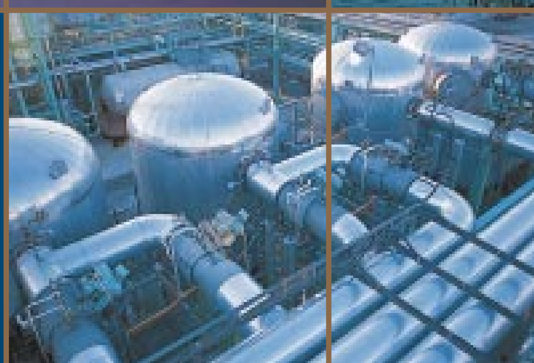
COMSTOCK RESOURCES

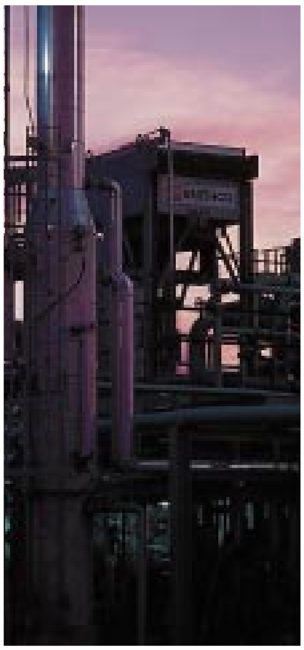


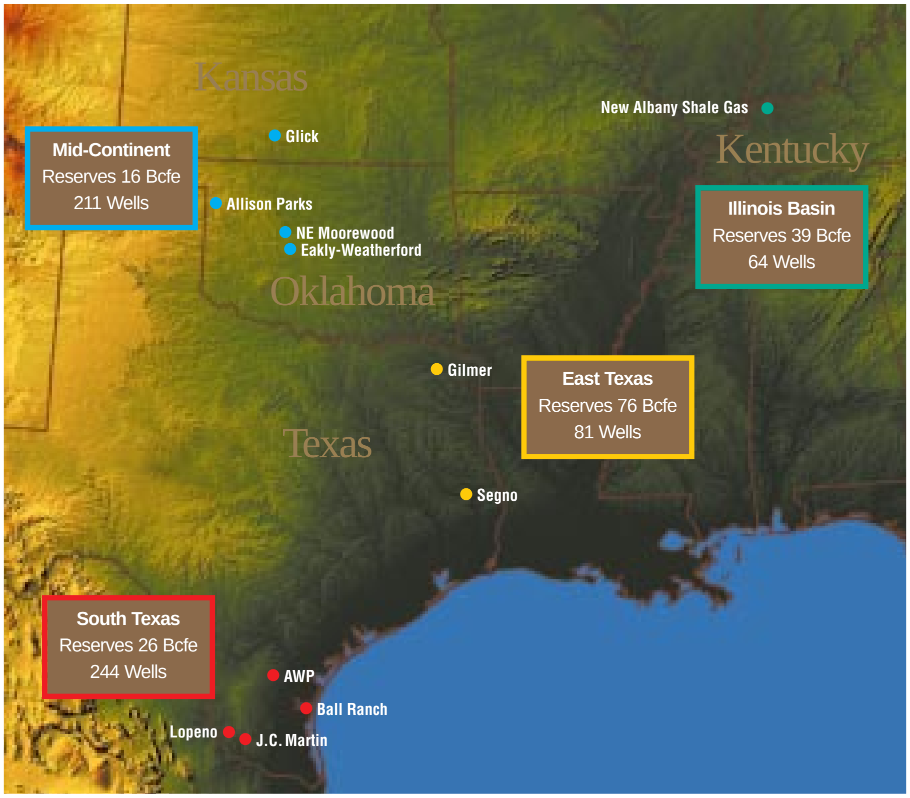
2001

ANNUAL REPORT

On December 17, 2001, we acquired interests in 600 producing wells with reserves of 164 Bcfe through the purchase of DevX Energy, Inc.

DEVX PROPERTIES





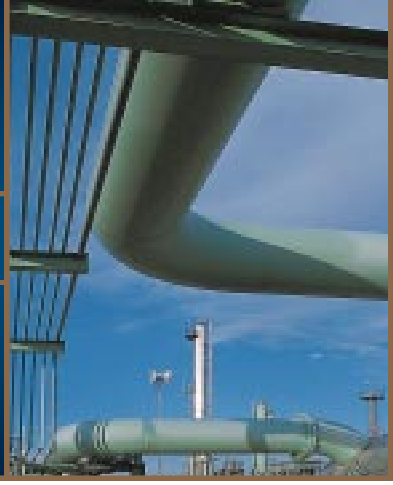
Comstock Resources, Inc. is a growing independent energy company engaged in the acquisition, development, production and exploration of oil and natural gas properties. Our operations are primarily focused in Texas, Louisiana and the Gulf of Mexico.

MAJOR PROPERTIES

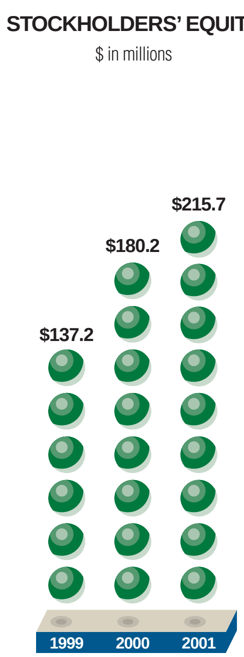
Region	2001 Reserves (Bcfe)		2001 Production (Bcfe)	
East Texas / North Louisiana	194	34%	9.2	25%
Gulf of Mexico	158	28%	13.9	37%
Southeast Texas	123	22%	13.4	36%
South Texas/Other	91	16%	.8	2%
	566		37.3	

PERFORMANCE HIGHLIGHTS

(in thousands except per share data)	1997	1998	1999	2000	2001
Financial Highlights					
Revenues	$ 89,344	$ 93,235	$ 92,144	$169,702	$168,400
Net income (loss)	$ 21,746	$(17,168)	$ (4,669)	$ 38,932	$ 34,854
Per common share	85¢	(71¢)	(19¢)	$ 1.21	$ 1.06
Cash from operations	$ 62,608	$ 50,163	$ 42,787	$112,128	$110,093
Per common share	$ 2.41	$ 2.00	$ 1.43	$ 3.27	$ 3.19
Total assets	$456,800	$429,672	$434,973	$489,930	$683,071
Total debt	$260,000	$278,104	$254,131	$234,101	$372,464
Stockholders' equity	$124,594	$109,663	$137,174	$180,173	$215,662
Operational Highlights					
Capital expenditures	$254,843	$ 67,387	$ 35,981	$ 83,394	$254,005
Net producing wells	294.0	311.7	274.0	271.9	453.5
Natural gas production (MMcf per day)	62.6	73.2	65.4	73.9	76.9
Oil production (Barrels per day)	3,680	7,044	5,831	4,951	4,203
Proved gas reserves (MMcf)	240,117	250,402	258,121	297,835	462,085
Proved oil reserves (MBbls)	20,927	20,245	19,467	17,451	17,348



TO OUR STOCKHOLDERS



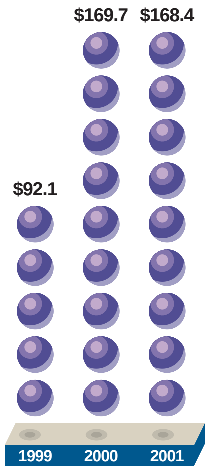
Comstock had another outstanding year in 2001. Our financial results almost matched the record setting results we had in 2000. Our drilling program turned in solid results and replaced all of our production. We drilled 52 wells in 2001 and 45 of the wells drilled were successful giving us an overall success percentage of 87%. When natural gas prices weakened in the last quarter of 2001 we were able to complete a large acquisition which increased our proved oil and natural gas reserves by 41% at a very attractive price of 98¢ per thousand cubic feet equivalent ("Mcfe"). Our 2001 drilling program combined with the acquisition replaced 539% of our 2001 production at a very reasonable all in cost of $1.26 per Mcfe in a year when many E&P companies were reporting large write-offs and very uneconomic finding costs.

FINANCIAL RESULTS

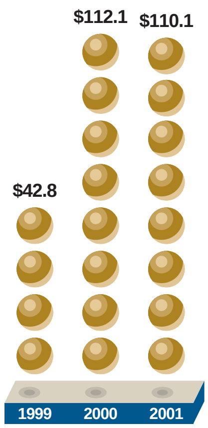
Our 2001 financial results were very comparable to our record setting 2000 financial results as our oil and gas production level and our oil and gas price realizations were within 1% of each other for

the two years. Our revenues totaled $168.4 million, a 1% decrease from 2000's record revenues of $169.7 million. Earnings before interest, taxes and depreciation and amortization ("EBITDA") of $131.6 million for 2001 was 4% less than 2000's EBITDA of $136.5 million. We generated $110.1 million ($3.19 per share), in operating cash flow in 2001 which was 2% less than 2000's operating cash flow of $112.1 million ($3.28 per share). Our earnings in 2001 totaled $34.9 million as compared to $38.9 million in 2000. On a per share basis, our net income in 2001 was $1.06 as compared to $1.21 in 2000. Our oil and natural gas production in 2001 totaled 37.3 billion cubic feet equivalent ("Bcfe") of natural gas, as

TOTAL REVENUES
$ in millions



OPERATING
CASH FLOW
$ in millions



compared to 2000's production of 37.8 Bcfe. The average oil and natural gas prices for 2001 realized by us were $25.40 per barrel for oil and $4.58 per thousand cubic feet ("Mcf") for natural gas as compared to an average oil price of $30.02 per barrel and an average natural gas price of $4.26 per Mcf in 2000. However these prices fell to $19.43 per barrel for oil and $2.49 per Mcf for natural gas in the fourth quarter of 2001. With the high prices in effect for much of 2001, we did see some increases in our operating costs. Our oil and gas operating costs were 9% higher in 2001, increasing to 87¢ per Mcfe produced. We also saw our general and administrative costs per Mcfe produced increase from 9¢ in 2000 to 12¢ in 2001 due to higher personnel costs in 2001. Our depreciation, depletion and amortization per Mcfe produced also increased in 2001 to $1.28 from $1.15 in 2000.

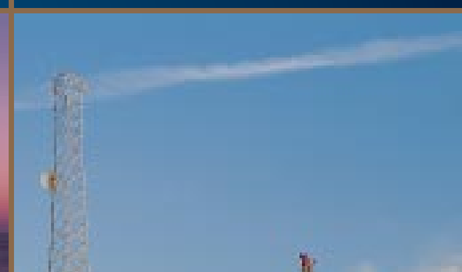
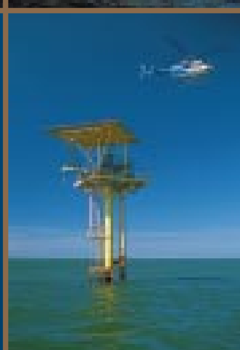
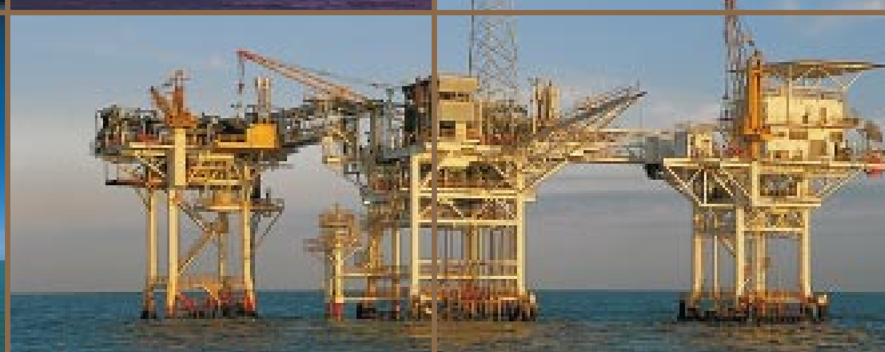
ACQUISITION OF DEVX ENERGY, INC.

On December 17, 2001 we completed the acquisition of DevX Energy, Inc. ("DevX") through a cash tender offer for all of DevX's outstanding common stock. The total purchase price paid for DevX, including liabilities assumed in the transaction, was $160.8 million. DevX was a publicly held independent energy company based in Dallas, Texas engaged in the exploration, development and acquisition of oil and gas properties, and was traded on the Nasdaq Stock Market under the symbol "DVXE." DevX had interests in 600 producing oil and gas wells located onshore primarily in East and South Texas, Kentucky, Oklahoma and Kansas. The acquisition of DevX added approximately 164 Bcfe of natural gas reserves. This acquisition complemented our existing oil and gas reserve base in East and South Texas and balanced our onshore reserve growth with our offshore reserve growth which has been driven by our successful Gulf of Mexico exploration program.

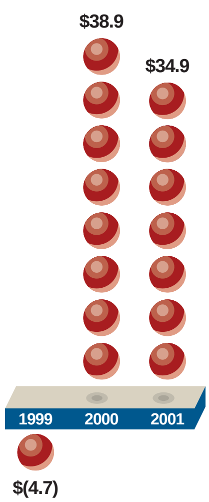
BALANCE SHEET

In 2001 we continued to improve our balance sheet. Debt as a percentage of our total capitalization fell from 56% at the end of 2000 to 48% at the end of the third

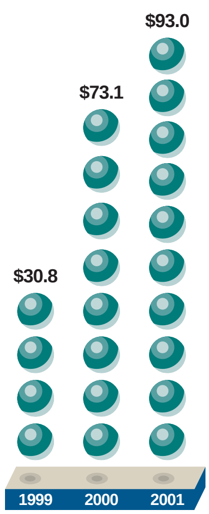



EARNINGS
$ in millions



DEVELOPMENT AND EXPLORATION EXPENDITURES
$ in millions



quarter as a result of generating profits and paying down our debt. The all cash acquisition of DevX increased our debt to 63% of our total capitalization. We will work in 2002 to reduce our debt level back to less than 50% of our total capitalization. In connection with the DevX acquisition, we entered into a new three year bank credit facility and we issued an additional $75 million of our Senior Notes due in 2007. Because of these financings, we are able to enter 2002 with substantial financial flexibility with over $80 million available under our bank revolving credit line.

DRILLING RESULTS

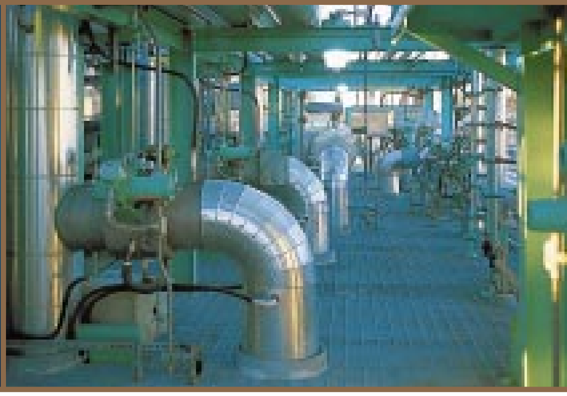
We had another outstanding year with the drill bit in 2001. We spent $77 million to drill 52 wells (35 development wells and 17 exploratory wells). We spent an additional $16 million on acquiring exploratory acreage, recompletions and workovers, and for new production facilities for our properties. Forty-five of the 52 wells drilled in 2001 were completed as producing wells for a drilling success rate of 87%. Of the seventeen exploratory wells drilled last year, 14 resulted in discoveries for an 82% drilling success rate. The drilling activity in 2001 added 55.1 Bcfe of new reserves.

EAST TEXAS / NORTH LOUISIANA REGION

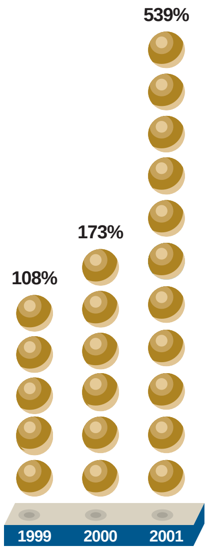
We own interests in 405 producing wells in East Texas and in North Louisiana which have long lived natural gas reserves that produce from relatively tight sands in the Hosston, Travis Peak and Cotton Valley formations. Production from this region averaged 25 million cubic feet of natural gas equivalent per day (“MMcfe/d”), a 6% increase from 2000’s average production of 24 MMcfe/d. In response to strong natural gas prices, we continued our drilling program in this region in 2001 and drilled 19 wells, (12.7 net wells). All of these wells were successful and were tested at an average per well rate of 1.5 MMcfe/d.

SOUTHEAST TEXAS REGION

We had only limited success in our Southeast Texas region in 2001. Production in this region averaged 37 MMcfe/d in 2001, a decrease of 18% from 2000’s production

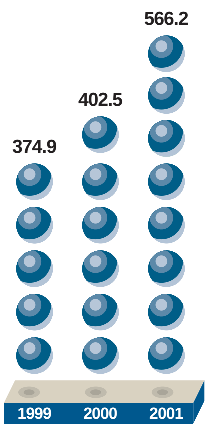


RESERVE REPLACEMENT PERCENTAGE



OIL AND NATURAL GAS RESERVES

billion cubic feet equivalent



of 45 MMcfe/d. New wells drilled in 2001 were not able to keep up with production declines from the flush production rates in 2000 when production increased 34% from the previous year. In 2001 we drilled seven successful wells (3.8 net) and three developmental dry holes (1.6 net) in this region. The seven successful wells were tested at an average per well rate of 1.9 MMcfe/d.

GULF OF MEXICO REGION

Our Gulf of Mexico region had a very successful drilling program in 2001 which will fuel production growth in this region in 2002. Production in 2001 from our Gulf of Mexico region averaged 38 MMcfe/d which was up 10% from production in 2000 of 35 MMcfe/d. We drilled 23 wells (6.7 net) in this region in 2001. Nineteen of the 23 wells were successful and were tested at an average per well rate of 7.6 MMcfe/d.

OUTLOOK FOR 2002

Despite the outlook for weaker natural gas prices, we expect to show strong production growth in 2002. With the DevX acquisition and new production coming on line in the Gulf of Mexico, our target for production is 45 to 50 Bcfe, a substantial increase over 2001. We also expect to see improvement to our costs per unit of production with the lower cost DevX properties. We are cutting back our drilling activity in 2002 in the face of weaker natural gas prices. We plan to spend $75 million to drill 49 wells. If natural gas prices improve in 2002 we expect to increase our drilling activity given our extensive inventory of drilling prospects in the Gulf of Mexico and South Texas. We are entering this period of lower commodity prices with substantial financial flexibility with a drilling program which will be funded out of operating cash flow and over $80 million available on our new revolving credit facility.

Our directors and management want to thank the stockholders for their continued support.

M. Jay Allison
Chairman and President

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

FORM 10-K/A
Amendment No. 1

(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, 2001

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. [%]

As of March 25, 2002, there were 28,572,553 shares of common stock outstanding.

As of March 25, 2002, the aggregate market value of the voting stock held by non-affiliates of the registrant was approximately $207.7 million.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy statement for the 2002 annual meeting of stockholders - Part III

COMSTOCK RESOURCES, INC.

ANNUAL REPORT ON FORM 10-K

For the Fiscal Year Ended December 31, 2001

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 2002 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" means the registrant, Comstock Resources, Inc.

"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 that is owned by us 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 East Texas/ North Louisiana, Gulf of Mexico, 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 566.2 Bcfe with an estimated Present Value of Proved Reserves of $540.7 million as of December 31, 2001. Our reserve base is 82% natural gas and 69% proved developed on a Bcfe basis as of December 31, 2001. In 2001 we had revenues of $168.4 million and generated earnings before interest, taxes, depreciation and amortization or "EBITDA" of $131.6 million.

Our proved reserves at December 31, 2001 and our 2001 average daily production are summarized below:

	Reserves at December 31, 2001				2001 Daily Production			
	Oil	Gas	Total	% of Total	Oil	Gas	Total	% of Total
	(MMBbls)	(Bcf)	(Bcfe)		(MBbls/d)	(MMcf/d)	(MMcfe/d)	
East Texas/North Louisiana . .	1.3	186.7	194.2	34.3	0.2	23.9	25.0	24.5
Gulf of Mexico	12.1	85.3	158.1	27.9	2.8	21.2	38.2	37.3
Southeast Texas	3.3	103.4	123.1	21.7	1.1	29.8	36.7	35.9
South Texas	0.3	27.0	28.8	5.1	0.1	0.7	1.0	1.0
Other Regions	0.3	59.7	62.0	11.0	—	1.3	1.3	1.3
Total	17.3	462.1	566.2	100.0%	4.2	76.9	102.2	100.0%

Strengths

Quality Properties. Our operations are focused in four geographically concentrated areas, the East Texas/ North Louisiana, Gulf of Mexico, Southeast Texas and South Texas regions, which account for approximately 34%, 28%, 22% and 5% 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 12.0 years and have extensive development and exploration potential.

Successful Exploration and Development Program. In 2001, we spent $51.4 million on the exploitation and development of our oil and natural gas properties for development drilling, recompletions, workovers and production facilities. Overall, we drilled 35 development wells, 18.8 wells net to us, with a 89% success rate. We also had a successful exploratory drilling program in 2001, spending a total of $33.4 million to drill 17 wells, 5.9 net to us, with a 82% success rate. We spent an additional $8.2 million in acquiring new acreage and seismic data in 2001 to support our exploration program.

Successful Acquisitions. We have historically grown through acquisitions. Since 1991, we have added 652.6 Bcfe of proved oil and natural gas reserves from 26 acquisitions at an average cost of $0.88 per Mcfe. Our application of strict economic and reserve risk criteria enable us to successfully evaluate and integrate acquisitions.

Efficient Operator. We operate 57% of our proved oil and natural gas reserve base as of December 31, 2001. 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 1,100 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 2001 our average natural gas price was $4.58 per Mcf, which represented a $0.31 premium to the 2001 NYMEX average monthly settlement price. Also in 2001, our average crude oil price was $25.40 per barrel, which represented a $2.53 barrel premium to the average monthly West Texas Intermediate crude oil price for 2001 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. 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 2001, we spent approximately $43.6 million to drill 35 development wells, 18.8 net to us, of which 31 wells, 17.0 net to us, were successful, representing a success rate of 89%. In addition, we spent approximately $7.8 million for new production facilities, leasehold costs and for recompletion and workover activities. For 2002, we have budgeted $40.0 million for development drilling and for workover and recompletion activity.

Pursue Exploration Opportunities. We conduct exploration activities to find additional reserves on our undeveloped acreage and in our core operating areas. In 2001, we spent approximately $33.4 million to drill 17 exploratory wells, 5.9 net to us, of which 14 wells, 4.8 net to us, were successful, representing a success rate of 82%. We also spent $8.2 million in acquiring new acreage and seismic data in 2001 to support our exploration program. We have budgeted $35.0 million in 2002 for exploration activities which will be focused primarily in the Gulf of Mexico 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 $0.87 in 2001. In addition, we have been able to grow our reserves and production substantially over the past five years with minimal increase to general and administrative expenses. As a result, our general and administrative expenses per Mcfe averaged only $0.12 in 2001.

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 652.6 Bcfe of proved oil and natural gas reserves from 26 acquisitions at a total cost of $577.2 million, or $0.88 per Mcfe. The acquisitions were acquired at an average of 74% 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 $75.0 million on development and exploration projects in 2002. We intend to primarily use our operating cash flow to fund our drilling expenditures in 2002. We may also make additional property acquisitions in 2002 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: East Texas/ North Louisiana, Gulf of Mexico, 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, 2001.

	Net Oil (MBbls)	Net Gas (MMcf)	MMcfe	%	Present Value of Proved Reserves	%
East Texas/ North Louisiana					(in thousands)	
Gilmer	531	72,515	75,702		$ 51,658	
Beckville	206	42,260	43,498		28,412	
Logansport	42	14,862	15,113		14,227	
Blocker	57	13,331	13,670		11,573	
Waskom	200	12,070	13,273		10,191	
Box Church	4	7,459	7,485		6,214	
Lisbon	54	4,032	4,353		5,153	
Longwood	45	5,159	5,429		5,110	
Ada	5	5,206	5,235		4,584	
Other	110	9,782	10,440		9,636	
	1,254	186,676	194,198	34.3	146,758	27.1
Gulf of Mexico						
South Timbalier/ South Pelto	2,305	50,020	63,847		104,884	
Ship Shoal	7,038	19,715	61,946		66,699	
Main Pass	1,445	2,621	11,294		13,373	
West Cameron	—	5,415	5,415		11,576	
East White Point	794	3,125	7,890		6,496	
Bay Marchand	469	312	3,125		3,282	
Other	69	4,077	4,491		5,313	
	12,120	85,285	158,008	27.9	211,623	39.1
Southeast Texas						
Double A Wells	2,887	90,518	107,842		104,127	
Sugar Creek	231	11,990	13,378		5,167	
Other	171	881	1,905		2,362	
	3,289	103,389	123,125	21.7	111,656	20.7
Illinois Basin						
New Albany Shale Gas	—	39,573	39,573	7.0	20,114	3.7
South Texas						
J.C. Martin	—	16,182	16,182		17,172	
Other	296	10,818	12,592		11,563	
	296	27,000	28,774	5.1	28,735	5.3
Mid-Continent						
N.E. Moorewood	32	5,207	5,398		5,671	
Other	150	10,128	11,028		10,278	
	182	15,335	16,426	2.9	15,949	3.0
Other Areas	207	4,827	6,068	1.1	5,844	1.1
Total	17,348	462,085	566,172	100.0	$ 540,679	100.0

East Texas/ North Louisiana

Approximately 34% or 194.2 Bcfe of our proved reserves are located in East Texas and North Louisiana where we own interests in 405 producing wells, 230.4 net to us, in 21 field areas. We operate 250 of these wells. The largest of our fields in this region are the Gilmer, Beckville and Logansport fields. Production from this region averaged 23.9 MMcf of natural gas per day and 181 barrels of oil per day during 2001. 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 2001 we spent $19.8 million drilling 19 wells, 12.6 net to us, and $2.3 million on workovers and recompletions in this region. We have budgeted approximately $24.0 million in 2002 for this region to drill 21 development wells and for recompletion and workover activity.

Gilmer

We own interests in 53 natural gas wells, 20.1 net to us, in the Gilmer field in Upshur County in East Texas. These wells produce from the Cotton Valley Lime formation at a depth of approximately 11,500 feet to 12,000 feet. Proved reserves attributable to our interests in the Gilmer field are 75.7 Bcfe which represents 13% of our total reserve base. We acquired our interests in the Gilmer field in December 2001 through the acquisition of the DevX Energy, Inc. In 2002 we plan to participate in the drilling of 21 infill development wells in the Gilmer field, which is expected to cost approximately $22.0 million.

Beckville

Our properties in the Beckville field, located in Panola and Rusk Counties, Texas, have proved reserves of 43.5 Bcfe which represents approximately 8% of our total reserves. We operate 72 wells in this field and own interests in four additional wells. During 2001, production attributable to our interest from this field averaged 9.4 MMcf of natural gas per day and 17 barrels of oil per day. The Beckville field produces from the Cotton Valley formation at depths ranging from 9,000 to 10,000 feet. In 2001, we drilled nine successful development wells, 7.5 net to us, at Beckville. No additional development drilling is planned for 2002 in this field unless natural gas prices increase.

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 15.1 Bcfe in the Logansport field represents approximately 3% of our total reserves. We operate 53 wells in this field and own interests in 34 additional wells. During 2001, net daily production attributable to our interest from this field averaged 3.8 MMcf of natural gas and 18 barrels of oil. We drilled two wells, 0.4 net to us, during 2001 in Logansport.

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 81 producing wells, 37.6 net to us, in ten field areas, the largest of which are the South Timbalier/South Pelto area (South Timbalier Blocks 11, 16, 34, 50 and South Pelto Blocks 5 and 15), the Ship Shoal area (Ship Shoal Blocks 66, 67, 68, 69 and 99 and South Pelto Block 1), the Main Pass area (Main Pass Blocks 21, 41, 43 and 58) and West Cameron area (West Cameron Blocks 152, 238, 248 and 249). We have 158.0 Bcfe of oil and natural gas reserves in the Gulf of Mexico region which represents 28% of our reserve base. We operate 23 of the wells that we own in this region. Production from the region averaged 21.2 MMcf of natural gas per day and 2,823 barrels of oil per day during 2001. We spent $11.6 million in this region in 2001 drilling eight development wells, 2.3 net to us, and $28.4 million drilling 15 exploratory wells, 4.4 net to us. We also spent $7.7 million acquiring leases and seismic data and $4.0 million for production facilities, recompletions and workovers. In 2002, we plan to spend $39.0 million for development and exploration activities in this region.

South Timbalier/South Pelto

We own working interests ranging from 25% to 33% in 19 producing wells 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 63.8 Bcfe attributable to this area which is 11% of our total reserves. Production attributable to our interest averaged 12.1 Mmcf of natural gas per day and 437 barrels of oil per day in 2001. 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 a geopressured Miocene section at a depth below 16,000 feet. We drilled 12 wells in the South Timbalier/South Pelto area in 2001. Two of these wells were successful development wells. The remaining ten wells were exploratory wells of which eight resulted in new discoveries and two were dry holes.

Ship Shoal

The Ship Shoal area is located in Louisiana state waters and in federal waters, offshore of Terrebonne Parish and near the state/federal waters boundary. We own a 99% to 100% working interest in Ship Shoal Blocks 66, 67, and 68 and South Pelto Block 1 and operate these properties. We have a 25% working interest in Ship Shoal Block 69 and a 60% working interest in Ship Shoal Block 99. In the Ship Shoal 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 40 feet. Our properties in the Ship Shoal area have estimated proved reserves of 61.9 Bcfe, which is 11% of our total reserves. We own interests in 26 producing wells in the Ship Shoal area which averaged 2.3 MMcf of natural gas per day and 1,568 barrels of oil per day during 2001.

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 at Main Pass Block 21. We also own nonoperated interests in 14 producing wells at Main Pass Blocks 41, 43 and 58 in federal waters with an average depth of 50 feet. Proved reserves for the total Main Pass area were 11.3 Bcfe, which is 2% of total reserves at December 31, 2001. Production attributable to our interests from the Main Pass Area was approximately 1.8 MMcf of natural gas per day and 652 barrels of oil per day in 2001.

West Cameron

We have interests in seven producing wells at West Cameron Blocks 152, 238, 248 and 249 located in federal waters with a depth of approximately 60 feet. These wells produce from complex multi-pay Pliocene aged sands at depths ranging from 5,000 to 11,500 feet. Our proved reserves in this field were 5.4 Bcfe which represents 1% of our total proved reserves. Production from the West Cameron properties net to our interest averaged 2.9 MMcf of natural gas per day in 2001.

Southeast Texas

Approximately 22% or 123.1 Bcfe of our proved reserves are located in Southeast Texas, where we own interests in 93 producing wells, 55.4 net to us, and operate 58 of these wells. Net daily production rates from the area averaged 29.8 MMcf of natural gas and 1,145 barrels of oil during 2001. We spent $12.9 million in the Southeast Texas region in 2001 drilling eight development wells, 3.9 net to us, and spent $4.3 million drilling two exploratory wells, 1.5 net to us. We also spent $1.2 million to acquire an additional leasehold in this region and for recompletions and workovers. In 2002, we plan to spend $2.0 million for exploration activities in this region. Additional development drilling is planned for this region once natural gas prices increase.

Double A Wells

Substantially all of the reserves in this region are in the Double A Wells field area in Polk County, Texas. The Double A Wells field is our largest field area with total estimated proved reserves of 107.8 Bcfe, which is 19% of our total reserves. Net daily production from the 56 producing wells at Double A Wells field averaged 28.7 MMcf of natural gas and 1,106 barrels of oil during 2001. 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 the interpretation of 3-D seismic data and drilled 19 successful wells from 1999 to 2001. In 2001, we drilled six wells, 2.7 net to us, in this field. Four of the wells, 2.0 net to us, were successful.

South Texas

Approximately 5% or 28.8 Bcfe of our proved reserves are located in South Texas, where we own interests in 260 producing wells, 46.1 net to us. In 2002, we plan to spend approximately $10.0 million primarily for exploration activity in this region.

J.C. Martin

Our largest field in South Texas is the J.C. Martin field which located in the structurally complex and highly prolific Wilcox Lobo Trend in Zapata County, Texas on the Mexican border. We own interests in 87 producing wells in the J.C. Martin field. We acquired our interests in the J.C. Martin field through our acquisition of DevX Energy, Inc. 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. Wells in this field were drilled to total depths ranging from 9,500 to 10,200 feet.

Acquisition Activities

Acquisition Strategy

We have concentrated our acquisition activity in the East Texas/North Louisiana, Gulf of Mexico, 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 652.6 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 field in South Texas. We also acquired interests in the New Albany Shale Gas field in Kentucky 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, 2001:

	Oil (MBbls)	Gas (MMcf)	Total (MMcfe)	Present Value of Proved Reserves (000's)
Proved Developed Producing	6,853	240,549	281,666	$ 301,822
Proved Developed Non-producing	5,359	75,230	107,385	119,014
Proved Undeveloped	5,136	146,306	177,121	119,843
Total Proved	17,348	462,085	566,172	$ 540,679

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 estimate. 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 declines 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, 2001. The market price for our oil production on December 31, 2001, after basis adjustments, was $18.73 per barrel as compared to $26.34 per barrel on December 31, 2000. The market price received for our natural gas production on December 31, 2001, after basis adjustments, was $2.69 per Mcf as compared to $10.51 per Mcf on December 31, 2000.

Drilling Activity Summary

During the three-year period ended December 31, 2001, we drilled development and exploratory wells as set forth in the table below.

	Year Ended December 31,					
	1999		2000		2001	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Oil	1	.4	—	—	2	.7
Gas	14	8.8	37	19.7	29	16.3
Dry	2	.8	—	—	4	1.8
	17	10.0	37	19.7	35	18.8
Exploratory Wells:						
Oil	2	.6	2	1.1	1	.3
Gas	5	.9	5	2.2	13	4.5
Dry	4	.9	5	1.5	3	1.1
	11	2.4	12	4.8	17	5.9
Total Wells	28	12.4	49	24.5	52	24.7

In 2002 to the date of this report, we have drilled eight development wells, 2.7 net to us, and four exploratory wells, 1.0 net to us. All of these wells were either successful or are still being evaluated by us.

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, 2001.

	Oil		Gas	
	Gross	Net	Gross	Net
Colorado	–	–	1	.3
Kansas	–	–	12	4.5
Kentucky	–	–	64	54.7
Louisiana	9	4.9	189	89.3
Mississippi	1	.1	1	.2
Offshore Gulf of Mexico	41	22.1	40	15.5
Oklahoma	3	.3	139	16.7
Texas	97	25.6	499	217.2
Wyoming	–	–	29	2.1
Total Wells	151	53.0	974	400.5

We operate 404 of the 1,125 producing wells presented in the above table.

Acreage

The following table summarizes our developed and undeveloped leasehold acreage at December 31, 2001. We have excluded acreage in which our interest is limited to a royalty or overiding royalty interests.

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Colorado	320	80	–	–
Kansas	6,400	4,064	–	–
Kentucky	9,107	6,666	13,265	12,192
Louisiana	77,792	57,109	7,923	1,807
Mississippi	1,360	210	–	–
New Mexico	–	–	171,816	75,598
Offshore Gulf of Mexico	41,981	17,970	20,765	6,596
Oklahoma	37,440	5,336	–	–
Texas	218,968	136,467	59,850	31,102
Wyoming	13,440	927	–	–
Total	406,808	228,829	273,619	127,295

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.

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 gas prices. A portion of the natural gas production from our Double A Wells field is sold under a long-term contract to Houston Pipe Line Company LP, a subsidiary of American Electric Power Company, Inc. ("HPL"). The contract with HPL expires on October 31, 2004 with pricing based on spot natural gas prices for natural gas delivered to the Houston Ship Channel. Total natural gas sales in 2001 to HPL accounted for approximately 24% of our total 2001 oil and gas sales.

A significant portion of our offshore Gulf of Mexico natural gas production in 2001 was sold to Adams Resources Marketing, Ltd. ("ARM"). Total natural gas sales in 2001 to ARM accounted for approximately 16% of our total 2001 oil and natural gas sales. Reliant Energy Services, Inc. is another significant purchaser of our natural gas production accounting for approximately 12% of our total 2001 oil and gas sales.

All of our oil production is sold at the well site at prices tied to the spot oil markets. Through October 2001, we sold our oil production from our offshore Gulf of Mexico properties and from the Double A Wells field to Williams-GulfMark Energy Company. Sales to Williams-GulfMark Energy accounted for approximately 19% of our total 2001 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 states we operate in 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. We provide reserves for the estimated costs of plugging and abandoning our wells, to the extent such costs exceed the estimated salvage value of the wells, on a unit of production basis.

Environmental

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 its 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 its 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 lease office space in Frisco, Texas covering 20,046 square feet at a monthly rate of $34,706. The lease expires on May 31, 2006. We also have a lease for office space formally used by DevX. The lease covers 9,573 square feet at a monthly rate of $19,458. This lease expires on December 3, 2003. We are currently attempting to sublease this office space. We also own production offices and pipe yard facilities near Marshall and Livingston, Texas, near Logansport, Louisiana and near Guston, Kentucky.

Employees

As of December 31, 2001, we had 60 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	46	President, Chief Executive Officer and Chairman of the Board of Directors
Roland O. Burns	42	Senior Vice President, Chief Financial Officer, Secretary, Treasurer and Director
Mack D. Good	51	Vice President of Operations
Stephen E. Neukom	52	Vice President of Marketing
Richard G. Powers	47	Vice President of Land
Daniel K. Presley	41	Vice President of Accounting and Controller
Michael W. Taylor	49	Vice President of Corporate Development
David K. Lockett	47	Director
Cecil E. Martin, Jr	60	Director
David W. Sledge	45	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 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 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 on July 17, 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 of since 1988. From 1973 to 1991 he served as chairman of a public accounting firm in Richmond, Virginia. Mr. Martin also serves as a director for CareerShop.com. 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. 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 2001.

PART II

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

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
2000 –	First Quarter	$ 5.94	$ 2.44
	Second Quarter	9.13	4.06
	Third Quarter	13.13	6.13
	Fourth Quarter	15.00	8.13
2001 –	First Quarter	$ 14.63	$ 9.65
	Second Quarter	12.48	8.95
	Third Quarter	10.12	5.00
	Fourth Quarter	8.15	5.26

As of March 25, 2002, we had 28,572,553 shares of common stock outstanding, which were held by 462 holders of record and approximately 7,400 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, the terms of the indenture for our senior notes due in 2007 and the terms of our 1999 Series A Preferred Stock from paying or declaring cash dividends.

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, 2001 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."

	Year Ended December 31,				
	1997	1998	1999	2000	2001
Statement of Operations Data:	($ in thousands, except per share data)				
Revenues:					
Oil and gas sales	$ 88,555	$ 92,961	$ 90,103	$ 169,350	$ 167,689
Gain on sales of property	85	—	130	33	12
Other income	704	274	1,911	319	699
Total revenues	89,344	93,235	92,144	169,702	168,400
Expenses:					
Oil and gas operating (1)	17,919	24,747	23,714	29,707	32,417
Exploration	2,810	8,301	1,832	3,192	4,215
Depreciation, depletion and amortization	26,235	51,005	45,171	44,958	49,191
General and administrative, net	2,668	1,617	2,399	3,537	4,351
Interest	5,934	16,977	23,361	24,611	20,737
Impairment of oil and gas properties	—	17,000	—	—	1,400
Total expenses	55,566	119,647	96,477	106,005	112,311
Income (loss) before income taxes	33,778	(26,412)	(4,333)	63,697	56,089
Income tax benefit (expense)	(11,622)	9,244	1,517	(22,294)	(19,631)
Net income (loss)	22,156	(17,168)	(2,816)	41,403	36,458
Preferred stock dividends	(410)	—	(1,853)	(2,471)	(1,604)
Net income (loss) attributable to common stock	$ 21,746	$ (17,168)	$ (4,669)	$ 38,932	$ 34,854
Weighted average shares outstanding:					
Basic	24,186	24,275	24,601	26,290	29,030
Diluted	26,008			34,219	34,552
Earnings per share:					
Basic	$ 0.90	$ (0.71)	$ (0.19)	$ 1.48	$ 1.20
Diluted	0.85			1.21	1.06
Other Financial Data:					
EBITDA(2)	$ 68,757	$ 66,871	$ 66,031	$ 136,458	$ 131,632
Ratio of EBITDA to interest expense (3)	11.3	3.5	2.8	5.5	6.3

	As of December 31,				
	1997	1998	1999	2000	2001
Balance Sheet Data:					
Cash and cash equivalents	$ 14,504	$ 5,176	$ 7,648	$ 7,105	$ 6,122
Property and equipment, net	410,781	404,017	395,862	434,913	638,576
Total assets	456,800	429,672	434,973	489,930	683,071
Total debt	260,000	278,104	254,131	234,101	372,464
Stockholders' equity	124,594	109,663	137,174	180,173	215,662

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

(2) EBITDA means income (loss) from continuing operations before income taxes, plus interest, depreciation, depletion and amortization, exploration expense and impairment of oil and gas properties. EBITDA is a financial measure commonly used in our industry and should not be considered in isolation or as a substitute for net income, cash flow provided by operating activities or other income or cash flow data prepared in accordance with generally accepted accounting principles or as a measure of a company's profitability or liquidity.

(3) For the purpose of this calculation interest expense includes capitalized interest of $230,000 in 2001.

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,		
	1999	2000	2001
Net Production Data:			
Oil (MBbls)	2,128	1,807	1,534
Natural gas (MMcf)	23,872	26,990	28,083
Natural gas equivalent (MMcfe)	36,642	37,833	37,287
Average Sales Price:			
Oil (MBbls)	$ 17.35	$ 30.02	$ 25.40
Natural gas (MMcf)	2.23	4.26	4.58
Average equivalent price (per Mcfe)	2.47	4.48	4.50
Expenses ($ per Mcfe):			
Oil and gas operating(1)	$ 0.65	$ 0.79	$ 0.87
General and administrative	0.07	0.09	0.12
Depreciation, depletion and amortization(2)	1.20	1.15	1.28
Cash Margin ($ per Mcfe)(3)	$ 1.75	$ 3.60	$ 3.51

(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.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Our oil and gas sales decreased $1.7 million or 1%, in 2001 to $167.7 million from $169.4 million in 2000. The slight decrease in sales is due to a 1% decrease in our oil and natural gas production in 2001. Our oil production in 2001 decreased by 15% and natural gas production increased by 4%. Our average oil price in 2001 decreased by 15% which was offset by a 8% increase to our average natural gas. On an equivalent unit basis, our average price received for our production in 2001 was $4.50 per Mcfe, which was almost the same as our average price in 2000 of $4.48 per Mcfe.

Our other income in 2001 increased to $699,000 from $319,000 in 2000. The increase is mostly due to a non-cash gain from the change in the fair value of our derivative financial instruments in 2001 of $255,000.

Our oil and gas operating expenses, which includes production taxes, increased $2.7 million or 9%, to $32.4 million in 2001 from $29.7 million in 2000. Our oil and gas operating expenses per equivalent Mcf produced increased by $0.08 to $0.87 in 2001 from $0.79 for 2000. The increase is due to higher field level operating costs including additional treating fees paid in 2001 to process our Btu rich natural gas.

In 2001, we had $4.2 million in exploration expense which represents the write-off of three offshore exploratory dry holes. Exploration expense for 2000 was $3.2 million which related to the write-off of five dry holes.

Our depreciation, depletion and amortization increased $4.2 to $49.2 million in 2001 from $45.0 million in 2000. The increase is attributable to higher capitalized costs on our properties which increased our amortization rate in 2001. Our depreciation, depletion and amortization per equivalent Mcf produced increased to $1.28 in 2001 from $1.15 in 2000.

Our general and administrative expenses, which are reported net of overhead reimbursements that we receive, increased $814,000 or 23%, to $4.4 million in 2001 from $3.5 million in 2000. The increase was primarily due to an increase in the number of employees and higher compensation paid to our employees in 2001.

Our interest expense decreased $3.9 million or 16% to $20.7 million in 2001 from $24.6 million for 2000. The decrease is due to lower average borrowings outstanding under our bank credit facility as well as a lower average interest rate under the bank credit facility. In 2001, we had a $65.6 million average outstanding balance under the bank credit facility at a weighted average interest of 5.6%. In 2000, our average outstanding balance was $104.2 million under the bank credit facility with a weighted average interest rate 6.9%.

We reported net income of $34.8 million, after deducting preferred stock dividends of $1.6 million, in 2001. These results compared to net income of $38.9 million, after deducting preferred stock dividends of $2.5 million, in 2000. Our income per share for 2001 was $1.06 on diluted weighted average shares outstanding of 34.6 million as compared to net income per share of $1.21 for 2000 on diluted weighted average shares outstanding of 34.2 million.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Our oil and gas sales increased by $79.2 million or 88% in 2000 to a record high level of $169.4 million from $90.1 million in 1999. The substantial increase in our sales is due to significantly higher oil and gas prices in 2000 combined with a 3% increase in our production. In 2000, our average oil price increased by 73% and our average natural gas price increased by 91% from 1999. Our oil production decreased in 2000 by 15% and our natural gas production in 2000 increased by 13%.

Our other income in 2000 decreased by $1.6 million to $319,000 from $1.9 million in 1999. Included in other income for 1999 was an insurance recovery in the amount of $1.7 that we received.

Our oil and gas operating expenses, which includes production taxes, increased by $6.0 million or 25% in 2000 to $29.7 million from $23.7 million in 1999. Our oil and gas operating expenses per equivalent Mcf produced in 2000 increased by $0.14 to $0.79 from $0.65 for 1999. The increase is related to higher production taxes resulting from the higher oil and gas prices we realized in 2000 as well as an increase of $3.6 million in our field level lifting costs for new wells put into production in 2000.

In 2000, we had $3.2 million in exploration expense which related to our write-off of five offshore exploratory dry holes. Our exploration expense in 1999 was $1.8 million which related to our write-off of four dry holes drilled in 1999.

Our depreciation, depletion and amortization decreased $213,000 to $45.0 million in 2000 from $45.2 million in 1999. Depreciation, depletion and amortization per equivalent Mcf produced averaged $1.15 in 2000, which decreased from $1.20 in 1999.

Our general and administrative expenses, which are reported net of overhead reimbursements that we receive, increased $1.1 million or 47% to $3.5 million in 2000 from $2.4 million in 1999. This increase was primarily due to higher compensation paid to our employees in 2000.

Our interest expense increased by $1.2 million to $24.6 million in 2000 from $23.4 million in 1999. This increase relates to the higher average interest rate on our debt. The 11¼% interest rate on our senior notes, issued to refinance $150.0 million of indebtedness under our bank credit facility on April 29, 1999, was significantly higher than the interest rates charged under our bank credit facility. Our weighted average interest rate under our bank credit facility was 6.9% in 2000, a decrease from the weighted average rate of 7.2% in 1999.

For 2000 we reported net income of $38.9 million, after preferred stock dividends of $2.5 million. This compares to a net loss of $4.7 million that we reported for 1999, after deducting preferred stock dividends of $1.9 million. Our net income per share for 2000 was $1.21 on diluted weighted average shares outstanding of 34.2 million as compared to a net loss per share of $0.19 for 1999 on weighted average shares outstanding of 24.6 million.

Acquisition of DevX Energy, Inc.

On December 17, 2001, we completed the acquisition of DevX by acquiring 100% of the common stock of DevX for $92.6 million though a cash tender offer and subsequent merger into a wholly owned subsidiary. As a result of the acquisition, DevX became a wholly owned subsidiary. DevX is an independent energy company engaged in the exploration, development and acquisition of oil and gas properties. DevX owns interests in 600 producing oil and gas wells located onshore primarily in East and South Texas, Kentucky, Oklahoma and Kansas. One of the primary reasons we acquired DevX was to add to our existing producing property base in our East Texas and South Texas regions. We are currently evaluating whether to divest the DevX properties in the Illinois Basin and Mid-Continent regions, which are not part of our core operating areas. The DevX acquisition added approximately 163.4 Bcfe of natural gas reserves to our reserve base. Subsequent to the acquisition, we repurchased approximately $49.8 million of DevX's publicly held 12½% senior notes for 110% of the principal amount plus accrued interest.

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 2001, our net cash flow provided by operating activities totaled $110.1 million. Our other primary funding source in 2001 was borrowings of $261.0 million under our previous and current revolving credit facilities.

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 2001, we incurred capital expenditures of $189.6 million for development and exploration activities and for the acquisition of DevX. We also repaid or refinanced $178.0 million of our long-term debt. In connection with the acquisition of DevX, we assumed $55.0 million of debt and a working capital deficit of $0.7 million.

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

	Year Ended December 31,		
	1999	2000	2001
Acquisitions of oil and gas properties	$ 4,458	$ 9,684	$160,794
Other leasehold costs	2,258	6,964	9,541
Workovers and recompletions	4,472	10,252	5,563
Offshore production facilities	4,462	1,629	907
Development drilling	11,521	35,047	43,646
Exploratory drilling	8,126	19,202	33,382
Other	684	616	172
Total	$ 35,981	$ 83,394	$254,005

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 $30.8 million, $73.1 million and $93.0 million on development and exploration activities in 1999, 2000 and 2001, respectively. We have budgeted approximately $75.0 million for development and exploration projects in 2002. 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. To the extent that natural gas prices do not recover from their current level, we anticipate reducing our spending on development and exploration activities by $10.0 million to $20.0 million in order to match these expenditures with our cash flow provided by operations.

We spent $4.5 million, $9.7 million and $160.8 million on acquisition activities in 1999, 2000 and 2001, respectively. We do not have a specific acquisition budget for 2002 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.

In connection with the completion of the DevX acquisition, we entered into a new $350.0 million revolving credit facility on December 17, 2001 with Toronto Dominion (Texas), Inc. as administrative agent. The new bank credit facility is a three year revolving credit line with an initial borrowing base of $270.0 million. The bank credit facility was used primarily to refinance our prior bank credit facility, to finance the DevX acquisition and to repurchase the DevX senior notes.

Indebtedness under the new bank credit facility is secured by substantially all of our assets. All of our subsidiaries are guarantors of this indebtedness. The revolving credit line 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 gas properties. The borrowing base may be affected by the performance of our properties and changes in oil and gas prices. The determination of the borrowing base is at the sole discretion of the administrative agent and the bank group. The revolving credit line bears interest, based on the utilization of the borrowing base, at our option at either (i) LIBOR plus 1.5% to 2.375% or (ii) the base rate plus 0.5% to 1.375%. The bank credit facility matures on January 2, 2005 and contains covenants that, among other things, restrict our ability to pay cash dividends, limit the amount of our consolidated debt and limit our ability to make certain loans and investments. Financial covenants include the maintenance of a current ratio, maintenance of tangible net worth and maintenance of an interest coverage ratio.

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

	2002	2003	2004	2005	2006	2007	2008	Total
				(in thousands)				
Bank credit facility	$ —	$ —	$ —	$ 227,000	$ —	$ —	$ —	$ 227,000
Senior notes	—	—	—	—	—	145,000	—	145,000
Other debt	229	—	—	—	—	—	235	464
Operating leases	661	656	452	477	198	—	—	2,444
Derivative liabilities	798	1,053	—	—	—	—	—	1,851
Preferred stock (1)	—	—	—	5,858	5,858	5,857	—	17,573
	$ 1,688	$ 1,709	$ 452	$ 233,335	$ 6,056	$ 150,857	$ 235	$ 394,332

(1) Represents redemption of our Series A 1999 Convertible Preferred Stock, which at our option, can be paid in shares of our common stock.

We believe that our cash flow from operations and our 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.

On March 7, 2002, we closed the sale in a private placement of $75.0 million of our 11¼% Senior Notes due 2007 (the "Notes") at a net price of 97.25% after the placements agents' discount. As a result of this transaction, $220.0 million of aggregate principal amount of the Notes were outstanding. The net proceeds were used to reduce amounts outstanding under our bank credit facility and the borrowing base under the credit facility was reduced to $240.0 million. The Notes are unsecured obligations of Comstock and are guaranteed by all of our subsidiaries.

Federal Taxation

At December 31, 2001, we had federal income tax net operating loss carryforwards of approximately $98.6 million. We have established an $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 the DevX carryforwards. The carryforwards expire from 2018 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 selected to use the more conservative 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 Securities and Exchange Commission and the Financial Accounting Standards Board. 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 current 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, 2001, we used an initial oil price of $19.86 per barrel and an initial natural gas price of $2.39 per Mcf. Such prices were escalated each year to a maximum price of $40.00 per barrel for oil and $5.00 per Mcf for natural gas. To the extent we had used lower prices in our impairment review, the $1.4 million impairment provision recorded in 2001 could have been significantly higher.

Related Party Transactions

In recent years we have not entered into any significant 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 2001, 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 $26.9 million.

We periodically use hedging transactions with respect to a portion of our oil and natural gas production to mitigate our exposure to price changes. While the use of these hedging 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, generally we 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 cap.

In connection with the DevX acquisition, we assumed certain derivative financial instruments entered into by DevX to manage natural gas price risks. The following table sets out the derivative financial instruments outstanding at December 31, 2001 which are held for natural gas price risk management:

Period Beginning	Period Ending	Volume (MMBtu)	Type of Instrument	Floor Price	Ceiling Price	Swap Price
January 1, 2002	December 31, 2002	640,000	Floor	$1.90	—	—
January 1, 2002	December 31, 2002	2,550,000	Floor	$2.00	—	—
January 1, 2002	December 31, 2002	1,600,000	Swap	—	—	$2.40
January 1, 2002	December 31, 2002	900,000	Collar	$4.00	$6.75	—
		5,690,000				
January 1, 2003	December 31, 2003	560,000	Floor	$1.90	—	—
January 1, 2003	December 31, 2003	2,250,000	Floor	$2.00	—	—
January 1, 2003	December 31, 2003	1,400,000	Swap	—	—	$2.40
		4,210,000				
		9,900,000				

The counterparty for the $1.90 floor position and $2.40 swap price position is a subsidiary of Enron Corporation, which has filed for bankruptcy protection. The net liability owed to Enron as of December 31, 2001 was $1.6 million. We intend to monitor this position and will assess the credit exposure to the extent this position becomes a net asset.

The fair value of the commodity price derivative financial instruments at December 31, 2001 was a net liability of $42,000. As of December 31, 2001, we have not designated these derivative financial instruments as cash flow hedges. Accordingly, all changes in fair value of these derivatives will be recorded in earnings unless we elect to designate these instruments as cash flow hedges.

On March 21 and 22, 2002, we hedged a portion of our natural gas production for the period April 2002 through October 2002 in order to increase the predictability of our cash flow from operations in order to support our planned 2002 drilling program. The hedges cover approximately 45% to 50% of our expected 2002 natural gas production from April 2002 to October 2002. We entered into price swaps covering 50 MMBtus per day of our natural gas production at an average price of $3.46. The price swaps will be settled using the closing index price for natural gas delivered to the Houston Ship Channel for 38.2 MMBtus per day and the closing contract price for natural gas delivered to the Henry Hub on the New York Mercantile Exchange for 11.8 MMBtus per day.

Interest Rates

At December 31, 2001, we had long-term debt of $372.2 million. Of this amount, $145.0 million bears interest at a fixed rate of 11¼%. The fair market value of the fixed rate debt as of December 31, 2001 was $142.1 million based on the market price of 98% of the face amount. We had $227.0 million outstanding under our revolving bank credit facility, which is subject to floating market rates of interest. Borrowings under the bank credit facility bear interest at a fluctuating rate that is linked 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. In March 2001, we entered into an interest rate swap agreement to hedge the impact of interest rate changes on $25.0 million of our floating rate debt beginning on April 30, 2001 and expiring on April 30, 2002. As a result of this interest rate swap, we realized a loss of $199,000 in 2001. The fair value of this interest rate derivative financial instrument was a net liability of $214,000 at December 31, 2001.

ITEM 8. FINANCIAL STATEMENTS

Our consolidated financial statements are included on pages F-1 to F-26 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.

Our independent public accountants, Arthur Andersen 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

Not applicable.

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, 2001.

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, 2001.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

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, 2001.

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, 2001.

PART IV

ITEM 14. EXHIBITS AND REPORTS ON FORM 8-K

Exhibits:

The following exhibits are included this report.

Exhibit No.	Description
2.1	Agreement and Plan of Merger among Comstock, Comstock Holdings, Inc., Comstock Acquisition Inc. and DevX Energy, Inc. dated as of November 12, 2001 (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K filed on November 13, 2001).
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 herein 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).
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 Voting Powers, Designations, Preferences, and Relative, Participating, Optional or Other Special Rights of the Series A 1999 Convertible Preferred Stock and Series B 1999 Non-Convertible Preferred Stock (incorporated herein by reference to Exhibit 4.1 to our Current Report on Form 8-K dated April 29, 1999).

Exhibit No.	Description
4.3	Stock Purchase Agreement dated April 29, 1999 between Comstock and certain purchasers (incorporated herein by reference to Exhibit 10.1 to our Current Report on Form 8-K dated April 29, 1999).
4.4	Certificate of Designation, Preferences and Rights of Series B Junior Participating Preferred Stock (incorporated herein by reference to Exhibit 2 to our Registration Statement on Form 8-A dated January 11, 2001).
4.5	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 herein by reference to Exhibit 10.5 to our Current Report on Form 8-K dated April 29, 1999).
4.6	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).
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.
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.
10.4	Placement Agreement dated February 28, 2002, by and between Comstock and Morgan Stanley & Co. Incorporated, TD Securities (USA), inc. and BMO Nesbitt Burns Corp. (incorporated herein by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on March 12, 2002).
10.5	Registration Rights Agreements dated March 7, 2002, by and between Comstock and Morgan Stanley & Co. Incorporated, TD Securities (USA), Inc. and BMO Nesbitt Burns Corp. (incorporated herein by reference to Exhibit 10.2 to our Current Report on Form 8-K filed on March 12, 2002).
10.6#	Employment Agreement dated May 16, 2000, by and between Comstock and M. Jay Allison (incorporated herein by reference to Exhibit 10.4 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2000).
10.7#	Employment Agreement dated May 16, 2000, by and between Comstock and Roland O. Burns (incorporated herein by reference to Exhibit 10.5 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2000).
10.8#	Comstock Resources, Inc. 1999 Long-term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 1999).
10.9#	Form of Nonqualified Stock Option Agreement between Comstock and certain officers and directors of Comstock (incorporated herein by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the year ended June 30, 1999).
10.10#	Form of Restricted Stock Agreement between Comstock and certain officers of Comstock (incorporated herein by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 1999).

Exhibit No.	Description
10.11	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).
10.12	Warrant Agreement dated July 31, 2001 by and between Comstock and Gary W. Blackie and Wayne L. Laufer (incorporated herein by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
10.13	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).
21*	Subsidiaries of the Company.
23*	Consent of Arthur Andersen LLP.
99.1*	Letter to the Securities and Exchange Commission regarding Arthur Andersen LLP Audit.

*Filed herewith.
Management contract or compensatory plan document.

Reports on Form 8-K:

Form 8-K Reports filed subsequent to September 30, 2001 are as follows:

Date	Item	Description
November 13, 2001	5	Entered into Agreement and Plan of Merger with DevX Energy, Inc.
December 21, 2001	2	Completed Acquisition of DevX Energy, Inc and Entered into a New Bank Credit Facility.
February 6, 2002	2	Historical and Proforma Financial Information of DevX Energy, Inc.
March 12, 2002	5	Issued $75 million of 11¼% Senior Notes due 2007.

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 25, 2002

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

/s/M. JAY ALLISON M. Jay Allison	President, Chief Executive Officer and Chairman of the Board of Directors (Principal Executive Officer)	March 25, 2002
/s/ROLAND O. BURNS Roland O. Burns	Senior Vice President, Chief Financial Officer, Secretary, Treasurer and Director (Principal Financial and Accounting Officer)	March 25, 2002
/s/DAVID K. LOCKETT David K. Lockett	Director	March 25, 2002
/s/CECIL E. MARTIN, JR. Cecil E. Martin, Jr.	Director	March 25, 2002
/s/DAVID W. SLEDGE David W. Sledge	Director	March 25, 2002

CONSOLIDATED FINANCIAL STATEMENTS OF

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

INDEX

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

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

We have audited the accompanying consolidated balance sheets of Comstock Resources, Inc. (a Nevada corporation) and subsidiaries as of December 31, 2000 and 2001, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Comstock Resources, Inc. and subsidiaries as of December 31, 2000 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

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

ARTHUR ANDERSEN LLP

Dallas, Texas,
March 8, 2002

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
As of December 31, 2000 and 2001

ASSETS

	December 31, 2000	December 31, 2001
	(In thousands)	
Cash and Cash Equivalents	$ 7,105	$ 6,122
Accounts Receivable:		
Oil and gas sales	34,637	20,015
Joint interest operations	4,574	4,717
Derivatives	—	1,342
Other Current Assets	2,842	7,418
Total current assets	49,158	39,614
Property and Equipment:		
Unevaluated oil and gas properties	5,206	13,416
Oil and gas properties, successful efforts method	659,505	901,206
Other	2,589	2,633
Accumulated depreciation, depletion and amortization	(232,387)	(278,679)
Net property and equipment	434,913	638,576
Derivatives	—	254
Other Assets	5,859	4,627
	$ 489,930	$ 683,071

LIABILITIES AND STOCKHOLDERS' EQUITY

	December 31, 2000	December 31, 2001
Current Portion of Long-Term Debt	$ 101	$ 229
Accounts Payable and Accrued Expenses	45,544	37,389
Derivatives	—	798
Total current liabilities	45,645	38,416
Long-Term Debt, less current portion	234,000	372,235
Deferred Taxes Payable	22,555	47,911
Derivatives	—	1,053
Reserve for Future Abandonment Costs	7,557	7,794
Stockholders' Equity:		
Preferred stock--$10.00 par, 5,000,000 shares authorized, 1,757,310 shares outstanding at December 31, 2000 and 2001	17,573	17,573
Common stock--$0.50 par, 50,000,000 shares authorized, 28,837,755 and 28,552,553 shares outstanding at December 31, 2000 and 2001, respectively	14,419	14,276
Additional paid-in capital	129,896	130,956
Retained earnings	19,329	54,183
Deferred compensation-restricted stock grants	(1,044)	(1,187)
Accumulated other comprehensive loss	—	(139)
Total stockholders' equity	180,173	215,662
	$ 489,930	$ 683,071

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, 1999, 2000 and 2001

	1999	2000	2001
	(In thousands, except per share amounts)		
Revenues:			
Oil and gas sales	$ 90,103	$ 169,350	$ 167,689
Gain on sales of property	130	33	12
Other income	1,911	319	699
Total revenues	92,144	169,702	168,400
Expenses:			
Oil and gas operating	23,714	29,707	32,417
Exploration	1,832	3,192	4,215
Depreciation, depletion and amortization	45,171	44,958	49,191
General and administrative, net	2,399	3,537	4,351
Interest	23,361	24,611	20,737
Impairment of oil and gas properties	—	—	1,400
Total expenses	96,477	106,005	112,311
Income (loss) before income taxes	(4,333)	63,697	56,089
Income tax benefit (expense)	1,517	(22,294)	(19,631)
Net income (loss)	(2,816)	41,403	36,458
Preferred stock dividends	(1,853)	(2,471)	(1,604)
Net income (loss) attributable to common stock	$ (4,669)	$ 38,932	$ 34,854
Net income (loss) per share:			
Basic	$ (0.19)	$ 1.48	$ 1.20
Diluted		$ 1.21	$ 1.06
Weighted average shares outstanding:			
Basic	24,601	26,290	29,030
Diluted		34,219	34,552

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 1999, 2000 and 2001

	Preferred Stock	Common Stock	Additional Paid-In Capital	Retained Earnings (Deficit)	Deferred Compensation Restricted Stock Grants	Accumulated Other Comprehensive Loss	Total
				(In thousands)			
Balance at December 31, 1998	$ —	$ 12,175	$ 112,432	$ (14,934)	$ (10)	$ —	$ 109,663
Issuance of preferred stock	30,000	—	—	—	—	—	30,000
Issuance of common stock	—	400	1,166	—	—	—	1,566
Value of stock options issued for exploration prospects		—	498	—	—	—	498
Restricted stock grants	—	113	759	—	(756)	—	116
Net loss attributable to common stock	—	—	—	(4,669)	—	—	(4,669)
Balance at December 31, 1999	30,000	12,688	114,855	(19,603)	(766)	—	137,174
Conversion of preferred stock	(12,427)	1,553	10,874	—	—	—	—
Issuance of common stock	—	150	706	—	—	—	856
Value of stock options issued for exploration prospects	—	—	2,990	—	—	—	2,990
Restricted stock grants	—	28	471	—	(278)	—	221
Net income attributable to common stock	—	—	—	38,932	—	—	38,932
Balance at December 31, 2000	17,573	14,419	129,896	19,329	(1,044)	—	180,173
Issuance of common stock	—	283	3,538	—	—		3,821
Value of stock options issued for exploration prospects	—	—	1,968	—	—	—	1,968
Restricted stock grants	—	28	333	—	(143)		218
Repurchases of common stock	—	(454)	(4,779)	—	—	—	(5,233)
Net income attributable to common stock	—	—	—	34,854	—	—	34,854
Unrealized hedge losses	—	—	—	—	—	(139)	(139)
Comprehensive income	—	—	—	—	—	—	34,715
Balance at December 31, 2001	$ 17,573	$ 14,276	$ 130,956	$ 54,183	$ (1,187)	$ (139)	$ 215,662

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, 1999, 2000 and 2001

	1999	2000	2001
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (2,816)	$ 41,403	$ 36,458
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Compensation paid in common stock	247	314	244
Depreciation, depletion and amortization	45,171	44,958	49,191
Impairment of oil and gas properties	—	—	1,400
Deferred income taxes	(1,517)	22,294	18,851
Exploration	1,832	3,192	4,215
Gain on sales of property	(130)	(33)	(12)
Gain on Derivatives	—	—	(254)
Working capital provided by operations	42,787	112,128	110,093
Decrease (increase) in accounts receivable	(5,754)	(15,596)	18,371
Decrease (increase) in other current assets	548	(1,933)	(1,229)
Increase (decrease) in accounts payable and accrued expenses	935	9,957	(17,145)
Net cash provided by operating activities	38,516	104,556	110,090
CASH FLOWS FROM INVESTING ACTIVITIES:			
Proceeds from sales of properties	778	33	45
Capital expenditures and acquisitions	(35,981)	(83,394)	(189,646)
Net cash provided by operating activities	(35,203)	(83,361)	(189,601)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings	10,378	18,408	261,730
Proceeds from senior notes offering	149,221	—	—
Debt issuance costs	(5,671)	—	—
Principal payments on debt	(184,351)	(38,438)	(178,355)
Proceeds from preferred stock offering	30,000	—	—
Proceeds from common stock issuances	296	763	1,989
Stock issuance costs	(714)	—	—
Repurchases of common stock	—	—	(5,232)
Dividends paid on preferred stock	—	(2,471)	(1,604)
Net cash provided by financing activities	(841)	(21,738)	78,528
Net increase (decrease) in cash and cash equivalents	2,472	(543)	(983)
Cash and cash equivalents, beginning of year	5,176	7,648	7,105
Cash and cash equivalents, end of year	$ 7,648	$ 7,105	$ 6,122

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Accounting policies used by Comstock Resources, Inc. ("Comstock") 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.

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.

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. 121 "Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to Be Disposed Of," ("SFAS 121") 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. No impairment was required in 1999 or 2000. In 2001 Comstock provided an impairment of $1.4 million for certain of its oil and gas properties.

Other property and equipment consists primarily of work boats, gas gathering systems, computer equipment and furniture and fixtures which are depreciated over estimated useful lives on a straight-line basis.

Other Assets

Other assets primarily consists 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.

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 which are included in Note 6.

Segment Reporting

Comstock presently operates in one business segment.

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. Since Comstock had no outstanding derivatives on January 1, 2001 there was no effect on the financial statements as a result of such adoption.

Major Purchasers

In 2001, Comstock had four purchasers of its oil and natural gas production which individually accounted for more than 10% of total oil and gas sales. Such purchasers accounted for 24%, 19%, 16% and 12% of total 2001 oil and gas sales. In 2000, Comstock had three purchasers which accounted for 29%, 21% and 11% of total 2000 oil and gas sales. In 1999, Comstock had two purchasers which accounted for 33% and 20% of total 1999 oil and gas sales.

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.

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 bases, 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.

Earnings Per Share

Basic and diluted earnings per share for 1999, 2000 and 2001 were determined as follows:

	Year Ended December 31,								
	1999			2000			2001		
	Income (Loss)	Shares	Per Share	Income (Loss)	Shares	Per Share	Income (Loss)	Shares	Per Share
Basic Earnings Per Share:									
Income (Loss)	$ (2,816)	24,601		$ 41,403	26,290		$ 36,458	29,030	
Less Preferred Stock Dividends	(1,853)	—		(2,471)	—		(1,604)	—	
Net Income (Loss) Available to Common Stockholders	$ (4,669)	24,601	$ (0.19)	38,932	26,290	$ 1.48	34,854	29,030	$ 1.20
Diluted Earning Per Share:									
Effect of Dilutive Securities:									
Stock Options				—	1,184		—	1,129	
Convertible Preferred Stock				2,471	6,745		1,604	4,393	
Net Income Available to Common Stockholders and Assumed Conversions				$ 41,403	34,219	$ 1.21	$ 36,458	34,552	$ 1.06

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. For the year ended December 31, 2001, Comstock's comprehensive income differed from net income by approximately $139,000, due to the recognition in comprehensive income of unrealized losses related to certain of Comstock's derivative instruments which have been designated as hedges. For the years ended December 31, 1999 and 2000, there were no differences between Comstock's net income or net loss and comprehensive income.

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,		
	1999	**2000**	**2001**
		(in thousands)	
Noncash activities –			
Common stock issued for compensation	$ 131	$ 93	$ 26
Value of vested stock options under exploration venture	498	2,990	3,028
Common stock issued in payment of preferred stock dividends	1,853	–	–
Cash payments –			
Interest payments	20,840	24,731	20,607
Income tax payments	–	–	243

New Accounting Standards

In July 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 141 ("SFAS 141") "Business Combinations." SFAS 141 requires the purchase method of accounting for all business combinations initiated after June 30, 2001 and eliminates the pooling-of-interests method.

In July 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 142 ("SFAS 142") "Goodwill and Other Intangible Assets." SFAS 142 requires the discontinuance of goodwill amortization. In addition, the SFAS 142 includes provisions regarding the reclassification of certain existing recognized intangibles as goodwill, reassessment of the useful lives of existing recognized intangibles, reclassification of certain intangibles out of previously reported goodwill and the testing for impairment of existing goodwill and other intangibles. SFAS 142 is required to be applied for fiscal years beginning after December 15, 2001, with certain early adoption permitted. Comstock does not expect the adoption of SFAS 142 to have a material effect on its financial condition or results of operations.

In August 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 143 ("SFAS 143") "Accounting for Asset Retirement Obligations," which Comstock will be required to adopt as of January 1, 2003. This statement requires Comstock to record a liability in the period in which an asset retirement obligation ("ARO") is incurred. Upon recognition of an ARO liability, additional asset cost would be capitalized to equal the amount of the liability. Upon initial adoption of SFAS 143, Comstock will recognize (1) a liability for any existing AROs not already provided for in Comstock's reserve for future abandonment costs (2) capitalized cost related to the additional liability and (3) accumulated depreciation on the additional capitalized cost. Comstock has not determined the effect, if any, the adoption of SFAS 143 will have on its financial statements.

In October 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 144 ("SFAS 144") "Accounting for the Impairment or Disposal of Long-Lived Assets," which supercedes SFAS 121. SFAS 144 addresses financial accounting and reporting for the impairment of long-lived assets and for long-lived assets to be disposed of. However, SFAS 144 retains the fundamental provisions of SFAS 121 for recognition and measurement of the impairment of long-lived assets to be held and used, and measurement of long-lived assets to be disposed of by sale. SFAS 144 is effective for fiscal years beginning after December 15, 2001. Comstock is in the process of assessing the effect of adopting SFAS 144, which will be effective for its first quarter of 2002.

(2) Acquisitions

Acquisition of DevX Energy, Inc.

On December 17, 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 is an independent energy company engaged in the exploration, development and acquisition of oil and gas properties. DevX owns interests in 600 producing oil and gas wells located onshore primarily in East and South Texas, Kentucky, Oklahoma and Kansas. One of the primary reasons Comstock acquired DevX was to add to its existing producing property base in the East Texas and South Texas regions. Comstock is currently evaluating whether to divest of the DevX properties in the Illinois Basin and Mid Continent regions, which are not part of its core operating areas. The DevX acquisition added approximately 163.4 billion cubic feet equivalent of natural gas reserves to Comstock's reserve base. Subsequent to the acquisition, Comstock repurchased approximately $49.8 million of DevX's publically held 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 & 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

Pro Forma Information (Unaudited)

Set forth in the following table is certain unaudited pro forma financial information for the years ended December 31, 2000 and 2001. This information has been prepared assuming the DevX acquisition was consummated on January 1, 2000 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, 2000. 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, 2000	Year Ended December 31, 2001
	(In thousands, except per share amounts)	
Revenues:		
Oil and gas sales	$ 211,555	$ 206,288
Change in fair value of derivatives	442	2,870
Other income	—	1,164
Total revenues	211,997	210,322
Expenses:		
Oil and gas operating	37,648	40,534
Exploration	3,992	4,751
Depreciation, depletion and amortization	58,431	60,880
Impairment	—	1,400
General and administrative, net	3,537	4,351
Interest	35,099	28,981
Change in fair value of derivatives	1,945	—
Income before income taxes	71,345	69,425
Provision for income taxes	(24,971)	(24,299)
Income	46,374	45,126
Preferred stock dividends	(2,471)	(1,604)
Net income attributable to common stock	$ 43,903	$ 43,522
Net income per share:		
Basic	$ 1.67	$ 1.49
Diluted	$ 1.36	$ 1.29

(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,	
	2000	2001
	(In thousands)	
Proved properties	$ 659,505	$ 901,206
Unproved properties	5,206	13,416
Accumulated depreciation, depletion and amortization	(231,667)	(277,670)
	$ 433,044	$ 636,952

Costs Incurred

	For the Year Ended December 31,		
	1999	2000	2001
		(In thousands)	
Property acquisitions			
Proved properties	$ 4,458	$ 11,302	$ 160,794
Unproved properties	2,258	5,346	8,210
Development costs	20,455	46,928	51,447
Exploration costs	8,126	19,202	33,382
	$ 35,297	$ 82,778	$ 253,833

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, Comstock capitalized interest expense of $0.2 million on its unproved properties which is included in the unproved property acquisition costs in 2001.

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,		
	1999	**2000**	**2001**
		(In thousands)	
Oil and gas sales	$ 90,103	$ 169,350	$ 167,689
Production costs	(23,714)	(29,707)	(32,417)
Exploration	(1,832)	(3,192)	(4,215)
Depreciation, depletion and amortization	(44,118)	(43,478)	(47,541)
Impairment of oil and gas properties	—	—	(1,400)
Operating income	20,439	92,973	82,116
Income tax expense	(7,154)	(32,541)	(28,741)
Results of operations of oil and gas producing activities	$ 13,285	$ 60,432	$ 53,375

(4) Long-Term Debt

Long-term debt is comprised of the following:

	As of December 31,	
	2000	**2001**
	(In thousands)	
Revolving Bank Credit Facility	$ 84,000	$ 227,000
11¼% Senior Notes due 2007	150,000	145,000
Other	101	464
	234,101	372,464
Less current portion	(101)	(229)
	$ 234,000	$ 372,235

On December 17, 2001, Comstock entered into a new bank credit facility which consists of a $350.0 million three year revolving credit commitment provided by a syndicate of banks for which Toronto Dominion (Texas), Inc. serves as administrative agent. The acquisition of DevX and the repurchase of the DevX 's senior notes were funded by borrowings under the new bank credit facility. The bank credit facility was also used to refinance Comstock's existing bank debt. The new bank credit facility is subject to borrowing base availability, which is 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, 2001 was $270.0 million. The revolving credit line bears interest, 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 base rate plus 0.5% to 1.375%. The facility matures on January 2, 2005. Indebtedness under the bank credit facility is secured by substantially all of Comstock's assets and Comstock's corporate subsidiaries are guarantors of the bank credit facility. The bank credit facility contains covenants that, among other things, restrict the payment of cash dividends, limit the amount of consolidated debt and limit Comstock's ability to make certain loan and investments. Financial covenants include the maintenance of a current ratio, maintenance of tangible net worth and maintenance of an interest coverage ratio.

Comstock issued $150.0 million in aggregate principal amount of 11¼% Senior Notes due in 2007 (the "Notes") on April 29, 1999. Interest on the Notes is payable semiannually on May 1 and November 1, commencing on November 1, 1999. The Notes are unsecured obligations of Comstock and are guaranteed by all of its principal operating subsidiaries. Comstock repurchased $5.0 million of the Notes in July 2001. The Notes can be redeemed beginning on May 1, 2004. The fair market value of the Notes as of December 31, 2001 was $142.1 million based on the market price of 98% of the face amount as of December 31, 2001.

On March 7, 2002, Comstock closed the sale in a private placement of $75.0 million of Notes at a net price of 97.25% after the placements agents' discount. As a result of this transaction, $220.0 million of aggregate principal amount of the Notes were outstanding. The net proceeds were used to reduce amounts outstanding under the bank credit facility. The borrowing base under the bank credit facility was reduced to $240.0 million in connection with the issuance of the additional Notes.

(5) Lease Commitments

Comstock rents office space under noncancellable leases. Minimum future payments under the leases are as follows:

	(In thousands)
2002	$ 661
2003	656
2004	452
2005	477
2006	198
	$2,444

(6) Stockholders' Equity

The authorized capital stock of Comstock consists of 10 million shares of common stock, par value $.50 per share (the "Common Stock"), and 5 million shares of preferred stock, par value $10.00 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.

On April 29, 1999, Comstock issued 3,000,000 shares of convertible preferred stock in a private placement and received proceeds of $30.0 million. The preferred stock accrues dividends at an annual rate of 9% which are payable quarterly in cash or Comstock has the option to issue shares of Common Stock. Each share of the preferred stock is convertible, at the option of the holder, into 2.5 shares of Common Stock. On May 1, 2005 and on each May 1, thereafter, so long as any shares of the preferred stock are outstanding, Comstock is obligated to redeem an amount of shares of preferred stock equal to one-third of the shares of the preferred stock outstanding on May 1, 2005 at $10.00 per share plus accrued and unpaid dividends. The mandatory redemption price may be paid either in cash or in shares of Common Stock. Comstock has the option to redeem the shares of preferred stock upon payment to the holders of the preferred stock at a specified rate of return on the initial purchase. Upon a change of control of Comstock, the holders of the preferred stock have the right to require Comstock to purchase all or a portion of the preferred stock.

In September and October 2000, holders of 1,242,690 shares of the convertible preferred stock converted their shares into 3,106,725 shares of Common Stock. As a result of these conversions, $12.4 million of preferred stockholders' equity was transferred to common stockholders' equity.

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, 2001 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 of 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 44,255, 8,182 and 5,342 shares of Common Stock in 1999, 2000 and 2001 respectively, in payment of fees aggregating $130,000, $93,000 and $26,000 for 1999, 2000 and 2001 respectively.

The outstanding preferred stock series provides that Comstock can issue Common Stock in lieu of cash for payment of quarterly dividends. In 1999, Comstock issued 640,525 shares of Common Stock in payment of dividends on its preferred stock of $1.9 million. Comstock paid the preferred stock dividends in cash in 2000 and 2001.

Options and warrants to purchase Common Stock were exercised to purchase 115,000 shares, 291,400 shares and 560,606 shares in 1999, 2000 and 2001, respectively. Such exercises yielded net proceeds of approximately $295,000, $763,000 and $2.0 million in 1999, 2000 and 2001, 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 (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. As of December 31, 2001, the Incentive Plans provide for future awards of stock options or restricted stock grants of up to 264,260 shares of Common Stock plus 1% of the outstanding shares of Common Stock each year beginning on January 1, 2002.

The following table summarizes stock option activity during 1999, 2000 and 2001 under the Incentive Plans:

	Number of Shares	Exercise Price	Weighted Average Exercise Price
Outstanding at December 31, 1998	3,890,500	$2.00 to $12.38	$7.81
Granted	1,010,000	$3.88	3.88
Exercised	(115,000)	$2.00 to $3.00	2.57
Forfeited	(155,500)	$3.00 to $12.38	7.81
Outstanding at December 31, 1999	4,630,000	$2.00 to $12.38	7.08
Granted	351,250	$6.69 to $8.88	8.24
Exercised	(291,400)	$2.00 to $4.81	2.62
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
Exercisable at December 31, 2001	2,995,400	$2.50 to $12.38	8.26

The following table summarizes information about the Incentive Plans stock options outstanding at December 31, 2001:

Exercise Price	Number of Shares Outstanding	Weighted Average Remaining Life	Number of Shares Exercisable
		(Years)	
$2.50	20,000	0.5	20,000
3.44	481,625	5.8	413,875
3.88	975,525	6.3	498,025
6.42	437,750	7.1	175,000
6.69	84,000	5.6	43,500
6.94	150,000	2.0	150,000
7.40	20,000	4.6	20,000
8.88	249,250	7.5	—
9.63	80,000	0.5	80,000
11.00	1,269,000	3.7	1,269,000
11.12	33,500	6.0	20,000
11.94	30,000	1.3	30,000
12.38	559,000	3.5	276,000
	4,389,650	4.9	2,995,400

Comstock accounts for the stock options issued under the Incentive Plans under APB 25, under which no compensation cost has been recognized. Had compensation cost for these plans been determined consistent with SFAS 123, net income attributable to common stock and earnings per share would have been reduced to the following pro forma amounts:

		1999	2000	2001
		(In thousands, except per share amounts)		
Net income (loss):	As Reported	$ (4,669)	$ 38,932	$ 34,854
	Pro Forma	(6,644)	36,958	33,168
Basic earnings per share:	As Reported	(0.19)	1.48	1.20
	Pro Forma	(0.27)	1.41	1.14
Diluted earnings per share:	As Reported		1.21	1.06
	Pro Forma		1.15	1.01

Because the SFAS 123 method of accounting has not been applied to options granted prior to January 1, 1995, the resulting pro forma compensation cost may not be representative of that to be expected in future years.

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 1999, 2000 and 2001, respectively: average risk-free interest rates of 5.7, 6.2 and 4.9 percent; average expected lives of 8.8, 7.8 and 7.4 years; average expected volatility factors of 64.2, 66.4 and 67.2; and no dividend yield. The estimated weighted average fair value of options to purchase one share of common stock issued under the Company's Incentive Plans was $2.86 in 1999, $5.98 in 2000 and $6.80 in 2001.

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 667,500 shares have been awarded under the Incentive Plans. As of December 31, 2001, 470,625 shares of such awards are vested. A provision for the restricted stock grants is made ratably over the vesting period. Compensation expense recognized for restricted stock grants for the years ended December 31, 1999, 2000 and 2001 was $116,000, $221,000 and $218,000, respectively.

Exploration Venture Warrants

On July 31, 2001 Comstock entered into a new exploration agreement with Bois d' Arc Offshore, Ltd. and its principals ("Bois d' Arc") which replaces an exploration agreement entered into on December 8, 1997. The 2001 Exploration Agreement establishes 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 venture, Bois d' Arc generates exploration prospects in the Gulf of Mexico utilizing 3-D seismic data and their extensive geological expertise in this region. Comstock advances funds for the acquisition of 3-D seismic data and leases as needed. After a prospect is identified, Comstock is reimbursed for the costs that were advanced and is entitled to a 40% non-promoted working interest in each prospect. 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.

During 2001, Bois d' Arc earned warrants to purchase 360,000 shares at $7.32 per share under the exploration agreement. 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. Such cost was capitalized as a cost of oil and gas properties in 2001. 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 for the warrants earned under the prior exploraton agreement which was capitalized to oil and gas properties was $1.5 million in 1998, $0.5 million in 1999, $3.0 million in 2000 and $1.0 million in 2001.

(7) 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 $79,000, $84,000 and $96,000 for the years ended December 31, 1999, 2000 and 2001, respectively.

(8) Income Taxes

The tax effects of significant temporary differences representing the net deferred tax liability at December 31, 2000 and 2001 were as follows:

	2000	2001
	(In thousands)	
Net deferred tax assets (liabilities):		
Property and equipment	$ (36,562)	$ (75,269)
Net operating loss carryforwards	13,457	34,504
Valuation allowance on net operating loss carryforwards	—	(8,043)
Other carryforwards	550	897
	$ (22,555)	$ (47,911)

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

	2000	2001
	(In thousands)	
Current	$ —	$ —
Deferred	22,294	19,631
	$ 22,294	$ 19,631

There were no significant differences between income taxes computed using the statutory rate of 35% and Comstock's effective tax rate in 2000 and 2001 of 35%.

At December 31, 2001, Comstock had the following carryforwards available to reduce future income taxes:

Types of Carryforward	Years of Carryforward	Amounts
($ in thousands)		
Net operations loss - U.S. federal	2018 - 2021	$ 98,583
Alternative Minimum tax credits	Unlimited	792
Charitable contributions carryforward	2003 - 2006	324

The utilization of $42.9 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 has been established for Comstock's estimate of the 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.

(9) 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 cap.

In connection with the DevX acquisition, Comstock assumed certain derivative financial instruments entered into by DevX to manage natural gas price risk. The following table sets out the derivative financial instruments outstanding at December 31, 2001 which are held for natural gas price risk management:

Period Beginning	Period Ending	Volume (MMBtu)	Type of Instrument	Floor Price	Ceiling Price	Swap Price
January 1, 2002	December 31, 2002	640,000	Floor	$1.90	—	—
January 1, 2002	December 31, 2002	2,550,000	Floor	$2.00	—	—
January 1, 2002	December 31, 2002	1,600,000	Swap	—	—	$2.40
January 1, 2002	December 31, 2002	900,000	Collar	$4.00	$6.75	—
		5,690,000				
January 1, 2003	December 31, 2003	560,000	Floor	$1.90	—	—
January 1, 2003	December 31, 2003	2,250,000	Floor	$2.00	—	—
January 1, 2003	December 31, 2003	1,400,000	Swap	—	—	$2.40
		4,210,000				
		9,900,000				

The counterparty for the $1.90 floor position and $2.40 swap price position is a subsidiary of Enron Corporation who has filed for bankruptcy protection. The net liability owed to Enron as of December 31, 2001, was $1.6 million. Comstock intends to monitor this position and will assess the credit exposure to the extent this position becomes a net asset.

As a result of certain hedging transactions for natural gas price risk, Comstock has realized the following gains and losses which were included in oil and gas sales:

	1999	2000	2001
		(In thousands)	
Realized Gains	$ 248	$ —	$ —
Realized Losses	(5,178)	—	—

Comstock periodically enters into interest rate swap agreements to hedge the impact of interest rate changes on its floating rate long-term debt. As of December 31, 2001, Comstock had an interest rate swap agreement covering $25.0 million of its floating rate debt which fixed the LIBOR rate at 4.5% for the period April 2001 through April 2002. Comstock has designated this position as a hedge. As a result of certain hedging transaction for interest rates, Comstock has realized the following gains or losses which were included in interest expense:

	1999	2000	2001
		(In thousands)	
Realized Gains	$ 169	$ 988	$ —
Realized Losses	—	—	(199)

Effective January 1, 2001, Comstock adopted SFAS 133 which required that all derivative financial instruments are to be included on the balance sheet at the fair value. 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.

Comstock has not designated any of the natural gas price derivative financial instruments acquired in the DevX acquisition as hedges. The change in fair value of these derivative contracts resulted in a gain of $254,000 which is included in other income in 2001. The interest rate swap has been designated swap as a cash flow hedge. As a result the change in fair value of this instrument of an unrealized after tax loss of $139,000 was recognized in other comprehensive income.

(10) Supplementary Quarterly Financial Data (Unaudited)

	First	Second	Third	Fourth	Total
	(In thousands, except per share amounts)				
2000 -					
Total revenues	$ 33,143	$ 38,634	$ 44,987	$ 52,938	$169,702
Net income attributable to common stock	$ 4,085	$ 7,934	$ 12,135	$ 14,778	$ 38,932
Net income per share:					
Basic	$ 0.16	$ 0.31	$ 0.47	$ 0.52	$ 1.48
Diluted	$ 0.14	$ 0.25	$ 0.37	$ 0.44	$ 1.21
2001 -					
Total revenues	$ 67,546	$ 46,575	$ 29,781	$ 24,498	$168,400
Net income attributable to common stock	$ 23,578	$ 12,439	$ 2,486	$ (3,649)	$ 34,854
Net income per share:					
Basic	$ 0.81	$ 0.43	$ 0.09	($ 0.13)	$ 1.20
Diluted	$ 0.68	$ 0.37	$ 0.09		$ 1.06

(11) 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, 2001.

	1999		2000		2001	
	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)
Proved Reserves:						
Beginning of year	20,245	250,402	19,467	258,121	17,451	297,835
Revisions of previous estimates	(1,695)	(14,272)	(1,725)	1,205	(1,177)	(10,959)
Extensions and discoveries	3,029	39,534	1,599	54,574	1,395	46,777
Purchases of minerals in place	16	6,329	416	11,059	1,213	156,515
Sales of minerals in place	—	—	(499)	(134)	—	—
Production	(2,128)	(23,872)	(1,807)	(26,990)	(1,534)	(28,083)
End of year	19,467	258,121	17,451	297,835	17,348	462,085
Proved Developed Reserves:						
Beginning of year	16,585	182,955	14,379	184,123	12,290	200,349
End of year	14,379	184,123	12,290	200,349	12,212	315,779

The following table sets forth the standardized measure of discounted future net cash flows relating to proved reserves at December 31, 2000 and 2001:

	2000	2001
	(In thousands)	
Cash Flows Relating to Proved Reserves:		
Future Cash Flows	$3,590,711	$1,566,780
Future Costs:		
Production	(527,939)	(453,416)
Development	(126,904)	(156,906)
Future Net Cash Flows Before Income Taxes	2,935,868	956,458
Future Income Taxes	(825,033)	(177,551)
Future Net Cash Flows	2,110,835	778,907
10% Discount Factor	(822,071)	(331,634)
Standardized Measure of Discounted Future Net Cash Flows	$1,288,764	$ 447,273

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, 1999, 2000 and 2001:

	1999	2000	2001
		(In thousands)	
Standardized Measure, Beginning of Year	$ 304,993	$ 468,713	$ 1,288,764
Net Change in Sales Price, Net of Production Costs	179,042	1,141,880	(1,298,306)
Development Costs Incurred During the Year Which Were Previously Estimated	5,303	17,340	26,627
Revisions of Quantity Estimates	(35,727)	(44,256)	(21,342)
Accretion of Discount	30,531	51,506	173,747
Changes in Future Development Costs	(437)	(41,525)	(6,571)
Changes in Timing and Other	(2,271)	(166,410)	(141,844)
Extensions and Discoveries	91,911	375,632	86,026
Purchases of Reserves in Place	7,787	62,621	120,147
Sales of Reserves in Place	—	(3,355)	—
Sales, Net of Production Costs	(66,389)	(139,643)	(135,272)
Net Changes in Income Taxes	(46,030)	(433,739)	355,297
Standardized Measure, End of Year	$ 468,713	$1,288,764	$ 447,273

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 yearend prices used in the reserve estimates were as follows:

	1999	2000	2001
Crude Oil (Per Barrel)	$ 24.56	$ 26.34	$ 18.73
Natural Gas (Per Mcf)	$ 2.51	$10.51	$ 2.69

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 [4]
Cecil E. Martin, Jr. [2,3,4]
David W. Sledge [3,4]

[1]Chairman of the Board of Directors
[2]Executive Committee
[3]Compensation Committee
[4]Audit 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

Subsidiaries

Comstock Oil & Gas, Inc.
Comstock Oil & Gas Holdings, Inc.
Comstock Oil & Gas – Louisiana, Inc.
Comstock Offshore, LLC
DevX Energy, Inc.

Exchange Listing

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

Commercial Banks

Toronto Dominion, *Administrative Agent*
Bank of Montreal, *Syndication Agent*
Fortis Capital Corp., *Documentation Agent*
Bank of Scotland
CIBC, Inc.
Comerica Bank
Compass Bank
Hibernia National Bank
Natexis Banques Populaires
PNC Bank
Union Bank of California, N.A.
Washington Mutual Bank, FA

Annual Meeting

The annual meeting of stockholders will be held on Monday, May 13, 2002 at 4:00 p.m. at the Westin Stonebriar Resort, 1549 Legacy Drive, Frisco, Texas. All stockholders are encouraged to attend.

Investor Relations

Requests for additional information should be directed to:

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(800) 877-1322
rburns@comstockresources.com

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

2000	High	Low
First Quarter	$5.94	$2.44
Second Quarter	$9.13	$4.06
Third Quarter	$13.13	$6.13
Fourth Quarter	$15.00	$8.13

2001	High	Low
First Quarter	$14.63	$9.65
Second Quarter	$12.48	$8.95
Third Quarter	$10.12	$5.00
Fourth Quarter	$8.15	$5.26

COMSTOCK RESOURCES

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