*

The exhibits to this report required to be filed pursuant to Item 15(c) are listed below.

Exhibit No.	Description
1.1	Underwriting Agreement, dated as of February 18, 2004 between Comstock and Banc of America Securities LLC and Harris Nesbitt Corp., acting as representatives of the several underwriters, for the sale of $175,000,000 of Comstock's 6⅞% Senior Notes due 2012 (incorporated by reference to Exhibit 99.2 to our Current Report on Form 8-K dated February 19, 2004).
3.1(a)	Restated Articles of Incorporation (incorporated by reference to Exhibit 3.1 to our Annual Report on Form 10-K for the year ended December 31, 1995).
3.1(b)	Certificate of Amendment to the Restated Articles of Incorporation dated July 1, 1997 (incorporated by reference to Exhibit 3.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 1997).
3.2	Bylaws (incorporated by reference to Exhibit 3.2 to our Registration Statement on Form S-3, dated October 25, 1996).

Exhibit No.	Description
4.1	Rights Agreement dated as of December 14, 2000, by and between Comstock and American Stock Transfer and Trust Company, as Rights Agent (incorporated herein by reference to Exhibit 1 to our Registration Statement on Form 8-A dated January 11, 2001).
4.2	Certificate of Designation, Preferences and Rights of Series B Junior Participating Preferred Stock (incorporated by reference to Exhibit 2 to our Registration Statement on Form 8-A dated January 11, 2001).
4.3	Indenture dated April 29, 1999 between Comstock and U.S. Trust Company of Texas, N.A., Trustee for the 11¼% Senior Notes due 2007 (incorporated by reference to Exhibit 10.5 to our Current Report on Form 8-K dated April 29, 1999).
4.4	First Supplemental Indenture, dated March 7, 2002, by and between Comstock and U.S. Trust Company of Texas, N.A., Trustee for the 11¼% Senior Notes due 2007 (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated March 12, 2002).
4.5*	Second Supplemental Indenture, dated February 25, 2004, by and between Comstock and The Bank of New York Trust Company, N. A. (formerly U.S. Trust Company of Texas, N.A.), Trustee for the 11¼% Senior Notes due 2007.
4.6*	Indenture dated February 25, 2004, between Comstock, the guarantors and The Bank of New York Trust Company, N. A., Trustee for debt securities to be issued by Comstock Resources, Inc.
4.7*	First Supplemental Indenture, dated February 25, 2004, between Comstock, the guarantors and The Bank of New York Trust Company, N.A., Trustee for the 6⅞% Senior Notes due 2012.
10.1	Credit Agreement, dated as of December 17, 2001, by and among Comstock, as borrower, each lender from time to time party thereto, Toronto Dominion (Texas), Inc., as administrative agent, and Toronto-Dominion Bank, as Issuing Bank (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated December 21, 2001).
10.2	Amendment No. 1 dated December 26, 2001 to the Credit Agreement, dated as of December 17, 2001, by and among Comstock, as borrower, each lender from time to time party thereto, Toronto Dominion (Texas), Inc., as administrative agent, and Toronto-Dominion Bank, as Issuing Bank (incorporated by reference to Exhibit 10.2 to our Annual Report on Form 10-K for the year ended December 31, 2001).
10.3	Amendment No. 2 dated February 4, 2002 to the Credit Agreement, dated as of December 17, 2001, by and among Comstock, as borrower, each lender from time to time party thereto, Toronto Dominion (Texas), Inc., as administrative agent, and Toronto-Dominion Bank, as Issuing Bank (incorporated by reference to Exhibit 10.3 to our Annual Report on Form 10-K for the year ended December 31, 2001).
10.4	Amendment No. 3 dated April 15, 2002 to the Credit Agreement, dated as of December 17, 2001, by and among Comstock, as borrower, each lender from time to time party thereto, Toronto Dominion (Texas), Inc., as administrative agent, and Toronto-Dominion Bank, as Issuing Bank (incorporated by reference to Exhibit 10.1 to our Quarterly Report for the quarter ended March 31, 2002).
10.5	Amendment No. 4 dated May 13, 2003 to the Credit Agreement, dated as of December 17, 2001, by and among Comstock, as borrower, each lender from time to time party thereto, Toronto Dominion (Texas), Inc., as administrative agent, and Toronto-Dominion Bank, as Issuing Bank (incorporated by reference to Exhibit 10.5 to our Quarterly Report for the quarter ended March 31, 2003).
10.6*	Amendment No. 5 dated January 30, 2004 to the Credit Agreement, dated as of December 17, 2001, by and among Comstock, as borrower, each lender from time to time party thereto, Toronto Dominion (Texas), Inc., as administrative agent, and Toronto-Dominion Bank, as Issuing Bank.

Exhibit No.	Description
10.7*	Amended and Restated Credit Agreement, dated as of February 25, 2004 among Comstock, as the borrower, the lenders from time to time party thereto, Bank of Montreal, as administrative agent and issuing bank, Bank of America, N.A., as syndication agent, and Comerica Bank, Fortis Capital Corp., and Union Bank of California, N.A. as co-documentation agents.
10.8#	Employment Agreement dated June 1, 2002, by and between Comstock and M. Jay Allison (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2002).
10.9#	Employment Agreement dated June 1, 2002, by and between Comstock and Roland O. Burns (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2002).
10.10#	Comstock Resources, Inc. 1999 Long-term Incentive Plan (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 1999).
10.11#	Form of Nonqualified Stock Option Agreement between Comstock and certain officers and directors of Comstock (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the year ended June 30, 1999).
10.12#	Form of Restricted Stock Agreement between Comstock and certain officers of Comstock (incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 1999).
10.13	Exploration Agreement dated July 31, 2001 by and between Comstock and Bois'd Arc Offshore Ltd. (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
10.14	Warrant Agreement dated July 31, 2001 by and between Comstock and Gary W. Blackie and Wayne L. Laufer (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
10.15	Supplement to the 2001 Exploration Agreement dated December 20, 2002 by and between Comstock and Bois'd Arc Offshore Ltd (incorporated by reference to Exhibit 10.14 to our Annual Report on Form 10-K for the year ended December 31, 2002.)
10.16	Office Lease Agreement dated August 12, 1997 between Comstock and Briar Center LLC (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 1997).
10.17	Dealer Manager Agreement, dated as of February 10, 2004 between Comstock and Bank of America Securities LLC and Harris Nesbitt Corp. in connection with the tender offer for Comstock's 11¼% Senior Notes due 2007 (incorporated by reference to Exhibit 99.1 to our Current Report on Form 8-K dated February 19, 2004).
21*	Subsidiaries of the Company.
23.1*	Consent of KPMG LLP.
23.2*	Consent of Ernst & Young LLP.
31.1*	Chief Executive Officer certification under Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Chief Financial Officer certification under Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Chief Executive Officer certification under Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Chief Financial Officer certification under Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

Management contract or compensatory plan document.

SIGNATURES

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

COMSTOCK RESOURCES, INC.

By: /s/ M. JAY ALLISON

M. Jay Allison
President and Chief Executive Officer
(Principal Executive Officer)

Date: March 12, 2004

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.

/s/ M. JAY ALLISON M. Jay Allison	*President, Chief Executive Officer and Chairman of the Board of Directors (Principal Executive Officer)*	March 12, 2004
/s/ ROLAND O. BURNS Roland O. Burns	*Senior Vice President, Chief Financial Officer, Secretary, Treasurer and Director (Principal Financial and Accounting Officer)*	March 12, 2004
/s/ DAVID K. LOCKETT David K. Lockett	*Director*	March 12, 2004
/s/ CECIL E. MARTIN, JR. Cecil E. Martin, Jr.	*Director*	March 12, 2004
/s/ DAVID W. SLEDGE David W. Sledge	*Director*	March 12, 2004

CONSOLIDATED FINANCIAL STATEMENTS OF COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

INDEX

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

The Board of Directors and Stockholders
Comstock Resources, Inc.

We have audited the accompanying consolidated balance sheet of Comstock Resources, Inc. and subsidiaries as of December 31, 2003, and the related consolidated statements of operations, stockholders' equity and comprehensive income, and cash flows for year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Comstock Resources, Inc. and subsidiaries at December 31, 2003, and the consolidated results of their operations and their cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States.

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

ERNST & YOUNG LLP

Dallas, Texas
February 26, 2004

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors of Comstock Resources, Inc.:

We have audited the accompanying consolidated balance sheet of Comstock Resources, Inc. and subsidiaries as of December 31, 2002 and the related consolidated statements of operations, stockholders' equity and comprehensive income, and cash flows for each of the years in the two year period ended December 31, 2002. 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 of America. 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 Comstock Resources, Inc. and subsidiaries as of December 31, 2002, and the results of their operations and their cash flows for each of the years in the two year period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

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

KPMG LLP

Dallas, Texas
March 19, 2003

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
As of December 31, 2002 and 2003

	December 31, 2002	December 31, 2003
	(In thousands)	
ASSETS		
Cash and Cash Equivalents	$ 1,682	$ 5,343
Accounts Receivable:		
Oil and gas sales	30,135	36,468
Joint interest operations	5,407	9,524
Other Current Assets	2,678	4,802
Total current assets	39,902	56,137
Property and Equipment:		
Unevaluated oil and gas properties	14,880	18,075
Oil and gas properties, successful efforts method	961,562	1,052,564
Other	2,570	4,047
Accumulated depreciation, depletion and amortization	(314,804)	(376,000)
Net property and equipment	664,208	698,686
Derivatives	3	—
Other Assets	6,940	6,133
	$ 711,053	$ 760,956
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Portion of Long-Term Debt	$ 270	$ 623
Accounts Payable and Accrued Expenses	49,470	63,874
Derivatives	57	—
Total current liabilities	49,797	64,497
Long-Term Debt, less current portion	366,002	306,000
Deferred Income Taxes Payable	52,577	81,629
Reserve for Future Abandonment Costs	16,677	19,174
Redeemable Convertible Preferred Stock — $10.00 par, liquidation value of $17,573,000, 5,000,000 shares authorized, 1,757,310 shares issued and outstanding at December 31, 2002	17,573	—
Stockholders' Equity:		
Common stock — $0.50 par, 50,000,000 shares authorized, 28,919,561 and 34,308,861 shares issued and outstanding at December 31, 2002 and 2003, respectively	14,460	17,154
Additional paid-in capital	133,828	166,242
Retained earnings	61,663	115,032
Deferred compensation-restricted stock grants	(1,487)	(8,772)
Accumulated other comprehensive loss	(37)	—
Total stockholders' equity	208,427	289,656
Commitments and Contingencies		
	$ 711,053	$ 760,956

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2001, 2002 and 2003

	2001	2002	2003
	(In thousands, except per share amounts)		
Oil and gas sales	$166,118	$142,085	$235,102
Operating expenses:			
Oil and gas operating	31,855	33,499	45,746
Exploration	6,611	5,479	4,410
Depreciation, depletion and amortization	47,429	53,155	61,169
Impairment	1,400	—	4,255
General and administrative, net	4,351	5,113	7,006
Total operating expenses	91,646	97,246	122,586
Income from operations	74,472	44,839	112,516
Other income (expenses):			
Interest income	196	62	73
Interest expense	(22,098)	(31,252)	(29,860)
Gain (loss) from derivatives	243	(2,326)	(3)
Other income	272	8,027	223
	(21,387)	(25,489)	(29,567)
Income from continuing operations before income tax expense	53,085	19,350	82,949
Income tax expense	(18,579)	(6,773)	(29,682)
Net income from continuing operations	34,506	12,577	53,267
Discontinued operations including loss on disposal, net of income taxes	396	(1,072)	—
Cumulative effect of change in accounting principle, net of income taxes	—	—	675
Net income	34,902	11,505	53,942
Preferred stock dividends	(1,604)	(1,604)	(573)
Net income attributable to common stock	$ 33,298	$ 9,901	$ 53,369
Basic net income per share:			
From continuing operations	$ 1.13	$ 0.38	$ 1.65
Discontinued operations	0.02	(0.04)	—
Cumulative effect of change in accounting principle	—	—	0.02
	$ 1.15	$ 0.34	$ 1.67
Diluted net income per share:			
From continuing operations	$ 1.00	$ 0.37	$ 1.51
Discontinued operations	0.01	(0.03)	—
Cumulative effect of change in accounting principle	—	—	0.02
	$ 1.01	$ 0.34	$ 1.53
Weighted average shares outstanding:			
Basic	29,030	28,764	31,964
Diluted	34,552	33,901	35,275

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2001, 2002 and 2003

	Common Stock	Additional Paid-In Capital	Retained Earnings	Deferred Compensation Restricted Stock Grants	Accumulated Other Comprehensive Income	Total
			(In thousands)			
Balance at December 31, 2000	$14,419	$129,896	$ 18,464	$(1,044)	$ —	$161,735
Issuance of common stock, net of deferred income taxes	283	3,538	—	—	—	3,821
Value of stock options issued for exploration prospects, net of deferred income taxes	—	1,968	—	—	—	1,968
Restricted stock grants, net of amortization	28	333	—	(143)	—	218
Repurchases of common stock	(454)	(4,779)	—	—	—	(5,233)
Preferred stock dividends	—	—	(1,604)	—	—	(1,604)
Net income	—	—	34,902	—	—	34,902
Unrealized hedge losses, net of income taxes	—	—	—	—	(139)	(139)
Comprehensive income	—	—	—	—	—	34,763
Balance at December 31, 2001	14,276	130,956	51,762	(1,187)	(139)	195,668
Issuance of common stock, net of deferred income taxes	156	1,547	—	—	—	1,703
Value of stock options issued for exploration prospects, net of deferred income taxes	—	836	—	—	—	836
Restricted stock grants, net of amortization	28	489	—	(300)	—	217
Preferred stock dividends	—	—	(1,604)	—	—	(1,604)
Net income	—	—	11,505	—	—	11,505
Unrealized hedge gains, net of income taxes	—	—	—	—	102	102
Comprehensive income	—	—	—	—	—	11,607
Balance at December 31, 2002	14,460	133,828	61,663	(1,487)	(37)	208,427
Issuance of common stock, net of deferred income taxes	287	4,697	—	—	—	4,984
Conversion of preferred stock	2,197	15,376	—	—	—	17,573
Value of stock options issued for exploration prospects, net of deferred income taxes	—	4,907	—	—	—	4,907
Restricted stock grants, net of amortization	210	7,434	—	(7,285)	—	359
Preferred stock dividends	—	—	(573)	—	—	(573)
Net income	—	—	53,942	—	—	53,942
Unrealized hedge gains, net of income taxes	—	—	—	—	37	37
Comprehensive income	—	—	—	—	—	53,979
Balance at December 31, 2003	$17,154	$166,242	$115,032	$(8,772)	$ —	$289,656

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2001, 2002 and 2003

	2001	2002	2003
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 34,902	$ 11,505	$ 53,942
Adjustments to reconcile net income to net cash provided by operating activities, net of acquisition effects:			
Cumulative effect of change in accounting principle, net of income taxes	—	—	(675)
Compensation paid in common stock	244	218	359
Depreciation, depletion and amortization	47,429	53,155	61,169
Debt issuance costs amortization	1,361	1,250	1,200
Impairment of oil and gas properties	1,400	—	4,255
Deferred income taxes	17,799	6,773	27,982
Dry hole costs and leasehold impairments	4,215	5,139	3,723
Gain on sales of property	(12)	—	—
Unrealized gain on derivatives	(254)	(119)	—
Non-cash effect of discontinued operations, net	614	1,395	—
Working capital provided by operations	107,698	79,316	151,955
Decrease (increase) in accounts receivable	18,371	(10,810)	(10,450)
Decrease (increase) in other current assets	(1,229)	4,740	(2,124)
Increase (decrease) in accounts payable and accrued expenses	(16,204)	11,191	14,404
Net cash provided by operating activities	108,636	84,437	153,785
CASH FLOWS FROM INVESTING ACTIVITIES:			
Proceeds from sales of properties	45	3,478	—
Capital expenditures and acquisitions	(188,192)	(83,381)	(92,930)
Net cash used for investing activities	(188,147)	(79,903)	(92,930)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings	261,730	31,736	23,402
Proceeds from senior notes offering	—	75,000	—
Debt issuance costs	—	(2,267)	—
Principal payments on debt	(178,355)	(112,928)	(83,051)
Proceeds from common stock issuances	1,989	1,089	3,028
Repurchases of common stock	(5,232)	—	—
Dividends paid on preferred stock	(1,604)	(1,604)	(573)
Net cash provided by (used for) financing activities	78,528	(8,974)	(57,194)
Net increase (decrease) in cash and cash equivalents	(983)	(4,440)	3,661
Cash and cash equivalents, beginning of year	7,105	6,122	1,682
Cash and cash equivalents, end of year	$ 6,122	$ 1,682	$ 5,343

The accompanying notes are an integral part of these statements.

(1) Summary of Significant Accounting Policies

Accounting policies used by Comstock Resources, Inc. ("Comstock" or the "Company") reflect oil and natural gas industry practices and conform to accounting principles generally accepted in the United States of America.

Basis of Presentation and Principles of Consolidation

Comstock is engaged in oil and natural gas exploration, development and production, and the acquisition of producing oil and natural gas properties. The consolidated financial statements include the accounts of Comstock and its wholly owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation.

Reclassifications

Certain reclassifications have been made to prior periods' financial statements to conform to the current presentation.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from those estimates. Changes in the future estimated oil and natural gas reserves or the estimated future cash flows attributable to the reserves that are utilized for impairment analysis could have a significant impact on the future results of operations.

Concentration of Credit Risk and Accounts Receivable

Financial instruments that potentially subject Comstock to a concentration of credit risk consist principally of cash and cash equivalents, accounts receivable and derivative financial instruments, Comstock places its cash with high credit quality financial institutions and its derivative financial instruments with financial institutions and other firms that management believes have high credit rating. For a discussion of the credit risks associated with Comstock's hedging activities, see Note 11. Substantially all of Comstock's accounts receivable are due from either purchasers of oil and gas or participants in oil and gas wells for which Comstock serves as the operator. Generally, operators of oil and gas wells have the right to offset future revenues against unpaid charges related to operated wells. Oil and gas sales are generally unsecured. Comstock's credit losses consistently have been within management's expectations.

Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair value of the Company's financial instruments as of December 31, 2002 and 2003:

	2002		2003	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Long term debt, including current portion	$366,272	$379,472	$306,623	$321,198

The fair market value of the fixed rate debt was based on the market price as of December 31, 2002 and 2003.

Derivatives are presented at their estimated fair value. The carrying amounts of cash and cash equivalents, accounts receivable, other current assets, and accounts payable and accrued expenses approximate fair value due to the short maturity of these instruments.

Other Current Assets

Other current assets at December 31, 2002 and 2003 consist of the following:

	As of December 31,	
	2002	2003
	(In thousands)	
Prepaid expenses	$1,109	$4,279
Insurance claims receivable	1,125	—
Inventory	444	523
	$2,678	$4,802

Property and Equipment

Comstock follows the successful efforts method of accounting for its oil and natural gas properties. Acquisition costs for proved oil and natural gas properties, costs of drilling and equipping productive wells, and costs of unsuccessful development wells are capitalized and amortized on an equivalent unit-of-production basis over the life of the remaining related oil and gas reserves. Equivalent units are determined by converting oil to natural gas at the ratio of six barrels of oil for one thousand cubic feet of natural gas. Cost centers for amortization purposes are determined on a field area basis. The estimated future costs of dismantlement, restoration and abandonment are included on the balance sheet in the reserve for future abandonment and accrued as part of depreciation, depletion and amortization expense. Costs incurred to acquire oil and gas leasehold are capitalized. Unproved oil and gas properties are periodically assessed and any impairment in value is charged to exploration expense. The costs of unproved properties which are determined to be productive are transferred to proved oil and gas properties and amortized on an equivalent unit-of-production basis. Exploratory expenses, including geological and geophysical expenses and delay rentals for unevaluated oil and gas properties, are charged to expense as incurred. Exploratory drilling costs are initially capitalized as unproved property but charged to expense if and when the well is determined not to have found proved oil and gas reserves.

In accordance with the Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS 144"), Comstock assesses the need for an impairment of the costs capitalized of its oil and gas properties on a property or cost center basis. If an impairment is indicated based on undiscounted expected future cash flows, then an impairment is recognized to the extent that net capitalized costs exceed discounted expected future cash flows based on escalated prices and including risk adjusted probable reserves, where appropriate. In 2001 and 2003, Comstock had a $1.4 million and $4.3 million, respectively, impairment of its oil and gas properties which primarily related to some minor valued fields where an impairment was indicated based on estimated future cash flows attributable to the fields' estimated proved oil and natural gas reserves.

Other property and equipment consists primarily of fractional interests in aircraft, work boats, gas gathering systems, computer equipment and furniture and fixtures which are depreciated over estimated useful lives ranging from 5 to 31½ years on a straight-line basis.

Other Assets

Other assets primarily consist of deferred costs associated with issuance of Comstock's 11¼% senior notes. These costs are amortized over the eight year life of the senior notes on a straight-line basis which approximates the amortization that would be calculated using an effective interest rate method.

Stock Options

Comstock applies the intrinsic value-based method of accounting prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB 25"), and related interpretations, in accounting for its incentive plan stock options. As such, compensation expense would be recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price. Statement of Financial Accounting Standards 123, "Accounting for Stock-Based Compensation" ("SFAS 123"), established accounting and disclosure requirements using a fair value-based method of accounting for stock-based employee compensation plans. As allowed by SFAS 123, Comstock has elected to continue to apply the intrinsic value-based method of accounting described above, and has adopted the disclosure requirements of SFAS 123.

The following table illustrates the effect on net income if the fair value based method had been applied to all outstanding stock options in each period.

	Year Ended December 31,		
	2001	2002	2003
	(In thousands, except per share amounts)		
Net income, as reported	$33,298	$ 9,901	$53,369
Add stock-based employee compensation expense included in reported net income, net of income taxes	159	142	233
Deduct total stock-based employee compensation expense determined under fair value based method for all rewards, net of income taxes	(1,845)	(1,066)	(1,942)
Pro forma net income	$31,612	$ 8,977	$51,660
Basic earnings per share:			
As Reported	$ 1.15	$ 0.34	$ 1.67
Pro Forma	$ 1.09	$ 0.31	$ 1.62
Diluted earnings per share:			
As Reported	$ 1.01	$ 0.34	$ 1.53
Pro Forma	$ 0.96	$ 0.31	$ 1.48

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for grants in 2001, 2002 and 2003, respectively: average risk-free interest rates of 4.9, 3.8 and 3.0%; average expected lives of 7.4, 5.9 and 5.9 years; average expected volatility factors of 67.2, 68.9 and 32.8; and 0% dividend yield for all years. The estimated weighted average fair value of options to purchase one share of common stock issued under the Company's Incentive Plans was $6.80 in 2001, $5.88 in 2002 and $6.38 in 2003.

Segment Reporting

Comstock presently operates in one business segment, the exploration and production of oil and natural gas.

Derivative Instruments and Hedging Activities

On January 1, 2001, Comstock adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"), which requires that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Comstock estimates fair value based on quotes obtained from the counterparties to the derivative contract. The fair value of derivative contracts that expire in less than one year are recognized as current assets or liabilities. Those that expire in more than one year are recognized as long-term assets or liabilities. Derivative financial instruments that are not accounted for as hedges are adjusted to fair value through income. If the derivative is designated as a cash flow hedge, changes in fair value are recognized in other comprehensive income until the hedged item is recognized in earnings.

Major Purchasers

In 2003, Comstock had three purchasers of its oil and natural gas production which individually accounted for 10% or more of total oil and gas sales. Such purchasers accounted for 18%, 14% and 10% of total 2003 oil and gas sales. In 2002, Comstock had two purchasers which accounted for 16% and 15% of total 2002 oil and gas sales. In 2001, Comstock had four purchasers which accounted for 24%, 19%, 16% and 12% of total 2001 oil and gas sales.

Revenue Recognition and Gas Balancing

Comstock utilizes the sales method of accounting for natural gas revenues whereby revenues are recognized based on the amount of gas sold to purchasers. The amount of gas sold may differ from the amount to which the Company is entitled based on its revenue interests in the properties. Comstock did not have any significant imbalance positions at December 31, 2001, 2002 or 2003.

General and Administrative Expenses

General and administrative expenses are reported net of reimbursements of overhead costs that are allocated to working interest owners of the oil and gas properties operated by Comstock.

Other Income

Included in other income in 2002 was $7.7 million related to refunds received in 2002 of severance taxes paid in prior years.

Income Taxes

Comstock accounts for income taxes using the asset and liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis, as well as the future tax consequences attributable to the future utilization of existing tax net operating loss and other types of carryforwards. 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 and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Comprehensive Income

Comprehensive income is defined as the change in equity of a business enterprise during a period from transactions and other events and circumstances from non-owner sources.

Earnings Per Share

Basic and diluted earnings per share for 2001, 2002 and 2003 were determined as follows:

	Year Ended December 31,								
	2001			2002			2003		
	Income	Shares	Per Share	Income	Shares	Per Share	Income	Shares	Per Share
	(In thousands except per share data)								
Basic Earnings Per Share:									
Net Income from Continuing Operations	$34,506	29,030		$12,577	28,764		$53,267	31,964	
Less Preferred Stock Dividends	(1,604)	—		(1,604)	—		(573)	—	
Net Income from Continuing Operations Available to Common Stockholders	32,902	29,030	$1.13	10,973	28,764	$ 0.38	52,694	31,964	$1.65
Income (loss) from Discontinued Operations, net of Income Taxes	396	29,030	0.02	(1,072)	28,764	(0.04)	—	31,964	—
Cumulative Effect of Change in Accounting Principle, net of Income Taxes	—	29,030	—	—	28,764	—	675	31,964	0.02
Net Income Available to Common Stockholders	$33,298	29,030	$1.15	$ 9,901	28,764	$ 0.34	$53,369	31,964	$1.67
Diluted Earnings Per Share:									
Net Income from Continuing Operations	$34,506	29,030		$12,577	28,764		$53,267	31,964	
Effect of Dilutive Securities:									
Stock Options	—	1,129		—	744		—	1,742	
Convertible Preferred Stock	—	4,393		—	4,393		—	1,569	
Net Income from Continuing Operations Available to Common Stockholders With Assumed Conversions	34,506	34,552	$1.00	12,577	33,901	$ 0.37	53,267	35,275	$1.51
Income (loss) from Discontinued Operations, net of Income Taxes	396	34,552	0.01	(1,072)	33,901	(0.03)	—	35,275	—
Cumulative Effect of Change in Accounting Principle, net of Income Taxes	—	34,552	—	—	33,901	—	675	35,275	0.02
Net Income Available to Common Stockholders	$34,902	34,552	$1.01	$11,505	33,901	$ 0.34	$53,942	35,275	$1.53

Stock options and warrants to purchase common stock at exercise prices in excess of the average actual stock price for the period that were anti-dilutive and that were excluded from the determination of diluted earnings per share are as follows:

	2001	2002	2003
	(In thousands except per share data)		
Stock options and warrants to purchase common stock	2,559	2,737	790
Exercise Price	\$9.63 - \$14.00	\$8.06 - \$14.00	\$13.59 - \$14.00

Statements of Cash Flows

For the purpose of the consolidated statements of cash flows, Comstock considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

The following is a summary of all significant noncash investing and financing activities and cash payments made for interest and income taxes:

	Year Ended December 31,		
	2001	2002	2003
	(In thousands)		
Noncash activities —			
Common stock issued for director compensation	\$ 26	\$ —	\$ —
Conversion of preferred stock	—	—	17,573
Value of vested stock options under exploration venture	3,028	1,286	7,549
Cash payments —			
Interest payments	\$20,837	\$28,987	\$29,115
Income tax payments	243	—	—

New Accounting Standards

Comstock adopted Statement of Financial Accounting Standards No. 143 ("SFAS 143") "Accounting for Asset Retirement Obligations," on January 1, 2003. This statement requires Comstock to record a liability in the period in which an asset retirement obligation ("ARO") is incurred, in an amount equal to the discounted estimated fair value of the obligation that is capitalized. Thereafter, each quarter, this liability is accreted up to the final retirement cost.

The adoption of SFAS 143 on January 1, 2003 resulted in a cumulative effect adjustment to record (i) a \$3.7 million decrease in the carrying value of oil and gas properties, (ii) a \$3.3 million decrease in accumulated depletion, depreciation and amortization, (iii) a \$1.5 million decrease in reserve for future abandonment, and (iv) a gain of \$675,000, net of income taxes, which was reflected as the cumulative effect of a change in accounting principle.

The following pro forma data summarizes the Company's net income and net income per share for the years ended December 31, 2001, 2002 and 2003 as if the Company had adopted the provisions of SFAS 143 on December 31, 2000, including aggregate pro forma asset retirement obligations on that date of $4.9 million.

	For the Year Ended December 31,		
	2001	2002	2003
	(In thousands except per share amounts)		
Net income, as reported	$34,902	$11,505	$53,942
Pro forma adjustments to reflect retroactive adoption of SFAS 143	7	(167)	(675)
Pro forma net income	$34,909	$11,338	$53,267
Net income per share:			
Basic – as reported	$ 1.15	$ 0.34	$ 1.67
Basic – pro forma	$ 1.15	$ 0.34	$ 1.65
Diluted – as reported	$ 1.01	$ 0.34	$ 1.53
Diluted – pro forma	$ 1.01	$ 0.33	$ 1.51

Comstock's primary asset retirement obligations relate to future plugging and abandonment expenses on its oil and gas properties and related facilities disposal. As of December 31, 2003, Comstock had $1.6 million held in an escrow account from which funds are released only for reimbursement of plugging and abandonment expenses on certain offshore oil and gas properties. This amount is included in Other Assets in the consolidated balance sheet.

The following table summarizes the changes in Comstock's total estimated liability:

	For the Year Ended December 31,		
	2001	2002	2003
	(In thousands)		
Beginning asset retirement obligations	$7,557	$ 7,794	$16,677
Cumulative effect adjustment	—	—	(1,476)
New wells placed on production and changes in estimates	237	826	(875)
Acquisition liabilities assumed	—	8,682	4,787
Liabilities settled	—	(625)	(685)
Accretion expense	—	—	746
Ending asset retirement obligations	$7,794	$16,677	$19,174

On January 1, 2003, Comstock adopted the provisions of Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections" ("SFAS 145"). Prior to SFAS 145, gains or losses on the early extinguishment of debt were required to be classified in a company's statements of operations as extraordinary gains or losses, net of associated income taxes, after the determination of income or loss from continuing operations. SFAS 145 requires, except in the case of events or transactions of a highly unusual and infrequent nature, that gains or losses from the early extinguishment of debt be classified as components of a company's income or loss from continuing operations. The adoption of the provisions of SFAS 145 did not affect Comstock"s financial position or reported financial results. Under the provisions of SFAS 145, gains or losses from the early extinguishment of debt will be recognized in the Consolidated Statements of Operations as components of other income or other expense and will be included in the determination of the income (loss) from continuing operations of those periods.

Comstock also adopted Statement of Financial Accounting Standards No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" ("SFAS 146"), in 2003. This statement establishes accounting and reporting standards that are effective for exit or disposal activities beginning after December 31, 2002 which require that a liability be recognized for an exit or disposal activity when that liability is incurred. The adoption of SFAS 146 had no effect on Comstock's financial statements.

In December 2002, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 148, "Accounting for Stock-Based Compensation — Transition and Disclosure, an amendment of FASB Statement No. 123". This Statement amends Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" ("SFAS 123"), to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS 123 to require prominent disclosures in both annual and interim financial statements. Certain of the disclosure modifications are included in the notes to these consolidated financial statements.

In January 2003, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirement for Guarantees, including Indirect Guarantees of Indebtedness of Others" ("FIN 45"). FIN 45 requires an entity to recognize a liability for the obligations it has undertaken in issuing a guarantee. This liability would be recorded at the inception of a guarantee and would be measured at fair value. Certain guarantees are excluded from the measurement and disclosure provisions while certain other guarantees are excluded from the measurement provisions of the interpretation. The adoption of the statement in 2003 had no effect on Comstock's financial statements.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities" ("FIN 46"), which was modified in December 2003. FIN 46 requires an entity to consolidate a variable interest entity if it is designated as the primary beneficiary of that entity even if the entity does not have a majority of voting interests. A variable interest entity is generally defined as an entity whose equity is unable to finance its activities or where the owners of the entity lack the risks and rewards of ownership. Comstock is not the primary beneficiary of any variable interest entities, and accordingly, the adoption of FIN 46 is not expected to have a material effect on Comstock's financial statements when adopted.

Comstock has been made aware of an issue that has arisen in the industry regarding the application of certain provisions of Statement of Financial Accounting Standards No. 141, "Business Combinations" ("SFAS 141"), and Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" ("SFAS 142"), to companies in the extractive industries, including oil and gas exploration and production companies. The issue is whether the provisions of SFAS 141 and SFAS 142 require companies to classify costs associated with mineral rights, including both proved and unproved lease acquisition costs, as intangible assets on the balance sheet, apart from other capitalized oil and gas property costs. Historically, Comstock has included oil and gas lease acquisition costs as a component of oil and gas properties. Also under consideration is whether SFAS 142 requires companies to provide additional disclosures prescribed by SFAS 142 for intangible assets for costs associated with mineral rights. In the event it is determined that costs associated with mineral rights are required to be classified as intangible assets, a substantial portion of Comstock's capitalized oil and gas property costs would be separately classified on our balance sheet as intangible assets. The reclassification of these amounts would not affect the method in which such costs are amortized or the manner in which Comstock assesses impairment of capitalized costs. As a result, net income would not be affected by the reclassification if it were to occur. As of December 31, 2003, Comstock had $380.6 million in capitalized leasehold costs, net of accumulated depletion.

(2) Acquisitions

In December 2002, Comstock acquired an interest in the Ship Shoal 113 Unit for $7.8 million. The acquisition included interests in 26 producing wells, 11.7 net wells, and seven production facilities in the Gulf of Mexico. In October 2003, Comstock acquired an additional interest in the Ship Shoal 113 Unit for $4.6 million.

Comstock also acquired interests in a South Texas field for $1.7 million in December 2002. The acquisition included interests in 15 producing wells, 15 net wells.

In December 2001, Comstock completed the acquisition of DevX Energy, Inc. ("DevX") by acquiring 100% of the common stock of DevX for $92.6 million through a cash tender offer and subsequent merger into a wholly owned subsidiary. As a result of the acquisition, DevX became a wholly owned subsidiary of Comstock. DevX was an independent energy company engaged in the exploration, development and acquisition of oil and gas properties. At the time of the acquisition, DevX owned interests in 600 producing oil and gas wells located onshore primarily in East and South Texas, Kentucky, Oklahoma and Kansas. The DevX acquisition added approximately 163.4 billion cubic feet equivalent of natural gas reserves to Comstock's reserve base (unaudited). Subsequent to the acquisition, Comstock repurchased approximately $49.8 million of DevX's 12½% senior notes which were due in 2008 for 110% of the principal amount plus accrued interest.

DevX's operations have been included in the consolidated financial statements since December 17, 2001.

The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition.

	December 17, 2001
	(In thousands)
Current assets	$ 8,317
Oil and gas properties	160,794
Derivatives	1,577
Total assets acquired	170,688
Current liabilities	8,990
Long-term debt	54,988
Deferred tax liability	7,324
Derivatives	1,873
Total liabilities assumed	73,175
Net assets acquired	$ 97,513

Set forth in the following table is certain unaudited pro forma financial information for the year ended December 31, 2001. This information has been prepared assuming the DevX acquisition was consummated on January 1, 2001 and is based on estimates and assumptions deemed appropriate by Comstock. The pro forma information is presented for illustrative purposes only. If the transactions had occurred in the past, Comstock's operating results might have been different from those presented in the following table. The pro forma information should not be relied upon as an indication of the operating results that Comstock would have achieved if the transactions had occurred on January 1, 2001. The pro forma information also should not be used as an indication of the future results that Comstock will achieve after the acquisition. Adjustments were made to adjust the historical operating results of DevX (i) to conform DevX to the successful efforts method of accounting for oil and gas activities; (ii) to reverse the costs of the closed Dallas and Ottawa corporate offices of DevX; and (iii) to record the pro forma interest expense based on Comstock's average interest rate under its bank credit facility.

	Year Ended December 31, 2001
	(In thousands, except per share amounts)
Oil and gas sales	$ 204,717
Total operating expenses	(113,349)
Total other income (expenses)	(24,947)
Income from continuing operations before income taxes	66,421
Provision for income taxes	(23,247)
Income from continuing operations	43,174
Discontinued operations	396
Net income	43,570
Preferred stock dividends	(1,604)
Net income from continuing operations attributable to common stock	$ 41,966
Net income from continuing operations per share:	
Basic	$ 1.42
Diluted	$ 1.24
Net income per share:	
Basic	$ 1.45
Diluted	$ 1.26

(3) Oil and Gas Producing Activities

Set forth below is certain information regarding the aggregate capitalized costs of oil and gas properties and costs incurred by Comstock for its oil and gas property acquisition, development and exploration activities:

Capitalized Costs

	As of December 31,	
	2002	2003
	(In thousands)	
Proved properties	$ 961,562	$1,052,564
Unproved properties	14,880	18,075
Accumulated depreciation, depletion and amortization	(313,608)	(374,686)
	$ 662,834	$ 695,953

Costs Incurred

	For the Year Ended December 31,		
	2001	2002	2003
	(In thousands)		
Property acquisitions			
Proved properties	$160,794	$11,435	$ 4,805
Unproved properties	7,113	4,268	4,447
Development costs	51,090	35,272	46,798
Exploration costs	35,778	31,414	35,516
Capitalized asset retirement costs	237	8,884	3,227
	$255,012	$91,273	$94,793

Due to the tax-free nature of the merger between Comstock and DevX in December 2001, additional deferred tax liabilities of $7.3 million were allocated to proved oil and gas properties and are included in the proved property acquisition costs in 2001.

In 2001, 2002 and 2003, Comstock capitalized interest expense of $230,000, $281,000 and $422,000, respectively, on its unproved properties under development which is included in the unproved property acquisition costs in each year.

Results of Operations for Oil and Gas Producing Activities

The following table includes revenues and expenses associated directly with Comstock's oil and natural gas producing activities. The amounts presented do not include any allocation of Comstock's interest costs or general corporate overhead and, therefore, are not necessarily indicative of the contribution to net earnings of Comstock's oil and gas operations. Income tax expense has been calculated by applying statutory income tax rates to oil and gas sales after deducting costs, including depreciation, depletion and amortization and after giving effect to permanent differences.

	For the Year Ended December 31,		
	2001	2002	2003
	(In thousands)		
Oil and gas sales	$166,118	$142,085	$235,102
Operating expenses:			
Oil and gas operating	(31,855)	(33,499)	(45,746)
Exploration	(6,611)	(5,479)	(4,410)
Depreciation, depletion and amortization	(47,140)	(52,869)	(60,867)
Impairment	(1,400)	—	(4,255)
Income from continuing operations	79,112	50,238	119,824
Provision for income taxes	(27,689)	(17,583)	(41,938)
Income from continuing operations, after tax	51,423	32,655	77,886
Discontinued operations, including loss on disposal, net of income taxes	396	(1,072)	—
Results of operations of oil and gas producing activities	$ 51,819	$ 31,583	$ 77,886

(4) Long-Term Debt

Long-term debt is comprised of the following:

	As of December 31, 2002	As of December 31, 2003
	(In thousands)	
Revolving Bank Credit Facility	$146,000	$ 86,000
11¼% Senior Notes due 2007	220,000	220,000
Other	272	623
	366,272	306,623
Less current portion	(270)	(623)
	$366,002	$306,000

At December 31, 2003, Comstock had a $350.0 million three year revolving credit commitment provided by a syndicate of banks for which Toronto Dominion (Texas), Inc. served as administrative agent. The bank credit facility was subject to borrowing base availability, which was redetermined semiannually based on the banks' estimates of the future net cash flows of Comstock's oil and natural gas properties. The borrowing base at December 31, 2003 was $260.0 million. Interest charged on the revolving credit line was based on the utilization of the borrowing base, at the option of Comstock at either (i) LIBOR plus 1.5% to 2.375% or (ii) the corporate base rate (generally the federal funds rate plus 0.5%) plus 0.5% to 1.375%. The facility would have matured on January 2, 2005. Indebtedness under the bank credit facility was secured by substantially all of Comstock's assets and Comstock's subsidiaries were guarantors of the bank credit facility. The bank credit facility contained covenants that, among other things, restricted the payment of cash dividends, limited the amount of consolidated debt and limited Comstock's ability to make certain loans and investments. Financial covenants included the maintenance of a current ratio, maintenance of tangible net worth and maintenance of an interest coverage ratio. The Company was in compliance with these covenants as of December 31, 2003.

Comstock issued $150.0 million in aggregate principal amount of 11¼% Senior Notes due in 2007 (the "1999 Notes") on April 29, 1999. Interest on the 1999 Notes is payable semiannually on May 1 and November 1, commencing on November 1, 1999. The 1999 Notes are unsecured obligations of Comstock and are guaranteed by all of its principal operating subsidiaries. The 1999 Notes can be redeemed beginning on May 1, 2004. Comstock repurchased $5.0 million of the 1999 Notes in July 2001. On March 7, 2002, Comstock closed the sale in a private placement of $75.0 million of additional 1999 Notes. As a result of this transaction, $220.0 million of aggregate principal amount of the 1999 Notes were outstanding at December 31, 2003.

The following table summarizes our debt as of December 31, 2003 by year of maturity:

	2004	2005	2006	2007	Total
Bank credit facility	$ —	$ 86,000	$ —	$ —	$ 86,000
11¼% Senior Notes	—	—	—	220,000	220,000
Other debt	623	—	—	—	623
	$ 623	$ 86,000	—	$220,000	$306,623

Pursuant to a tender offer, Comstock repurchased $197.7 million in principal amount of the 1999 Notes for $212.2 million plus accrued interest on February 25, 2004. Comstock intends to redeem the remaining $22.3 million in principal amount of the 1999 Notes on May 1, 2004 when the notes are first callable at a price of 105.625 of par value. The total amount required to repurchase the remaining outstanding 1999 Notes is $23.6 million. The early extinguishment of the 1999 Notes will result in a pretax loss of $19.8 million in 2004.

In connection with the repurchase of the 1999 Notes, Comstock sold $175.0 million of senior notes in an underwritten public offering. The new senior notes are due on March 1, 2012 and bear interest at 6⅞% which is payable semiannually on March 1 and September 1, commencing September 1, 2004. The notes are unsecured obligations of Comstock and are currently guaranteed by all of its subsidiaries.

On February 25, 2004, Comstock also entered into a new $400.0 million bank credit facility with Bank of Montreal, as the administrative agent. The new credit facility is a four year revolving credit commitment that matures on February 25, 2008. Borrowings under the new credit facility are limited to a borrowing base that will be set at $300.0 million upon the retirement of all of the 1999 Notes. Borrowings under the new credit facility were used to refinance amounts outstanding under the prior bank credit facility and to fund the repurchase of the 1999 Notes.

Indebtedness under the new credit facility is secured by substantially all of Comstock's assets and is guaranteed by all of its subsidiaries. The new credit facility is subject to borrowing base availability, which will be redetermined semiannually based on the banks' estimates of the future net cash flows of our oil and natural gas properties. The borrowing base may be affected by the performance of Comstock's properties and changes in oil and natural gas prices. The determination of the borrowing base will be at the sole discretion of the administrative agent and the bank group. Borrowings under the new credit facility will bear interest, based on the utilization of the of the borrowing base, at Comstock's option at either (1) LIBOR plus 1.25% to 1.75% or (2) the base rate (which is the higher of the prime rate or the federal funds rate) plus 0% to 0.5%. A commitment fee of 0.375% is payable on the unused borrowing base. The new credit facility contains covenants that, among other things, restrict the payment of cash dividends, limit the amount of consolidated debt that Comstock may incur and limit the Company's ability to make certain loans and investments. The only financial covenants are the maintenance of a current ratio and maintenance of a minimum tangible net worth.

(5) Commitments and Contingencies

Lease Commitments

Comstock rents office space under noncancelable leases. Rent expense for the years ended December 31, 2001, 2002 and 2003 was $526,000, $495,000 and $535,000, respectively. Minimum future payments under the leases are as follows:

	(In thousands)
2004	491
2005	516
2006	238
2007	10
	$1,255

Contingencies

From time to time, Comstock is involved in certain litigation that arises in the normal course of its operations. The Company records a loss contingency for these matters when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. Comstock has accrued $2.0 million related to its estimate of losses to be incurred in resolving certain contingencies. After consideration of amounts accrued, the Company does not believe the resolution of these matters will have a material effect on the Company's financial position or results of operations.

(6) Convertible Preferred Stock

On December 31, 2002, Comstock had 1,757,310 shares of convertible preferred stock (the "Series 1999 Preferred Stock") outstanding. The Series 1999 Preferred Stock accrued dividends at an annual rate of 9% which were payable quarterly in cash or Comstock had the option to issue shares of common stock. Dividends paid per share were $0.91 per share in 2001 and 2002 and $0.33 in 2003. Each share of the Series 1999 Preferred Stock was convertible, at the option of the holder, into 2.5 shares of common stock. In April and June of 2003, the holders of the Series 1999 Preferred Stock converted their preferred shares into 4,393,275 shares of common stock, resulting in no shares of the Series 1999 Preferred Stock remaining outstanding. This conversion reduced Comstock's annual preferred stock dividend requirement by $1.6 million and increased stockholders' equity by $17.6 million.

(7) Stockholders' Equity

The authorized capital stock of Comstock consists of 50 million shares of common stock, $.50 par value per share (the "Common Stock"), and 5 million shares of preferred stock, $10.00 par value per share. The preferred stock may be issued in one or more series, and the terms and rights of such stock will be determined by the Board of Directors. There were no shares of preferred stock outstanding at December 31, 2003.

Comstock's Board of Directors has designated 500,000 shares of the preferred stock as Series B Junior Participating Preferred Stock (the "Series B Junior Preferred Stock") in connection with the adoption of a shareholder rights plan. At December 31, 2003, there were no shares of Series B Junior Preferred Stock issued or outstanding. The Series B Junior Preferred Stock is entitled to receive cumulative quarterly dividends per share equal to the greater of $1.00 or 100 times the aggregate per share amount of all dividends (other than stock dividends) declared on Common Stock since the immediately preceding quarterly dividend payment date or, with respect to the first payment date, since the first issuance of Series B Junior Preferred Stock. Holders of the Series B Junior Preferred Stock are entitled to 100 votes per share (subject to adjustment to prevent dilution) on all matters submitted to a vote of the stockholders. The Series B Junior Preferred Stock is neither redeemable nor convertible. The Series B Junior Preferred Stock ranks prior to the Common Stock but junior to all other classes of preferred stock.

Under a plan adopted by the Board of Directors, non-employee directors can elect to receive shares of Common Stock valued at the then current market price in payment of annual director and consulting fees. Under this plan, Comstock issued 5,342 shares of Common Stock in 2001, in payment of fees aggregating $26,000.

Stock options were exercised to purchase 560,606 shares, 310,758 shares and 576,025 shares in 2001, 2002 and 2003, respectively. Such exercises yielded net proceeds of approximately $2.0 million, $1.1 million and $3.0 million in 2001, 2002, and 2003, respectively.

During 2001, Comstock repurchased 907,400 shares of Common Stock in open market purchases totaling $5.2 million. Such shares were retired upon repurchase.

Stock Options

On June 23, 1999, the stockholders approved the 1999 Long-term Incentive Plan for the management including officers, directors and managerial employees which replaced the 1991 Long-term Incentive Plan. The 1999 Long-term Incentive Plan together with the 1991 Long-term Incentive Plan (collectively, the "Incentive Plans") authorize the grant of non-qualified stock options and incentive stock options and the grant of restricted stock to key executives of Comstock. The options under the Incentive Plans have contractual lives ranging from five to ten years and become exercisable after lapses in vesting periods ranging from zero to ten years from the grant date. As of December 31, 2003, the Incentive Plans provide for future awards of stock options or restricted stock grants of up to 318,082 shares of Common Stock plus 1% of the outstanding shares of Common Stock each year beginning on January 1, 2004.

The following table summarizes information about the Incentive Plans stock options outstanding at December 31, 2003:

Exercise Price	Number of Shares Outstanding	Weighted Average Remaining Life (Years)	Number of Shares Exercisable
$ 3.44	90,000	3.8	90,000
3.88	731,250	4.5	731,250
6.42	437,750	5.1	176,000
6.69	45,000	4.5	32,500
7.40	10,000	2.6	10,000
8.70	30,000	3.4	30,000
8.88	249,250	5.5	—
9.20	273,750	5.0	1,000
11.00	1,150,000	2.0	1,150,000
11.12	33,500	4.0	21,000
12.15	30,000	4.4	30,000
12.38	328,250	2.8	328,250
18.20	140,500	6.0	1,500
	3,549,250		2,601,500

The following table summarizes stock option activity during 2001, 2002 and 2003 under the Incentive Plans:

	Number of Shares	Exercise Price	Weighted Average Exercise Price
Outstanding at December 31, 2000	4,689,850	$ 2.00 to $12.38	$ 7.45
Granted	493,250	$ 6.42 to $11.12	$ 6.80
Exercised	(580,450)	$ 2.00 to $11.94	$ 3.86
Forfeited	(213,000)	$ 6.56 to $11.12	$ 6.61
Outstanding at December 31, 2001	4,389,650	$ 2.50 to $12.38	$ 7.89
Granted	303,750	$ 8.70 to $9.20	$ 9.15
Exercised	(313,875)	$ 2.50 to $6.69	$ 3.55
Forfeited	(209,000)	$ 9.63 to $11.94	$10.52
Outstanding at December 31, 2002	4,170,525	$ 3.44 to $12.38	$ 8.18
Granted	170,500	$12.15 to $18.20	$17.14
Exercised	(576,025)	$ 3.44 to $12.38	$ 5.26
Forfeited	(215,750)	$12.38	$12.38
Outstanding at December 31, 2003	3,549,250	$ 3.44 to $18.20	$ 8.83
Exercisable at December 31, 2003	2,601,500	$ 3.44 to $18.20	$ 8.52

Restricted Stock Grants

Under the Incentive Plans, officers and managerial employees may be granted a right to receive shares of Common Stock without cost to the employee. The shares vest over a specified period with credit given for past service rendered to Comstock. Restricted stock grants for 56,250 shares were made in each of the years 2001 and 2002. Restricted stock grants in 2003 totaled 420,000 shares. The weighted average fair value per share of the restricted stock grants were $6.42, $9.20 and $18.20 in 2001, 2002 and 2003, respectively. In the aggregate, 1,143,750 restricted stock grants have been awarded under the Incentive Plans. As of December 31, 2003, 583,125 shares of such awards are vested. A provision for the restricted stock grants is made over the related vesting period. Compensation expense recognized for restricted stock grants for the years ended December 31, 2001, 2002 and 2003 was $218,000, $217,000 and $359,000 respectively.

(8) Exploration Venture

On July 31, 2001, Comstock entered into a new exploration agreement with Bois d' Arc Offshore, Ltd. and its principals (collectively, "Bois d' Arc"), which replaces an exploration agreement entered into on December 8, 1997. The 2001 Exploration Agreement established a joint exploration venture between Comstock and Bois d' Arc covering the state coastal waters of Louisiana and Texas and corresponding federal offshore waters in the Gulf of Mexico. The new venture was effective April 1, 2001 and will end on December 31, 2006. Under the joint exploration venture, Bois d' Arc generates exploration prospects in the Gulf of Mexico utilizing 3-D seismic data and their extensive geological expertise in the region. Comstock advances 100% of the funds for the acquisition of 3-D seismic data and leases as needed. Comstock recovers its advances based on Bois d' Arc's ability to sell interests in drillable prospects. Upon a sale of a successful prospect by Bois d' Arc, Comstock is reimbursed for the costs that were advanced and is entitled to a 40% non-promoted working interest in each prospect generated. Comstock capitalizes advances made for leases as unevaluated properties and expenses advances made for seismic costs as exploration costs.

Under the exploration agreement, Bois d' Arc has the opportunity to earn warrants to purchase up to 1,620,000 shares of Common Stock. Warrants to purchase 60,000 shares are earned by Bois d' Arc for each prospect which results in a successful discovery. The exercise price on the new warrants is determined based on the current market price for the Common Stock on a semiannual basis each year that the venture is in operation. The agreement requires that Comstock must fund a minimum of $5.0 million for the acquisition of seismic data over the term of the agreement or Bois d' Arc has the right to terminate the agreement.

Bois d' Arc earned warrants to purchase 360,000, 240,000 and 900,000 shares of Common Stock under the exploration agreement in 2001, 2002 and 2003, respectively. The value of the warrants based on the Black-Scholes option pricing model was $5.64 per option share or an aggregate of $2.0 million in 2001, $5.36 per option share or an aggregate of $1.3 million in 2002 and $8.36 per option share or $7.5 million in 2003. Such costs were capitalized as a cost of oil and gas properties.

Bois d' Arc had also earned warrants to purchase 600,000 shares of Common Stock at $14.00 per share under the prior exploration agreement during the period from January 1998 to April 2001. The value of these warrants based on the Black-Scholes option pricing model was $9.97 per option share. The estimated value of $6.0 million for the warrants earned under the prior exploration agreement were capitalized to oil and gas properties in 1998 through 2001.

In total, there are warrants outstanding to purchase 2.1 million shares of Common Stock which were earned under the exploration agreements. These warrants are exercisable at a weighted average exercise price of $12.09 and have a weighted average remaining life of 6.9 years.

(9) Retirement Plan

Comstock has a 401(k) Profit Sharing Plan which covers all of its employees. At its discretion, Comstock may match a certain percentage of the employees' contributions to the plan. The matching percentage is determined annually by the Board of Directors. Comstock's matching contributions to the plan were $96,000, $116,000 and $125,000 for the years ended December 31, 2001, 2002 and 2003, respectively.

(10) Income Taxes

The tax effects of significant temporary differences representing the net deferred tax liability at December 31, 2002 and 2003 were as follows:

	2002	2003
	(In thousands)	
Net deferred tax assets (liabilities):		
Property and equipment	$(88,931)	$(91,715)
Net operating loss carryforwards	43,037	15,939
Valuation allowance on net operating loss carryforwards	(8,043)	(8,043)
Other carryforwards	1,360	2,190
	$(52,577)	$(81,629)

The following is an analysis of the consolidated income tax expense:

	2001	2002	2003
		(In thousands)	
Current	$ —	$ —	$ 1,700
Deferred	18,579	6,773	27,982
	$18,579	$6,773	$29,682

There were no significant differences between income taxes computed using the statutory rate of 35% and Comstock's effective tax rate in 2001 and 2002 of 35%. In 2003, Comstock's effective tax rate was 36% which differed from the statutory rate of 35% because of state income taxes.

At December 31, 2003, Comstock had the following carryforwards available to reduce future income taxes:

Types of Carryforward	Years of Expiration Carryforward	Amounts
		(In thousands)
Net operating loss - U.S. federal	2017 - 2021	$45,541
Alternative minimum tax credits	Unlimited	1,920
Charitable contributions carryforward	2004 - 2007	771

The utilization of $39.4 million of the net operating loss carryforwards of DevX are limited to approximately $1.1 million per year pursuant to a prior change of control. Accordingly, a valuation allowance of $23.0 million, with a tax effect of $8.0 million, has been established for Comstock's estimate of DevX's net operating loss carryforwards that it will not be able to utilize. Realization of Comstock's and DevX's net operating carryforwards requires Comstock to generate taxable income within the carryforward period.

(11) Derivatives and Hedging Activities

Comstock uses swaps, floors and collars to hedge oil and natural gas prices. Swaps are settled monthly based on differences between the prices specified in the instruments and the settlement prices of futures contracts quoted on the New York Mercantile Exchange. Generally, when the applicable settlement price is less than the price specified in the contract, Comstock receives a settlement from the counterparty based on the difference multiplied by the volume hedge. Similarly, when the applicable settlement price exceeds the price specified in the contract, Comstock pays the counterparty based on the difference. Comstock generally receives a settlement from the counterparty for floors when the applicable settlement price is less than the price specified in the contract, which is based on the difference multiplied by the volumes hedged. For collars, generally Comstock receives a settlement from the counterparty when the settlement price is below the floor and pays a settlement to the counterparty when the settlement price exceeds the cap. No settlement occurs when the settlement price falls between the floor and the cap. Comstock is exposed to credit losses in the event of non-performance by the counterparties of its financial instruments. Collateral or other security to support financial instruments subject to credit risk is not required but management monitors the credit standing of the counterparties.

In 2002, Comstock hedged a portion of its natural gas production for the period April 2002 through October 2002. The Company entered into price swaps covering 50 MMBtus per day of its natural gas production at an average price of $3.46 for April 2002 to October 2002. Comstock realized a $1.3 million gain on this hedge position in 2002, which was included in oil and gas sales and increased its average natural gas price realization from $3.26 per Mcf to $3.30 per Mcf. The ineffectiveness of these hedges was determined to be insignificant. During 2003, Comstock did not hedge any of its oil or natural gas production.

Comstock assumed certain natural gas price derivative financial instruments in connection with the acquisition of DevX. These derivative financial instruments were not designated as cash flow hedges. Comstock had an unrealized gain of $243,000 on these contracts in 2001. In 2002, Comstock realized a loss of $2.3 million related to these instruments.

Comstock had no oil and natural gas price financial instruments outstanding at December 31, 2003.

Comstock periodically enters into interest rate swap agreements to hedge the impact of interest rate changes on its floating rate long-term debt. As a result of certain hedging transactions for interest rates, Comstock has realized the following losses which were included in interest expense:

	2001	2002	2003
		(In thousands)	
Realized Losses	$(199)	$(218)	$(108)

The ineffectiveness of these hedges was determined to be insignificant.

As of December 31, 2003, Comstock had no interest rate financial instruments outstanding.

(12) Discontinued Operations

In April and July 2002, Comstock sold certain marginal oil and gas properties for cash proceeds of $3.5 million plus forgiveness of certain accounts payables related to the properties. The properties sold include various interests in nonoperated properties in Nueces, Hardeman, Montague and Wharton counties in Texas. Comstock realized a loss of $1.8 million ($1.2 million, after tax) on these property sales. The results of operations of these sold properties, including the losses on disposal, have been presented as discontinued operations in the accompanying consolidated statements of operations.

Prior year results have also been reclassified to report the results of operations of the properties as discontinued operations. Results for these properties reported as discontinued operations were as follows:

	Year Ended December 31, 2001	Year Ended December 31, 2002
	(In thousands)	
Oil and gas sales	$1,571	$ 390
Operating expenses	(963)	(264)
Loss on disposal	—	(1,778)
Income (loss) before taxes	608	(1,652)
Income tax provision (benefit)	212	(580)
Income (loss) from discontinued operations	$ 396	$(1,072)

(13) Supplementary Quarterly Financial Data (Unaudited)

	First	Second	Third	Fourth	Total
	(In thousands, except per share amounts)				
2002 —					
Total oil and gas sales	$26,490	$38,004	$35,550	$42,041	$142,085
Net income (loss) from continuing operations attributable to common stock	$(4,698)	$ 3,206	$ 2,970	$ 9,495	$ 10,973
Net income (loss) attributable to common stock	$(5,423)	$ 2,804	$ 3,025	$ 9,777	$ 9,901
Net income (loss) from continuing operations per share:					
Basic	$ (0.16)	$ 0.11	$ 0.10	$ 0.33	$ 0.38
Diluted		$ 0.11	$ 0.10	$ 0.29	$ 0.37
Net income (loss) per share:					
Basic	$ (0.19)	$ 0.10	$ 0.10	$ 0.33	$ 0.34
Diluted		$ 0.09	$ 0.10	$ 0.29	$ 0.34

	First	Second	Third	Fourth	Total
	(In thousands, except per share amounts)				
2003 —					
Total oil and gas sales	$68,576	$57,161	$56,866	$52,499	$235,102
Net income attributable to common stock before change in accounting principle	$20,157	$13,965	$12,920	$ 5,652	$ 52,694
Net income attributable to common stock	$20,832	$13,965	$12,920	$ 5,652	$ 53,369
Net income per share before change in accounting principle per share:					
Basic	$ 0.70	$ 0.44	$ 0.38	$ 0.17	$ 1.65
Diluted	$ 0.60	$ 0.40	$ 0.36	$ 0.16	$ 1.51
Net income per share:					
Basic	$ 0.72	$ 0.44	$ 0.38	$ 0.17	$ 1.67
Diluted	$ 0.62	$ 0.40	$ 0.36	$ 0.16	$ 1.53

(15) Oil and Gas Reserves Information (Unaudited)

Set forth below is a summary of the changes in Comstock's net quantities of crude oil and natural gas reserves for each of the three years ended December 31, 2003:

	2001		2002		2003	
	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)
Proved Reserves:						
Beginning of year	17,451	297,835	17,348	462,085	20,849	488,784
Revisions of previous estimates	(1,177)	(10,959)	(11)	(5,182)	(2,098)	(6,718)
Extensions and discoveries	1,395	46,777	2,360	39,467	961	46,614
Purchases of minerals in place	1,213	156,515	2,637	29,651	1,103	7,613
Sales of minerals in place	—	—	(182)	(4,066)	(11)	(195)
Production	(1,534)	(28,083)	(1,303)	(33,171)	(1,615)	(34,320)
End of year	17,348	462,085	20,849	488,784	19,189	501,778
Proved Developed Reserves:						
Beginning of year	12,290	200,349	12,212	315,779	13,937	319,155
End of year	12,212	315,779	13,937	319,155	13,206	332,668

The following table sets forth the standardized measure of discounted future net cash flows relating to proved reserves at December 31, 2002 and 2003:

	2002	2003
	(In thousands)	
Cash Flows Relating to Proved Reserves:		
Future Cash Flows	$3,088,593	$3,831,134
Future Costs:		
Production	(646,018)	(748,399)
Development and Abandonment	(190,534)	(218,017)
Future Net Cash Flows Before Income Taxes	2,252,041	2,864,718
Future Income Taxes	(639,286)	(860,196)
Future Net Cash Flows	1,612,755	2,004,522
10% Discount Factor	(691,640)	(806,857)
Standardized Measure of Discounted Future Net Cash Flows	$ 921,115	$1,197,665

The following table sets forth the changes in the standardized measure of discounted future net cash flows relating to proved reserves for the years ended December 31, 2001, 2002 and 2003:

	2001	2002	2003
		(In thousands)	
Standardized Measure, Beginning of Year	$ 1,288,764	$ 447,273	$ 921,115
Net Change in Sales Price, Net of Production Costs	(1,298,306)	590,290	309,775
Development Costs Incurred During the Year Which Were Previously Estimated	26,627	35,272	41,090
Revisions of Quantity Estimates	(21,342)	(11,636)	(53,933)
Accretion of Discount	173,747	54,068	128,029
Changes in Future Development and Abandonment Costs	(6,571)	(12,052)	(6,894)
Changes in Timing and Other	(141,844)	(58,022)	(43,177)
Extensions and Discoveries	86,026	150,317	196,275
Purchases of Reserves in Place	120,147	105,206	47,229
Sales of Reserves in Place	—	(5,243)	(256)
Sales, Net of Production Costs	(135,272)	(108,586)	(189,356)
Net Changes in Income Taxes	355,297	(265,772)	(152,232)
Standardized Measure, End of Year	$ 447,273	$ 921,115	$1,197,665

The estimates of proved oil and gas reserves utilized in the preparation of the financial statements were estimated by independent petroleum consultants of Lee Keeling and Associates in accordance with guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board, which require that reserve reports be prepared under existing economic and operating conditions with no provision for price and cost escalation except by contractual agreement. All of Comstock's reserves are located onshore in or offshore to the continental United States of America.

Future cash inflows are calculated by applying year-end prices adjusted for transportation and other charges to the year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements in existence at year-end.

Comstock's average year-end prices used in the reserve estimates were as follows:

	2001	2002	2003
Crude Oil (Per Barrel)	$18.73	$30.07	$31.19
Natural Gas (Per Mcf)	$ 2.69	$ 5.04	$ 6.44

Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the appropriate statutory tax rates to the future pre-tax net cash flows relating to proved reserves, net of the tax basis of the properties involved. The future income tax expenses give effect to permanent differences and tax credits, but do not reflect the impact of future operations.

CORPORATE INFORMATION

Directors

M. Jay Allison[1,2]
Roland O. Burns[2]
David K. Lockett[3,4,5]
Cecil E. Martin, Jr.[2,3,4,5]
David W. Sledge[3,4,5]

[1] *Chairman of the Board of Directors*
[2] *Executive Committee*
[3] *Compensation Committee*
[4] *Audit Committee*
[5] *Corporate Governance / Nominating Committee*

Management

M. Jay Allison
President and Chief Executive Officer

Roland O. Burns
Senior Vice President,
Chief Financial Officer,
Treasurer and Secretary

Mack D. Good
Vice President of Operations

Stephen E. Neukom
Vice President of Marketing

Richard G. Powers
Vice President of Land

Daniel K. Presley
Vice President of Accounting and Controller

Michael W. Taylor
Vice President of Corporate Development

Website

www.comstockresources.com

Primary Subsidiaries

Comstock Oil & Gas, LP
Comstock Oil & Gas – Louisiana, LLC
Comstock Offshore, LLC

Independent Public Accountants

Ernst & Young LLP

Independent Petroleum Consultants

Lee Keeling and Associates

Exchange Listing

The Company's common stock is listed for trading on the New York Stock Exchange under the symbol "CRK".

Commercial Banks

Bank of Montreal,
Administrative Agent
Bank of America,
Syndication Agent
Comerica Bank,
Co-Documentation Agent
Fortis Capital Corp.,
Co-Documentation Agent
Union Bank of California,
Co-Documentation Agent
Bank of Nova Scotia
Bank of Scotland
Compass Bank
Credit Lyonnais
Hibernia National Bank
Natexis Banques Populaires
Washington Mutual Bank

Annual Meeting

The annual meeting of stockholders will be held on Monday, May 10, 2004 at 10:00 a.m. at the Westin Stonebriar Resort, 1549 Legacy Drive, Frisco, Texas.

Investor Relations

Requests for additional information should be directed to:
Roland O. Burns at rburns@comstockresources.com
5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034
(800) 877-1322

Transfer Agent and Registrar

For stock certificate transfers, changes of address or lost stock certificates, please contact:
American Stock Transfer & Trust Company
59 Maiden Lane, New York, New York 10038
(800) 937-5449

Stock Market Prices

	2002	
	High	Low
First Quarter	$7.95	$5.70
Second Quarter	$9.47	$6.65
Third Quarter	$8.10	$5.50
Fourth Quarter	$9.74	$6.61

	2003	
	High	Low
First Quarter	$10.65	$8.95
Second Quarter	$14.50	$9.40
Third Quarter	$15.20	$12.10
Fourth Quarter	$19.94	$13.30

COMSTOCK RESOURCES
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