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Prima Energy Corporation

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Dear Fellow Shareholders:

The story for 2001 and the foreseeable future was and will be natural gas prices. During 2001, Rocky Mountain natural gas prices ranged from a high of $8.63 per MMBtu in January to a low of $1.05 per...

2001 Annual Report and Form 10-K

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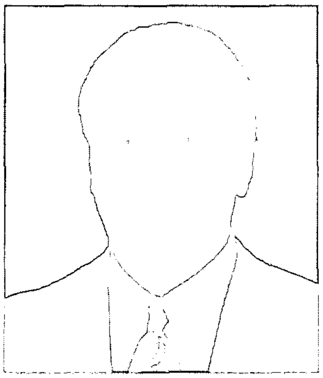
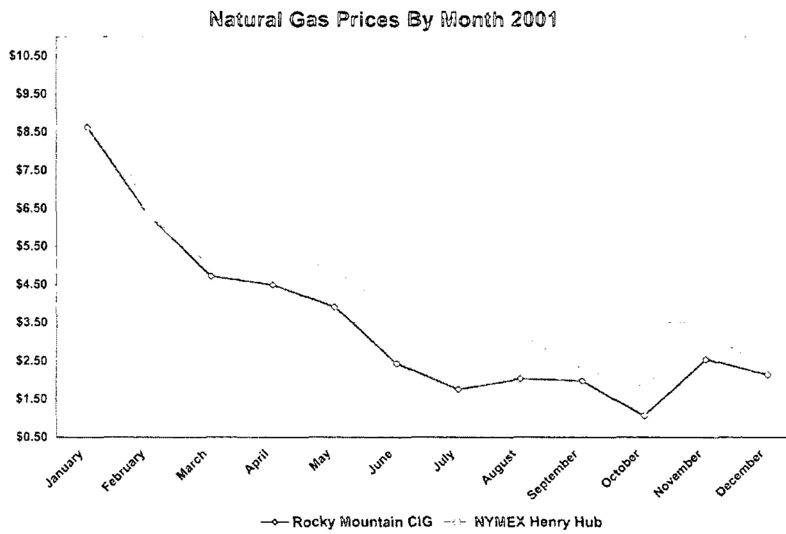


Richard H. Lewis
Chairman and Chief
Executive Officer

MMBtu in October. Average year-end gas prices utilized in our reserve calculations, pursuant to Securities & Exchange Commission requirements, declined from $7.51 per Mcf at the end of 2000 to $1.94 at the close of 2001. Average prices attributable to our coalbed methane reserves in the Powder River Basin of Wyoming declined by 81% from $7.14 at the end of 2000 to $1.38 per Mcf at the end of 2001.



The extreme volatility created a challenging environment in which to plan, budget and operate a natural gas oriented company. While, in hindsight, we did not make all the correct calls, the hedges we had in place and the decision to postpone certain drilling and hook-up capital expenditures were timely. The hedges in place covering 2001 production or still in place at the end of the year, contributed $10,787,000 of gains last year, including $6,315,000 realized and $4,472,000 unrealized but marked to market at year-end*. We elected to postpone some production acceleration activities last fall, as we did not want to produce initial flush production into what we perceived as a temporarily depressed market.

I think of greater prospective importance are the information and insight that we gained from operating in this environment. Natural gas supply and demand are in near balance and relatively modest excesses or shortages can have substantial effects on prices. Significant changes in market prices will, at the margin, either stimulate new supply and dampen demand, or discourage new supply and stimulate demand.

While we have maintained a cautious near-term position, we think the evidence is compelling that natural gas deliverability in the U.S. is currently declining and demand is rising. With no significant incremental supplies expected from new sources for several years, we believe this confirms our longer term bullish outlook.

Prima Energy Corporation is an independent oil and gas company engaged in the exploration for, acquisition, development and production of crude oil and natural gas. Through its wholly owned subsidiaries, Prima is also engaged in oil and gas property operations, oilfield services and natural gas gathering, marketing and trading. The Company's current activities are principally conducted in the Rocky Mountain Region.

Prima Energy Corporation
1099 18th Street, Suite 400
Denver, Colorado 80202
(303) 297-2100

NOTICE OF ANNUAL MEETING OF STOCKHOLDERS

To Be Held May 15, 2002

Notice is hereby given that the Annual Meeting of Stockholders of Prima Energy Corporation, a Delaware corporation, will be convened at 3:00 p.m., Mountain Daylight Time, on Wednesday, May 15, 2002, in the Grand Ballroom, The Oxford Hotel, 1600 17th Street, Denver, Colorado, 80202 for the following purposes:

1. To elect two (2) directors, as the Class II directors, for the term expiring in 2005 or until their respective successors shall be elected and qualified;

2. To consider and vote upon a proposal to ratify the selection of Deloitte & Touche LLP to serve as independent auditors of Prima Energy Corporation, for fiscal 2002; and

3. To transact such other business as may properly come before the meeting or any adjournment or adjournments thereof.

Only stockholders of record at the close of business on March 27, 2002 are entitled to notice of and to vote at the meeting.

Stockholders are cordially invited to attend the meeting in person. Whether or not you plan to be present at the meeting, you are requested to sign and return the enclosed proxy in the enclosed envelope so that your shares may be voted in accordance with your wishes and in order that the presence of a quorum may be assured. The giving of such proxy will not affect your right to vote in person, should you later decide to attend the meeting. Please date and sign the enclosed proxy and return it promptly in the enclosed envelope. Your vote is important.

By Order of the Board of Directors

Sandra J. Irlando

SANDRA J. IRLANDO
Secretary

Denver, Colorado
April 10, 2002

PROXY STATEMENT

PRIMA ENERGY CORPORATION
1099 18th Street, Suite 400
Denver, Colorado 80202
(303) 297-2100

ANNUAL MEETING OF STOCKHOLDERS
To Be Held May 15, 2002

GENERAL

This Proxy Statement is furnished in connection with the solicitation of Proxies by the Board of Directors of Prima Energy Corporation (hereinafter the "Company" or "Prima"), Suite 400, 1099 18th Street, Denver, Colorado 80202. The Proxy Statement is to be used at the Annual Meeting of Stockholders (the "Meeting") to be held in the Grand Ballroom, The Oxford Hotel, 1600 17th Street, Denver, Colorado, on Wednesday, May 15, 2002, at 3:00 p.m., for the purposes set forth in the accompanying Notice of Annual Meeting of Stockholders. This Proxy Statement and the enclosed Proxy Card were sent to stockholders on or about April 10, 2002.

The Company will pay for all expenses for soliciting Proxies, including clerical work, printing and postage. The Company will reimburse brokers and other persons holding stock in their names, or in the name of nominees, for their expenses in sending Proxy materials to principals and obtaining their Proxies. In addition to solicitations by mail, employees and directors of the Company may solicit Proxies personally or by telephone, facsimile or other form of wire or electronic communication. Such persons will receive no additional compensation for such services.

Shares represented by a properly executed Proxy will be voted at the Meeting and, when instructions have been given by the stockholder, will be voted in accordance with those instructions. If no instructions are given, the stockholder's shares will be voted as recommended by the Board of Directors. A Proxy may be revoked at any time by a stockholder before it is exercised by one of two methods. The stockholder may give written notice to the Secretary of the Company by signing and delivering a Proxy that is dated later. Or if the stockholder attends the Meeting in person, he may either give notice of revocation to the inspectors of election at the Meeting or may vote at the Meeting.

QUORUM AND VOTING

Only stockholders of record at the close of business on March 27, 2002 will be entitled to vote at the Meeting. On that date, there were issued and outstanding 12,728,672 shares of the Company's $0.015 par value common stock ("Common Stock"), entitled to one vote per share. In the election of directors, cumulative voting is not allowed. There are no outstanding shares of preferred stock.

The only matters that management intends to present at the Meeting are: (a) the election of two directors as Class II directors for the term expiring in 2005; and (b) the ratification of the selection of Deloitte & Touche LLP to serve as independent auditors of Prima for fiscal 2002. If any other matter or business is properly presented at the Meeting, the proxy holders will vote upon it in accordance with their best judgment.

A majority of the outstanding Common Stock, present in person or by Proxy and entitled to vote, will constitute a quorum for the transaction of business at the Meeting. Under Delaware law and the Company's Certificate of Incorporation, if a quorum is present at the Meeting, the two nominees for election as Class II directors who receive the greatest number of votes cast at the Meeting by the shares present in person or by Proxy and entitled to vote shall be elected as the Class II directors. The affirmative vote by the holders of a majority of the shares of Common Stock present in person or by Proxy at the Meeting and entitled to vote is required to ratify the selection of Deloitte & Touche LLP as the Company's independent auditors for fiscal 2002. In the election of the Class II directors, any action other than a vote for a nominee will have the practical effect of voting against the nominee. Abstention from voting on Proposal 2 on the Proxy Card or on any other matter presented at the Meeting will have the practical effect of voting against any such matter since it is one less vote for approval. Broker nonvotes on any such matter will not be considered "shares present" for voting purposes. At the 2000 and 2001 Annual Meeting of Stockholders, approximately 84% and 88% respectively of the then-outstanding shares of the Company's Common Stock were present in person or by Proxy.

Beneficial Ownership of Prima's Common Stock

The following table sets forth, as of March 22, 2002, the beneficial ownership of Prima's Common Stock (i) by each person or group of persons known by the Company to beneficially own more than 5% of the outstanding Common Stock, (ii) the nominees as Class II director and each of the directors of Prima, (iii) the executive officers named in the Summary Compensation Table set forth under the caption "Executive Compensation" below, and (iv) the nominees and all directors and executive officers as a group.

Name of Beneficial Owner	Amount and Nature of Beneficial Ownership(1)(2)	Percent of Class
Richard H. Lewis 1099 18th Street, Suite 400, Denver, CO 80202	2,018,561 (3)	15.2
Robert G. James 80 Ludlow Drive, Chappaqua, NY 10514	1,399,077 (4)	11.0
James R. Cummings	13,150 (5)	*
Douglas J. Guion	114,995 (6)	*
Catherine James Paglia	14,620 (7)	*
George L. Seward	405,908 (8)	3.2
Neil L. Stenbuck	16,666 (9)	*
Michael J. McGuire	26,161(10)	*
Michael R. Kennedy	11,723(11)	*
John H. Carpenter	12,967(12)	*
All executive officers and directors as a group (11 persons including those named above)	2,865,640(13)	21.3

* Indicates less than 1%.

(1) Except as stated in the following notes, each person has sole voting and investment powers associated with shares stated as beneficially owned by him.

(2) Beneficial ownership includes shares over which the indicated beneficial owner exercises voting and/or investment power. Shares of Common Stock subject to options currently exercisable or exercisable within 60 days are deemed outstanding for computing the percentage ownership of the person holding the options but not deemed outstanding for computing the percentage ownership of any other person.

(3) Includes 553,750 shares purchasable under stock options granted pursuant to Prima Energy Corporation Stock Incentive Plans (the "Employee Plans"), 33,781 shares allocated to Mr. Lewis' account in the Employee Stock Ownership Trust ("ESOT") as a participant in the Employee Stock Ownership Plan ("ESOP"), 35,000 shares owned by a family foundation, 193,565 shares owned by a family limited partnership and 142,692 shares owned by the wife and children of Mr. Lewis. Mr. Lewis disclaims beneficial interest of the shares owned by his wife and children, the family foundation, and the shares owned by the family limited partnership in which he has no pecuniary interest.

(4) The number of shares and nature of beneficial ownership is based on information contained in Schedule 13D and Form 4 filed with the Securities and Exchange Commission. Includes 59,609 shares held by a family foundation. Mr. James disclaims beneficial ownership of the share held in the foundation.

(5) Includes 4,500 shares purchasable under stock options granted pursuant to the Prima Energy Corporation Non-Employee Directors Stock Option Plan ("the Directors Plan") and 550 shares owned by the daughter of Mr. Cummings. Mr. Cummings disclaims beneficial ownership of the shares owned by his daughter.

(6) Includes 16,875 shares purchasable under stock options granted pursuant to the Directors Plan.

(7) Includes 10,125 shares purchasable under stock options granted pursuant to the Directors Plan.

(8) Includes 16,875 shares purchasable under stock options granted pursuant to the Directors Plan and 540 shares owned by the wife of Mr. Seward. Mr. Seward disclaims beneficial ownership of the shares owned by his wife.

(9) Consists of 16,666 shares purchasable under stock options granted pursuant to the Employee Plans.

(10) Consists of 24,250 shares purchasable under stock options granted pursuant to the Employee Plans, and 1,911 shares allocated to Mr. McGuire's account in the ESOT as a participant in the ESOP.

(11) Includes 9,875 shares purchasable under stock options granted pursuant to the Employee Plans, and 1,623 shares allocated to Mr. Kennedy's account in the ESOT as a participant in the ESOP.

(12) Consists of 5,600 shares purchasable under stock options granted pursuant to the Employee Plans, and 7,367 shares allocated to Mr. Carpenter's account in the ESOT as a participant in the ESOP.

(13) Includes 690,142 shares purchasable under stock options granted pursuant to the Employee Plans, 48,375 shares purchasable under stock options granted pursuant to the Directors Plan and 96,155 shares allocated to the ESOT accounts of individuals who are employee directors or officers of Prima.

ELECTION OF CLASS II DIRECTORS
(Proposal 1 of Proxy Card)

The Company's Certificate of Incorporation and Bylaws provide that the number of members of the Board of Directors shall be fixed by resolution of the Board. The size of the Board is currently set at six. The Company's Certificate of Incorporation also provides for the classification of the Board of Directors into three classes, as nearly equal in number as possible; all such classes will serve for three years with one class being elected each year. Currently the number of directors in each of the three classes is two. The term of the Class I directors expires at the 2004 Annual Meeting of Stockholders, the Class II directors at this Meeting and the Class III directors at the 2003 Annual Meeting of Stockholders. The Board of Directors intends to submit two nominees (Douglas J. Guion and Neil L. Stenbuck) at the Meeting as the Class II directors.

The Company has no nominating or similar committee of its Board of Directors. Therefore, it is the recommendation of the Board of Directors that the Board for the coming year consist of a total of six (6) members. Unless authority is withheld, it is intended that the shares represented by your Proxy will be voted for the election of the nominees (Douglas J. Guion and Neil L. Stenbuck) as the Class II directors. If these nominees are unable to serve for any reason, your Proxy will be voted for such persons as shall be designated by the Board of Directors to replace such nominees. The Board of Directors has no reason to expect that the nominees will be unable to serve.

THE BOARD OF DIRECTORS UNANIMOUSLY RECOMMENDS A VOTE "FOR" THE ELECTION OF THE NOMINEES FOR CLASS II DIRECTORS, DOUGLAS J. GUION AND NEIL L. STENBUCK.

Certain information concerning such nominees, as well as the other current directors, is set forth below:

Name	Age	Positions with the Company	Period of Service as Director or Officer	Class of Director
Richard H. Lewis	52	Chairman of the Board, Chief Executive Officer, President	Since April 1980	III (3)
Neil L Stenbuck	48	Executive Vice President, Chief Financial Officer and Director	Since May 2001	II (2)
James R. Cummings	67	Director	Since August 2000	I (1)
Douglas J. Guion	53	Director	Since October 1988	II (2)
Catherine James Paglia	49	Director	Since May 2000	III (3)
George L. Seward	51	Director	Since April 1980	I (1)

(1) Current term expires in 2004

(2) Current term expires in 2002

(3) Current term expires in 2003

The following includes additional information concerning the Company's directors, including their business experience:

Mr. Lewis founded Prima in April 1980 and has served as its Chairman of the Board and Chief Executive Officer since that time. He graduated from the University of Colorado in 1971 with a B.S. degree in Finance and Accounting. From 1971 until 1980, Mr. Lewis was employed as a certified public accountant with Arthur Andersen LLP, international public accounting firm, serving as an audit manager from 1976. Mr. Lewis serves on the Advisory Council to the School of Business at the University of Colorado and is active in various civic and industry organizations. Mr. Lewis served as the natural gas producer appointed representative on a select panel that studied and reported to the Colorado legislature on electric restructuring in Colorado. In 2000, Mr. Lewis was inducted into the Ernst & Young Entrepreneur of the Year Hall of Fame. He is Vice President and serves on the Board of the Colorado Oil & Gas Association, a non-profit trade organization. Mr. Lewis is the Chairman of the Board of Entre Pure Industries, Inc., a privately held company involved in the purified water and ice business.

Mr. Cummings has been a Director of Prima since August 2000. He served 20 years as a partner with Deloitte & Touche LLP ("Deloitte"). Mr. Cummings' career with Deloitte included serving as Partner-in Charge of the Denver tax department, National Industry Director of the U.S. Energy Resources Group and Partner-in-Charge of the National Special Acquisitions Group. Mr. Cummings served many of Deloitte's national oil and gas and other energy clients on industry, regulatory and tax matters. He also served as engagement partner on several litigation and regulatory engagements. Mr. Cummings has been a frequent speaker and author and has testified before Congressional and Treasury Department hearings involving the oil and gas industry. He has been involved in many professional activities including serving on the Board of the Independent Petroleum Association of America, the Colorado Society of Certified Public Accountants, the Petroleum Accountants Society of Colorado and the Denver Petroleum Club.

Mr. Guion has been a Director of Prima since October 1988. In 1987, Mr. Guion founded Colorado Energy Minerals, Inc., a privately held oil and gas company owned by him and his family. He co-founded Golden Buckeye Petroleum Corporation in 1980 and served as its Chairman of the Board until that company merged with Prima in 1988. Prior to 1980, Mr. Guion spent 10 years as a co-owner and manager for various geological and geophysical consulting firms and in various other business enterprises, including home building and real estate. Mr. Guion holds a B.S. degree in Geophysical Engineering from the Colorado School of Mines. He is a Registered Professional Engineer, Registered Geophysicist and Certified Petroleum Geologist.

Ms. Paglia has been a Director of Prima since May 2000. She has been a member of the Board of Directors of Enterprise Asset Management, Inc. since December 1997, and since June 1999 has been working full time managing and overseeing investment opportunities for the privately held investment firm. She has been a director of Strategic Distribution, Inc., a publicly held industrial distribution business, since 1990, and served in various management capacities at the company from January 1989 to April 1997. Ms. Paglia served as Executive Vice President and Chief Financial Officer of Fine Host Corporation, a publicly held contract food service company, from April 1997 to September 1998. From January 1989 to April 1997, Ms. Paglia served as a Managing Director of Interlaken Capital, Inc., a private investment firm, where she managed investment opportunities. From 1982 through 1988, she was employed by Morgan Stanley & Co. Incorporated, serving as a Managing Director in the corporate finance area during the last two years of her tenure. She has a B.A. from Carleton College in Northfield, MN and an M.B.A. from Harvard University.

Mr. Seward has been a Director of Prima since April 1980. He served as Corporate Secretary from 1980 until 1988. He has been engaged in the farming and ranching business since his graduation from Colorado State University with a B.A. degree in 1972. Since 1975, Mr. Seward has operated Seward Land and Cattle Company, a privately held company, as its majority stockholder and President.

Mr. Stenbuck has been a Director of Prima since May 2001 and has served as Executive Vice President and Chief Financial Officer of the Company since July 2001. He was previously with Basin Exploration, Inc., where he served as Vice President — Finance, Chief Financial Officer, Treasurer and a director from 1995 to 2001. Prior to joining Basin, Mr. Stenbuck was with United Meridian Corporation where he served as Vice President — Capital via the 1994 merger between UMC and General Atlantic Resources, Inc., where he held the same position beginning in 1989. He joined General Atlantic in 1987 as Vice President — Finance and Accounting. Mr. Stenbuck is a Certified Public Accountant. He received a B.S.B.A. degree in Accounting and Finance from the University of Arizona in 1975.

Fine Host Corporation, of which Ms. Paglia was Executive Vice President and Chief Financial Officer from April 1997 to September 1998, filed a Chapter 11 petition for reorganization under federal bankruptcy laws in January 1999.

Other Executive Officers

The following paragraphs set forth certain information concerning executive officers that are not also directors of the Company:

Michael J. McGuire, age 51, was named Executive Vice President of Exploration in July 1998. He was with Cities Service Oil Company, Exploration and Production Research, from 1973 to 1978 where he worked on exploration projects worldwide. In 1978, he joined Amoco Production Company, where he managed exploration and development projects throughout the Rocky Mountain states and in Africa. From 1986 to 1998 he operated McGuire Geological Consulting, LLC. Mr. McGuire received a B.S. degree in Geology from the University of Nebraska in 1972 and an M.S. degree in Geology from Oklahoma State University in 1975. He has been involved in many professional industry organizations. Mr. McGuire has served as an Associate Editor of the American Association of Petroleum Geologists. He has also served on the Board of Directors for the Potential Gas Committee and has served as Chairman of the Coalbed Methane Committee and Vice President of the Western Region. He is a Certified Petroleum Geologist. Mr. McGuire is currently a member of the Board of Directors for White Crown Federal Credit Union, Denver.

Michael R. Kennedy, age 41, joined Prima as Executive Vice President for Corporate Development in July 1998. In May 2001, he became Prima's Executive Vice President of Engineering and Operations. Prior to joining Prima, Mr. Kennedy was employed by Ensign Oil & Gas, Inc. from January 1995 to July 1998 in various capacities, including Vice President — Asset Development and Corporate Planning. His experience includes serving as General Manager for Martin Exploration from 1992 to 1994, as well as investment banking with San Diego Securities and various engineering capacities with Sun Exploration & Production Company. Mr. Kennedy received a B.S. degree in Petroleum Engineering from Colorado School of Mines, an M.S. degree in Petroleum Engineering from USC, an MBA from Pepperdine University and completed doctoral studies (ABD) in Applied Mineral Economics from Colorado School of Mines. He is a former member of the Board of Directors of the Colorado Oil & Gas Association and a current member of the Board of Directors of the Independent Petroleum Association of Mountain States and the Denver Petroleum Club.

John H. Carpenter, age 46, joined Prima as Vice President of Marketing in April 1994. Mr. Carpenter has 20 years experience in the oil and gas industry, primarily in the marketing, sales and trading of natural gas. Prior to joining Prima, Mr. Carpenter was a vice president with Barrett Fuels Corporation, a natural gas trading subsidiary of Barrett Resources Corporation, for four years. He also assisted in the initiation of natural gas trading activities for Public Service Company of Colorado in its wholly owned subsidiary, Fuel Resources Development Co., where he worked for eight years and was its manager of marketing. He received his B.A. degree in Journalism and Master of Science in Administration degree, both from the University of Denver.

Sandra J. Irlando, age 50, has been Prima's Vice President of Accounting since June 1993, Secretary since June 1994 and Controller since 1988. She joined Golden Buckeye Petroleum Corporation in 1985 as Tax Manager and became its Controller in 1987. Prior to joining Golden Buckeye, Ms. Irlando worked as a certified public accountant. She received a B.S.B.A. degree in Accounting from the University of Denver.

G. Walter Lunsford, age 50, has been Vice President of Land since June 1993. He served as Secretary from October 1988 to June 1994 and was Land Manager of Prima from October 1988 to June 1993. He served as Secretary and Land Manager for Golden Buckeye Petroleum Corporation from 1982 until 1988. Mr. Lunsford received a B.S. degree from Indiana University and is a Registered Professional Landman and member of the American Association of Professional Landmen.

Gregory R. Vigil, age 36, will join Prima effective May 15, 2002 as Vice President of Corporate Development. From 2000 until late last year, Mr. Vigil was Vice President — Business Development & Engineering at McMurry Energy Company. From 1999 to 2000, Mr. Vigil served as Director, Business Development & Engineering of McMurry Oil Company. His previous experience includes business development responsibilities with MCNIC Oil & Gas Company and various engineering positions with BP Exploration (Alaska) Inc., Snyder Oil Corporation and a private engineering consulting firm. Mr. Vigil graduated from the Colorado School of Mines in 1988 with a Bachelor of Science in Petroleum Engineering. He is a registered professional engineer in both Colorado and Wyoming and is a member of the Society of Petroleum Engineers.

All officers of the Company are employed on a full time basis. There are no other arrangements or understandings between any of the directors or officers and any other person pursuant to which he or she was or is to be selected as a director, nominee or officer.

No family relationship exists between the nominees for Class II director or any of the directors and executive officers of the Company with the exception of Mr. Lunsford, who is the brother-in-law of Mr. Guion. Ms. Paglia is the daughter of Mr. Robert James, who is a greater than 10% stockholder of Prima. Neither the nominees for Class II director nor any of the directors is a director of any company with a class of securities registered pursuant to Section 12 of the Securities Exchange Act of 1934 or subject to the requirements of Section 15(d) of that Act, with the exception of Ms. Paglia, who is a director of Strategic Distribution, Inc.

Board and Committee Meetings

The Board of Directors held six formal meetings during the year ended December 31, 2001. Mr. Stenbuck joined the Board in May 2001. All directors attended at least 75 percent of the aggregate of the total number of meetings of the Board of Directors and the meetings of the Committees described below of which each respective director is a member, for the period during which they were a member. In addition to those meetings, certain business was conducted by unanimous written consent of the Board of Directors. The Company's officers have made a practice of keeping directors informed of corporate activities by personal meetings and telephone discussions and (as indicated above) directors ratify or authorize certain actions of the Company through unanimous written consents.

The audit committee of the Board of Directors consists of Ms. Paglia, Mr. Cummings and Mr. Seward. Its functions include recommending to the Board of Directors the independent auditors to be employed, discussing the scope of the independent auditors' examinations, reviewing the financial statements and independent auditors' report, soliciting recommendations from the independent auditors regarding internal controls and other matters, establishing guidelines for the Board of Directors review of related party transactions for potential conflicts of interest, making recommendations to the Board of Directors and other related tasks as requested by the Board of Directors. During the year ended December 31, 2001, the committee met formally three times.

The compensation committee of the Board of Directors consists of Messrs. Cummings, Guion, Seward and Ms. Paglia. The committee has the authority to establish policies concerning compensation and employee benefits for all employees of the Company. The committee reviews and makes recommendations concerning the Company's compensation policies and the implementation of those policies and determines compensation and benefits for executive officers. During the year ended December 31, 2001, the committee met formally two times.

At present, the Company has no other standing committees.

Director Compensation

Non-employee directors receive an annual retainer, payable quarterly, of $10,000. In addition, non-employee directors receive $1,000 per Board meeting attended. No compensation is paid for attendance at committee meetings or for telephonic meetings. Directors and members of committees of the Board of Directors who are employees of the Company or its affiliates are not compensated for their Board activities. Directors are reimbursed for travel expenses incurred for attending Board and committee meetings.

The Company has a Non-Employee Directors' Stock Option Plan. The Plan provides for each non-employee director to receive options to purchase 22,500 shares of Prima Common Stock on the effective date of the Plan, or if later, upon election or appointment to the Board of Directors. On each subsequent anniversary date, each non-employee director receives additional stock options to purchase 5,625 shares of Common Stock. The exercise price is the fair market value on the date of grant. The options expire in ten years if not exercised, and vest 20% per year over five years.

EXECUTIVE COMPENSATION

Summary Compensation Table

The following table sets forth certain information regarding compensation paid or accrued during each of the Company's last three fiscal years, to its Chief Executive Officer and the four executive officers whose salary and bonus exceeded $100,000 for the last fiscal year for services in their capacity as such.

Summary Compensation Table

Name and Principal Position	Year	Annual Compensation		Long-term Compensation Options(#)	All Other Compensation (2)
		Salary	Bonus		
Richard H. Lewis	2001	$400,000	$100,000	100,000	$8,500
President and Chief Executive	2000	373,333	200,000	none	8,000
Officer	1999	333,336	350,000	none	8,000
Neil L. Stenbuck(1)	2001	$125,000	$ 25,000	50,000	none
Executive Vice President and	2000	n/a	n/a	n/a	n/a
Chief Financial Officer	1999	n/a	n/a	n/a	n/a
Michael J. McGuire	2001	$177,000	$ 6,000	10,000	$8,500
Executive Vice President	2000	167,000	30,000	none	8,000
of Exploration	1999	154,000	15,000	none	7,800
Michael R. Kennedy	2001	$140,000	$ 12,000	10,000	$8,500
Executive Vice President of	2000	130,000	30,000	none	6,813
Engineering and Operations	1999	125,000	10,000	none	6,250
John H. Carpenter	2001	$ 97,800	$ 5,000	3,000	$5,265
Vice President of Marketing	2000	95,800	7,500	none	4,753
	1999	94,000	0	none	4,685

(1) Mr. Stenbuck became an officer and employee of Prima July 2001.

(2) Amounts consist of allocations during each of the years under Prima's Employee Stock Ownership Plan ("ESOP"). The ESOP is qualified under Section 401(a) of the Internal Revenue Code of 1986, as amended, and is for the benefit of all eligible employees of the Company. Allocations to participants are made annually as of the last day of the plan's year, September 30, and are allocated among the participants in proportion to their eligible compensation for the year. Contributions are payable at a minimum rate of 5% of eligible salaries (consisting of salary, bonus, and, in the case of certain non-officer employees, overtime). Plan participants become fully vested in the ESOP after six years of service to the Company. Mr. Lewis and Mr. Carpenter are both fully vested in the ESOP. Mr. McGuire and Mr. Kennedy are both 40% vested. Mr. Stenbuck was not a participant as of September 30, 2001.

Option Grants In 2001

The table below shows information regarding the grant of non-qualified stock options made to the named executive officers under the Prima Energy Corporation 1993 Stock Incentive Plan and the 2001 Stock Incentive Plan ("Stock Incentive Plans"). The amounts shown for the named executive officers as potential realizable values are based on arbitrarily assumed annualized rates of stock price appreciation of 5% and 10% over the full ten-year term of the options. No gain to the optionee is possible without an increase in stock price above the price on the option grant date, which will benefit all stockholders proportionately. The 5% and 10% assumed rates of appreciation are derived from the rules of the SEC and do not represent the Company's estimate or projection of the future Common Stock price. There can be no assurance that the potential realizable values shown on this table will be achieved.

	Individual Grants				Potential Realizable Values at Assumed Annual Rates of Stock Price Appreciation For Option Term	
Name	Options Granted #	Percent of Total Options Granted to Employees In 2001	Exercise Price Per Share	Expiration Date	5%	10%
Richard H. Lewis	100,000	46.3	$33.25	3/11/2011	$2,091,000	$5,299,000
Neil L. Stenbuck	50,000	23.1	30.27	5/15/2011	952,000	2,412,000
Michael J. McGuire	10,000	4.6	33.25	3/11/2011	209,100	529,900
Michael R. Kennedy	10,000	4.6	33.25	3/11/2011	209,100	529,900
John H. Carpenter	3,000	1.4	33.25	3/11/2011	62,700	159,000

The options granted to Messrs. Lewis, McGuire, Kennedy and Carpenter were granted at an exercise price equal to the closing price of the Common Stock on the date of grant and vest at a rate of 20% per year beginning March 12, 2001. The options granted to Mr. Stenbuck were granted at an exercise price equal to the closing price of the Common Stock on the date of grant and vest at a rate of 33 1/3% per year beginning May 16, 2001. Upon a Change of Control of the Company, as defined in the Stock Incentive Plan, all options granted under the plan would become exercisable in full. Options granted are non-transferable except by will or the laws of descent and distribution, may be exercised during the grantee's lifetime only by the grantee and must be exercised no later than ten years from the date of grant. The options expire if not exercised, in most cases, within twelve months of the grantee's death or total and permanent disability, on the effective date of termination of employment or, with the discretion of the Compensation Committee, within three months after normal or early retirement, and are subject to certain other conditions.

Aggregated Option Exercises and Fiscal Year-End Option Value Table

The following table sets forth information concerning each exercise of stock options during the year ended December 31, 2001 by the Company's Chief Executive Officer and the named executive officers and the fiscal year-end value of unexercised options held by each of them.

Aggregated Option Exercises
For Year Ended December 31, 2001
And Year-End Option Values

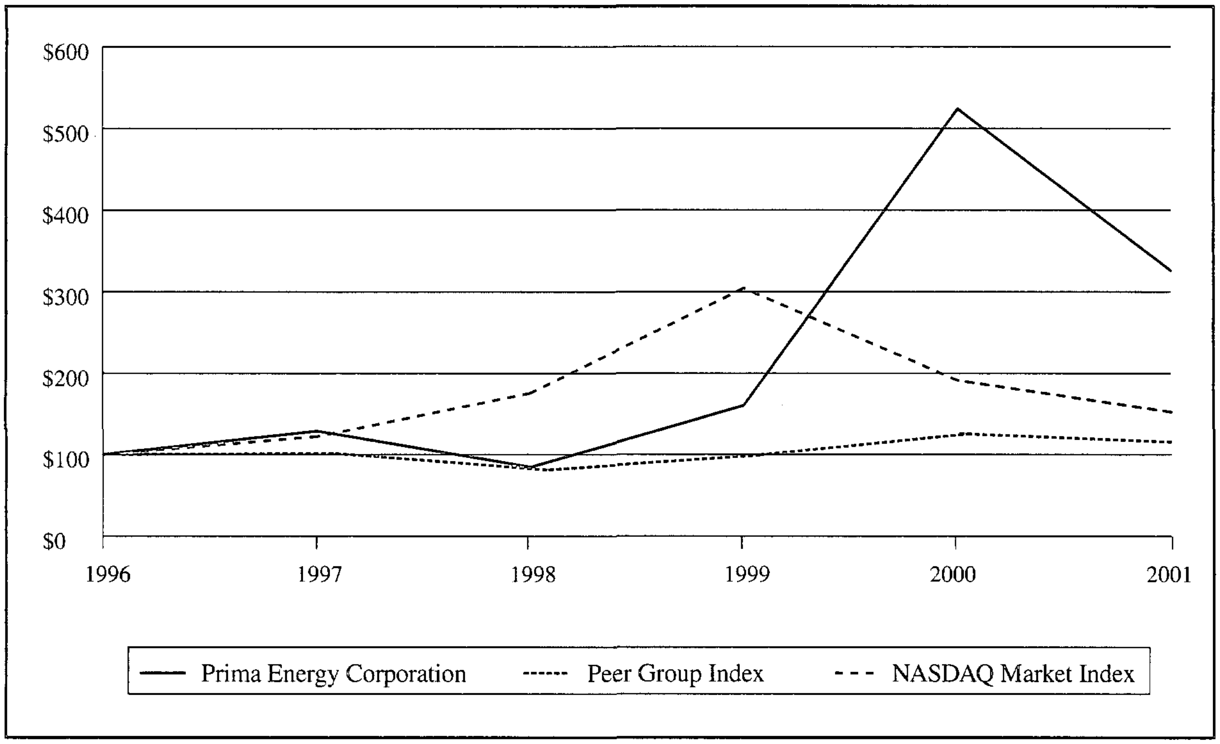
Name	Shares Acquired on Exercise(#)	Value Realized ($)(1)	Number of Unexercised Options at Year End(#)		Value of Unexercised In-The-Money Options at Year End($)(2)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Richard H. Lewis	30,000	$672,600	533,750	190,000	$9,062,350	$1,357,500
Neil L. Stenbuck	0	$ 0	0	50,000	$ 0	$ 0
Michael J. McGuire	10,000	$224,300	22,250	41,500	$ 308,410	$ 436,625
Michael R. Kennedy	13,125	$222,206	7,875	41,500	$ 103,906	$ 415,625
John H. Carpenter	2,500	$ 62,954	5,000	3,000	$ 88,017	$ 0

(1) Value realized equals the fair market value of the Common Stock on the date exercised less the exercise price, times the number of shares exercised. Fair market value is determined by the average of the high and low sales price for the date exercised.

(2) For all unexercised options held as of December 31, 2001, the aggregate dollar value of the excess of the market value of the stock underlying the options over the exercise price of those options. On December 31, 2001, the closing sale price of the Common Stock was $21.75 per share.

PERFORMANCE GRAPH

The following graph shows the changes over the past five year period in the value of $100 invested in: (1) Prima Energy Corporation Common Stock; (2) the NASDAQ Market Index; and (3) a peer group consisting of all the publicly-held companies within SIC code 1311, Crude Petroleum and Natural Gas, consisting of approximately 190 companies. The year-end values of each investment are based on share price appreciation and assume that $100 was invested December 31, 1996 and that all dividends are reinvested. Calculations exclude trading commissions and taxes. The comparison of past performance in the graph is required by the SEC and is not intended to forecast or be indicative of possible future performance of the Company's Common Stock.



	As of December 31,					
	1996	1997	1998	1999	2000	2001
Prima Energy Corporation	$100.00	$129.10	$ 84.54	$160.34	$524.21	$325.76
Peer Group Index	100.00	101.36	81.19	99.18	125.99	115.60
NASDAQ Market Index	100.00	122.32	172.52	304.29	191.25	152.46

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

Messrs. Cummings, Guion, and Seward and Ms. Paglia have comprised the compensation committee since May 2001, with Mr. Guion serving as chairperson. None of the committee members were officers or employees of the Company during 2001. No executive officer of the Company serves or served on the compensation committee of another entity during 2001 and no executive officer of the Company serves or served as a director of another entity who has or had an executive officer serving on the Board of Directors of the Company. Mr. Guion is the brother-in-law of Mr. Lunsford, Vice President of Land for the Company. See "Certain Relationships and Related Transactions" below for information regarding a transaction in which both the Company and Mr. Guion participated.

COMPENSATION COMMITTEE REPORT

Under rules established by the Securities and Exchange Commission, the Company is required to provide certain information regarding the compensation of its Chief Executive Officer and other executive officers whose salary and bonus exceed $100,000 per year. Disclosure requirements include a report explaining the rationale and considerations that lead to fundamental executive compensation decisions. The following report has been prepared to fulfill this requirement.

The Compensation Committee ("Committee") of the Board of Directors sets and administers the policies that govern the annual compensation and long-term compensation of executive officers of the Company. The Committee consists of Messrs. Cummings, Guion, and Seward and Ms. Paglia, none of whom is an employee of the Company. The Committee makes all decisions concerning compensation of executive officers who receive salary and bonus in excess of $100,000 annually, determine the total amount of bonuses to be paid annually and grant all awards of stock options under the Company's Stock Incentive Plans. The Committee's policy is to offer executive officers competitive compensation packages that will permit the Company to attract and retain highly qualified individuals and to motivate and reward such individuals on the basis of the Company's performance.

At present, the executive compensation package consists of base salary, cash bonus awards and long-term incentive opportunities in the form of stock options and participation in an employee stock ownership plan ("ESOP"). Executive officers participate in the ESOP on the same basis as all Company employees. The Company does not provide any deferred compensation plan, nor does it provide a pension plan, 401K plan or other retirement benefits other than the ESOP.

Executive salaries are reviewed by the Committee on an annual basis and are set for individual executive officers based on subjective evaluations of each individual's performance, the Company's performance and a comparison to salary ranges for executives of other companies in the oil and gas industry with characteristics similar to those of the Company. This allows the Committee to set salaries in a manner that is both competitive and reasonable within the Company's industry.

Cash bonuses may be awarded on an annual basis for exceptional effort and performance. The use of a specific formula to evaluate management performance is not employed because it is difficult to define an appropriate formula and it restricts the flexibility of the Committee. The Committee considers the achievements of the Company, specifically including earnings for the year, return on stockholders' equity and growth in proved oil and natural gas reserves, in determining appropriate levels for bonus awards. Following a review of the Company's performance after the close of the 2001 fiscal year, in March of 2002 the Committee determined that cash bonuses should be awarded, set a total dollar limit for the bonus pool and awarded cash bonuses to the Company's Chief Executive Officer and the other named executive officers, based upon their respective contributions to the Company's performance during the year, as assessed by the Committee.

Stock options may be granted to key employees, including executive officers of the Company. Such stock based awards continue to be an important element of the executive compensation package because they aid in the objective of aligning the key employees' interests with those of the stockholders by giving key employees a direct stake in the performance of the Company. Decisions concerning the granting of stock options are made based upon the individual performance of the executive, his or her level of responsibility, base salary and the number of options already granted to the executive. Options for 216,000 shares were granted to all employees in 2001.

The compensation of Richard H. Lewis, Chief Executive Officer, consists of the same components as for other executive officers of the Company, and is largely dependent upon the overall performance of the Company and a comparison to compensation being paid by comparable peer companies to their chief executive officers. For the year ended December 31, 2001, the base salary of Mr. Lewis increased approximately 7% to $400,000 from $373,336, due to a salary increase awarded in September 2000. A cash bonus award for 2001 of $100,000 was paid in 2002, compared to $200,000 paid in March 2001. Mr. Lewis was granted options to acquire 100,000 shares of Common Stock in March 2001. The amount of the bonus awarded for 2001 took into account a number of factors concerning the Company's performance. For 2001, the Company reported record revenues, earnings, production and cash flow. However, at year-end 2001, the Company's reserves were lower than reported in the prior year, primarily due to lower product prices in effect at the end of the year.

Compensation Committee of the Board of Directors:
Douglas J. Guion, Chairperson
James R. Cummings
Catherine James Paglia
George L. Seward

AUDIT COMMITTEE REPORT

The Audit Committee is composed of three non-employee directors. The Board of Directors has made a determination that the members of the Audit Committee satisfy the requirements of the NASD Stock Market as to independence, financial literacy and experience. The Audit Committee operates under a written charter approved by the full Board. The Audit Committee is responsible for providing independent, objective oversight of the Company's accounting functions and internal controls.

Review of Audited Financial Statements with Management. The Audit Committee has reviewed and discussed the audited financial statements with the management of the Company.

Review of Financial Statements and Other Matters with Independent Accountants. The Audit Committee discussed with the independent auditors the matters required to be discussed by SAS 61 (Codification of Statements on Auditing Standards, AU Section 380). The Audit Committee has received and reviewed the written disclosures and the letter from Deloitte & Touche LLP ("Deloitte"), the Company's independent accountants, required by Independence Standards Board Standard No. 1, "Independence Discussions with Audit Committees," and has discussed with Deloitte the independent accountants' independence.

Recommendation to Include Financial Statements in Annual Report. Based on the review and discussions referred to above, the Audit Committee recommended to the Board of Directors that the audited financial statements be included in the Company's Annual Report on Form 10-K for the year ended December 31, 2001 for filing with the Securities and Exchange Commission.

Audit Fees. The aggregate fees billed by Deloitte for the professional services rendered for the audit of the Company's annual financial statements for the year ended December 31, 2001 and for the reviews of the financial statements included in the Company's Quarterly Reports on Form 10-Q for the year were $73,700.

Financial Information Systems Design and Implementation and Other Fees. Deloitte performed no financial information systems design and implementation services, internal audit or tax services during 2001. Deloitte did perform an audit of the Prima Energy Corporation Employee Stock Ownership Plan and Trust during 2001, including preparation of Form 5500. Total fees billed for these services were $15,000. The audit committee has concluded that the provision of these services is compatible with maintaining the accountants' independence.

Audit Committee of the Board of Directors:
Catherine James Paglia, Chairperson
James R. Cummings
George L. Seward

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Certain of the Company's directors and executive officers have participated, either individually or through entities which they control, in oil and gas prospects or properties in which the Company has an interest. These participations, which have been on a working interest basis, have been in prospects or properties originated or acquired by the Company. In some cases, the interests sold to affiliated and non-affiliated participants were sold on a promoted basis requiring these participants to pay a portion of the Company's costs. Each of the participations by directors and executive officers is believed to have been on terms no less favorable to the Company than it could have obtained from non-affiliated participants. Such participations create interests that may conflict with those of the Company. It is expected that joint participations with the Company will occur from time to time in the future. All participations by the officers and directors have and will continue to be approved by the disinterested members of the Board of Directors and are subject to standard industry operating agreements.

At any point in time, there are receivables and payables with officers and directors that arise in the ordinary course of business as a result of participations in jointly held oil and gas properties. Amounts due to or from officers and directors resulting from billings of joint interest costs or receipts of production revenues on these properties are handled on terms pursuant to standard industry joint operating agreements which are no more or less favorable than these same transactions with unrelated parties. No officer or director owed amounts in excess of $60,000 during 2001.

In June 2000, the Company acquired oil and gas leases covering 26,680 net undeveloped acres from a company controlled by Mr. Guion for a negotiated price of $12 per net acre, or a total of $320,000. Additional acreage in the same general area was subsequently acquired from Mr. Guion under an area of mutual interest agreement, at cost. The aggregate amounts paid for these property interests, including the initial acquisition, totaled $376,000 in 2000 and $290,000 in 2001. All leases acquired were subject to an overriding royalty reserved by Mr. Guion or entities that he controls of 3% or less, depending on the net revenue interest of the leases, proportionately reduced to the working interest acquired. The disinterested members of the Board of Directors approved the transactions.

The Company is a 6% limited partner in a real estate limited partnership that owns 22 acres of undeveloped land in Phoenix, Arizona. The land was acquired in 1987 and is held by the partnership for investment and capital appreciation. The Company has invested $256,668 in the partnership from inception. No funds have been invested since 1991. One of the general partners of the partnership is a company controlled by the brother of the Company's president. The Company participated on the same basis as the other limited partners. The disinterested members of the Board of Directors approved the transaction.

SECTION 16 REPORTING

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires the Company's officers and directors, and persons who own more than 10% of a registered class of the Company's equity securities, to file reports of ownership and changes in ownership with the Securities and Exchange Commission and the National Association of Securities Dealers, Inc. Officers, directors, and greater than 10% stockholders are required by SEC regulation to furnish the Company with copies of all Section 16(a) filings.

Based solely on its review of copies of such forms received by the Company or written representations that no Form 5's were required for those persons, the Company believes that, during the year ended December 31, 2001, its officers, directors, and greater than 10% beneficial owners complied with all applicable filing requirements except as Follows. Mr. George L. Seward, a director of Prima, failed to timely file one Form 4 during 2001 reporting the sale of 10,000 shares of Common Stock. The Form 4 was due May 10, 2001 and filed February 20, 2002. Mr. Michael R. Kennedy, an officer of Prima, failed to timely file one Form 4 during 2001 reporting the exercise of stock options and subsequent sale of 8,125 shares of Common Stock. The Form 4 was due December 10, 2001 and filed February 5, 2002.

PROPOSAL TO RATIFY THE SELECTION OF DELOITTE & TOUCHE LLP AS AUDITORS
(Proposal 2 on Proxy Card)

The independent certified public accounting firm of Deloitte & Touche LLP has been engaged by the Company to audit the accounts and financial statements of the Company annually since the Company's inception on April 11, 1980 through December 31, 2001.

Although Delaware corporate law or the Company's Certificate of Incorporation or Bylaws does not require ratification by stockholders of the appointment of Deloitte & Touche LLP, management feels a decision of this nature should be made with the consideration of the Company's stockholders. If stockholder approval is not received, management will reconsider the appointment.

It is expected that a representative of Deloitte & Touche LLP will be present at the Meeting and will be given the opportunity to make a statement if he or she so desires. It is also expected that the representative will be available to respond to appropriate questions from stockholders.

THE BOARD OF DIRECTORS UNANIMOUSLY RECOMMENDS A VOTE "FOR" RATIFICATION OF THE SELECTION OF DELOITTE & TOUCHE LLP AS THE COMPANY'S INDEPENDENT AUDITORS FOR THE YEAR ENDING DECEMBER 31, 2002.

OTHER BUSINESS

The Board of Directors of the Company is not aware of any other matters that are to be presented at the Meeting, and it has not been advised that any other person will present any other matters for consideration at the Meeting. Nevertheless, if other matters should properly come before the Meeting, the stockholders present, or the person, if any, authorized by a valid Proxy to vote on their behalf, shall vote on such matters in accordance with their judgment.

DEADLINE FOR RECEIPT OF STOCKHOLDER PROPOSALS FOR ANNUAL MEETING SCHEDULED TO BE HELD IN MAY, 2003

Any proposal by a stockholder to be presented at the Company's Annual Meeting of Stockholders scheduled to be held in May 2003, must be received at the offices of the Company, Suite 400, 1099 18th Street, Denver, Colorado 80202, no later than December 12, 2002 in order to be considered for inclusion in the Company's Proxy Statement and form of Proxy for that meeting.

ANNUAL REPORTS AND CONSOLIDATED FINANCIAL STATEMENTS

You are referred to the Company's annual report, including consolidated financial statements, for the year ended December 31, 2001, enclosed herein for your information. The annual report is not incorporated in this Proxy Statement and is not to be considered part of the soliciting material.

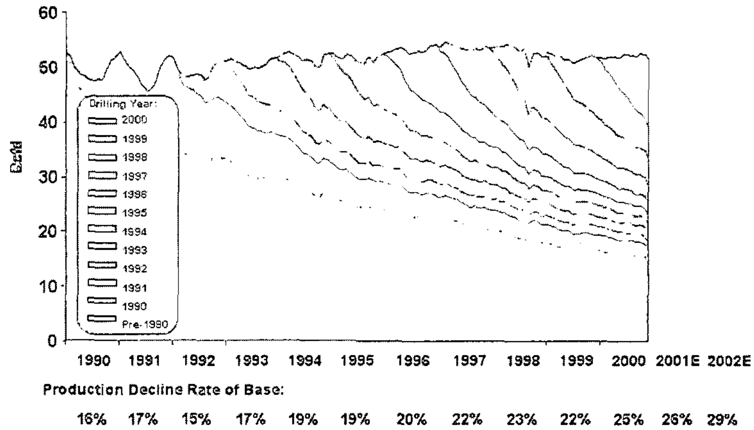
By Order of the Board of Directors

Sandra J. Irlando

SANDRA J. IRLANDO
Secretary

Denver, Colorado
April 10, 2002

U.S. Natural Gas Production History
Indicates 29% 2002 Decline Rate



Source: EOG Resources, Inc.

A few bullet points cited by many analysts and prognosticators to support this conclusion include the following:

Supply Side

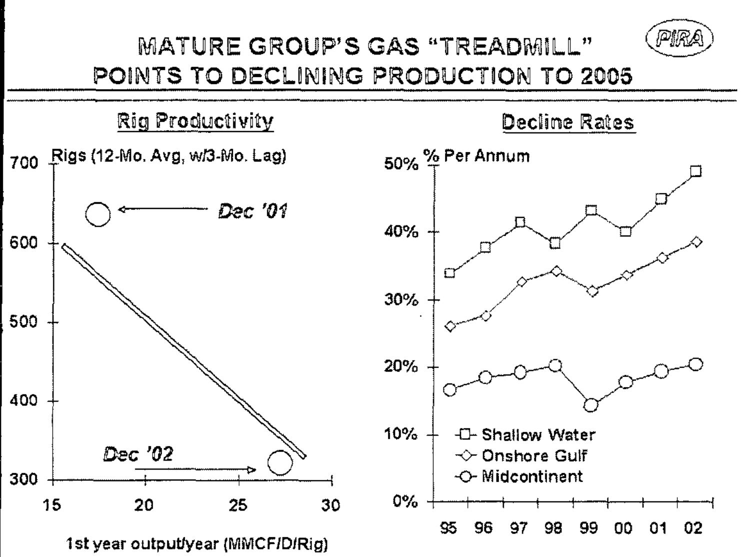
• Production data compiled by well, by the year in which it was placed on production, shows faster decline rates for recent-vintage additions. As a result, the total U.S. production base now exhibits an annual decline rate of approximately 29%, compared to 15% a few years ago. Significant new supplies (approximately 16 Bcf of gas per day) must be brought on line each year just to replace the production decline from existing wells.

• Over the past few years our industry has experienced a significant decline in the average gas deliverability added per working drilling rig.

• During the high-price cycle, industry experienced an anemic supply response (essentially flat) despite a very robust rig count (approximately 1,100 drilling for gas last summer) and aggressive capital expenditures.

• As natural gas prices deteriorated, industry experienced a dramatic decline in the active rig count (currently just over 600 drilling for gas). We believe the effects on deliverability from this decline will become more pronounced as the year progresses.

MATURE GROUP'S GAS "TREADMILL" POINTS TO DECLINING PRODUCTION TO 2005



Source: PIRA Energy Group

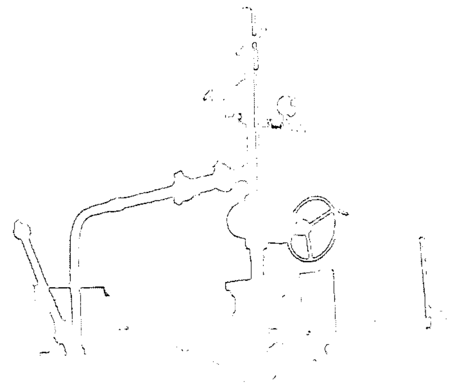
Demand Side

• We are coming off one of, if not *the*, warmest winters recorded, significantly reducing heating demand. Although not impossible, this is unlikely to recur for awhile. We would expect a more normalized weather pattern over time.

• The nation has been in a recession with industrial and manufacturing utilization reaching the lowest level in over twenty years. Many sectors of the economy are large natural gas consumers. Recent reports reflect an improving economy that will fuel rising natural gas demand.

• New electric generation facilities either recently placed in service or in process will expand capacity in the U.S. by approximately 15%. Virtually all of these new electric generation facilities are designed to be natural gas fired.

I would point out that we learned from the past cycle that the elasticity of natural gas demand results in plant shut-downs, renewed conservation efforts, fuel switching and a myriad



of competitive forces when prices reach extremely high levels.

We expect that in this environment, the need to remove excessive roadblocks, streamline regulatory processes, and encourage natural gas supply development will become more obvious.

We also believe that the Rocky Mountain region will be one of only a very few supply areas to experience meaningful production growth over the next few years. We intend to continue pursuing our objective of building a premier Rocky Mountain independent with significant exposure to natural gas. Natural gas represents 85% of our proved reserves. In addition, our prospective leasehold base, which includes significant probable reserves, is also very strongly natural gas oriented.

Our objective is to be opportunistic in optimizing our asset base, and our financial strength provides us the flexibility to enhance or expand our opportunity portfolio. This will require a disciplined capital allocation process, identification and managment of risks, leveraging off third parties, stringent cost controls, and implementation of best practices.

We are well positioned, as outlined in the following Form 10-K, to create additional shareholder value, and we look to the future with considerable optimism. While the challenges are inevitable, we will focus on the opportunities.

On behalf of all of us at Prima I thank you for your continued support.

Richard H. Lewis
Chairman and Chief Executive Officer
March 20, 2002

* The realized gains included $3,381,000 reported in oil and gas sales, $2,057,000 in gains on derivatives, and $877,000 treated as the pre-tax cumulative effect of a change in accounting principle. The unrealized mark-to-market gains at year end included $4,378,000 reported as gains on derivatives and $94,000 of deferred hedging gains.

Forbes 200 Best Small Companies In America List

Over the past decade, Prima has been one of a very select few companies to make this Forbes list seven times. The primary qualification for making this list is return on equity over a five year period. Forbes designs the criteria to eliminate "short lived, high flying companies," to ensure that it is difficult both to make and stay on the list.

We would like to express appreciation to our employees for their dedication and effort this past year.

Prima Energy Corporation Operation and Financial Summary

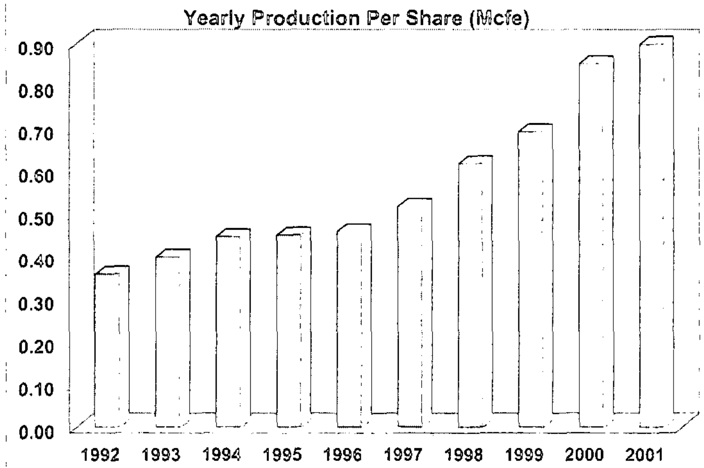
	Years Ended or As Of December 31,				
	1997	1998	1999	2000	2001
Balance Sheet Data:					
Total assets	$57,921,000	$66,866,000	$72,665,000	$104,900,000	$135,444,000
Net oil and gas properties	41,070,000	52,946,000	39,915,000	65,717,000	90,572,000
Working capital	7,952,000	5,467,000	21,408,000	25,678,000	28,122,000
Long-term debt	240,000	120,000	0	0	0
Net stockholders' equity	43,214,000	51,308,000	58,908,000	80,298,000	101,740,000
Common shares outstanding	12,982,626	12,986,480	12,856,591	12,793,373	12,734,995
Income Statement Data:					
Total revenues	$37,907,000	$29,094,000	$29,222,000	$52,179,000	$60,287,000
Oil and gas sales	17,840,000	16,612,000	20,644,000	44,437,000	44,548,000
Net income	8,102,000	8,065,000	9,027,000	21,895,000	23,768,000
Net income per diluted share	0.61	0.61	0.69	1.65	1.80
Cash Flow Data:					
Cash flow from operating activities before changes in operating assets and liabilities	$15,446,000	$17,075,000	$17,326,000 [2]	$37,163,000	$39,698,000
Production:					
Natural gas (Mcf)	5,344,000	6,476,000	7,163,000	8,683,000	9,277,000
Oil (Bbls)	255,000	286,000	322,000	440,000	431,000
Average daily production (Mcfe) [1]	18,833	22,444	24,918	30,937	32,501
Estimated Proved Reserves:					
Mcf of natural gas equivalent (Mcfe) [1]	83,638,000	88,163,000	143,719,000	176,546,000	135,586,000
Natural gas (Mcf)	63,490,000	71,207,000	124,111,000	154,172,000	115,222,000
Oil (Bbls)	3,358,000	2,826,000	3,268,000	3,729,000	3,394,000
Estimated Future Net Cash Flows From Proved Reserves:					
Estimated future net cash flows	$136,391,000	$115,801,000	$190,008,000	$975,940,000	$156,624,000
Estimated present value of future net cash flows before income taxes (10 percent discount)	75,540,000	65,318,000	108,551,000	576,052,000	91,905,000
Well Information:					
Total wells drilled (gross/net)	50/36.4	38/14.9	43/34.1	186/183.6	139/135.6
Productive wells drilled (gross/net)	46/33.7	34/13.6	42/33.3	183/181.6	137/135.3
Productive wells owned at year end (gross/net)	539/333.1	566/338.5	422/321.7	446/348.8	613/536.8 [3]
Total wells operated at year end	372	375	372	393	695
Total Leasehold Acreage:					
Gross acres	246,000	313,000	442,000	516,000	595,000
Net acres	164,000	231,000	291,000	356,000	393,000

(1) Oil production has been converted to a common unit of production (Mcf of natural gas) on the basis of relative energy content (one barrel of oil to six Mcf of natural gas).

(2) Before $5,704,000 of income taxes resulting from the $26 million sale of Bonny Field Assets.

(3) Excludes 136 gross, 133.7 net CBM wells in Wyoming that were shut-in awaiting hook-up at December 31, 2001.

The following questions and responses by Prima's management address various issues of interest to Prima's shareholders. Our Annual Report on Form 10-K, which follows, provides additional information and greater detail with respect to many of these matters.

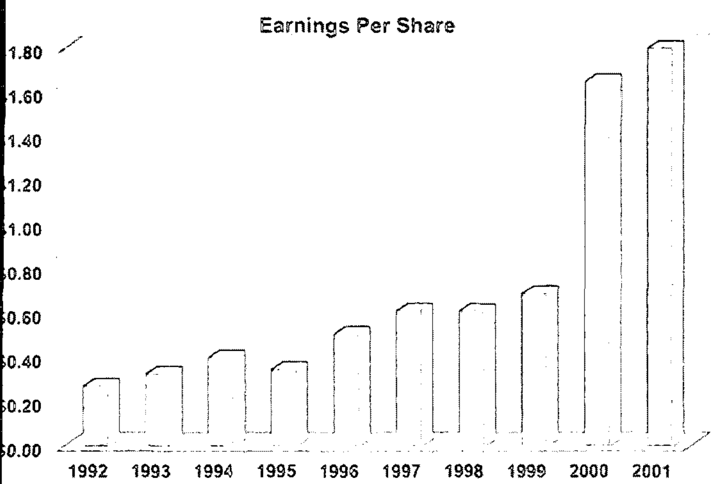


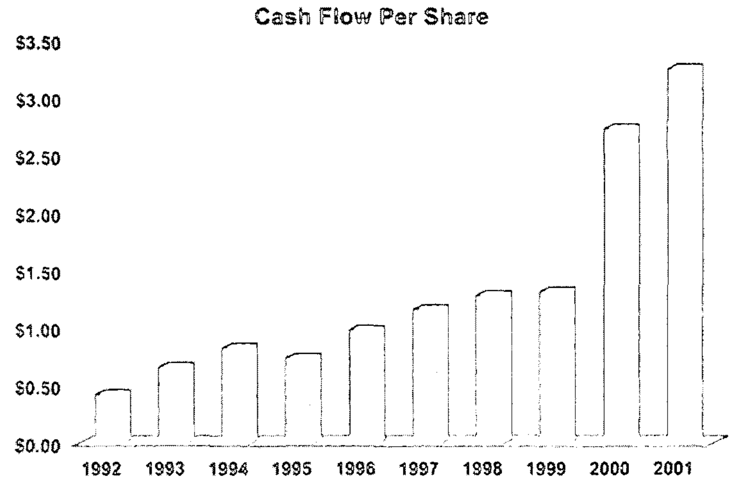
Q. How do you measure your success in creating shareholder value?

A. *(Richard Lewis, Chairman of the Board and Chief Executive Officer)* We have always endeavored to be among the lowest cost producers with one of the highest cash flow margins for reinvestment in the industry. Historically, we have generated significantly higher "all-in" cash flows per unit produced than our finding and development costs to replace and expand our reserve base. We have wanted to grow our reserves, production, cash flow and earnings at industry-leading compound annual rates on a per share basis. While all of these are important, the real measure of success is economic value added in excess of cost of capital. While this can be a difficult and subjective calculation, it is one I think all companies should do. Reserves should be calculated at expected costs and prices utilizing the forward curve and appropriate discount rates. Varying discounts rates should be utilized to reflect different risk levels applicable to subcatagories of reserves. The economic value of undeveloped acreage, prospects, leads and other assets like our service companies also need to be included. In order for us to meet our goal of delivering superior returns to shareholders, we must grow our net asset value at a rate above our cost of capital.

Q. What were the highlights of Prima's operating results in 2001?

A. *(Neil Stenbuck, Chief Financial Officer and Executive Vice President)* Prima reported strong operating results for 2001, with record levels achieved on both a nominal and per-share basis in the Company's oil and gas production volumes, revenues, net income, and operating cash flows. Compared to the prior year, which had also reflected strong growth and record results, 2001 production grew 5%, revenues were up 16%, net income was 9% higher and net cash provided by operating activities increased by 18%. Production volumes were up on contributions from CBM properties and revenues were significantly enhanced during 2001, in a declining price environment, by gas and oil hedges that were put in place. Our oilfield service operations also performed well in 2001, with revenue growth of 29%. Although cash flow was not affected, net income for 2001 was adversely impacted by a mid-year increase in our depletion rate, which was made primarily to reflect changes in reserve estimates caused by lower gas prices. Overall, for the year 2001, Prima's net income totaled $23,768,000, or $1.80 per diluted share, for a 30% rate of return on book equity, and net cash provided by operating activities reached $43,008,000.





Q. Would you comment on Prima's stock price performance?

A. *(Neil Stenbuck)* Prima's stock has performed very well over the long term, generating significantly higher total returns to shareholders over the three-, five- and ten-year periods ended December 31, 2001 than were delivered by the S&P 500, NASDAQ Market Index, the Russell 2000, or our peer group index (see table below). However, following on the heels of 2000, when our stock appreciated 227%, last year's stock price performance was a disappointing -38%. Movements in our stock price will generally reflect both the fundamentals of our industry, perhaps most clearly observable in gas and oil price movements, and the specific performance results achieved by Prima. During the past two years, the unprecedented volatility of natural gas prices played an unusually large role. In 2000, when gas (and oil) prices were strong and rising, and optimism about future prices abounded, Prima's stock was a significant outperformer in a very strong sector. During 2001, when average gas and oil prices were high but declining throughout the year and ebullience about future prices was more tempered, the stock prices of most oil and gas exploration and production companies declined, including Prima's. Looking forward, we are optimistic about the fundamentals of our business, and believe we will have the opportunity to continue to deliver superior returns to shareholders if we continue to execute well, as we have in the past.

Annual Average Returns

Name	One Year	Three Year	Five Year	Ten Year
Prima Energy	-37.9%	56.8%	26.6%	34.8%
S&P 500	-11.9	-1.0	10.7	12.9
NASDAQ	-20.3	-4.0	8.8	12.1
Russell 2000	2.5	6.4	7.5	11.5
Peer Group Index (SIC 1311)	-8.2	12.5	2.9	7.2

Q. Would you comment on insider trading activity?

A. *(Richard Lewis)* We have sought, since the inception of the Company in 1980, to align the interests of shareholders, employees, management and the Board of Directors. The founders of the Company had large initial stock positions, which incentivized their efforts to create shareholder value. While many of the early investors in Prima have maintained substantial stock positions, many have also sold shares over the years for various reasons, including: financial, tax and estate planning, investment diversification, charitable gifting, funding college educations, personal residences, medical expenses and retirement funding.

In 1988 we adopted an employee stock ownership plan through which every full-time Prima employee becomes a shareholder of the Company. This continues to serve as Prima's only retirement benefit. In 1993, a modification to the plan was made to allow fully-vested employees the opportunity to sell a portion of the Prima stock in their accounts on a quarterly basis to diversify their retirement assets.

We also initiated a stock option plan in 1993. In order to attract and retain the key people required to grow our company, we needed a stock-based incentive plan whereby the people most responsible for future share performance would benefit to the extent they were successful. As options have vested, many option holders have exercised and sold shares for many of the reasons previously stated.

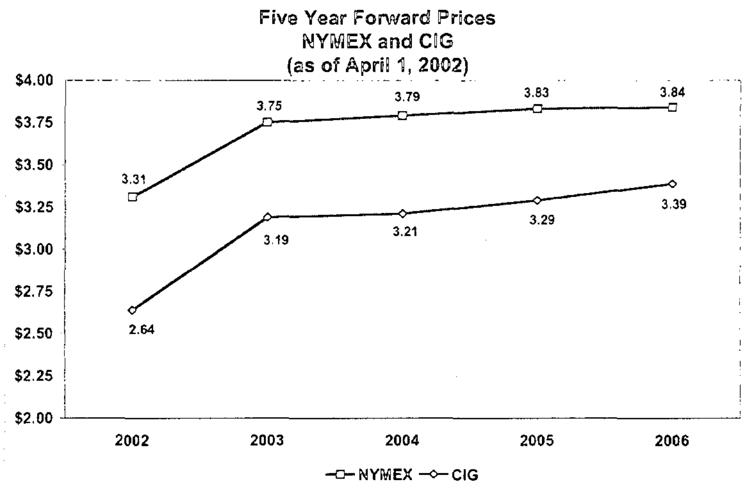
I might add that Prima does not have a 401-K plan, a pension plan or any deferred compensation plans. The risks and rewards to insiders are directly linked to share price performance, whether they own shares directly or through participation in the ESOP or stock options.

Q. Why have natural gas prices been so volatile?

A. (*John Carpenter, Vice President of Marketing*) Natural gas is used primarily for space heating and cooling, manufacturing processes, and electric generation. Volatility in natural gas prices is a response to the amount of supply available versus the amount consumed. Gas not being consumed is typically placed in storage fields, and the seasonally-adjusted amount of gas in storage is a key indicator of the supply and demand balance. Last year proved to be the most volatile price environment for natural gas since its deregulation nearly 15 years ago. Rocky Mountain prices ranged from a high of $8.63 per MMBtu in January to a low of $1.05 per MMBtu in October. We started out 2001 with low storage levels and a cold winter on the heels of a hot summer, which caused shortages of electricity in some regions. Natural gas was in short supply and the price responded by moving upward. High demand and prices spurred increased drilling activity to fill the void. Rigs drilling for natural gas rose to a peak in mid-2001 of almost 1,100, but declined to less than 750 by year end and were just over 600 at last report. Natural gas prices trended lower throughout the year due to conservation in response to high prices, mild weather reducing space heating and cooling demand, and impacts of a recession on manufacturing and industrial usage. Gas storage levels began 2001 at a record low for that time of year of 1,729 Bcf or 52% full, and ended the year with 2,980 Bcf or 90% full.

Q. What is the "Rocky Mountain basis differential" and how is it determined?

A. (*John Carpenter*) The Rocky Mountain basis differential is a measurement defining the difference in price between gas delivered to certain points within this region and gas delivered to certain points in other regions of the country. The most commonly referred to basis differential for Prima's gas is the Colorado Interstate Pipeline (CIG) price versus the NYMEX Henry Hub delivery location in Louisiana. Gas located at Henry Hub typically trades higher than CIG prices. Henry Hub, on an annual basis, has traded from $0.25 to $1.15 per MMBtu higher than CIG since 1995. The average basis differential during this time period was $0.56 per MMBtu. The basis is determined to a significant extent by the availability of transportation capacity on pipelines to move natural gas from one point to another for sale. During time periods when pipeline capacity is limited out of the Rocky Mountain area, wellhead prices in the Rockies decrease as gas in the area competes for local market. When this occurs, price differentials between CIG and Henry Hub tend to widen. Conversely, basis differentials tend to contract when pipeline capacity out of the region is readily available. Basis differentials are traded using financial derivative products ("swaps"), and can be secured readily for at least five years into the future. The current five-year Henry Hub to CIG differential is $0.56 per MMBtu.



> "These futures prices reflect the market's expectation that natural gas prices will remain at historically high levels during the next several years."

Q. What is your outlook for natural gas prices over the near, intermediate and long term?

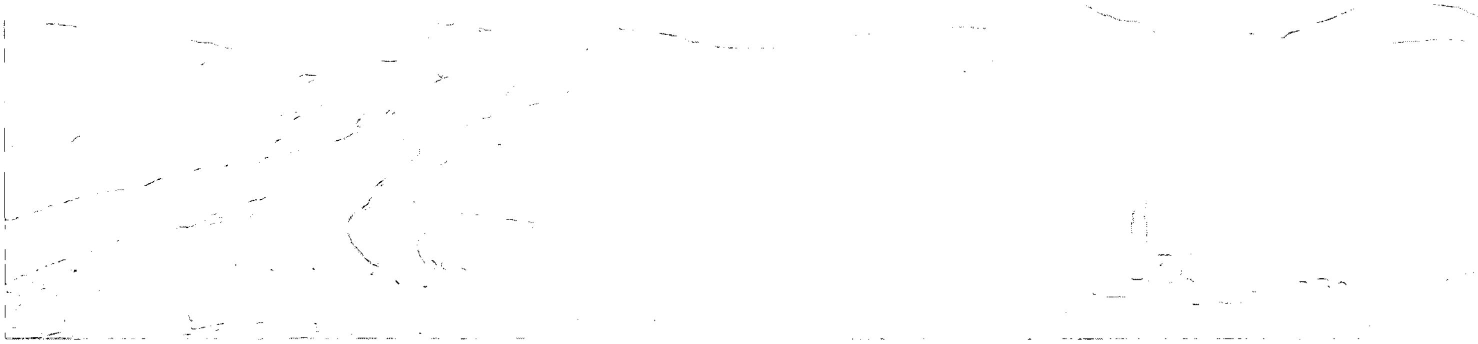
A. *(John Carpenter)* Natural gas NYMEX futures contracts and financial derivative products, including basis swaps, have provided producers, transporters, end-users and speculators with instant access to fixed futures and basis prices out at least five years into the future. On April 1, 2002, natural gas production could be sold forward at Henry Hub for five years for $3.70 per MMBtu and the Rocky Mountain basis differential for the five year period was quoted at $0.56. These futures prices reflect the market's expectation that natural gas prices will remain at historically high levels during the next several years. Prima's expectations on NYMEX prices and basis are similar to those indicated by these futures quotations. We do believe, however, that peak and trough prices will vary widely, as they did in 2001, due to variable market conditions. Volatility in natural gas prices should allow Prima the opportunity from time to time to hedge production at prices above the projected long-term average. Our goal is to take advantage of price spikes and hedge our production accordingly. Our current hedge position, which covers a significant portion of our production in the first half of 2002 but lower amounts thereafter through the first quarter of 2003, is summarized in Item 7A of our Form 10-K.

Q. Why did you sell the Stones Throw CBM project? Are you considering other asset sales?

A. *(Richard Lewis)* Stones Throw, which was Prima's first CBM development project, is located in the northern Powder River Basin, in an area of multiple coal seams that are relatively thin and shallow. Prima received an offer for the Stones Throw property and nearby undeveloped acreage, which we believe fully valued the reserve potential of these properties. Selling these holdings allows Prima to high-grade our CBM position and focus our efforts on retained acreage with much higher reserve potential. The transaction resulted in Prima selling about 30% of our CBM acreage but only about 2.5% of the estimated year-end PV-10 of our proved and probable CBM reserves. Although Prima is not actively marketing any assets, similar opportunities to monetize non-core assets at a favorable valuation may be considered.

Q. What do you intend to do with the Company's nearly $40 million of cash and marketable securities (including proceeds from the March 2002 property sale)?

A. *(Richard Lewis)* We intend to utilize these funds to create additional shareholder value. Our success in creating value will always present reinvestment risk as well as opportunity. As we look to expand or enhance our opportunity portfolio, we will endeavor to



utilize the stringent criteria and discipline in the capital allocation process that has served us well historically. Our challenge is to identify, create, evaluate and seize those opportunities.

Q. Under what circumstances would Prima consider utilizing debt to finance new investments?

A. *(Richard Lewis)* Probably the most likely scenario under which Prima would utilize debt financing would be to fund an acquisition. The utilization of debt and the extent thereof, would depend on the size and nature of the transaction and assets involved. We have considerable flexibility to expand our horizons, given that none of our existing assets have any debt against them, we have $40 million in the bank, and we continue to generate significant cash flow. We are well aware that our historical utilization of 100% equity financing from internally generated cash flow has resulted in Prima having one of the highest costs of capital in the industry. The utilization of prudent debt financing would lower our cost of capital which could enhance our competitive position.

Q. Do you have any off-balance-sheet debt?

A. *(Neil Stenbuck)* Prima does not have any off balance sheet debt. The Company has, at times, entered into operating leases for oilfield equipment, such as gas compressors. Such arrangements are customary and routine in the business and have never, in the aggregate, been material to Prima's overall financial position.

Q. What is the difference between proved and probable reserves? Why do you disclose probable reserves?

A. *(Michael Kennedy, Executive Vice President of Engineering and Operations)* Reserves designated "proved" meet an SEC definition that is generally associated with a 90% or greater probability of occurrence. Reserves designated "probable" meet a standard promulgated by the Society of Petroleum Engineers that is generally associated with a probability of occurrence between 50% and 90%. The primary difference between Prima's proved and probable reserves is simply distance from existing production, with proved reserves being closer to producing wells.

Prima discloses its estimated probable reserves, most of which are attributable to our CBM properties in the Powder River Basin, because the volumes are significant relative to our estimated proved reserves, and we believe, though there is no assurance, that a substantial portion of these reserves will become proved in the future as additional drilling proceeds in these areas.

Q. Would you comment on the changes in Prima's proved and probable reserves during 2001?

A. *(Michael Kennedy)* Prima's proved reserves decreased about 41 Bcfe, from 176.5 Bcfe at the end of 2000 to 135.6 Bcfe at the close of 2001. Net of 2001 production of 11.9 Bcfe, most of the 29 Bcfe decrease in proved reserves was due to significantly lower year-end gas and oil prices used in preparing reserve estimates as of December 31, 2001. Lower product prices reduce estimated reserves in two ways. First, each

> "...Prima's largest (CBM) reserve targets are relatively deep, thick coals in our project areas west and northwest of Gillette."

well's economic limit, or minimum economic production level, is higher at lower prices. Therefore all wells, producing as well as undeveloped, reach their projected economic limit sooner, eliminating the reserves recovered at the "tail-end" of each well's projected life. Second, lower prices worsen the economics of non-producing investment opportunities such as drilling and recompletions, so that some of these reserves become uneconomic and are eliminated. Another, relatively minor, contributing factor to the downward revision in Prima's proved reserves was the application of stricter criteria this year by Prima's reserve auditors in designating proved CBM reserves. Prima did not add significant proved reserves in 2001 because most of our drilling activity was in areas where the reserves were already proved or was conducted in CBM project areas where the reserves were still categorized as probable at year-end.

Despite the sharply lower gas and oil prices used and the stricter criteria employed for estimating CBM reserves, Prima's estimated probable reserves at the end of 2001 totaled 314 Bcfe, declining only modestly from the 336 Bcfe estimated at the end of 2000. Although these factors caused a substantial reduction of previously-estimated CBM probable reserves, the adjustments were largely offset by results of Prima's 2001 drilling activities, which allowed reserves attributed to certain deep, high-reserve coals to be classified as probable at the end of 2001 for the first time.

Q. Why has Prima's CBM development in the PRB been relatively slow compared to other public companies that are active in that play?

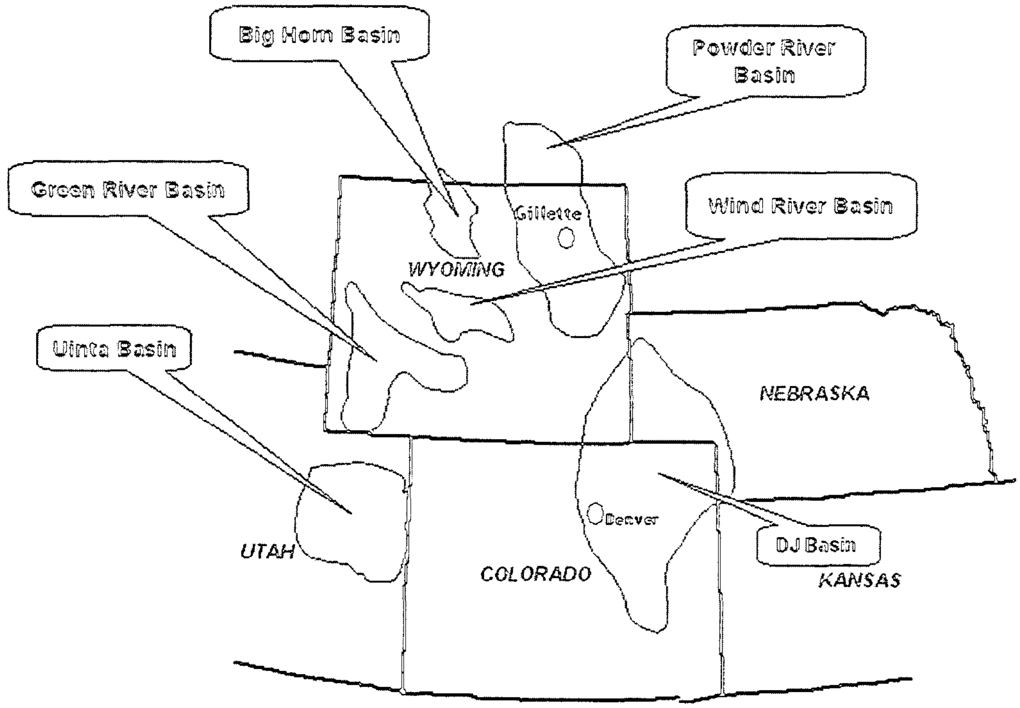
A. *(Michael Kennedy)* Most of the CBM production in the Powder River Basin to date has come from the coals along the east edge of the play, in an area about 10 to 15 miles wide, immediately west and down-dip from the open pit coal mines in eastern Campbell County. Most of Prima's acreage is farther west, where the coals are deeper and will take longer to de-water. Although the reserve potential is favorable in these coals, the cost to de-water them is too great without coincident development by other operators with up-dip and/or interspersed acreage.

Also, more than 80% of Prima's CBM acreage is leased from the federal government's Bureau of Land Management, which must issue a permit for each well drilled on that acreage. This compares to an estimated 50% of the total play represented by federal acreage. The BLM's issuance of drilling permits has been severely constrained by federal environmental assessment requirements. We believe our ability to drill on BLM acreage will improve significantly if, as expected, a record of decision is completed later this year for an Environmental Impact Statement covering CBM development in the area.

Q. What are your plans and timetable for developing CBM reserves in the Powder River Basin?

A. *(Michael Kennedy)* At our Porcupine-Tuit CBM project, located about 50 miles south of Gillette, Prima is planning to hook-up 23 existing wells and drill an additional 40 to 60 wells this year. This is an area with a single coal seam approximately 80 feet thick found at a depth of about 600 feet, with encouraging production from nearby wells operated by other companies.

Beyond Porcupine-Tuit, Prima's largest reserve targets are relatively deep, thick



coals in our project areas west and northwest of Gillette. In order to minimize cost and risk, Prima will be working this year to coordinate testing and development of these coals with offset operators in these areas. Some of this drilling may begin this year but much of the development will probably begin in 2003.

Q. What is Prima's exploration strategy and what types of activities can we expect?

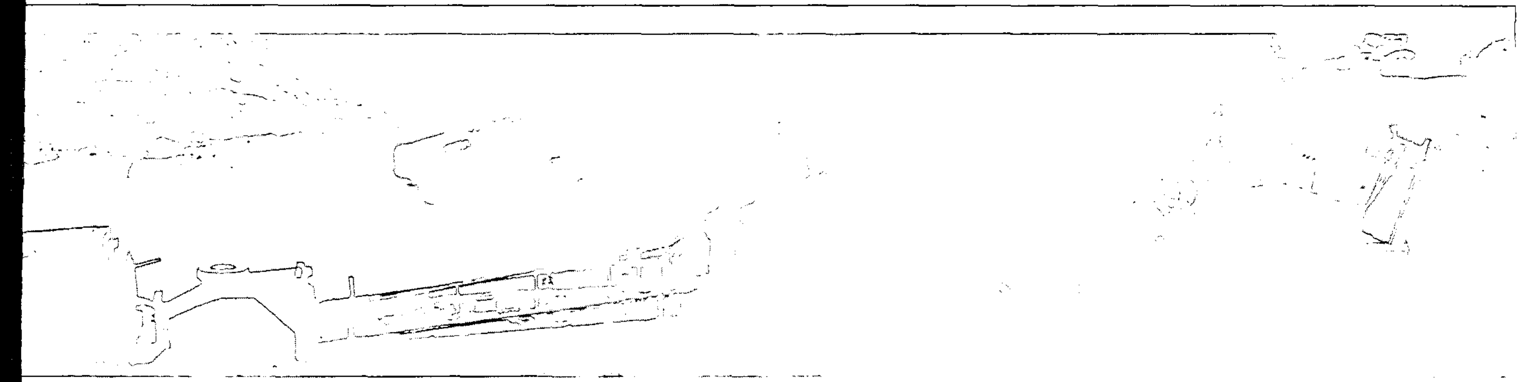
A. (*Michael McGuire, Executive Vice President of Exploration*) The objective of our exploration activities is to expose a portion of our capital to higher-risk projects where we believe the potential investment returns warrant the higher risk. Prima typically allocates 5% to 20% of its capital expenditures budget for exploration activities, which may include leasehold acquisition, geologic and geophysical evaluation, and drilling. We seek to capitalize on growing natural gas markets by developing existing and new opportunities, generally within the Rocky Mountains. At the end of 2001, Prima controlled approximately 367,000 net undeveloped acres in the Rocky Mountain region.

An important component of our exploration strategy has been to look for opportunities to acquire sizeable acreage positions at relatively low cost and with favorable lease terms, in areas that we believe have significant upside potential from multiple sands or coals, but which have not yet become established plays. We are then positioned to benefit from activities of others as the play matures, as well as from our own subsequent investments.

During the coming year, we intend to focus our exploration activities on select plays and basins where the Company already holds significant lease positions. We plan to continue to evaluate and expand our inventory of internally generated projects, to pursue participation in projects generated by other oil and gas companies, and to generate new opportunities within existing fields as a result of the application of new technology.

Q. Does Prima have any exposure to the Enron Corporation bankruptcy? What precautions does the Company take to manage credit risks related to third party purchasers and counterparties?

A. (*Neil Stenbuck*) Prima was not selling any of its gas or oil to Enron or its subsidiaries at the time of their bankruptcy filings, so we did



not experience any loss related to sales of our production. We did, however, have a derivatives contract in place with an Enron affiliate. We had an unrealized mark-to-market gain of $241,000 under the contract when we elected to terminate the agreement under default provisions in the contract. The full amount of this receivable was reserved for as a bad debt at December 31, 2001. The assumed loss under this contract represented approximately 2% of our total realized and unrealized gains on oil and gas derivatives last year.

We generally sell our gas and oil at or near the wellhead to affiliates of substantial, investment-grade companies. We also limit our derivatives contracts to conventional instruments, including futures contracts executed directly on the floor of the New York Mercantile Exchange. When we enter into over-the-counter derivatives contracts, such as swap agreements, we do so only with financial institutions that we believe to be reputable and which carry an investment grade rating. We also attempt to avoid concentrations of exposure with any single counterparty. While these measures can limit our credit risk, they cannot eliminate it.

Q. Have you engaged your independent auditors to provide any services other than the basic audit function?

A. *(Neil Stenbuck)* The Company's independent auditors, Deloitte & Touche, also provide audit services for the Prima Energy Corporation Stock Ownership Plan. The fees paid to Deloitte & Touche to audit the Plan and provide related services in 2001 totaled $15,000. Prima has not engaged Deloitte & Touche to provide any other services during the past three years.

Comparison of Natural Gas Well and Other Energy Sources Surface Impact
To produce 750,000 Therms over 20 years (1 therm=100,000 Btu)*

Natural Gas Well: One natural gas well (1.5 Bcf over 20 yrs) is needed with an initial disturbance of approximately 2 acres. Once drilled, the majority of land is reclaimated leaving approximately a 40' x 40' square for operations (0.04 acre).

Wind: Approximately 15 wind turbines are needed, which occupy an estimated 80 acres (acre=43,560 square feet).

Solar: Approximately a 4-acre array of solar panels is needed, which is approximately 1½ football field lengths per side.

Coal: Requires approximately 125,000,000 pounds, which is equal to a cube 110 feet on each side.

Wood: Requires approximately 76,000 spruce trees 12 inches in constant diameter and 100 feet tall.

*750,000 therms is the total energy consumption for approximately 470 residences for 20 years.

Note: All require access roads.

Source: Williams Exploration and Production

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[x] Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2001.

[ ] Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

Commission file number 0-9408

PRIMA ENERGY CORPORATION

(Exact name of Registrant as specified in its charter)

DELAWARE	84-1097578
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1099 18th Street, Suite 400, Denver, Colorado 80202
(Address of principal executive offices) (Zip Code)

(303) 297-2100
(Registrant's telephone number, including area code)

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

Securities registered pursuant to Section 12(g) of the Act
Common Stock, $0.015 Par Value
(Title of Class)

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

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

Aggregate market value of the 8,965,191 shares of Common Stock held by non-affiliates of the Registrant as of March 15, 2002 was $225,519,380 (based upon the mean of the closing bid and asked prices on the Nasdaq System).

As of March 15, 2002, Registrant had outstanding 12,728,672 shares of Common Stock, $0.015 Par Value, its only class of voting stock.

Document Incorporated by Reference

Parts of the following document are incorporated by reference to Part III of the Form 10-K Report: Proxy Statement for the Registrant's 2002 Annual Meeting of Stockholders.

TABLE OF CONTENTS

PART I

ITEMS 1 and 2. BUSINESS and PROPERTIES

The "Company" or "Prima" is used in this report to refer to Prima Energy Corporation and its consolidated subsidiaries. Items 1 and 2 contain "forward-looking statements" that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. These statements include, without limitation, statements relating to the drilling and completion of wells, well operations, utilization rates of oilfield service equipment, gathering and compression of wells, reserve estimates (including estimates for future net revenues associated with such reserves and the present value of such future net reserves), business strategies, and other plans and objectives of Prima management for future operations and activities and other such matters. The words "believes," "plans," "intends," "strategy," "budgeted," "expected" or "anticipates" and similar expressions identify forward-looking statements. Prima does not undertake to update, revise or correct any of the forward-looking information. Readers are cautioned that such forward-looking statements should be read in connection with Prima's disclosures under the heading: "Cautionary Statement for the Purposes of the 'Safe Harbor' Provisions of the Private Securities Litigation Reform Act of 1995".

General - The Company

Prima was incorporated in April 1980 for the purpose of engaging in the exploration for, and the acquisition, development and production of crude oil and natural gas, and for other related business activities. In October 1980, the Company became publicly owned with a $3.6 million common stock offering. In subsequent years, the Company's activities were expanded through its wholly owned subsidiaries to include oil and gas property operations, oilfield services, and natural gas gathering, marketing and trading. However, a substantial majority of Prima's consolidated assets and revenue continue to be related to its oil and gas production operations.

The Company organizes its principal activities in operating segments that consist of the acquisition, exploration, development and operation of oil and gas properties, and providing oilfield services for wells which it operates and for unaffiliated third parties. During 2000, the Company initiated gas gathering and compression operations, but these activities were not material to Prima's operations at December 31, 2001. Prima's oil and gas exploration, development and production activities are conducted by Prima Oil & Gas Company, a wholly owned subsidiary. Wholly owned subsidiaries of Prima Oil & Gas Company conduct the following activities: oilfield services by Action Oil Field Services, Inc. and Action Energy Services; natural gas gathering and compression by Arete Gathering Company, LLC; and natural gas marketing and trading by Prima Natural Gas Marketing, Inc. For a more detailed discussion of the Company's business segments, including revenues earned from third parties, operating earnings and total assets, see "Segment Information" in the Notes to Consolidated Financial Statements.

Prima's activities are principally conducted in the Rocky Mountain region of the United States. The Company owns or controls leasehold interests in over 595,000 gross, 393,000 net acres, predominately in the Denver Basin of Colorado, the Powder River, Wind River, Big Horn and Green River basins of Wyoming and the Wasatch Plateau and Overthrust Belt of Utah. For a discussion of these areas, see "Properties with Production, Development, Exploitation and Lower-Risk Exploration Activities" and "Other Exploratory Prospects and Acreage" below.

Prima has identified more than 1,400 potential exploitation and development opportunities on its acreage as of the end of 2001, including drilling, recompletion and refracturing projects. Of these, 491 were assigned proved oil and gas reserves at year-end 2001. Most of the identified non-proved opportunities represent potential drilling locations on the Company's acreage in the Powder River Basin coalbed methane ("CBM") play, where the Company's internal and independent engineers have assigned estimated probable reserves. These numbers reflect only those projects that might be economically viable using unescalated year-end oil and gas prices, and have been adjusted to exclude identified opportunities associated with certain CBM assets that were sold in March 2002 (see "Subsequent Event" in the Notes to Consolidated Financial Statements). Prima plans to continue to identify, develop and exploit opportunities in its principal business operations over the next few years, including the multi-year set of opportunities that the Company has identified on its acreage holdings in the Powder River Basin CBM play.

At December 31, 2001, the Company reported the following:

- $135,444,000 of assets.
- $28,122,000 of net working capital.
- Estimated net proved reserves of 135.6 Bcfe, with a pre-tax present value using a 10% discount factor ("PV10") of $92 million, based on constant year-end average prices of $1.94 per Mcf of natural gas and $19.71 per barrel of oil. An alternate price case using average prices of $2.33 per Mcf and $21.53 per barrel, based upon five-year forward prices at the end of 2001, resulted in estimated net proved reserves of 156.1 Bcfe with PV10 of $122 million.
- 563,000 gross, 367,000 net, undeveloped acres and 32,300 gross, 26,500 net, developed acres.
- Operations of 695 productive wells, representing approximately 93% of the productive wells in which Prima owns a working interest.

For the year ended December 31, 2001, the Company reported the following:

- Net income of $23,768,000.
- Cash provided by operating activities of $43,008,000.
- Average daily net production of 25,416 Mcf of natural gas and 1,181 barrels of crude oil (32,501 Mcfe).
- Average price realizations of $3.60 per Mcf of natural gas and $25.88 per barrel of crude oil.

Strategy

Objective. The Company seeks to create shareholder value by identifying, evaluating and seizing opportunities where it can acquire, develop, operate and market future reserves at superior margins on a risk-adjusted present value basis. It is a goal of the Company to be one of the lowest cost producers with the highest cash flow margins for reinvestment in the industry. Prima also seeks to create value through oil and gas service operations that complement the Company's exploration and production activities.

Acreage. Prima attempts to acquire leasehold acreage at reasonable costs with attractive terms in prospective areas. The Company can potentially benefit from the activities of other operators in these areas as well as from its own activities.

Operations. It is generally the Company's objective to operate the oil and gas properties in which it has significant economic interests. Prima believes that, as operator, it is in a better position to control costs, safety, timeliness and quality of work, and other factors affecting the profitability of a property.

Exploitation. The Company intends to continue its exploitation efforts in all of the operating areas. In the Denver Basin, we plan to continue well refracturing, restimulation and development drilling, to the extent warranted by ongoing results and economic success. Prima has been drilling wells in the Denver Basin for 20 years, and refracturing wells in the area for over seven years. We also plan to continue exploitation activity in the Powder River Basin, for both conventional and coal seam reservoirs, and in the Wind River Basin, depending upon the merit of each activity and subject to regulatory considerations. These activities are generally low to moderate-risk endeavors that meet our economic criteria.

Exploration. The Company typically allocates 5% to 20% of its capital expenditures budget for exploration activities. These activities may include leasehold acquisition, geologic and geophysical evaluation, and either drilling our own internally-generated prospects or participating in other operators' prospects. The objective of our exploration activities is to expose a portion of our capital to higher-risk projects where, we believe, the potential warrants the higher risk. As compared to individual exploitation activities, exploration projects could have a more significant impact on the value of the Company but the likelihood of success is lower.

Gathering, Marketing and Trading. The Company, to the extent possible and warranted, markets its own natural gas and crude oil. Prima believes it can better monitor its product pricing, and service and market conditions by actively marketing and selling its products. The Company may own assets downstream of the wellhead, including but not limited to gathering and compression facilities. This is done, where warranted, in an effort to improve overall project economics and enable Prima to capture more of the value chain from wellhead to burner tip. Prima may also gather, compress and market third-party gas.

Well Drilling and Servicing. Prima believes that it can better control the timing, quality and cost of work performed on its wells by owning and operating various well servicing equipment. The Company also intends for this activity to constitute a separate profit center for work performed for third parties. We have been involved in various aspects of the well servicing business for 14 years in the Denver Basin and started an oilfield drilling and service company in the Powder River Basin in 1999.

Merger, Acquisition and Divestiture. In its ordinary course of business, the Company regularly reviews merger, acquisition and divestiture opportunities related to the oil and gas industry that could enhance its business.

OIL AND GAS PRODUCTION OPERATIONS

Properties with Production, Development, Exploitation and Lower-Risk Exploration Activities

Denver Basin

Location, Operations and Acreage. Prima's activities in the Denver Basin are conducted primarily in the Wattenberg Area, which encompasses more than 1,000 square miles, between 20 and 55 miles northeast of Denver, Colorado. Prima also owns leasehold interests and conducts operations on 4,480 acres near Denver International Airport ("DIA"), where it has drilled and completed ten wells. Prima operated 395 wells in the Denver Basin (including those near DIA) as of December 31, 2001. Our leasehold position in the Denver Basin at the end of 2001 was 18,400 gross, 15,500 net, developed acres, with an additional 14,000 gross, 13,000 net, undeveloped acres.

Formations and Production. The Company's drilling and production activities have been centered in a portion of the Wattenberg Area where the primary productive reservoirs are found in the Codell and Niobrara sands. The Codell and Niobrara sands blanket large areas of the field at depths of approximately 7,000 to 7,300 feet and have moderate porosity and low permeability. These formations require fracture stimulation to establish economic production. Recoverable reserves from any individual wellbore are controlled by reservoir quality, thickness and fracture stimulation techniques. Our Denver Basin wells produce both natural gas and crude oil. Prima's natural gas production in this area averages approximately 1,240 Btu per Mcf and generally sells at a slight premium to Rocky Mountain spot price due to the high Btu content. Natural gas liquids (propane, butane, ethane, isobutane, pentane) are processed out of the well stream and sold separately by third-party gatherer/purchasers but their value is reflected in our wellhead price for natural gas. Our crude oil in this area is sweet and generally commands a premium to Eastern Colorado and West Texas Intermediate postings. During 2001, Denver Basin properties accounted for approximately 72% of the Company's total Mcfe produced and 78% of the Company's total oil and gas revenues excluding hedging gains, with natural gas averaging 16,658 Mcf per day and crude oil averaging 1,134 barrels per day net to Prima's interests.

Reserves and Development Costs. The Denver Basin represented 47% of Prima's year-end proved oil and gas reserves on an Mcfe basis. Codell/Niobrara wells drilled and completed in this area typically cost approximately $275,000 and target approximately 250,000 to 300,000 Mcfe of gross recoverable reserves per well. At year-end 2001, the Company controlled approximately 200 potential drillsites in the Denver Basin, with 35 of these attributed proved undeveloped reserves. The Company's strategy has been to selectively drill wells utilizing advanced drilling and completion techniques, and utilize improved marketing and cost controls to enhance economic returns and establish proved reserves on additional acreage. There is no assurance that these locations will ultimately be drilled or that, if drilled, such wells will prove to be commercially productive.

Codell/Niobrara Refracturing. Advancements in refrac stimulation technology (applying a new fracture treatment to a producing formation in an older well) have enabled Prima to add deliverability and reserves from the Codell and Niobrara formations. The Company targets older wells with declining deliverability for restimulation, and gives priority to those that qualify for Section 29 tax credits of approximately $0.65 per Mcf on production through the year 2002. Refracs completed by Prima in 2001 resulted in initial incremental production rates averaging 110 Mcf of natural gas and 9 barrels of oil per day. The refracs cost an average of approximately $110,000 and target approximately 125,000 Mcfe of incremental recoverable reserves.

2001 Activity. During 2001, the Company participated in the drilling of 19 gross (18.8 net) wells and the refracturing or recompleting of 63 gross (58.4 net) wells in the Denver Basin. All of these operations have been successfully completed and all of the wells have been placed on or returned to production. New wells and recompletion operations in the Denver Basin are characterized by flush production at relatively high rates for a few months, after which lower production levels are established at relatively shallow decline rates. The Company generally accelerates these operations when oil and gas prices are high and defers them when prices are low, to enhance the impact on investment returns from the flush production. Because of oil and gas price declines, and high line-pressure attributable to limited processing capacity in the area, Prima elected to postpone certain drilling and recompletion operations that had been scheduled for the third and fourth quarters of 2001. Following a recent recovery in gas prices and the completion of an expansion of a third-party owned gas processing plant, the Company has resumed recompletion operations, but is still deferring new wells until costs decline or prices increase further.

Future Activity. The Company intends to continue its development and exploitation activities in the Denver Basin. We are currently budgeting for capital investments in the Denver Basin aggregating between $5 million and $8 million in 2002. Planned activities include approximately six new Codell/Niobrara wells in the Wattenberg Area, 36 Codell/Niobrara refrac stimulations and six well recompletions. However, such plans are subject to revision based on economic conditions, performance results, activities conducted in other areas, and other factors.

Powder River Basin – Coalbed Methane

Location, Operations, Acreage. The coalbed methane play in the Powder River Basin is prospective over a vast geographic area encompassing approximately three million acres in northeastern Wyoming. The Company has been active in this CBM play since 1999, and its operations have included drilling, producing, oilfield services, and gathering and compression. According to the Wyoming Oil & Gas Commission, over 12,000 CBM wells have been drilled to date, and approximately 8,100 wells were producing approximately 817 MMcf of natural gas per day as of December 2001. The Wyoming Oil & Gas Commission also indicated that more than 60 drilling rigs were being utilized in the area in February 2002, making this the most active play in the United States. Prima has assembled a significant leasehold position within the play, with parcels stretching from the southernmost part of the play to its known limits on the northern end. This leasehold position is generally close to gathering and transportation infrastructure and, in several instances, is relatively close to areas of known production. At December 31, 2001, Prima held 10,200 gross, 9,900 net, developed acres, with an additional 141,000 gross, 130,000 net, undeveloped acres in this play. This acreage is comprised of approximately 81% federal, 9% state, and 10% fee (private) leases. The federal leases have an initial ten-year term, state leases have a five-year term, and the terms of fee leases vary from a few months to several years. The Company organized its Powder River Basin CBM acreage into 28 defined project areas for the convenience of operations management. On March 5, 2002, Prima closed the sale of a portion of its CBM acreage, representing approximately 4,000 gross and net developed acres, and 40,000 gross, 35,000 net, undeveloped acres. The acreage sold represented most of six project areas located in the northern portion of the play and included the Company's partially-developed Stones Throw project – see "Subsequent Event" in the Notes to Consolidated Financial Statements. Prima retained its acreage elsewhere in the Powder River Basin CBM play where our assessment is that deeper, thicker undeveloped coals hold the potential for better economic returns than obtainable on the acreage sold.

Formation and Production. The primary target coals are located in the Fort Union formation at depths ranging from 200 to 2,000 feet. It is common to encounter multiple coal zones varying in thickness from a few feet to over 175 feet between these depths. The methane in coal beds is absorbed, or attached, within the coal layers and is held in place by water within the coals. When water is produced from the coal seam, the pressure is reduced, allowing the gas to desorb from the coal. Operators in the area have experienced de-watering times that range from a few days to over one year, and the de-watering time is influenced by well density, coal depth, permeability, well location and other factors. Individual well production rates have ranged from a few Mcf to over 1,000 Mcf per day, and have averaged approximately 125 Mcf per day within the play to date. To produce gas in this CBM play, wells must generally be hooked-up to a low-pressure gathering system and compression, commonly referred to as "screw compression", which holds wellhead pressures to approximately five pounds per square inch gauged ("psig"). The gas must then move through a gathering system where, at its terminus, gas needs to be boosted up to about 1,400 psig to enter a high-pressure header system line. This high-pressure boost is commonly referred to as "reciprocating compression". CBM gas from this area is generally somewhat less than 1,000 Btu per Mcf and may require carbon dioxide extraction to meet interstate pipeline gas quality specifications. Prima established its first significant Powder River Basin CBM production in 2001 from the Stones Throw and Kingsbury properties, with production rates generally increasing throughout the year. Combined, during 2001 these properties accounted for approximately 12% of the Company's Mcfe produced and 5% of its total oil and gas revenues excluding hedging gains, with net gas production averaging 3,980 Mcf per day for the full year and 6,995 Mcf per day in the final quarter of the year.

Reserves and Development Costs. Powder River Basin CBM properties accounted for 46% of Prima's year-end proved oil and gas reserves on an Mcfe basis. CBM wells generally cost from $75,000 to $125,000 to drill, equip and complete through the sales meter, depending on location and depth, exclusive of gathering and compression costs. A typical well will establish gross recoverable reserves of 200,000 to 500,000 Mcf. At year-end 2001, the Company's reserve report for the CBM area included 116 proved developed producing wells, 81 wells classified as proved developed non-producing and 230 locations assigned proved undeveloped reserves. Based on engineering estimates prepared as of December 31, 2001, and excluding assets sold on March 5, 2002, the Company believes it has a potential inventory of over 1,600 drill sites in this play, subject to economic viability which will vary with regional gas prices and other factors. The Company cautions that well reserves and production capabilities may vary considerably depending on location, thickness and depths of coals, number of coals present, permeability, gas content, desorption, completion and production methods and other factors, and will vary from one group of wells to another throughout the basin. There is no assurance that these potential wells will be drilled or that those drilled will ultimately develop economic reserves.

Permits - Drilling, Water Discharge and Air Quality. Drilling permits for this CBM play are issued by the Wyoming Oil & Gas Commission for wells located on state and private lands. The Bureau of Land Management ("BLM") also issues drilling permits on federal leaseholds following completion of an environmental impact statement. The first environmental impact statement for the CBM play was completed in 1999 and provided for the drilling of approximately 5,900 wells. These permits have all been issued, and there has essentially been a moratorium on issuing drilling permits for federal leaseholds pending issuance of a second environmental impact statement ("EIS"), unless the location qualifies under an Environmental Assessment that provides for the issuance of approximately 2,500 special drainage permits on federal leaseholds pending completion of the EIS. The EIS, which is expected to provide for the drilling of approximately 50,000 CBM wells in the area, inclusive of wells drilled to date, is currently underway with a record of decision expected in the latter part of 2002. The Company anticipates much greater accessibility to its federal acreage after this EIS is issued. A significant delay in the issuance of additional drilling permits on federal acreage would significantly impact the Company's development plans for the area. Water produced from CBM wells is generally potable (drinking water quality) and can be discharged on the surface. Water discharge permits are issued by the Wyoming Department of Environmental Quality ("DEQ"). Issuance of water discharge permits slowed during the past year in order to address the sodium absorption ratio and mineral content of water discharged in the basin and its potential impact on agriculture. This issue is most acute for producers in the northwestern portion of the play and Prima's operations are focused primarily on the eastern side of the basin. An alternative to surface discharge is water re-injection back into the ground, or "water recharge wells" which could be used in the play, but add to expense. Air discharge permits, which are required to operate natural gas fired compressors, are also issued by the DEQ, and take approximately four months to be issued. The Company has not encountered significant difficulties to date in acquiring air permits for its CBM operations.

Natural Gas Transportation Infrastructure. The transportation infrastructure in this basin is currently capable of moving approximately 1.4 Bcf (1,400,000 Mcf) per day of natural gas. High-pressure header systems, including Bighorn Gas Gathering LLC, Fort Union Gas Gathering LLC, and Thunder Creek Gas Services LLC, feed downstream into interstate pipeline capacity provided by Colorado Interstate Gas Company, Wyoming Interstate Pipeline, KM Interstate, Williston Basin Interstate Pipeline, and MIGC Inc. Downstream of these interstate pipelines, the pipeline grid is being enhanced by three current projects. Trailblazer Pipeline is expected to be on line in June 2002 with a 324,000 Mcf per day expansion that will move gas from the Cheyenne, Wyoming Hub to the mid-continent. Kern River Pipeline is expected to be on line in May 2003 with an additional 900,000 Mcf per day that will move gas from southwest Wyoming to Nevada and California markets. Front Range Pipeline, which delivers natural gas from Cheyenne, Wyoming to Denver, Colorado, is anticipated to add 440,000 Mcf per day of capacity by December 2002. Williams, Northern Border, Colorado Interstate Gas, Williston Basin Interstate and KM pipelines have also announced potential projects to move gas from the basin, but firm commitments and dates are pending. The Company estimates that at year-end 2001 about 800,000 Mcf per day of CBM gas was flowing. We caution that Prima does not own firm transportation for its own account, and may have difficulty moving gas from the basin if pipelines fill to capacity. The Company does, however, have an option with a third party that owns and controls firm header and pipeline capacity from the basin that would allow the Company, at certain junctures, to enter into a firm sales arrangement for gas production in its Kingsbury project area, which is described below.

2001 Activity. During 2001, Prima drilled 118 gross (116.5 net) CBM wells in this play. From 1999, when Prima commenced its CBM operations, through the end of 2001, the Company drilled a total of 286 gross (283.8 net) wells in the play. All but seven of the CBM wells drilled by the Company to-date have been located within six of the Company's 28 project areas. The concentration of Prima's development activities to-date within these project areas, and on the specific coals targeted so far, reflect a number of considerations other than estimated recoverable reserves and projected production rates. The Company's CBM activities have been limited to fee lands, state lands, and certain coals underlying federal lands for which drilling permits have been attainable. These activities have largely been focused on relatively shallow coals, near development activities of other operators. The higher potential coals identified on the Company's lands have not yet been developed. These deeper, thicker coal sequences are also either undeveloped or are in the early stages of development by other operators, and are expected to initially take longer to de-water than coals that have been under development and production in the region for a period of time. The following is a brief description of activities in the six project areas where most of Prima's CBM operations have been conducted to-date.

Stones Throw Area. The 9,900-acre Stones Throw project area, located approximately 30 miles north of Gillette, Wyoming, was the first chosen by the Company for CBM development. Its selection was due to Prima's control of a significant portion of fee acreage within the project area and its proximity to both an existing CBM field and related infrastructure. By the end of 2001, Prima had drilled 153 wells at Stones Throw, including 42 that were drilled during the past year. Wells drilled in this area have targeted the Canyon, Cook, or Wall coal, at depths between 500 and 850 feet. Prima installed a gathering system with leased compression facilities at Stones Throw, establishing capacity to produce up to 10 million cubic feet of gas per day. Gross production from the field reached approximately 8 MMcf of gas per day and averaged 6.3 MMcf per day net to Prima in the fourth quarter of 2001, from 106 wells that were hooked up and producing during the period. This field, the associated gathering system, and certain surrounding acreage were sold in March 2002, following the Company's decision to focus future CBM exploitation and development activities on other lands that it holds in the play where the presence of thicker, deeper coals is expected to yield superior investment returns -- see "Subsequent Event" in the Notes to Consolidated Financial Statements.

Kingsbury Area. Prima drilled seven additional wells during 2001 in the 10,300-acre Kingsbury project area, which is located 15 miles west of Gillette. The Company also completed and hooked up 26 of the 32 wells that have been drilled to date in the Kingsbury area. We elected to have the low-pressure gathering system installed by a third party that already had such facilities in place in the area, and entered into a market-price based sales agreement. All but six wells drilled by Prima to-date at Kingsbury have been completed in the Lower Anderson coal, but several developable coals are present within this project area. Aggregate gas production from the 26 wells that have been producing gas or de-watering has gradually increased as de-watering has progressed, and gross production at Kingsbury was recently averaging approximately 1,100 Mcf of gas per day.

North Shell Draw Area. The 7,400-acre North Shell Draw project area is located approximately 25 miles northwest of Gillette, Wyoming. Prima had drilled 36 wells within this project area through the end of 2001, including 22 drilled during the past year. All of the wells drilled to date have targeted the Lower Anderson coal, but several other developable coals are also present. Encouraging results were obtained from production testing seven of the North Shell Draw wells during the third quarter of 2001. This data will be used to design facilities, structure gas gathering arrangements and plan 2002 drilling activities for the area. Prima plans to install, or arrange for a third party to install, a gathering system and compression at North Shell Draw by late 2002.

Porcupine-Tuit Area. The 5,600-acre Porcupine-Tuit project area is located approximately 50 miles south of Gillette, Wyoming. The Company has drilled 23 Wyodak-coal wells, including 15 in 2001, in this project area, which exhibits favorable coal quality and thickness at relatively shallow depths. Other operators in the area have already reported encouraging performance from completions in the same coal and Prima conducted a short duration, two-well production test with positive results. The Company has arranged for third-party installation of gathering and compression facilities in 2002, and production is expected to be initiated in the third quarter of the year. Drilling in the area will also likely resume in the second half of the year, subject to obtaining drilling permits on federal lands. Prima's acreage position in the Porcupine-Tuit area was enhanced by an acquisition closed in the fourth quarter of 2001 that added approximately 1,800 gross, 800 net, undeveloped acres.

Hensley Area. The 4,800-acre Hensley project area is located approximately 20 miles northwest of Gillette, Wyoming. Prima has drilled and completed 18 wells in the project area, including 15 in 2001. Eight of these were drilled to the Lower Canyon coal, seven targeted the Wall coal, and three were drilled to the Upper Anderson coal. The Company has delayed entering into a gathering agreement with a third party pending resolution of development plans for this project area. We anticipate that after the Company negotiates such a gathering agreement, 16 of the existing wells at Hensley could be placed on-line within a few months.

Cedar Draw. During 2001, the Company drilled 17 wells on the 3,800-acre Echeta federal unit within the 6,000-acre Cedar Draw project area, located approximately 20 miles northwest of Gillette, Wyoming. Three separate coals were targeted by these wells, which have provided test data that will be used to formulate plans for further development. Cedar Draw is in close proximity to the North Shell Draw area, and the Company anticipates coordinating development of the two projects, including infrastructure installation and the scheduling of additional drilling during 2002.

Future Activity. Prima recently reduced the pace of its development activities in the CBM play due to low gas prices, regulatory constraints, and delays in infrastructure development required to tie-in new wells. The Company plans to actively develop its CBM acreage as infrastructure development proceeds and regulatory constraints are addressed. The Company currently anticipates drilling between 60 and 110 CBM wells in 2002. Among the project areas with significant planned new drilling activity during the year are Porcupine-Tuit and Wild Turkey, where the primary target coal is the Big George. Our capital investments in the CBM play during 2002 are expected to total between $10 and $15 million. However, these plans are subject to change based on economic conditions, availability of required permits, activities of other operators and gas transporters, and other factors.

Powder River Basin – Conventional

Location, Operations, Acreage. Prima has been active in lease acquisition, drilling and production from conventional reservoirs in the Powder River Basin since 1994. The Company owns the deep rights (below the coals) in approximately 162,000 gross, 149,000 net, acres in the basin, and we currently operate 13 of the 17 conventional reservoir Powder River Basin wells in which we have an interest. The Company has conducted a modest amount of exploration in the area, in addition to acquiring proved properties, and discovered the Cedar Draw Field, approximately 21 miles northwest of Gillette, Wyoming, in 1997 as a field extension to Amos Draw. At the end of 2001, Prima operated six wells and had a non-operated working interest in two other wells in the Cedar Draw Field.

Formations and Production. At December 31, 2001, Prima's production from conventional reservoirs in the Powder River Basin was derived primarily from the Muddy formation, located at a depth of approximately 9,600 feet, and the Turner formation, found at a depth of about 10,000 feet. Both of these formations are localized in nature, have moderate porosity and permeability, and typically require fracture stimulation to establish economic production. The production stream includes natural gas, natural gas liquids, and sweet crude oil. Natural gas from these two formations averages approximately 1,280 Btu per Mcf and is sold at a slight premium to Rocky Mountain indices, or spot prices. The crude oil sells for a premium to postings for Wyoming crude oil in this area. During 2001, production from Prima's conventional Powder River Basin properties accounted for approximately 8% of the Company's Mcfe produced and 8% of the Company's total oil and gas revenues excluding hedging gains, with natural gas averaging 2,142 Mcf per day and crude oil averaging 40 barrels per day net to our interests.

Reserves and Development Costs. The Powder River Basin conventional play represented approximately 4% of Prima's proved oil and gas reserves at the end of 2001, on an Mcfe basis. Muddy formation wells in this area typically cost from $750,000 to $850,000 to drill and complete, and average 1.2 to 1.5 Bcfe per well. At the end of 2001, the Company carried only proved developed reserves in its reserve report for conventional reservoirs in this area, but three additional development drilling locations have been identified on Prima's lands subject to higher gas prices. The Company also has identified several conventional exploratory prospects on its acreage in the Powder River Basin.

2001 and Future Activity. No conventional development wells were drilled in the Powder River Basin in 2001. Although no development drilling activity targeting conventional reservoirs in the Powder River Basin is currently planned for 2002, the Company intends to continue its evaluation of prospects and leads in the conventional play, as further discussed under "Other Exploratory Prospects and Acreage" below.

<u>Wind River Basin</u>

Location, Operations and Acreage. The Wind River Basin is located in central Wyoming, and Prima's production in the basin is located in the Cave Gulch area, comprising approximately three square miles. Prima has been active in the area since 1987, primarily as a non-operating working interest owner, but we also operate one producing well and have overriding royalty interests in ten wells. Prima owns working interests ranging from 4.5% to 24% in 29 gross (2.08 net wells) in the area. Our Wind River Basin acreage position is 1,100 gross, 150 net, developed acres, with 42,000 gross, 25,000 net, undeveloped acres at year-end 2001.

Formations and Production. The primary producing formations in the Cave Gulch area are the Fort Union at approximately 4,750 feet, the Lance from 4,900 to 8,800 feet, and the Frontier/Lakota/Muddy sands from 16,000 to 19,000 feet. The Frontier and Lakota/Muddy formations are lenticular in nature, with the Fort Union and Lance being localized reservoirs. The Lance formation has particularly thick intervals of producing reservoirs which, when completed and fractured together, have resulted in production of up to 18,000 Mcf per day from a single well. Lakota/Muddy wells in the area have produced up to 45,000 Mcf per day from a single well. The Fort Union, which appears sporadically at shallow depths, can be evaluated on the way down to the Lance or Lakota/Muddy, and has been completed and produced in approximately 18% of the locations where deeper wells have been drilled. Production from this area includes natural gas, natural gas liquids and sweet crude oil. The natural gas averages approximately 1,150 Btu per Mcf and is sold at a slight premium to Rocky Mountain indices, or spot prices. The crude oil sells for a premium to postings for Wyoming crude oil in this area. During 2001, production from Prima's Wind River properties accounted for approximately 8% of total Mcfe produced and 9% of the Company's total oil and gas revenues excluding hedging gains, with natural gas averaging 2,636 Mcf per day and crude oil averaging 7 barrels per day net to our interests.

Reserves and Development Costs. The Wind River Basin represented approximately 3% of Prima's proved oil and gas reserves at the end of 2001, on an Mcfe basis. Lance formation wells cost approximately $1.6 million to drill and complete, and target approximately 2 Bcfe per well. The deep Frontier/Lakota/Muddy wells cost approximately $9.5 million per well, and target 15 to 18 Bcfe per well. The year-end 2001 reserve report for this area included one proved developed non-producing opportunity.

2001 and Future Activity. Activity in the Cave Gulch area has decelerated as the field reaches its limits of known areal extent and producing horizons. No new wells were drilled in 2001, but two successful recompletion operations were conducted. Future activities, which generally would be initiated by a third-party operator, are expected to be limited. Prima anticipates modest capital expenditures in this area for new drilling or recompletions during 2002.

Other Exploratory Prospects and Acreage

Prima holds the following undeveloped acreage positions, except where noted, where recent developments have occurred or the Company either plans activities or is aware of activities planned by others that could benefit the Company. There is no assurance that any of the anticipated activities will occur or, if undertaken, that they will result in favorable outcomes.

Wyoming

Prima controls 425,000 gross, 264,000 net, undeveloped acres in the Powder River, Wind River, Big Horn and Green River basins in Wyoming.

Merna Prospect. Prima owns approximately 75,800 gross, 28,700 net, undeveloped acres in the Merna Prospect, located in the northern Green River Basin, Sublette County, Wyoming. The acreage is primarily prospective for natural gas development from the over-pressured Upper Cretaceous Lance Formation at a depth of approximately 13,000 feet. This prospect is located approximately 20 miles northwest of the Pinedale Anticline which is expected to produce over 2.0 Tcf of natural gas from the Upper Cretaceous Lance and Mesaverde formations. The Company entered into an agreement with a third party to support that party's effort to re-enter and complete an existing well and to drill a second well on offsetting acreage. In exchange for the information obtained from these operations, Prima agreed to allow the third party to participate in the drilling of an additional test well on, and to earn, a portion of Prima's acreage. Initial results of the project have been encouraging but not conclusive. The Company anticipates that the third party will drill at least one well and conduct additional production testing in 2002. Prima will evaluate any proposals to participate in such operations based on available technical data.

South Jonah Prospect. Prima owns approximately 5,900 gross, 3,700 net, undeveloped acres in the South Jonah Prospect, which is located in the northern Green River Basin, Sublette County, Wyoming. This prospect is located approximately ten miles from the Jonah Field, which is expected to produce over 2.5 Tcf of natural gas from the over-pressured Upper Cretaceous Lance Formation. There has been significant activity by other operators in the South Jonah area during the past two years. Five new wells have been drilled in the area to test the Lance and Mesaverde formations, and one well was re-entered to test the Lance Formation. Four of the wells were completed and are waiting on pipeline connections and two of the wells are currently being tested. Two of the wells directly offset Prima's acreage. The Company anticipates that additional drilling and production testing in the area will be conducted by other operators during 2002.

Hell's Half Acre Prospect. Prima owns approximately 17,200 gross, 5,500 net, undeveloped acres in the Hell's Half Acre Prospect, which is located in the eastern Wind River Basin, Natrona County, Wyoming. This prospect is a seismically-defined structure located approximately ten miles southeast of Cave Gulch Field. Cave Gulch Field is expected to produce between 1.0 and 1.5 Tcf of natural gas from the Tertiary Fort Union and Cretaceous Lance, Mesaverde, Frontier, and Muddy formations. During 2001, Prima participated with a 7% working interest in the Miller Ranch No. 11-9 well, which was drilled to a total depth of 12,592 feet to test the Upper Cretaceous Mesaverde Formation. Although the well encountered gas in several horizons it was determined to be non-commercial and was plugged and abandoned. This well did not evaluate the deeper potential of the prospect, which is the Company's primary objective in the area. Additional drilling is expected to evaluate the deeper potential, however, based on indications from third parties with interests in the prospect, no activity is anticipated until late 2002 or 2003.

Klondike Prospect. Prima owns approximately 102,000 gross, 26,000 net undeveloped acres in the southern Big Horn Basin, Hot Springs and Washakie counties, Wyoming. This exploration play is prospective for both oil and natural gas. A third-party operator has indicated an interest in drilling several wells on the acreage this year, but no firm plans have yet been formulated.

Powder River Basin Prospects. Prima owns deep rights on approximately 162,000 gross, 149,000 net, undeveloped acres in the Powder River Basin, Campbell and Converse counties, Wyoming. Much of this acreage was acquired for its CBM potential, but a significant portion was also acquired for deeper conventional prospects. In 1997, Prima discovered the Cedar Draw Field, which is an extension to Amos Draw Field.

Prima participated with a 15% interest in a test well on the 7,600 acre Jim Hill Draw Federal Unit in Converse County, Wyoming during 2001. The Jim Hill Draw Unit is located approximately one mile west of the Sand Dunes Field, which has produced more than 24 million barrels of oil and 56 Bcf of natural gas. The primary objective of the test well was the Cretaceous Muddy Sandstone, at approximately 12,100 feet. The well was unsuccessful and no further activity is currently planned.

Prima owns approximately 26,000 gross and net undeveloped acres in the Brooks Draw area located in Natrona County, Wyoming. The position is prospective for natural gas and oil from the highly fractured Cretaceous Niobrara, Turner and Newcastle Formations. During 2000 and 2001, third-party operators drilled several horizontal wells in this area designed to intersect fractures from a single well bore. While initial reports of results were encouraging, activity does not appear to have been sustained and ultimate economics of the play are not clearly defined at this stage of development. Prima plans to monitor activity in this area, and may participate in well(s) where our acreage is included within the spacing units of wells proposed by other operators. No such activity is anticipated for 2002.

The Company intends to continue to identify and pursue Powder River Basin conventional prospects in the future.

Utah

Prima has continued to expand its acreage position on the Wasatch Plateau located in east-central Utah. At the end of 2001, the Company held 105,000 gross, 74,000 net, undeveloped acres in Utah. Net acreage holdings were increased to approximately 100,000 in early 2002 through the exercise of an option covering interests under a portion of this acreage. The four prospects defined in Utah have conventional oil and gas potential as well as CBM potential.

The Company has a 37.5% non-operated working interest in a well drilled in 2000 in the Helper Field, located immediately north of Price, Utah. The well was placed on production in late-January 2001 and at last report was producing in excess of 400 Mcf of natural gas per day. This well is completed in Cretaceous Ferron coals between 1,850 to 1,950 feet.

East Clear Creek Prospect. Prima owns approximately 9,000 gross and net acres in the East Clear Creek Prospect, which is located approximately 15 miles west of Price, Utah. This prospect is one mile east of Clear Creek Field, which has produced 136 Bcf of natural gas from 16 wells drilled to the Cretaceous Ferron sandstone. Two miles east of Prima's prospect is Gordon Creek Field where a third party completed three Ferron sandstone wells during 2001. These new wells are currently waiting for pipeline connections. The Company's initial exploration at East Clear Creek will target the Ferron sandstone at a depth of approximately 6,000 feet on a seismically defined structure. Prima is currently working with the U.S. Forest Service to complete an Environmental Impact Statement (EIS) for this area and anticipates drilling its first well in the summer of 2003.

Coyote Flats Prospect. Prima controls approximately 76,000 gross, 71,000 net, undeveloped acres within its Coyote Flats Prospect area. The prospect is located 15 to 25 miles northwest of Price, Utah. Significant hydrocarbon production exists in the area. The Company's leasehold position is approximately 15 miles northwest of the Drunkard's Wash Field, which produces from the Cretaceous Ferron coals and sandstones and is expected to ultimately produce in excess of 1.2 Tcf of natural gas. Prima's objective at Coyote Flats is to test the hydrocarbon potential of sandstone and coal bed reservoirs in the Cretaceous Blackhawk formation, the Emery and Ferron members of the Mancos, and the Dakota formation. The primary CBM target on Prima's lease block is the Emery formation. The Emery coals are found across the majority of the lease position at depths ranging from 2,000 to 5,000 feet, with an average coal thickness of 60 to 70 feet. The lease block is also on trend with CBM production from the Cretaceous Blackhawk coals at the Castlegate Field, approximately 10 to 15 miles to the east, and Blackhawk coals are present under the Coyote Flats lease block at depths ranging from the surface to 3,000 feet. Gas shows have been reported from both the Emery and Blackhawk intervals. In addition to the CBM potential of the block, significant gas shows have been reported from the Cretaceous Ferron sandstones, Mancos shales, and Dakota sandstones. The Company anticipates drilling its first well at Coyote Flats during the second half of 2002.

Flat Canyon Prospect. Prima owns approximately 6,200 gross and net acres in the Flat Canyon Prospect located in Emery County, Utah. Prima's acreage immediately offsets the Flat Canyon Field, which was discovered in 1952. The Flat Canyon Field has produced 9.6 Bcf of natural gas and 14,000 barrels of oil from six wells completed in the Cretaceous Ferron sandstones. Prima intends to test the Cretaceous Ferron and Dakota formations at depths between 6,500 and 7,500 feet on the prospect. A secondary objective at Flat Canyon is the Cretaceous Blackhawk coals, which are 10 to 30 feet thick at depths of 1,100 to 2,500 feet. Prima is currently working with the U.S. Forest Service and the

Bureau of Land Management to permit two wells on this prospect. The Company anticipates drilling its first well at Flat Canyon during the summer of 2003.

Christmas Meadows Prospect. Prima owns or controls a 50% farmout interest in the Table Top Federal Unit that consists of approximately 23,000 acres. The Federal Unit is located in Summit County, Utah approximately 30 miles south of Evanston, Wyoming. The prospect objective is a seismically defined structural feature. The project has been delayed for several years while the U.S. Forest Service has been conducting an Environmental Impact Statement and considering a revision of the forest plan for the area. Prima and its partners intend to cause a well to be drilled on the prospect shortly after the Forest Service completes this work, but no drilling activity is expected to take place during 2002.

California

East Lost Hills Prospect. During the second quarter of 1998, the Company participated for a 6.25% interest in a deep exploratory well located in the San Joaquin Basin of central California. A dispute arose as to Prima's ownership in the prospect during the drilling of the initial test well, following a blowout and Prima's election not to participate in sidetrack operations. After evaluating its legal position and the development progress of the prospect since that time, including estimated costs incurred to date, Prima elected not to pursue legal action to enforce its ownership claim. The Company no longer asserts an interest in the East Lost Hills Prospect.

Reserves

The Company's net proved reserves at the end of 2001 are comprised of approximately 85% natural gas and 15% crude oil. Net proved reserves as of December 31, 2001 were estimated by the Company's engineers and audited by Netherland, Sewell and Associates, Inc., independent petroleum engineers. Prior year reserve estimates were prepared or audited in part by Netherland, Sewell and Associates, Inc. and in part by Ryder Scott Company, independent petroleum engineers.

The table below sets forth the estimated quantities of net proved reserves attributed to the Company's property interests at the end of each of the last three years, and the present value of estimated future net cash flows attributed to such reserves using prices in effect as of the respective year-end dates, held constant. The average net realizable prices used to estimate reserve quantities at the end of 2001, 2000, and 1999, respectively, were as follows: $1.94, $7.51 and $1.90 per Mcf for natural gas; and $19.71, $26.48 and $24.68 per barrel of oil. Projected future net cash flows from production of proved reserves were discounted by ten percent per annum to derive present values and the "Standardized Measure" of discounted future net cash flows after income taxes, as specified by the Securities and Exchange Commission. The 10% discount factor is not necessarily a market rate, and present value, no matter what discount factor used, is materially affected by assumptions as to future prices and costs and the timing of future production, which may prove to be inaccurate. For further information concerning estimated proved reserves and the discounted future net cash flows related to these reserves, see unaudited "Supplementary Oil And Gas Information" in the Notes to Consolidated Financial Statements.

	2001	2000	1999
Estimated proved natural gas reserves (Mcf)	115,222,000	154,172,000	124,111,000
Estimated proved oil reserves (barrels)	3,394,000	3,729,000	3,268,000
Present value of estimated future net cash flows, before future income tax expense	$91,905,000	$576,052,000	$108,551,000
Standardized measure of discounted future net cash flows	$66,801,000	$371,121,000	$75,466,000

Proved reserve quantities at the end of 2001 and the related present value of future net cash flows before income taxes were also estimated using an alternate price case based upon five-year forward prices quoted on December 31, 2001, as adjusted for transportation and quality differentials. Using prices averaging $2.33 per Mcf of natural gas and $21.53 per barrel of oil, estimated proved reserves totaled approximately 135 Bcf of natural gas and 3.5 million barrels of oil, with associated pre-tax PV10 of $122 million.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing and amounts of development expenditures. Oil and gas reserve engineering should be recognized as a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate is a function of the quality of available engineering and geological data and interpretation, and judgment. Results of drilling, testing and production after estimates are prepared may justify revisions. Accordingly, reserve estimates are often materially different from the quantities of oil and natural gas that are ultimately produced. The Company has had no major discovery or other event that is believed to have caused a significant upward or downward change in estimated proved reserves subsequent to December 31, 2001. Oil and natural gas prices have historically been volatile and are expected to continue to be so in the future. Changes in product prices affect the economic limits, and therefor recoverable reserve quantities of oil and gas wells, as well as the present value of estimated future net cash flows and the standardized measure of discounted future net cash flows.

Since January 1, 2001, the Company has filed Department of Energy Form EIA-23, "Annual Survey of Oil and Gas Reserves," as required by operators of domestic oil and gas properties. There are differences between the reserves as reported on Form EIA-23 and reserves as reported herein. Form EIA-23 requires that operators report on total proved developed reserves for operated wells only and that the reserves be reported on a gross operated basis rather than on a net interest basis.

Production

The Company's net natural gas production averaged 25,416 Mcf per day for the year ended December 31, 2001 compared to 23,724 Mcf per day for the year ended December 31, 2000 and 19,625 Mcf per day during the year ended December 31, 1999. Net oil production averaged 1,181 barrels per day for the year ended December 31, 2001 compared to 1,202 barrels per day during the year ended December 31, 2000 and 882 barrels per day during the year ended December 31, 1999. The following table summarizes information with respect to the Company's producing oil and gas properties for each of these periods.

	2001	2000	1999
Quantities Sold:			
Natural gas (Mcf)	9,277,000	8,683,000	7,163,000
Oil (barrels)	431,000	440,000	322,000
Average Sales Price (including hedging effects):			
Natural gas (per Mcf)	$3.60	$3.63	$2.10
Oil (per barrel)	$25.88	$29.29	$17.42
Average Production Costs per Equivalent Mcf (1)	$0.56	$0.53	$0.42

(1) Oil production has been converted to a common unit of production (Mcf of natural gas) on the basis of relative energy content (one barrel of oil to six Mcf of natural gas).

Productive Wells

The following table summarizes total gross and net productive wells for the Company at December 31, 2001.

	Productive Wells			
	Oil		Gas	
	Gross (1)	Net (2)	Gross (1)(3)	Net (2)(3)
Operated:				
Colorado	9	8.5	386	354.4
Wyoming	0	0.0	300	296.0
Non-operated:				
Colorado	0	0.0	18	7.9
Utah	0	0.0	1	0.4
Wyoming	0	0.0	35	3.3
Total (4)	9	8.5	740	662.0

Additionally, Prima owns royalty interests in 52 gross wells that are not included in the above table.

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(1) A gross well is a well in which a working interest is held. The number of gross wells is the total number of wells in which a working interest is owned.

(2) A net well is deemed to exist when the sum of fractional ownership interests in gross wells equals one. The number of net wells is the sum of the fractional working interests owned in gross wells expressed as whole numbers and fractions thereof.

(3) Includes 136 gross, 133.7 net, CBM wells in Wyoming that were shut-in awaiting hook-up at December 31, 2001.

(4) Wells are classified as oil wells or gas wells according to predominate production stream. Multiple completions (26 wells) are counted as one well.

Developed and Undeveloped Acreage

At December 31, 2001, the Company held leased acreage as set forth below:

	Developed Acreage (1)		Undeveloped Acreage (2)	
Location	Gross (3)	Net (4)	Gross (3)	Net (4)
Big Horn Basin	0	0	102,000	26,000
Denver Basin	18,400	15,500	14,000	13,000
Green River Basin	0	0	84,000	35,000
Powder River Basin	11,300	10,800	197,000	178,000
Uinta Basin	0	0	105,000	74,000
Wind River Basin	1,100	150	42,000	25,000
Other basins	1,500	50	19,000	16,000
Total	32,300	26,500	563,000	367,000

(1) Developed acres are acres spaced or assigned to productive wells.

(2) Undeveloped acreage are those lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

(3) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Many of the leases summarized in the table above as undeveloped acreage will expire at the end of their respective primary terms unless production has been obtained from the acreage subject to the lease prior to that date, in which event the lease will remain in effect until the cessation of production. Prima has generally been able to obtain extensions of the primary terms of its federal leases for the period that it is unable to obtain drilling permits due to a pending EIS. The following table sets forth the expiration dates of the gross and net acres subject to leases summarized in the table of undeveloped acreage.

	Acres Expiring	
Twelve Months Ending:	Gross	Net
December 31, 2002	16,000	7,000
December 31, 2003	20,000	12,000
December 31, 2004	59,000	30,000
December 31, 2005	92,000	61,000
December 31, 2006	43,000	42,000
December 31, 2007 and later	291,000	214,000

Drilling Activities

Certain information with regard to the Company's drilling activities for the years ended December 31, 2001, 2000 and 1999 is set forth below:

	2001		2000		1999	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	123	121.33	178	176.69	33	27.14
Dry	0	0.00	3	2.00	1	0.75
	123	121.33	181	178.69	34	27.89
Exploratory:						
Productive	14	14.00	5	4.90	9	6.19
Dry	2	0.25	0	0.00	0	0.00
	16	14.25	5	4.90	9	6.19
Total:						
Productive	137	135.33	183	181.59	42	33.33
Dry	2	0.25	3	2.00	1	0.75
	139	135.58	186	183.59	43	34.08

Since December 31, 2001 and through March 15, 2002 the Company has participated in nine gross (7.5 net) refracs or recompletions in the Denver Basin, all of which have been restored to production. On March 15, 2002, the Company also owned interests in 104 gross (101.7 net) CBM productive wells in the Powder River Basin that were awaiting hook-up to gas compression and transportation facilities (excludes wells sold on March 5, 2002).

Natural Gas and Oil Marketing and Trading

The Company's marketing and trading activities consist of marketing the Company's own production, marketing the production of others from wells operated by the Company, purchase and resale of third party natural gas, and basis trading the differential in price between the Rocky Mountain region and other areas of the United States. Financial instruments are used from time to time to hedge the price of a portion of the Company's production as well as purchases for resale.

Natural Gas. The terms and conditions of our various natural gas sales contracts vary as to price, quantity, term and other conditions, but in general follow 30-day spot or day-to-day prices as posted. The Company does occasionally sell fixed price gas for terms in excess of 30 days as a hedge on its production when warranted by its assessment of market conditions and to protect from downward price movements, but had no direct customer sales for a fixed price at year-end 2001. Prima has one significant purchaser of its natural gas in the Denver Basin, Duke Energy Field Services, LLC ("Duke"), which accounted for 31% of the Company's total consolidated revenues in 2001. Duke is not affiliated with Prima, and while loss of Duke as a customer could have a material adverse effect on the Company, we believe an ample market exists to sell the natural gas to alternate customers. The Company currently has three gathering agreements, one in the Denver Basin, one in the Wind River Basin, and one in the Powder River CBM play, to get its gas from the wellhead into high-pressure header systems or interstate pipelines. Prima has not, however, contracted for downstream transportation on a firm basis. As such, we have no liability to pay reservation (demand) charges for header or pipeline capacity, but we also have no assurance that our gas will flow every day. No significant curtailments of gas production occurred in 2001. In its areas of activity, Prima has also engaged in purchasing and re-selling third-party gas. These arrangements typically provide for the purchase of natural gas at a known price or index, with a corresponding sale. The Company does from time to time have open purchase or sale commitments without corresponding contracts, which could result in a loss. Prima's Chief Executive Officer reviews such positions before they are committed to, and we monitor (mark-to-market) these positions regularly. The Company had no purchase-for-resale trading obligations at year-end 2001. In 2001, total revenues from the sale of Prima's natural gas production, including related hedging effects, were $33,392,000, or 75% of oil and gas sales and 55% of consolidated revenues.

Oil. The Company's oil production is sold under a number of contracts at prices posted in the area of activity, plus a negotiated bonus determined by quality and location. The contracts are generally month-to-month in duration. Our point of sale for crude oil is at the well, where oil is picked up and trucked by the purchaser to pipelines or refineries. During

2001, one purchaser, Valero Energy Corporation (via its acquisition of Ultramar Diamond Shamrock) accounted for approximately 16% of Prima's total consolidated revenues for the year. Prima is not affiliated with Valero, and believes that it can sell its crude to other purchasers on comparable terms should we lose Valero as a customer. In 2001, total revenues from the sale of Prima's crude oil, including related hedging effects, were $11,156,000, or 25% of oil and gas sales and 19% of consolidated revenues.

Risk Management. To mitigate its risk from changes in benchmark oil and gas prices, the Company from time to time uses commodity futures and energy swaps. Such transactions can also be used to protect the Company from an expanding NYMEX to CIG basis differential, which can occur when natural gas supplies exceed pipeline capacity out of the Rocky Mountain region or due to other factors, such as regional weather differences. During 2001, Prima entered into derivatives contracts covering approximately 45% of its natural gas production and 19% of its crude oil production. A portion of these contracts did not meet all of the conditions required for utilization of hedge accounting, but were nevertheless viewed by management as providing considerable revenue protection in the event of declining oil and gas prices or widening basis differentials. Approximately 24% of the Company's natural gas production and 19% of its crude oil production in 2001 were covered by derivatives contracts that qualified for hedge accounting. See "Quantitative and Qualitative Disclosures about Market Risk" below for additional disclosures, including the Company's open derivative positions as of March 15, 2002.

OILFIELD SERVICES

Prima conducts its oilfield services business under the names of Action Oilfield Services in Colorado and Action Energy Services in Wyoming.

Action Oilfield Services. Action Oilfield Services ("AOS") has been active in the Denver Basin since 1986, operating out of a field office and yard near LaSalle, Colorado. AOS owns various well servicing equipment including completion rigs, a swab rig, tractor trailer rigs for water hauling, and oilfield rental equipment, such as pumps, tanks and blowout preventers. During 2001, we experienced high utilization rates for our people and equipment due to strong demand for services for well recompletions, re-works and drilling in the area. We intend to continue to grow our well servicing activities in the Denver Basin. AOS provides services for Prima as well as third-party operators in the area. During 2001, 27% of AOS's revenues were from activities performed on wells for Prima. The Company's share of fees paid to AOS on Company-owned properties and the costs associated with providing these services are eliminated in the consolidated financial statements. Third-party revenues recorded by AOS in 2001 totaled $5,683,000, or 9% of Prima's consolidated revenues.

Action Energy Services. Prima formed Action Energy Services ("AES") in the first quarter of 1999, to conduct well drilling and servicing activities in the Powder River Basin. AES leases an office and yard in Gillette, Wyoming. In addition to providing well services similar to those offered by AOS in the Denver Basin, AES has six CBM drilling rigs. We intend to continue to conduct both drilling and well servicing activities in the Powder River Basin, on behalf of both Prima and unaffiliated third parties. During 2001, 48% of AES's revenues were applicable to well interests owned by Prima, and these revenues have been accounted for in the same manner as noted for AOS. AES's third-party revenues were $2,224,000 in 2001, representing 4% of the Company's consolidated revenues.

GAS GATHERING SERVICES

Arete Gathering Company, LLC. Prima formed Arete Gathering Company, LLC ("Arete") in the third quarter of 2000 to provide gas compression and gathering services for the CBM play in the Powder River Basin. Arete installed its first gathering system in Prima's Stones Throw Area between mid-2000 and the first quarter of 2001. These assets were included in the sale transaction consummated in March 2002 -- see "Subsequent Event" in the Notes to Consolidated Financial Statements. No other gathering systems have been installed by Arete to date. We will evaluate future opportunities to build gathering and compression systems in the Powder River Basin based on the size and estimated reserve potential of our acreage blocks, proximity to header systems and pipelines, competitive options provided by third parties, and other factors affecting the economics of each project. In areas where Prima does not have a significant contiguous acreage block, or where third party gathering systems have already been installed, we will generally elect not to have Arete build a gathering system. Where Arete does install gathering and compression infrastructure, we will seek to provide such services to third parties to benefit from economies-of-scale and enhance our overall economic returns.

OTHER PROPERTIES, EQUIPMENT AND REAL ESTATE

Prima leases its Denver office space at an average annual rate of approximately $275,000. Such offices consist of 15,840 square feet and the lease continues until November 2007. The Company owns office furniture and equipment with a net book value at December 31, 2001 of $207,000.

Prima has leased office space with yard and shop facilities in Gillette, Wyoming. The yard and shop area is used to store and maintain various well-servicing equipment, drilling rigs and production equipment. Net book value of our service equipment, office furniture and equipment and leasehold improvements at this location was $2,421,000 on December 31, 2001.

The Company owns 160 acres of land in Weld County, Colorado near LaSalle, Colorado. The shop, office building and yard facilities located on the land are used for the Company's field and oilfield service operations. Net book value of the land, buildings and office furniture and equipment at December 31, 2001 was $170,000.

Prima owns approximately ten acres of surface land with no mineral rights on the western side of Greeley, Colorado. The land was acquired in March 2001 in exchange for minor undeveloped mineral rights. This ten-acre parcel is part of a planned 760-acre commercial and office park development. Prima plans to hold this land, which had a net book value of $944,000 at the end of 2001, for future sale, exchange or development.

The Company also owns service company and related equipment, including completion rigs, swab rigs, tractor trailer rigs used for water hauling, oilfield rental equipment and various oilfield vehicles, with a net book value of $1,991,000 at December 31, 2001.

Prima is a 6% limited partner in a real estate limited partnership that currently owns approximately 22 acres of undeveloped land in Phoenix, Arizona for investment and capital appreciation. The book value of this partnership interest was $257,000 at December 31, 2001.

EMPLOYEES AND OFFICES

As of December 31, 2001, the Company had 144 full-time employees, including 38 in its Denver office and 106 field employees. Of the field employees, Action Oilfield Services employed 51 people, Action Energy Services employed 31 people, and 24 were employed in Prima's lease and well management operations. Prima field employees also handled work for Arete Gathering Company. Prima also contracts the services of independent consultants involved in land, geology, engineering, accounting, regulatory affairs, and other disciplines as needed. The Company believes its relations with its employees are good. Prima's principal executive offices are located at 1099 18th Street, Suite 400, Denver, Colorado 80202.

ITEM 3. LEGAL PROCEEDINGS

The Company is a party to various legal proceedings arising in the ordinary course of its business. As of the date of the filing of this report, none of these is anticipated to have a material adverse impact on Prima's financial position or results of operations.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of the Company's security holders during the fourth quarter of the fiscal year ended December 31, 2001.

Cautionary Statement for the Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995

Prima is including the following cautionary statement to take advantage of the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statement made by, or on behalf of, the Company. The factors identified in this cautionary statement are important factors (but not necessarily all of the important factors) that could cause actual results to differ materially from those expressed in any forward-looking statement made by, or on behalf of, the Company. Where any such forward-looking statement includes a statement of the assumptions or bases underlying such forward-looking statement, the Company cautions that, while it believes such assumptions or bases to be reasonable and makes them in good faith, assumed facts or bases almost always vary from actual results, and the differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, the Company, or its management, expresses an expectation or belief as to the future results, such expectation or belief is expressed in good faith and believed to have a reasonable basis, but there can be no assurance that the statement of expectation or belief will result, or be achieved or accomplished. The Company does not undertake to update, revise or correct any of the forward-looking information. Taking into account the foregoing, the following are identified as important risk factors that could cause actual results to differ materially from those expressed in any forward-looking statement made by, or on behalf of, the Company:

Volatility of Oil and Natural Gas Prices. Historically, oil and natural gas prices have been volatile and are likely to continue to be volatile. Prices are affected by, among other things, market supply and demand factors, market uncertainty, and actions of the United States and foreign governments and international cartels. These factors are beyond the control of the Company. Excluding hedging effects, average natural gas and oil prices realized by the Company at the end of 2001 were 74% and 26% lower, respectively, than at the end of the prior year. To the extent that oil and gas prices decline, the Company's revenues, cash flows, earnings and operations are adversely impacted. Low oil and gas prices, in adversely affecting cash flow and access to capital, could reduce our ability to replace production and grow. The Company is unable to accurately predict future oil and natural gas prices.

Uncertainty of Oil and Natural Gas Reserve Estimates. Estimates of the Company's proved reserves and future net revenues are based on engineering reports prepared by the Company's engineers and audited by independent engineers. These estimates are based on several assumptions that the Securities and Exchange Commission requires oil and natural gas companies to use, including that oil and natural gas prices in effect as of the end of the year remain constant. Such estimates are inherently imprecise indications of future net revenues. Actual future production, revenues, taxes, production costs and development costs may vary substantially from those assumed in the estimates. Any significant variance could materially affect the estimates. In addition, the Company's reserves might be subject to upward or downward adjustment based on future production, results of future exploration and development, prevailing oil and natural gas prices and other factors.

Risks of Oil and Natural Gas Exploration, Development and Production. The search for oil and natural gas often results in unprofitable efforts, not only from dry holes, but also from wells which, though productive, do not produce oil or natural gas in sufficient quantities to return a profit on the costs incurred. No assurance can be given that the Company's exploration, development and acquisition activities in the future will result in the addition of any oil or natural gas reserves that will be commercially productive. In addition, the cost of drilling, completing and operating wells is often uncertain, and drilling may be delayed or canceled as a result of many factors, including unacceptably low oil and natural gas prices, availability of drilling rigs, oil and natural gas property title problems, government regulation, inclement weather conditions and financial instability of well operators and working interest owners. Furthermore, the availability of a ready market for the Company's oil and natural gas depends on numerous factors beyond its control, including demand for and supply of oil and natural gas, general economic conditions, proximity of natural gas reserves to pipelines, availability and terms for pipeline space, weather conditions and government regulation.

Need to Replace Reserves. As is customary in the oil and gas exploration and production industry, the Company's future success depends upon its ability to continue to find, develop or acquire additional oil and gas reserves that are economically recoverable. Unless the Company replaces the reserves that it produces through successful development, exploration or acquisition, the Company's proved reserves will decline. Further, approximately 47% of the Company's proved reserves at December 31, 2001 were located in the Wattenberg Area of the Denver Basin, where wells are characterized by relatively rapid initial decline rates. Additionally, approximately 36% of the Company's total proved reserves at December 31, 2001, were undeveloped. Recovery of such reserves will require significant capital expenditures and successful drilling and/or recompletion operations. There can be no assurance that the Company will continue to be successful in its effort to develop or replace its proved reserves.

Acquisitions Risks. We continually evaluate opportunities for property or corporate acquisitions that could enhance our business. The successful acquisition of producing properties requires an assessment of several factors, including recoverable reserves, future oil and gas prices, future capital and operating costs, and potential environmental and other liabilities. The accuracy of these assessments is inherently uncertain. In connection with these assessments, we would intend to perform a review of the subject properties consistent with industry practices. However, such review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every property and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. While it is our current intention to continue to concentrate on acquiring properties with development, exploitation and exploration potential located in our core operating areas, we cannot assure you that in the future we will not decide to pursue acquisitions or properties located in other geographic regions. To the extent that such acquired properties are substantially different than our existing properties, our ability to efficiently realize the economic benefits of such transactions may be limited. We may not be able to successfully integrate future property or corporate acquisitions. We seek to make selective niche acquisitions of oil and gas properties, and we will pursue corporate acquisitions that we believe will be accretive. However, integrating acquired properties and businesses involves a number of special risks. These risks include the possibility that management may be distracted from normal business concerns by the need to integrate operations and systems and in retaining and assimilating additional employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results.

Dependence On Transportation Facilities Owned by Others. Our business depends on transportation facilities owned by others. The marketability of our oil and gas production depends in part on the availability, proximity and capacity of pipeline systems owned by third parties. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships could materially affect our operations. Federal and state regulation of oil and gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

Derivatives Activities. Part of the Company's business strategy is to periodically use both commodity futures contracts and price and basis swaps to mitigate the impact of the volatility of oil and natural gas prices on a portion of our production and gas marketing activities. In certain circumstances, significant reductions in production, due to unforeseen events, could require the Company to make payments under such agreements even though payments are not offset by production. To reduce this risk, the Company generally strives to enter into derivatives for only a portion of its projected production. Derivatives may also prevent the Company from receiving the full advantage of increases in oil or natural gas prices. Further, such transactions may expose us to additional risk of financial loss in certain circumstances, including instances in which counterparties to our futures contracts fail to perform under the contracts or ineffectiveness of our derivatives result in losses not offset by increased sales revenue. The terms of our hedging agreements may also require that we furnish cash collateral, letters of credit or other forms of performance assurance in the event that mark-to-market calculations result in settlement obligations by us to the counterparties, which could encumber our liquidity and capital resources. We adopted Statement of Financial Accounting Standards (SFAS) No. 133 on January 1, 2001, which requires us to record each hedging transaction as an asset or liability measured at its fair value. Each quarter we must record changes in the value of our hedges, which could result in significant fluctuations in net income and stockholders' equity from period to period.

Capital Requirements. We anticipate continuing to make substantial expenditures to find, develop, acquire and produce oil and gas reserves. We expect to have sufficient cash provided by operating activities and from available net working capital to fund planned capital expenditures in 2002. However, we have not established a line of credit to provide additional capital if required to respond to new opportunities. While we believe that we could arrange for borrowings or issuance of securities to fund such opportunities, should lower oil and gas prices or operating difficulties *result in our cash flow from operations being less than expected or if capital markets were to deteriorate, we may be unable to obtain additional funds to expand our business.*

Demand For Oilfield Services. Our oilfield services operations are dependent on the level of demand in our operating markets. Both short-term and long-term trends in oil and natural gas prices affect demand. Because oil and natural gas prices are volatile, the level of demand for our services can also be volatile. Although Prima utilizes its service companies in its oil and gas operations, the substantial majority of the demand for their services is dependent on third parties. In addition to oil and gas prices, factors which can influence activity levels for our oilfield service operations include competition, our experience and reputation, the availability of labor, and the weather.

Competition. The Company competes with numerous other companies and individuals, including many that have significantly greater resources, in virtually all facets of its business. Such competitors may be able to pay more for desirable leases and to evaluate, bid for and purchase a greater number of properties than the financial or personnel resources of the Company permit. The ability of the Company to increase reserves in the future will be dependent on its ability to select and acquire suitable producing properties and prospects for future exploration and development. The availability of a market for oil and natural gas production depends upon numerous factors beyond the control of producers, including but not limited to the availability of other domestic or imported production, the locations and capacity of pipelines, and the effect of federal and state regulation on such production. Domestic oil and natural gas must compete with imported oil and natural gas, coal, nuclear energy, hydroelectric power and other forms of energy.

Operating Hazards and Uninsured Risks. The oil and gas business involves a variety of operating risks, including the risk of fire, explosions and blow-outs, as well as risks associated with production, marketing and general economic conditions. The Company maintains insurance against some, but not all, of these risks, any of which could result in substantial losses to the Company. There can be no assurance that any insurance would be adequate to cover any losses or exposure to liability or whether insurance will continue to be available at premium levels that justify its purchase or whether it will be available at all.

Government Regulation. All aspects of the oil and gas industry are extensively regulated by federal, state and local governments in all areas in which the Company has operations. Regulations govern such things as drilling permits, environmental protection and pollution control, spacing of wells, the unitization and pooling of properties, reports concerning operations, royalty rates and various other matters including taxation. As an example, the Company's exploration and development plans for its Powder River Basin CBM properties are dependent upon the timing, content and implementation of a pending record of decision by the Bureau of Land Management concerning an environmental impact statement covering CBM development in the area. Oil and gas industry legislation and administrative regulations are periodically changed for a variety of political, economic and other reasons. These regulations may substantially increase the cost of doing business and sometimes prevent or delay the commencement or continuance of any given exploration or development project and may adversely affect the economics of capital projects. At the present time, it is impossible to predict what effects current and future proposals or changes in existing laws or regulations will have on operations, estimates of oil and natural gas reserves, or future revenues. The costs of complying, monitoring compliance and dealing with the agencies that administer these regulations can be significant.

Environmental Regulation. We must comply with complex environmental regulations. Our operations are subject to complex and constantly changing environmental laws and regulations adopted by federal, state and local governmental authorities where we are engaged in exploration or production operations. New laws or regulations, or changes to current requirements, could have a material adverse effect on our business. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. We could face significant liabilities to the government and third parties for discharges of oil, natural gas or other pollutants into the air, soil or water, and we could have to spend substantial amounts on investigations, litigation and remediation. We cannot be sure that existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced or altered in the future, will not materially adversely affect our results of operations and financial condition. As a result, we may face material indemnity claims with respect to properties we own or have owned.

Key Personnel. We depend on the continued services of our executive officers. Loss of the services of any of these people could have a material adverse effect on our operations. We currently do not have employment agreements with any of our executive officers, including Richard H. Lewis, who serves as the Company's Chief Executive Officer, President and Chairman of the Board of Directors.

PART II

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

Prima's common stock trades on the Nasdaq National Market under the symbol "PENG." The following table sets forth the Nasdaq high and low sales prices for Prima's common stock for each quarterly period during the Company's years ended December 31, 2001 and 2000. These prices have been restated to reflect the effect of the three for two split of Prima's common stock distributed on February 24, 2000 and the three for two split of Prima's common stock distributed on December 11, 2000.

Year Ended December 31, 2001	HIGH	LOW
Quarter Ended March 31, 2001	$38.94	$25.25
Quarter Ended June 30, 2001	32.17	22.81
Quarter Ended September 30, 2001	27.69	19.99
Quarter Ended December 31, 2001	25.48	19.50
Year Ended December 31, 2000		
Quarter Ended March 31, 2000	$18.50	$10.50
Quarter Ended June 30, 2000	36.92	15.17
Quarter Ended September 30, 2000	37.83	20.71
Quarter Ended December 31, 2000	39.92	23.08

The above quotations are from sources believed to be reliable. They do not include any retail mark-ups, mark-downs or commissions and may not represent actual transactions.

On March 15, 2002, the closing sale price for the Company's common stock was $25.20 per share. Prima's common stockholders of record at March 15, 2002 totaled 849.

Holders of common stock are entitled to receive such dividends as may be declared by Prima's Board of Directors. No cash dividends were declared or paid in 2001, 2000 or 1999. Future cash dividends, if any, will be evaluated based among other things, on operating results, capital requirements and financial condition of the Company at the time.

During 2001, Prima issued a total of 10,125 common shares and options to acquire a total of 135,000 common shares that were not registered under the Securities Act of 1933, as amended. The shares and options were issued as follows:

- Prima issued a total of 10,125 common shares during July 2001 to a former director of Prima upon exercise of stock options previously granted to that director under Prima's Non-Employee Directors' Stock Option Plan.
- Options to acquire a total of 22,500 common shares were granted by Prima to directors of Prima under the terms of Prima's Non-Employee Directors' Stock Option Plan.
- Options to acquire a total of 112,500 common shares were granted to certain officers of Prima under the terms of Prima's 2001 Incentive Stock Plan.

No underwriter was involved in any of the transactions and no sales commissions, fees, or similar compensation were paid by Prima to any person in connection with the issuance of the shares and options. Prima believes that the grant of the options and the issuance of the shares in each instance was exempt from the registration requirements of Section 5 of the Securities Act by virtue of Section 4(2) of the Securities Act and/or under Rule 506 of Regulation D promulgated by the SEC thereunder, since each recipient of the common shares and options was a director and/or executive officer of Prima.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth a summary of selected consolidated financial data. This data should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations and the Consolidated Financial Statements and notes thereto.

	Years Ended December 31,				
	2001	2000	1999	1998	1997
	(in thousands, except per share amounts)				
Income Statement Data:					
Revenues:					
Oil and gas sales	$44,548	$44,437	$20,644	$16,612	$17,840
Gains on derivative instruments, net	6,435	0	0	0	0
Oilfield services	8,090	6,278	4,974	4,148	3,214
Trading revenues	0	0	2,318	3,956	15,999
Interest, dividend and other	1,214	1,464	1,286	4,378	854
	60,287	52,179	29,222	29,094	37,907
Expenses:					
Depletion of oil and gas properties	9,190	6,150	4,650	6,260	4,935
Depreciation of other property	1,369	1,054	817	616	497
Lease operating expense	3,295	2,623	2,012	2,041	1,720
Ad valorem and production taxes	3,344	3,421	1,765	1,272	1,355
Oilfield services	5,482	4,585	3,377	2,701	2,368
General and administrative	3,559	2,916	1,712	1,143	972
Impairment of natural gas swap	241	0	0	0	0
Trading costs	0	0	2,827	3,936	15,323
	26,480	20,749	17,160	17,969	27,170
Income before income taxes and cumulative effect of change in accounting principle	33,807	31,430	12,062	11,125	10,737
Provision for income taxes	10,650	9,535	3,035	3,060	2,635
Net income before cumulative effect of change in accounting principle	23,157	21,895	9,027	8,065	8,102
Cumulative effect of change in accounting principle	611	0	0	0	0
Net income	$23,768	$21,895	$9,027	$8,065	$8,102
Basic net income per share before cumulative effect adjustment	$1.82	$1.72	$0.70	$0.62	$0.62
Cumulative effect adjustment	0.05	0.00	0.00	0.00	0.00
Basic net income per share	$1.87	$1.72	$0.70	$0.62	$0.62
Diluted net income per share before cumulative effect adjustment	$1.75	$1.65	$0.69	$0.61	$0.61
Cumulative effect adjustment	0.05	0.00	0.00	0.00	0.00
Diluted net income per share	$1.80	$1.65	$0.69	$0.61	$0.61
Balance Sheet Data (at end of period):					
Total assets	$135,444	$104,900	$72,665	$66,866	$57,921
Net property and equipment	96,005	70,597	44,467	55,607	43,181
Long-term debt	0	0	0	120	240
Stockholders' equity	101,740	80,298	58,908	51,308	43,214
Working capital	28,122	25,678	21,408	5,467	7,952

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This Item 7 contains "forward-looking statements" which are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. These statements include, without limitation, statements relating to liquidity, financing of operations, continued volatility of oil and natural gas prices, estimates of future production and net cash flows attributable to proved reserves, future expenditures, and other such matters. The words "anticipates," "believes," "expects," "intends" or "estimates" and similar expressions identify forward-looking statements. Prima does not undertake to update, revise or correct any of the forward-looking information. Readers are cautioned that such forward-looking statements should be read in connection with Prima's disclosures under the heading: "Cautionary Statement for the Purposes of the 'Safe Harbor' Provisions of the Private Securities Litigation Reform Act of 1995".

The following discussion is intended to assist in understanding the Company's financial position and results of operations for the three-year period ended December 31, 2001. The Consolidated Financial Statements and notes thereto should be referred to in conjunction with this discussion.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operation are based upon the information reported in our consolidated financial statements. The preparation of these financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our decisions on historical experience and various other sources that are believed to be reasonable under the circumstances. Actual results may differ from the estimates we calculated due to changing business conditions or unexpected circumstances. Policies we believe are critical to understanding our business operations and results of operations are detailed below. For additional information on our significant accounting policies you should see Notes to Consolidated Financial Statements, particularly Notes 1 and 11, in our accompanying consolidated financial statements.

Revenue Recognition - We are engaged in the exploration, development, acquisition and production of natural gas and crude oil. Our revenue recognition policy is significant because our revenue is a key component of our results of operations and our forward looking statements contained in Liquidity and Capital Resources. We derive our revenue primarily from the sale of produced natural gas and crude oil. Revenue is recorded in the month our production is delivered to the purchaser, but payment is generally received between 20 and 90 days after the date of production. At the end of each period we make estimates of the amount of production delivered to the purchaser and the price we received. We use our knowledge of our properties, their historical performance, NYMEX and local spot market prices and other factors as the basis for these estimates. Variances between our estimates and the actual amounts received, which have historically been minimal, are recorded in the month such estimates are revised or when payment is received.

Fair Value of Derivative Instruments - Beginning in 2001, the estimated fair values of our derivative instruments are recorded on our consolidated balance sheet. All of our derivative instruments are entered into to mitigate risks related to the prices we will receive for our future natural gas and oil production. We do not use derivative instruments for trading purposes. Although our derivatives are reported on the balance sheet at fair value, to the extent that instruments qualify for hedge accounting treatment, changes in fair value are not included in our consolidated results of operations. Instead, they are recorded net of taxes directly to stockholders' equity until the hedged oil or natural gas quantities are produced. To the extent changes in the fair values of derivatives relate to instruments not qualifying for hedge accounting treatment, such changes are recorded in income in the period they occur. In determining the amounts to be recorded, we are required to estimate the fair values of derivatives. Our estimates are based upon various factors that include contract volumes and prices, contract settlement dates, quoted closing prices on the NYMEX or over-the-counter and, where applicable, volatility and the time value of options. The calculation of the fair value of collars and floors requires the use of the Black-Scholes option-pricing model. The estimated future prices are compared to the prices fixed by the derivatives agreements and the resulting estimated future cash inflows or outflows over the lives of the hedges are discounted to calculate the fair value of the derivative contracts. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts, regional price differences and interest rates. We periodically validate our valuations using independent third party quotations.

Reserve Estimates - The Company's estimates of gas and oil reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of gas and oil that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable gas and oil reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as expected future production rates, gas and oil prices, operating costs, severance taxes, and development costs, all of which may in fact vary considerably from actual results. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to an extent that these reserves may later be determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of gas and oil attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected therefrom may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company's gas and oil properties and/or the rate of depletion of the gas and oil properties. Actual production, revenues and expenditures with respect to the Company's reserves will likely vary from estimates, and such variances may be material.

Full Cost Method - We use the full cost method of accounting for our oil and gas activities. Under this method, all costs incurred in the acquisition, development and exploration of oil and gas properties are capitalized into cost centers that are established on a country-by-country basis (we have a single cost center for the United States). Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. Capitalized costs also include salaries, employee benefits, costs of consulting services and other expenses that are directly related to acquisition, development and exploration activities. Costs associated with production and general corporate activities are expensed in the period incurred.

Depletion - The capitalized costs of our oil and gas properties, plus estimated future development and abandonment costs related to our proved reserves, are amortized on a unit-of-production method based on our estimate of total proved reserves. The quantities of estimated proved oil and gas reserves is a significant component of amortization and revisions in such estimates may alter the rate of future expense. Generally, if reserve volumes increase or decrease, then the amortization rate per unit of production will change inversely. However, when capitalized costs change, the amortization rate moves in the same direction. The per-unit rate is not affected by production volumes.

Full Cost Ceiling Limitation - Under the full cost method, we are subject to quarterly calculations of a limitation, or "ceiling", on the amount of our oil and gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and gas properties exceed the cost center ceiling, we are subject to a ceiling test writedown to the extent of such excess. A ceiling test writedown is a non-cash charge to earnings. If required, it would reduce earnings and impact stockholders' equity in the period of occurrence and result in lower amortization expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and requires subjective judgments. Given the volatility of natural gas and oil prices, it is likely that our estimate of discounted future net cash flows from proved reserves will change in the future. If natural gas and oil prices decline, even if only for a short period of time, or if we have downward revisions to our estimated proved reserves, it is possible that writedowns of our oil and gas properties could occur. While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas reserves that are included in the discounted present value of the reserves do not require judgment. The future net revenues associated with our estimated proved reserves are not based on our assessment of future prices or costs. The ceiling calculation dictates that prices and costs in effect as of the last day of the quarter are held constant. However, we may not be subject to a writedown if prices increase shortly after the end of a quarter in which a writedown might otherwise be required.

Unevaluated Costs - Unevaluated costs are excluded from our amortization base until we have evaluated the properties associated with these costs. The costs associated with unevaluated leasehold acreage and wells that have not yet been determined to be productive or non-productive are not initially included in our amortization base. Leasehold and associated costs are either transferred to our amortization base with the costs of drilling related wells or are assessed quarterly for possible impairment or reduction in value. Leasehold costs are transferred to our amortization base if estimated fair value is below cost. The decision to withhold costs from amortization and the timing of transferring such costs into the amortization base involves a significant amount of management judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and results of drilling on adjacent acreage.

Other Property and Equipment – Oilfield service equipment and other property and equipment are carried at cost. Renewals and betterments are capitalized, while repairs and maintenance are expensed. Capitalized costs are depreciated using the straight-line method over the estimated useful lives of the assets. The carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including disposal value if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. Changes in such estimates could cause the Company to reduce the carrying value of property and equipment.

Income Taxes - We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared. We, therefore, estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating loss carryforwards. Any differences between estimates we initially used and subsequently determined to be appropriate are recorded in the period in which our estimate is revised.

Liquidity and Capital Resources

The Company's principal sources of liquidity have been the internal generation of cash flow from operations and existing net working capital. Additional potential sources of capital include proceeds from the sale of assets, borrowings, and issuances of common stock or other securities.

Net cash provided by operating activities totaled $43,008,000 in the year ended December 31, 2001, compared to $36,376,000 for the year ended December 31, 2000 and $12,006,000 for the year ended December 31, 1999. Net working capital at December 31, 2001 totaled $28,122,000, as compared to $25,678,000 at the end of the prior year. Prima's cash equivalents and short-term investments totaled $25,755,000 at December 31, 2001, compared to $22,693,000 at December 31, 2000, and the Company was free of long-term debt at both dates.

The Company's revenues and cash flows are substantially derived from oil and gas sales, which are dependent on oil and gas production volumes and sales prices. Prima's aggregate net production volumes have increased from 2,765,000 Mcfe in the first quarter of 2001, to 2,892,000 Mcfe in the second quarter, 3,088,000 Mcfe in the third quarter and 3,118,000 in the most recent quarter, but gas prices have declined more significantly during the same periods. As a consequence, the Company's oil and gas sales revenue, including derivatives qualifying for hedge accounting, declined from $16,357,000 in the first quarter, to $11,909,000 in the second quarter, $9,163,000 in the third quarter and $7,119,000 in the latest quarter. For the full year in 2001, Prima's oil and gas sales totaled $44,548,000, approximately flat with the prior year, on a 5% increase in total net production. Prima's future revenues will continue to be significantly affected by volatility in oil and gas prices.

This volatility in oil and gas prices is also reflected in year-end estimates of the Company's proved oil and gas reserves and related future net cash flows. Estimated future net cash flows from proved oil and gas reserves were

$156,624,000 at December 31, 2001 compared to $975,940,000 at December 31, 2000 and $190,008,000 at December 31, 1999. The standardized measure of discounted future net cash flows of the Company's proved oil and natural gas reserves was $66,801,000 at December 31, 2001, compared to $371,121,000 at December 31, 2000 and $75,466,000 at December 31, 1999. The fluctuations in both future net cash flows and the standardized measure were primarily attributable to the volatility of commodity prices. The Company's average realized prices as of the last day of each of the past three years, which were therefore used without future escalation in preparing year-end reserve estimates, were as follows for 2001, 2000 and 1999, respectively: $1.94, $7.51 and $1.90 per Mcf of natural gas; and $19.71, $26.48 and $24.68 per barrel of oil.

The Company increased its net working capital, with the sale of certain oil and gas properties on March 5, 2002 for approximately $13,539,000 of cash. The assets sold included the Company's Stones Throw CBM project in the northern Powder River Basin, the associated gathering system facilities and approximately 35,000 net undeveloped acres in the Stones Throw area. These properties accounted for approximately 6.1% of Prima's total estimated proved oil and gas reserves and 4.5% of the related estimated present value of future net cash flows before income taxes, as of the end of 2001. The producing wells sold accounted for approximately 9.6% of Prima's total oil and gas sales revenue before hedging gains in the fourth quarter of 2001.

The Company's average daily net production in the fourth quarter of 2001 totaled approximately 33,900 Mcfe, including 6,300 Mcf per day of CBM production from the Stones Throw Field, which was sold on March 5, 2002. In the absence of an acquisition in the interim, Prima does not expect significant production from new sources until the third quarter of this year, when production from the Company's Porcupine-Tuit CBM project is expected to commence. No other major variances from recent production levels are expected in the near term. Prima has drilled 23 Wyodak coal wells at Porcupine-Tuit to-date and has 72 additional locations in the project area identified for near-term drilling, but 63 of these are on federal lands for which drilling access is presently limited. Production reported for several nearby wells owned by other operators have been in the 150 to 400 Mcf per day per well range, after brief de-watering periods. The Company expects production from its wells in this area to exhibit similar performance, but cannot precisely forecast when production will be initiated or how the wells will then perform. The timing and amounts of production that may be added later in the year from other new activities, including other CBM projects and exploration also cannot be precisely forecast.

Prima invested $35,248,000 in additions to oil and gas properties during 2001, compared to $31,952,000 in 2000 and $18,617,000 in 1999. During 2001, $31,114,000 was expended for development, $1,620,000 for exploratory activities, $2,114,000 for acquisitions of unproved oil and gas properties, and $400,000 for purchases of proved properties. Other uses of funds in 2001 included $3,866,000 for treasury stock repurchases, $1,956,000 for purchases of oilfield service equipment and facilities, and $125,000 for other assets.

Excluding acquisitions, Prima currently plans to make capital investments in 2002 aggregating between $25 million and $30 million. Among anticipated 2002 drilling activities are 60 to 110 CBM wells, six to 12 wells in the Denver Basin, and three to six exploratory wells. The Company also intends to invest in various hook-up and infrastructure projects, including the Porcupine-Tuit CBM project in the Powder River Basin, and anticipates conducting 40 to 50 refracturing or recompletion operations in the Denver Basin. A significant portion of the 2002 budget has also been reserved for acquisition of additional acreage for future exploration or exploitation, or for other opportunities identified during the year. Activities planned by the Company for 2002 are weighted toward the second half of the year. This may enable the Company to benefit from development and operating efficiencies related to the expected issuance by the Bureau of Land Management of a record of decision concerning an environmental impact statement (EIS) for CBM development in the Powder River Basin. Approximately 82% of Prima's Powder River Basin acreage is federal, and access to federal lands has been limited pending completion of the EIS. The Company has also been deferring certain investments to benefit from anticipated improvements in gas prices and service costs, which have recently begun to materialize. Prima does not establish a specific budget for property acquisitions, but the Company continues to pursue such opportunities on an ongoing basis. The strong financial condition of the Company allows for considerable flexibility in responding to opportunities. Spot market prices for gas and oil have risen by approximately 20% from levels prevailing when the Company's budgeting process was initially completed. These prices, if deemed sustainable, may result in an acceleration of activities, which could include additional Powder River Basin CBM and Denver Basin drilling.

In January 2001, Prima's Board of Directors approved a repurchase program of up to 5% of the Company's common stock then outstanding, or approximately 640,000 shares. As of December 31, 2001, approximately 485,000 shares remained subject to repurchase under this authorization.

Prima expects to fund its exploration, development, and exploitation operations, the expansion of its service companies, and any re-purchases of common stock primarily with cash provided by operating activities and working capital. The Company also regularly reviews opportunities for acquisition of assets or companies related to the oil and gas industry that could expand or enhance its existing business. If a sufficiently large transaction is consummated, it could involve the incurrence of debt or issuance of equity securities.

Results of Operations

As noted above, the Company's primary source of revenues is the sale of oil and natural gas production. Because of significant fluctuations in oil and natural gas prices and variances in production volumes, the Company's operating results for any period are not necessarily indicative of future operating results.

Historically, oil and natural gas prices have been volatile and are likely to continue to be volatile. Prices are affected by, among other things, market supply and demand factors, market uncertainty, and actions of the United States and foreign governments and international cartels. These factors are beyond the control of the Company. Prima's revenues, cash flows, earnings and operations are adversely affected when oil and gas prices decline. Gas prices have declined significantly since reaching record high levels early in 2001, and oil prices have also declined during the past year, albeit more modestly. These price declines have unfavorably impacted the Company's operating results, as more fully described below. The Company cannot accurately predict future oil and natural gas prices, but historically oil and gas supply and demand have responded to changes in price levels to correct from short-lived extreme levels of high or low prices.

2001 vs 2000

For the year ended December 31, 2001, the Company earned net income of $23,768,000, or $1.80 per diluted share, on revenues of $60,287,000, compared to net income of $21,895,000, or $1.65 per diluted share, on revenues of $52,179,000 for the year ended December 31, 2000. Expenses, other than income taxes, were $26,480,000 for 2001 compared to $20,749,000 for 2000. Revenues increased $8,108,000 or 16%, expenses increased $5,731,000 or 28% and net income increased $1,873,000 or 9% in 2001.

Revenues for 2001 included $9,816,000 of gains from oil and gas derivatives (see "Derivative Activities" in Notes to Consolidated Financial Statements). This total included hedging gains of $3,381,000, which were reflected in oil and gas sales, plus $6,435,000 of separately reported gains on derivative instruments not qualifying for hedge accounting, of which $2,057,000 were realized and $4,378,000 were unrealized as of December 31, 2001. During the prior year the company recognized $42,000 of hedging gains. Derivative instruments that did not qualify for hedge accounting were principally NYMEX gas swaps for which the Company did not elect to enter into corresponding swaps for Rocky Mountain basis differentials.

Oil and gas sales reported for 2001 totaled $44,548,000, compared to $44,437,000 for 2000, an increase of less than 1%. The flat sales results were creditable to a 5% year-over-year growth in production volumes offset by approximately a like-sized decline in the average price realized per equivalent unit of natural gas and oil production. Excluding gains from derivative instruments, oil and gas sales reported for 2001 were $41,167,000, compared to $44,395,000 for 2000, a decrease of $3,228,000 or 7%.

The following information is provided excluding effects of derivatives. The average sales price received by the Company for natural gas production was $3.24 per Mcf in 2001, compared to $3.63 per Mcf in 2000, a decrease of $0.39 per Mcf, or 11%. The average price received per barrel of oil was $25.68 in 2001, compared to $29.20 in 2000, representing a decrease of $3.52 per barrel or 12%. On an Mcf equivalent basis, the average price received was $3.47

per Mcfe in 2001 compared to $3.92 per Mcfe in the prior year, representing an overall 11% decline in average prices. The portion of the Company's total oil and gas revenues that was derived from natural gas was 73% in 2001 compared to 71% in 2000.

The $3,381,000 of gains from derivative transactions that were accounted for as hedges in 2001 had the effect of increasing average price realizations reported for the year by $0.36 per Mcf of natural gas, $0.20 per barrel of oil, and $0.29 per Mcfe. These hedges covered approximately 24% of the Company's natural gas production and 19% of its oil production for the year. Total gains realized on all derivatives related to production months in 2001, including the portion reported as non-hedge derivatives, totaled $5,438,000. During 2000, the Company hedged approximately 1% of its gas production and 5% of its oil production, and realized gains of $42,000 were included in oil and gas revenues. These gains had the effect of increasing average price realizations by $0.09 per barrel of oil, but had a negligible impact on average price realizations per Mcf of gas or per Mcfe.

The Company's natural gas production totaled 9,277,000 Mcf in 2001 compared to 8,683,000 Mcf in 2000, representing a current year increase of 594,000 Mcf, or 7%. Prima's oil production totaled 431,000 barrels and 440,000 barrels in 2001 and 2000, respectively, representing a decrease of 9,000 barrels, or 2%. On an equivalent unit basis, the Company's production increased approximately 5%, to 11,863,000 Mcfe in the recent year from 11,325,000 Mcfe in 2000. Total production was 78% natural gas and 22% oil in 2001, compared to 77% gas and 23% oil in the prior year. Net production from the Company's CBM operations, which totaled 1,453,000 Mcf in 2001 compared to 7,000 Mcf in 2000, more than offset net decreases from the Company's other producing properties, which were attributable to natural declines and limited new activity.

The Company's depletion expense for oil and gas properties was $9,190,000, or $0.77 per Mcfe, in 2001, compared to $6,150,000, or $0.54 per Mcfe, in 2000. The substantial increase in the depletion rate reflects a number of factors, including: significant declines in oil and gas prices, which, under the methodology prescribed, affects estimates of oil and gas reserves that can be economically recovered through future production; increases in oilfield service costs, which impacted actual costs incurred during the past year and the assumptions required to be used in estimating future development costs; and use of more conservative assumptions for estimating undeveloped CBM reserves, pending additional performance-related data. The depletion rate per Mcfe was increased mid-year 2001 to reflect these factors, and averaged $0.90 during the second half of the year.

Depreciation of other fixed assets, which include service equipment, office furniture and equipment, and buildings, was $1,369,000 and $1,054,000 for 2001 and 2000, respectively. The increase of $315,000, or 30%, was due primarily to acquisitions of oilfield service equipment in 2000 and 2001.

Lease operating expenses ("LOE") totaled $3,295,000 for the year ended December 31, 2001 compared to $2,623,000 for the year ended December 31, 2000, an increase of $672,000 or 26%. The increase was primarily attributable to new production from CBM wells. Ad valorem and production taxes were $3,344,000 and $3,421,000 for the same periods, a decrease of $77,000 or 2%. Production taxes fluctuate with revenues and changing mill levy rates. Total lifting costs (LOE plus ad valorem and production taxes) were 15% of oil and gas revenues and $0.56 per Mcfe for 2001 compared to 14% and $0.53 per Mcfe for 2000.

Oilfield services include the operations of Action Oilfield Services, Inc. (Colorado) and Action Energy Services (Wyoming), wholly-owned subsidiaries. Related revenues include well servicing fees from completion and swab rigs, CBM drilling rigs, trucking, water hauling, equipment rentals, and other related activities. Services are provided to both Prima and unaffiliated third parties, but intercompany billings are eliminated in consolidation. Revenues from third parties totaled $8,090,000 for the year ended December 31, 2001 compared to $6,278,000 for the year ended December 31, 2000, an increase of $1,812,000, or 29%. Costs of oilfield services provided to third parties were $5,482,000 in 2001 compared to $4,585,000 for 2000, an increase of $897,000 or 20%. Higher revenues and costs both reflected increases in the amount of equipment placed in service and the portion of services provided to third parties. Approximately 34% of fees billed by the service companies in 2001 were for Company-owned property interests, compared to 37% in 2000. Improved revenues were also partially attributable to rate increases resulting from increased demand for oilfield services.

General and administrative expenses ("G&A"), net of third party reimbursements and amounts capitalized, were $3,559,000 for the year ended December 31, 2001 compared to $2,916,000 for the year ended December 31, 2000. Net G&A costs increased by $643,000 or 22% due to expansion of the Company's activities and operations, partially offset by increased amounts capitalized. Third party reimbursements of management and operator fees decreased from $426,000 in 2000 to $371,000 in 2001 due to the Company's acquisition of additional ownership interests in certain managed properties. Capitalized G&A increased from $1,200,000 in 2000 to $1,573,000 in 2001, reflecting additional costs incurred to grow exploration and development activities.

The impairment of a natural gas swap in 2001 relates to a derivatives contract with Enron North America Corp, which filed for bankruptcy protection in December 2001. Prima had an unrealized gain of $241,000 due from Enron when the Company terminated the contract under default provisions in the agreement. Although this amount was reflected in gains on derivative instruments in 2001, the full amount was reserved for and reflected as an impairment expense in the same period.

The provision for income taxes was $10,650,000 for the year ended December 31, 2001 compared to $9,535,000 for the year ended December 31, 2000, an increase of $1,115,000 or 12%. The Company's effective tax rate increased to 31.5% in 2001 from 30.3% in 2000. The effective tax rates in both years were less than statutory rates due to permanent differences in financial and taxable income, consisting primarily of statutory depletion deductions and Section 29 tax credits. The higher effective tax rate in 2001 was primarily attributable to a $2,377,000, or 8%, increase in pre-tax income without a proportionate increase in permanent differences.

2000 vs 1999

Prima earned net income in 2000 of $21,895,000, or $1.65 per diluted share, on revenues of $52,179,000, compared to net income of $9,027,000, or $0.69 per diluted share, on revenues of $29,222,000 in 1999. Expenses, other than income taxes, were $20,749,000 for 2000 compared to $17,160,000 for 1999. Revenues increased $22,957,000 or 79%, expenses increased $3,589,000 or 21% and net income increased $12,868,000 or 143% in 2000, compared to 1999.

Oil and gas sales in 2000 were $44,437,000 compared to $20,644,000 in 1999, an increase of $23,793,000 or 115%. This increase was due to both significantly higher product prices and increased production. The Company's net natural gas production was 8.7 Bcf for 2000 compared to 7.2 Bcf in 1999, an increase of 1.5 Bcf or 21%. Net oil production was 440,000 barrels in 2000 compared to 322,000 barrels for 1999, an increase of 118,000 barrels or 37%. On an Mcfe basis, the Company's production for 2000 increased 2.2 Bcfe or 25%. The average price received per Mcf of natural gas sold was $3.63 for 2000 compared to $2.10 per Mcf for the prior year, an increase of $1.53 per Mcf or 73%. The average price received per barrel of oil sold was $29.29 in 2000 compared to $17.42 in 1999, an increase of $11.87 per barrel or 68%. During the year ended December 31, 2000, the Company hedged approximately 1% of its gas production and 5% of its oil production. Hedging gains of $42,000 were included in oil and gas revenues for the year, which increased the average price received per barrel of oil by $0.09 and had no material effect on the price realized for natural gas or per equivalent unit of production. The Company hedged approximately 25% of its oil production and 15% of its natural gas production in 1999. Hedging losses of $180,000 were included in oil and gas revenues for the year, which decreased average prices received by $0.17 per barrel of oil, by $0.02 per Mcf of natural gas, and by $0.02 per Mcfe of production.

The Company's depletion of oil and gas properties was $6,150,000, or $0.54 per Mcfe, on 11,325,000 equivalent Mcf produced in 2000. This compared to $4,650,000, or $0.51 per Mcfe, on 9,093,000 equivalent Mcf produced in 1999. The higher depletion rate for 2000 reflected higher oilfield service costs experienced during the fourth quarter of 2000, as industry activity escalated. Depreciation of other fixed assets, including service equipment, office furniture and equipment and buildings, was $1,054,000 and $817,000 for 2000 and 1999, respectively. Depreciation expense on these assets increased $237,000, or 29%, due primarily to acquisitions of oilfield service equipment.

LOE was $2,623,000 in 2000 compared to $2,012,000 in 1999. Ad valorem and production taxes were $3,421,000 and $1,765,000, respectively, for the same periods. Production taxes increased with oil and gas revenues, on higher production volumes and product prices. Total lifting costs were 14% of oil and gas revenues and $0.53 per Mcfe for 2000, compared to 18% and $0.42 for 1999.

Oilfield services revenues were $6,278,000 and $4,974,000 in 2000 and 1999, respectively. Costs for oilfield services were $4,585,000 in 2000 compared to $3,377,000 in 1999. These amounts reflect an increase in revenues of $1,304,000, or 26%, and an increase in costs of $1,208,000 or 36%. Utilization levels in the Wattenberg Area remained high and activity levels increased steadily during the period in the Powder River Basin of Wyoming, where service operations were initiated in March 1999. During 2000 and 1999, 37% and 26%, respectively, of the gross fees billed by the service companies were for Prima-owned property interests.

Trading revenues and costs relate to the marketing of third-party gas by Prima Natural Gas Marketing, Inc., a wholly owned subsidiary. Trading activities fluctuate with natural gas markets and the Company's ability to develop markets that meet the Company's trading criteria. The Company engaged in no trading activities during 2000. In 1999, the Company marketed 1,311,000 Mmbtus of natural gas, with trading revenues of $2,318,000 and costs of $2,827,000.

G&A, net of third-party reimbursements, totaled $2,916,000 for 2000 compared to $1,712,000 for 1999, an increase of $1,204,000 or 70%. Third-party reimbursements were $426,000 and $619,000 during 2000 and 1999, respectively. The Company's G&A increased due to expansion of the Company's operations, particularly increased activities in the Powder River Basin. The Company capitalized G&A costs of $1,200,000 and $780,000 in 2000 and 1999, respectively, reflecting these increases in exploration and development activities.

The provision for income taxes was $9,535,000 for 2000 compared to $3,035,000 for 1999. The effective tax rate was 30.3% in 2000 compared to 25.2% in 1999. The Company's effective tax rate increased primarily because pre-tax income increased $19,368,000 or 161% for 2000, while permanent differences did not increase proportionately.

New Accounting Pronouncements

In July 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standard ("SFAS") No. 141, "Business Combinations." SFAS No. 141 is intended to improve the transparency of the accounting and reporting for business combinations by requiring that all business combinations be accounted for under a single method, the purchase method. This statement is effective for all business combinations initiated after June 30, 2001. Management does not believe the adoption of this statement will have a material effect on the Company's financial position or results of operations.

In July 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets." This statement applies to intangibles and goodwill acquired after June 30, 2001, as well as goodwill and intangibles previously acquired. Under this statement, goodwill as well as other intangibles determined to have an infinite life will no longer be amortized. These assets will be reviewed for impairment on a periodic basis. This statement is effective for the Company in the first quarter of 2002. Management does not believe the adoption of this statement will have a material effect on the Company's financial position or results of operations.

In August 2001, the FASB issued SFAS No. 143 "Accounting for Asset Retirement Obligations." SFAS No. 143 provides the accounting requirements for retirement obligations associated with long-lived assets and requires the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying costs of the asset. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002, and early adoption is permitted. The Company is currently assessing, but has not yet determined, the impact of SFAS No. 143 on its consolidated results of operations, cash flows or financial position.

In October 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 144 requires that long-lived assets be measured at the lower of carrying amount or fair value less costs to sell, whether reported in continuing operations or in discontinued operations. Therefore, discontinued operations will no longer be measured at net realizable value or include amounts for operating losses that have not yet occurred. SFAS No. 144 is effective for financial statements issued for fiscal years beginning after December 15, 2001 and generally is to be applied prospectively. Management does not believe the adoption of this statement will have a material effect on the Company's financial position or results of operations.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company's primary market risks relate to changes in prices received on sales of natural gas and oil production. The Company periodically enters into derivative contracts to mitigate a portion of this commodity price risk. Such derivatives consist of commodity futures or price swaps (agreements with counterparties to exchange floating prices for fixed prices), and options on such futures or price swaps. These instruments reduce the Company's exposure to decreases in gas and oil prices, or increases in differentials between NYMEX and Rocky Mountain gas prices, but they also generally limit the benefits realized by the Company from increases in prices or narrowing of basis differentials. By hedging only a portion of its exposure to changes in prices, the Company is able to benefit from increases in gas and oil prices or improvements in basis differentials, but it remains exposed to market risk on the portion of its production not covered by such derivatives. The Company also retains risks related to the ineffective portion of its derivatives instruments, when applicable.

The Company has derivative positions that are intended to offset risks associated with downward price movements in benchmark NYMEX gas and oil prices and basis swaps to protect the Company from increases in the differential between NYMEX and Rocky Mountain gas prices. The Company's derivatives contracts generally represent cash flow hedges that are determined to be qualifying or non-qualifying for hedge accounting treatment in accordance with the provisions of SFAS 133. See Derivative Activities in Notes to Consolidated Financial Statements for additional information with respect to derivatives and related accounting policies.

All derivatives transactions are executed by personnel who have appropriate skills, experience and supervision. The personnel involved in these activities must follow prescribed trading limits and parameters that are regularly reviewed by the Company's Chief Executive Officer. All derivatives transactions are approved by the Company's Chief Executive Officer before being entered into and significant transactions are reviewed by the Company's Board of Directors. The Company uses only conventional derivative instruments and attempts to manage its credit risk by entering into derivative contracts only with financial institutions that are believed to be reputable and which carry an investment grade rating.

Following are disclosures regarding the Company's market risk instruments. Investors and other users are cautioned to avoid simplistic use of these disclosures. Users should realize that the actual impact of future commodity price movements will likely differ from the amounts disclosed below due to ongoing changes in risk exposure levels and concurrent adjustments to positions. It is not possible to accurately predict future movements in natural gas and oil prices.

During 2001, the Company sold 431,000 barrels of oil. A hypothetical decrease of $2.57 per barrel (10% of average prices for the period exclusive of hedging transactions) would have decreased the Company's production revenues by $1,108,000 for the period. The Company sold 9,277,000 Mcf of natural gas during the same period. A hypothetical decrease of $ 0.32 per Mcf (10% of average prices for the period exclusive of hedging transactions) would have decreased the Company's production revenues by $2,969,000 for the period.

The Company closed certain derivative instruments between December 31, 2001 and March 15, 2002, for net realized gains totaling $2,450,000. As of March 15, 2002, open oil and gas derivative instruments showed net unrealized losses of $48,000, as follows:

Time Period	Market Index	Total Volumes (MMBtu or Bbls)	Contract Price	Unrealized Gains (Losses)
Natural Gas Futures				
April – June 2002	NYMEX	2,300,000	$ 3.152	$ 69,000
July – September 2002	NYMEX	2,100,000	3.214	59,000
October – December 2002	NYMEX	1,000,000	3.308	(4,000)
January – February 2003	NYMEX	300,000	3.630	(35,000)
Natural Gas Basis Swaps				
November – December 2002	NYMEX/CIG	600,000	0.34	42,000
January – March 2003	NYMEX/CIG	900,000	0.34	63,000
Crude Oil Futures				
May – June 2002	NYMEX	30,000	21.60	(98,000)
July – September 2002	NYMEX	45,000	21.45	(144,000)
Total Unrealized Losses				$ (48,000)

As of December 31, 2001, the Company had $4,378,000 of unrealized gains on derivatives that did not qualify for hedge accounting, which had been reported as revenue in 2001, and $94,000 of unrealized mark-to-market gains on derivatives treated as hedges, which amount was included in other comprehensive income for 2001. This total of $4,472,000 exceeded the aggregate of gains realized on derivatives in 2002 through March 15 and the net unrealized loss on derivatives outstanding at that date by $2,070,000. This amount less the $94,000 of unrealized hedging gains which were not reported as revenue in 2001 would be recorded as a reduction of current period or future revenue if gas and oil prices were to remain at levels reflected on futures markets as of March 15, 2002. Such amounts will change, however, potentially significantly, as gas and oil prices rise or fall before such contracts expire or are terminated.

The table above excludes commodity positions with Enron North America Corp, which filed for bankruptcy protection in December 2001. Prima's unrealized hedge gain due from Enron totaled approximately $241,000 when the Company terminated the contract under default provisions in the agreement. Although this amount was reflected in gains on derivative instruments in 2001, the full amount was reserved for and reflected as an impairment expense in the same period.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The Consolidated Financial Statements that constitute Item 8 are attached at the end of this Annual Report on Form 10-K. An index to these Consolidated Financial Statements is also included in Item 14(a) of this Annual Report on Form 10-K.

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

Since the Company's inception, there has not been any Form 8-K filed under the Securities Exchange Act of 1934 reporting a change in accountants in which there was a reported disagreement on any matter of accounting principles or practices or financial statement disclosure.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

ITEM 11. EXECUTIVE COMPENSATION

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Pursuant to instruction G(3) to Form 10-K, Items 10, 11, 12, and 13 are omitted because the Company will file a definitive proxy statement pursuant to Regulation 14A under the Securities Exchange Act of 1934 not later than 120 days after the close of the fiscal year. The information required by such Items will be included in the definitive proxy statement to be so filed for the Company's annual meeting of stockholders scheduled for May 15, 2002 and is hereby incorporated by reference.

PART IV

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

(a) (1) Financial Statements

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

(a) (2) Financial Statement Schedules

Financial statement schedules have been omitted because they are not applicable or the information required therein is included elsewhere in the financial statements or notes thereto.

(a) (3) Exhibits

The following Exhibits are filed herewith pursuant to Rule 601 of the Regulation S-K or are incorporated by reference to previous filings.

Exhibit No.	Document
3	Certificate of Incorporation of Prima Energy Corporation, Delaware, as filed August 18, 1988. (Incorporated by reference to Registration of Securities of Certain Successor Issuers on Form 8-B dated January 20, 1989.)
3	Certificate of Amendment of Certificate of Incorporation of Prima Energy Corporation filed May 1, 1989. (Incorporated by reference to Annual Report on Form 10-K for Prima Energy Corporation dated June 30, 1989.)
3	Bylaws of Prima Energy Corporation. (Incorporated by reference to Registration of Securities of Certain Successor Issuers on Form 8-B dated January 20, 1989.)
3	Certificate of Amendment of the Certificate of Incorporation of Prima Energy Corporation. (Incorporated by reference to Quarterly Report on Form 10-Q for Prima Energy Corporation dated June 30, 1997.)
3	Certificate of Amendment of the Certificate of Incorporation of Prima Energy Corporation. (Incorporated by reference to Quarterly Report on Form 10-Q for Prima Energy Corporation dated September 30, 2000.)
3	Certificate of Amendment of the Certificate of Incorporation of Prima Energy Corporation. (Incorporated by reference to Quarterly Report on Form 10-Q for Prima Energy Corporation dated June 30, 2001 and filed August 14, 2001.)
4	Rights Agreement dated as of May 23, 2001, between Prima Energy Corporation and Computershare Trust Company, Inc., as Rights Agent, including the form of Certificate of Designation, Powers, Preferences and Rights of Series A Participating Preferred Stock dated May 29, 2001, as Exhibit A, the Form of Right Certificate, as Exhibit B, and the Summary of Rights to Purchase Preferred Shares. (Incorporated by reference to Current Report on Form 8-K for Prima Energy Corporation dated May 23, 2001 and filed June 6, 2001.)
10	Prima Energy Corporation Employee Stock Ownership Plan (Incorporated by reference to Annual Report on Form 10-K for Prima Energy Corporation dated June 30, 1989.)
10	Prima Energy Corporation 1993 Stock Incentive Plan. (Incorporated by reference to Annual Report on Form 10-K for Prima Energy Corporation dated December 31, 1993.)
10	Agreement of Lease between Denver-Stellar Associates LP, Landlord and Prima Energy Corporation, Tenant, effective December 1, 2000. (Incorporated by reference to Annual Report on Form 10-K for Prima Energy Corporation dated December 31, 2000.)
21	Subsidiaries of the Registrant
23	Consent of Deloitte & Touche LLP

(b) *Reports on Form 8-K*

During the quarter ended and subsequent to December 31, 2001, the Company filed the following reports on Form 8-K:

- Report dated November 13, 2001, reporting earnings for the quarter and nine months ended September 30, 2001, and providing an update on operating activities and commodity hedging.
- Report dated March 4, 2002, reporting year-end 2001 reserves, year 2002 estimated capital expenditures, and the sale of assets.
- Report dated March 20, 2002, reporting year-end 2001 financial results and providing an update of operating activities and commodity hedging transactions.

INDEPENDENT AUDITORS' REPORT

Prima Energy Corporation:

We have audited the accompanying consolidated balance sheets of Prima Energy Corporation ("Company") and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, comprehensive income, 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 of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company and its subsidiaries at December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, in 2001 the Company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."

DELOITTE & TOUCHE LLP

March 15, 2002
Denver, Colorado

PRIMA ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2001 and 2000

ASSETS

	2001	2000
CURRENT ASSETS		
Cash and cash equivalents	$ 23,337,000	$ 20,382,000
Available for sale securities, at market	2,418,000	2,311,000
Receivables (net of allowance for doubtful accounts: $295,000 and $44,000)	5,806,000	8,902,000
Derivatives, at fair value	4,472,000	0
Inventory	1,415,000	1,409,000
Other	710,000	1,042,000
Total current assets	38,158,000	34,046,000
OIL AND GAS PROPERTIES, at cost, accounted for using the full cost method:		
Proved	130,710,000	100,270,000
Unproved	13,132,000	9,382,000
Less accumulated depreciation, depletion and amortization	(53,270,000)	(43,935,000)
Oil and gas properties – net	90,572,000	65,717,000
PROPERTY AND EQUIPMENT, at cost		
Oilfield service equipment	9,159,000	7,664,000
Furniture and equipment	694,000	729,000
Field office, shop and land	473,000	473,000
	10,326,000	8,866,000
Less accumulated depreciation	(4,893,000)	(3,986,000)
Property and equipment – net	5,433,000	4,880,000
OTHER ASSETS	1,281,000	257,000
	$135,444,000	$104,900,000

See accompanying notes to consolidated financial statements.

PRIMA ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS (cont'd.)
DECEMBER 31, 2001 and 2000

LIABILITIES AND STOCKHOLDERS' EQUITY

	2001	2000
CURRENT LIABLITIES		
Accounts payable	$ 1,668,000	$ 3,207,000
Amounts payable to oil and gas property owners	1,910,000	2,501,000
Ad valorem and production taxes payable	3,272,000	1,857,000
Accrued and other liabilities	1,408,000	803,000
Deferred tax liability	1,778,000	0
Total current liabilities	10,036,000	8,368,000
AD VALOREM TAXES, non-current	3,302,000	3,213,000
DEFERRED INCOME TAX LIABILITY	20,366,000	13,021,000
Total liabilities	33,704,000	24,602,000
STOCKHOLDERS' EQUITY		
Preferred stock, $0.001 par value, 2,000,000 shares authorized; no shares issued or outstanding	0	0
Common stock, $0.015 par value, 35,000,000 shares authorized; 12,890,346 and 12,793,373 shares issued	193,000	192,000
Additional paid-in capital	3,147,000	1,760,000
Retained earnings	102,240,000	78,472,000
Accumulated other comprehensive income (loss)	26,000	(126,000)
Treasury stock, 155,351 and no shares, at cost	(3,866,000)	0
Stockholders' equity – net	101,740,000	80,298,000
	$135,444,000	$104,900,000

See accompanying notes to consolidated financial statements.

PRIMA ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 2001, 2000 and 1999

	2001	2000	1999
REVENUES			
Oil and gas sales	$44,548,000	$44,437,000	$20,644,000
Gains on derivative instruments, net	6,435,000	0	0
Oilfield services	8,090,000	6,278,000	4,974,000
Trading revenues	0	0	2,318,000
Interest, dividend and other income	1,214,000	1,464,000	1,286,000
	60,287,000	52,179,000	29,222,000
EXPENSES			
Depreciation, depletion and amortization:			
Depletion of oil and gas properties	9,190,000	6,150,000	4,650,000
Depreciation of property and equipment	1,369,000	1,054,000	817,000
Lease operating expense	3,295,000	2,623,000	2,012,000
Ad valorem and production taxes	3,344,000	3,421,000	1,765,000
Oilfield services	5,482,000	4,585,000	3,377,000
General and administrative	3,559,000	2,916,000	1,712,000
Impairment of natural gas swap	241,000	0	0
Cost of trading	0	0	2,827,000
	26,480,000	20,749,000	17,160,000
Income Before Income Taxes and Cumulative Effect of Change in Accounting Principle	33,807,000	31,430,000	12,062,000
Provision for Income Taxes	10,650,000	9,535,000	3,035,000
Net Income Before Cumulative Effect of Change in Accounting Principle	23,157,000	21,895,000	9,027,000
Cumulative Effect of Change in Accounting Principle (net of income taxes of $265,000)	611,000	0	0
NET INCOME	$23,768,000	$21,895,000	$ 9,027,000
Basic Net Income per Share Before Cumulative Effect of Change in Accounting Principle	$ 1.82	$ 1.72	$ 0.70
Cumulative Effect of Change in Accounting Principle	0.05	0.00	0.00
BASIC NET INCOME PER SHARE	$ 1.87	$ 1.72	$ 0.70
Diluted Net Income per Share Before Cumulative Effect of Change in Accounting Principle	$ 1.75	$ 1.65	$ 0.69
Cumulative Effect of Change in Accounting Principle	0.05	0.00	0.00
DILUTED NET INCOME PER SHARE	$ 1.80	$ 1.65	$ 0.69

See accompanying notes to consolidated financial statements.

PRIMA ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
FOR THE YEARS ENDED DECEMBER 31, 2001, 2000 and 1999

	2001	2000	1999
Net income	$23,768,000	$21,895,000	$ 9,027,000
Other comprehensive income:			
Change in fair value of hedges	3,475,000	0	0
Reclassification adjustment for realized gains on hedges included in net income	(3,381,000)	0	0
Deferred income tax expense related to change in fair value of hedges	(35,000)	0	0
Change in fair value of available-for-sale securities	147,000	170,000	(551,000)
Reclassification adjustment for realized losses included in net income	1,000	18,000	81,000
Deferred income tax (expense) benefit related to change in fair value of available-for-sale securities	(55,000)	(70,000)	175,000
	152,000	118,000	(295,000)
COMPREHENSIVE INCOME	$23,920,000	$22,013,000	$ 8,732,000

See accompanying notes to consolidated financial statements.

PRIMA ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY FOR THE YEARS ENDED DECEMBER 31, 2001, 2000 and 1999

	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total
BALANCES, January 1, 1999	$ 196,000	$ 4,308,000	$ 47,550,000	$ 51,000	$ (797,000)	$ 51,308,000
Net income			9,027,000			9,027,000
Exercise of stock options	2,000	843,000				845,000
Tax benefit from exercise of non-qualified stock options		477,000				477,000
Other comprehensive income				(295,000)		(295,000)
Treasury stock purchased					(2,454,000)	(2,454,000)
BALANCES, December 31, 1999	198,000	5,628,000	56,577,000	(244,000)	(3,251,000)	58,908,000
Net income			21,895,000			21,895,000
Exercise of stock options	1,000	591,000				592,000
Tax benefit from exercise of non-qualified stock options		720,000				720,000
Other comprehensive income				118,000		118,000
Treasury stock purchased					(1,935,000)	(1,935,000)
Treasury stock canceled	(7,000)	(5,179,000)			5,186,000	0
BALANCES, December 31, 2000	192,000	1,760,000	78,472,000	(126,000)	0	80,298,000
Net income			23,768,000			23,768,000
Exercise of stock options	1,000	525,000				526,000
Tax benefit from exercise of non-qualified stock options		732,000				732,000
Other comprehensive income				152,000		152,000
Treasury stock purchased					(3,866,000)	(3,866,000)
Other		130,000				130,000
BALANCES, December 31, 2001	$ 193,000	$ 3,147,000	$102,240,000	$ 26,000	$ (3,866,000)	$101,740,000

See accompanying notes to consolidated financial statements.

PRIMA ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2001, 2000 and 1999

	2001	2000	1999
OPERATING ACTIVITIES			
Net income	$23,768,000	$21,895,000	$ 9,027,000
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	10,559,000	7,204,000	5,467,000
Deferred income taxes	9,123,000	7,319,000	2,281,000
Unrealized derivative activities	(4,378,000)		
Current taxes from sale of oil and gas properties	0	0	(5,704,000)
Other	626,000	745,000	551,000
Changes in operating assets and liabilities:			
Receivables	3,096,000	(3,618,000)	(588,000)
Inventory	(6,000)	(572,000)	(225,000)
Other current assets	241,000	(129,000)	(374,000)
Accounts payable and payables to owners	(2,130,000)	2,124,000	489,000
Production taxes payable	1,504,000	2,344,000	86,000
Accrued and other liabilities	605,000	(936,000)	996,000
Net cash provided by operating activities	43,008,000	36,376,000	12,006,000
INVESTING ACTIVITIES			
Additions to oil and gas properties	(35,248,000)	(31,952,000)	(18,617,000)
Purchases of other properties	(1,958,000)	(1,613,000)	(2,673,000)
Purchases of securities	(125,000)	(249,000)	(497,000)
Proceeds from sales of property	435,000	280,000	27,871,000
Net cash provided by (used in) investing activities	(36,896,000)	(33,534,000)	6,084,000
FINANCING ACTIVITIES			
Treasury stock purchased	(3,866,000)	(1,935,000)	(2,454,000)
Proceeds from exercise of stock options	526,000	592,000	845,000
Other	183,000	0	(120,000)
Net cash used in financing activities	(3,157,000)	(1,343,000)	(1,729,000)
Increase in cash and cash equivalents	2,955,000	1,499,000	16,361,000
Cash and cash equivalents, beginning of year	20,382,000	18,883,000	2,522,000
CASH AND CASH EQUIVALENTS, end of year	$23,337,000	$20,382,000	$18,883,000

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2001, 2000 and 1999

1. ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

Business

Prima Energy Corporation ("Prima") is an independent oil and gas company primarily engaged in the exploration for, and the acquisition, development and production of, crude oil and natural gas. Through its wholly owned subsidiaries, Prima is also engaged in oil and gas property operations, oilfield services and natural gas gathering, marketing and trading. Prima's current activities are conducted principally in the Rocky Mountain region of the United States.

Basis of Presentation

The accompanying consolidated financial statements include the accounts of Prima and its wholly owned subsidiaries, herein collectively referred to as the "Company." The Company's proportionate share of capital expenditures, production revenue and operating expenses from working interests in oil and gas properties is included in the consolidated financial statements. All significant intercompany transactions have been eliminated. Certain amounts in prior years have been reclassified to conform with the classifications at December 31, 2001.

Use of Estimates

The preparation of the financial statements of the Company 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 results could differ from these estimates.

Comprehensive Income

Comprehensive income consists of net income and unrealized gains and losses on marketable equity securities held for sale and the effective component of derivative instruments classified as cash flow hedges, net of tax. Comprehensive income is presented in the consolidated statements of stockholders' equity and comprehensive income.

Consolidated Statements of Cash Flows

Cash in excess of daily requirements is invested in money market accounts and commercial paper with maturities of three months or less. Such investments are deemed to be cash equivalents for purposes of the consolidated financial statements.

Supplemental disclosures of cash flow information:

Cash paid for income taxes was $905,000, $2,722,000 and $4,725,000 for the years ended December 31, 2001, 2000 and 1999, respectively. Cash paid for interest in 2000 and 1999 was $15,000 and $37,000, respectively. No amounts were paid for interest in 2001.

Supplemental schedule of noncash investing and financing activities:

The Company purchased oilfield service assets for $460,000 in March 1999. A summary of the transaction is as follows:

Fair value of assets acquired	$ 460,000
Cash paid	276,000
Note payable issued to seller	$ 184,000

Estimated Fair Value of Financial Instruments and Available for Sale Securities

Cash in excess of daily requirements is invested in money market accounts and commercial paper with maturities of three months or less. The carrying amount of cash equivalents approximates fair value because of the short maturity and high credit quality of those investments.

The Company classifies marketable securities as "available for sale," states them at market value and reports unrealized gains and losses, net of deferred income taxes, as an adjustment to stockholders' equity. Available for sale securities are readily marketable and available for use in the Company's operations should the need arise. Therefore, the Company has classified its portfolio as a current asset. Realized gains and losses are determined on the specific identification method.

Commencing with its adoption of Statement of Financial Accounting Standards No. 133 on January 1, 2001 (see Note 4), the Company has recognized all derivatives on its balance sheet at their estimated fair values. The fair values of these contracts are determined based on various factors, including contract volumes and prices, contract settlement dates, quoted closing prices on the NYMEX or over-the-counter and, where applicable, volatility and the time value of options. The calculation of the fair value of collars and floors requires the use of the Black-Scholes option-pricing model, but the Company had no such positions during 2001. Substantially all of the Company's derivatives transactions are settled based upon reported settlement prices on the NYMEX or as quoted in relatively liquid over-the-counter markets by a number of market makers.

Inventory

Inventory consists of various tubular goods and surface production facility equipment intended to be used in the Company's oil and gas operations and is stated at the lower of cost or market value using the first-in, first-out valuation method.

Oil and Gas Properties

The Company utilizes the full cost method of accounting for oil and gas activities. Under this method, all costs associated with property acquisition, exploration and development, including costs of unsuccessful exploration, are capitalized within a cost center. The Company's oil and gas properties are all located within the United States, which constitutes one cost center. No gain or loss is recognized upon the sale or abandonment of undeveloped or producing oil and gas properties unless the sale represents a significant portion of oil and gas properties and the gain significantly alters the relationship between capitalized costs and proved oil and gas reserves of the cost center. Depreciation, depletion and amortization of oil and gas properties is computed on the units of production method based on proved reserves. Amortizable costs include estimates of future development costs of proved undeveloped reserves. The Company invests in unevaluated oil and gas properties for the purpose of future exploration for proved reserves. The costs of such assets are included in unproved oil and gas properties at the lower of cost or estimated fair market value and are not subject to amortization.

Capitalized costs of oil and gas properties may not exceed an amount equal to the present value, discounted at 10%, of the estimated future net cash flows from proved oil and gas reserves plus the cost, or estimated fair market value if lower, of unproved properties. Should capitalized costs exceed this ceiling, an impairment is recognized. The present value of estimated future net cash flows is computed by applying prices of oil and natural gas as of the balance sheet date of the calculation to estimated future production of proved oil and gas reserves as of such date, less estimated future expenditures to be incurred in developing and producing the proved reserves and assuming continuation of existing economic conditions. The Company did not recognize any impairment losses during the three-year period ended December 31, 2001.

The Company does not accrue costs for future site restoration, dismantlement and abandonment costs related to proved oil and gas properties because the Company estimates that such costs will be offset by the salvage value of equipment sold upon abandonment of such properties. The Company's estimates are based upon its historical experience and upon review of its current properties and restoration obligations.

Property and Equipment

Property and equipment is recorded at cost. Renewals and betterments that substantially extend the useful lives of the assets are capitalized. Maintenance and repairs are expensed when incurred. Depreciation is provided using the straight-line method over the estimated useful lives of the assets, ranging from three to 15 years. Long-lived assets, other than oil and gas properties, are evaluated for impairment to determine if current circumstances and market conditions indicate the carrying amount may not be recoverable. The Company did not recognize any impairment losses during the three-year period ended December 31, 2001.

Natural Gas Revenues

The Company utilizes the accrual method of accounting for natural gas revenues whereby revenues are recognized as the Company's entitlement share of gas is produced based on its net revenue interests in the properties. The Company records a receivable (payable) to the extent it receives less (more) than its proportionate share of gas revenues. At December 31, 2001, the imbalance position was not significant.

Oilfield Services and Operator Fees

Fees earned from providing oilfield services and operating wells for third parties are recorded when the services are performed. Oilfield services fees are recognized as income. Operating fees are recorded as a reduction of general and administrative expenses.

Income Taxes

Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. The deferred income tax assets and liabilities represent the future tax return consequences of those differences, which will either be taxable or deductible when the assets and liabilities are recovered or settled. Deferred income taxes are also recognized for tax credits that are available to offset future federal income taxes. Deferred income taxes are measured by applying currently enacted tax rates.

Derivative Instruments and Hedging Activities

The Company periodically enters into derivative contracts to mitigate risks associated with downward price movements in benchmark NYMEX gas and oil prices or, in the case of basis swaps, to protect the Company from increases in the differential between NYMEX and Rocky Mountain gas prices. The Company's derivatives contracts generally represent cash flow hedges that are determined to be qualifying or non-qualifying for hedge accounting treatment in accordance with the provisions of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133").

SFAS 133 prescribes that the fair value of all derivatives should be recognized as either assets or liabilities in the statement of financial position. SFAS 133 also establishes requirements for designation and documentation of hedging relationships and ongoing effectiveness assessments. Hedge effectiveness is measured based on the relative changes over time in the fair values of a derivative and the related hedged item. If a cash flow hedge qualifies for hedge accounting under SFAS 133, and is so designated by the Company, changes in the fair value of the derivative are recorded initially in other comprehensive income and then recognized in the income statement when the hedged item affects earnings. If a cash flow hedge does not qualify for hedge accounting under SFAS 133, or if the Company so elects, changes in the fair value of the derivative are immediately recognized in earnings. The Company generally elects to use hedge accounting when conditions to do so are satisfied.

The Company has determined that pursuant to SFAS 133 requirements, and based on its current sources of oil and gas production, swaps, collars, puts or floors that are based on NYMEX oil prices or CIG gas prices qualify as cash flow hedges. Derivatives based on NYMEX gas prices will not so qualify unless the Company has entered into corresponding transactions to hedge basis differentials between NYMEX and CIG indices. In addition, stand-alone basis differential swaps and sales of call options do not qualify for hedge accounting.

The adoption of SFAS 133 as of January 1, 2001 resulted in the recognition of a current asset of $1,241,000, a current liability of $549,000, and net-of-tax cumulative effect adjustments reducing other comprehensive income by $129,000 and increasing net income by $611,000. The $611,000 is reflected as the cumulative effect of a change in accounting principle in the December 31, 2001 financial statements.

Earnings Per Share

Basic net income per share is computed by dividing net income by the weighted average common shares outstanding during the period. Diluted net income per share includes the potential dilution that could occur upon exercise of the options to acquire common stock described in Note 10, computed using the treasury stock method. The treasury stock method assumes that the increase in the number of shares issued is reduced by the number of shares which could have been repurchased by the Company with the proceeds from the exercise of the options (which were assumed to have been at the average market price of the common shares during the reporting period).

New Accounting Pronouncements

In July 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standard ("SFAS") No. 141, "Business Combinations." SFAS No. 141 is intended to improve the transparency of the accounting and reporting for business combinations by requiring that all business combinations be accounted for under a single method, the purchase method. This statement is effective for all business combinations initiated after June 30, 2001. Management does not believe the adoption of this statement will have a material effect on the Company's financial position or results of operations.

In July 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets." This statement applies to intangibles and goodwill acquired after June 30, 2001, as well as goodwill and intangibles previously acquired. Under this statement, goodwill as well as other intangibles determined to have an infinite life will no longer be amortized. These assets will be reviewed for impairment on a periodic basis. This statement is effective for the Company in the first quarter of 2002. Management does not believe the adoption of this statement will have a material effect on the Company's financial position or results of operations.

In August 2001, the FASB issued SFAS No. 143 "Accounting for Asset Retirement Obligations." SFAS No. 143 provides the accounting requirements for retirement obligations associated with long-lived assets and requires the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying costs of the asset. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002, and early adoption is permitted. The Company is currently assessing, but has not yet determined, the impact of SFAS No. 143 on its consolidated results of operations, cash flows or financial position.

In October 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 144 requires that long-lived assets be measured at the lower of carrying amount or fair value less costs to sell, whether reported in continuing operations or in discontinued operations. Therefore, discontinued operations will no longer be measured at net realizable value or include amounts for operating losses that have not yet occurred. SFAS No. 144 is effective for financial statements issued for fiscal years beginning after December 15, 2001 and generally is to be applied prospectively. Management does not believe the adoption of this statement will have a material effect on the Company's financial position or results of operations.

2. AVAILABLE FOR SALE SECURITIES

The Company's available for sale securities are comprised of marketable equity securities, including closed-end bond funds. For the years ended December 31, 2001 and 2000, the Company sold securities with a market value of $166,000 and $57,000 which resulted in realized losses of $1,000 and $18,000, respectively. The net unrealized gain or loss on securities at December 31, 2001 and 2000 is included in accumulated other comprehensive income, net of deferred income taxes of $(20,000) and $(75,000), respectively. The change in net unrealized gain or loss on securities for the years ended December 31, 2001 and 2000 was as follows:

	2001	2000
Net unrealized gain (loss), beginning of year	$ (201,000)	$ (389,000)
Net unrealized gain (loss), end of year	(53,000)	(201,000)
Net change in unrealized gain or loss	$ 148,000	$ 188,000

The components of fair value as of December 31, 2001 and 2000 were as follows:

	2001	2000
Cost (including reinvested distributions)	$ 2,471,000	$ 2,512,000
Gross unrealized gains	88,000	43,000
Gross unrealized losses	(141,000)	(244,000)
Fair value	$ 2,418,000	$ 2,311,000

3. EARNINGS PER SHARE AND COMMON STOCK

The following table reconciles the numerator and denominator used in the calculation of basic and diluted net income per share.

	Income (Numerator)	Shares (Denominator)	Per Share Amount
Year Ended December 31, 2001:			
Basic Net Income per Share	$ 23,768,000	12,731,181	$ 1.87
Effect of Stock Options	0	487,970	
Diluted Net Income per Share	$ 23,768,000	13,219,151	$ 1.80
Year Ended December 31, 2000:			
Basic Net Income per Share	$ 21,895,000	12,748,917	$ 1.72
Effect of Stock Options	0	544,006	
Diluted Net Income per Share	$ 21,895,000	13,292,923	$ 1.65
Year Ended December 31, 1999:			
Basic Net Income per Share	$ 9,027,000	12,854,196	$ 0.70
Effect of Stock Options	0	282,647	
Diluted Net Income per Share	$ 9,027,000	13,136,843	$ 0.69

The Board of Directors of Prima approved two separate three for two stock splits of the Company's common stock during 2000. All share and per share amounts included in these financial statements have been restated to show the retroactive effects of the stock splits.

During 2000, the Company purchased 108,150 shares of its common stock for its treasury for $1,935,000. The Board of Directors authorized the retirement of 431,199 shares of common stock held in the treasury as of December 31, 2000. These shares were returned to an authorized but unissued status. In January 2001, the Board approved a repurchase program of up to 5% of the Company's common stock then outstanding, or approximately 640,000 shares. In 2001, the Company purchased 155,351 treasury shares for $3,866,000. This represents approximately 1.2% of the shares then outstanding, or 24% of the shares authorized under the repurchase program.

During 2000, the shareholders of Prima approved an increase in the number of authorized shares of common stock from 12,000,000 to 18,000,000 shares. During 2001, the shareholders approved an additional increase to 35,000,000 authorized shares.

4. DERIVATIVE ACTIVITIES

Crude oil and natural gas futures, options and swaps, and basis swaps, are used from time to time in order to hedge the price of a portion of the Company's production and to lock in the basis from NYMEX to the Rocky Mountains. These cash flow hedging derivatives are entered into to mitigate the risk of fluctuating oil and natural gas prices and fluctuating basis differentials, which can adversely affect operating results. The Company uses only conventional derivative instruments and attempts to manage its credit risk by entering into derivative contracts only with financial institutions that are believed to be reputable and which carry an investment grade rating. While such hedges can reduce the adverse effects of oil and gas price declines, they may also limit the benefits of price increases.

The Company has entered into various cash flow hedges related to its oil and gas production. Some of these derivatives qualify for hedge accounting, while others are non-qualifying. The following table summarizes the income statement effects of these transactions in 2001, 2000 and 1999:

	2001	2000	1999
Realized gains (losses) on derivatives qualifying for hedge accounting, included in oil and gas sales	$ 3,381,000	$ 42,000	$ (180,000)
Realized gains on non-qualifying hedges	2,057,000	-	-
Unrealized gains on non-qualifying hedges	4,378,000	-	-
Aggregate amounts reported on consolidated statements of income	$ 9,816,000	$ 42,000	$ (180,000)

In addition, the Company had $94,000 of unrealized mark-to-market gains as of December 31, 2001 on derivatives qualifying for hedge accounting, which amount has been included in other comprehensive income for 2001. The realized gains on derivatives that qualified for hedge accounting, which were included in oil and gas sales, related to approximately 24%, 1% and 15% of the Company's natural gas production in 2001, 2000 and 1999, respectively, and 19%, 5% and 25%, respectively, of its oil production for the same three years.

As of December 31, 2001, the Company had recorded a current asset of $4,472,000, representing the aggregate unrealized mark-to-market gains for its open derivative positions, which are summarized below:

Time Period	Market Index	Total Volumes (MMBtu)	Contract Price	Unrealized Gains
Natural Gas Futures				
January 1 – March 31, 2002	NYMEX	1,900,000	3.6201	$ 1,935,000
April 1 – June 30, 2002	NYMEX	2,300,000	3.1525	1,089,000
July 1 – September 30, 2002	NYMEX	2,100,000	3.2136	892,000
October 1 – December 31, 2002	NYMEX	1,000,000	3.3076	393,000
January 1 – February 28, 2003	NYMEX	300,000	3.6300	103,000
Natural Gas Basis Swaps				
November – December, 2002	NYMEX/CIG	600,000	0.3400	24,000
January 1, 2003 – March 31, 2003	NYMEX/CIG	900,000	0.3400	36,000
Total Unrealized Gains				$ 4,472,000

Oil and gas prices are volatile and the market value of these derivatives will change as the underlying commodity futures prices change. Mark-to-market adjustments could result in significant earnings volatility. The actual gains or losses realized will depend on the applicable futures prices in effect at the time such positions expire or are closed. The table above excludes commodity positions with Enron North America Corp, which filed for bankruptcy protection in December 2001. Prima's unrealized gain on derivatives due from Enron totaled approximately $241,000 when the Company terminated the contract under default provisions in the agreement. Although this amount was reflected in gains on derivative instruments in 2001, the full amount was reserved for and reflected as an impairment expense in the same period.

5. INCOME TAXES

The provision for income taxes consists of the following components:

	2001	2000	1999
Current:			
Federal	$ 2,067,000	$ 2,114,000	$ 5,340,000
State	(275,000)	102,000	1,118,000
	1,792,000	2,216,000	6,458,000
Deferred:			
Federal	8,732,000	6,656,000	(4,828,000)
State	782,000	382,000	(652,000)
	9,514,000	7,038,000	(5,480,000)
Tax credits	(391,000)	281,000	2,057,000
Provision for income taxes	$ 10,915,000	$ 9,535,000	$ 3,035,000

The provision for income taxes includes $265,000 of current expense that was netted in the cumulative effect of change in accounting method. During 2001, 2000 and 1999, the Company recognized income tax deductions of $1,979,000, $1,946,000 and $1,247,000, respectively, from the exercise of nonqualified stock options. Stockholders' equity has been credited in the amount of $732,000, $720,000 and $477,000 for the income tax benefit of these deductions. During 2001, the Company recognized taxable income of $207,000 from short-swing profits. Stockholders' equity has been reduced in the amount of $77,000 for the current income tax expense associated with this income.

The significant components of deferred tax assets and liabilities included in the balance sheet are as follows:

	2001	2000
Deferred Tax Assets :		
Minimum tax credit carryforwards	$ 1,727,000	$ 1,336,000
State income taxes	663,000	395,000
Other	68,000	109,000
Total Deferred Tax Assets	2,458,000	1,840,000
Deferred Tax Liabilities :		
Intangible drilling costs	21,259,000	13,916,000
Derivatives	1,655,000	0
Depreciation	641,000	492,000
Land held for investment	370,000	0
Other	677,000	362,000
Total Deferred Tax Liabilities	24,602,000	14,770,000
Net Deferred Tax Liabilities (including current component of $1,778,000 in 2001)	$22,144,000	$12,930,000

A reconciliation of income tax computed at the federal statutory tax rate to the Company's effective tax rate is as follows:

	2001	2000	1999
Federal statutory income tax rate	34.0%	34.0%	34.0%
Percentage depletion	(1.2)	(1.5)	(2.2)
Section 29 credits	(3.0)	(3.1)	(10.5)
State taxes, net of federal benefits	1.0	1.0	2.6
Other	0.7	(0.1)	1.3
Effective tax rate	31.5%	30.3%	25.2%

At December 31, 2001, the Company had minimum tax credit carryforwards of approximately $1,727,000, which may by carried forward indefinitely.

6. SEGMENT INFORMATION

The Company organizes its activities in operating segments that consist of 1) the acquisition, exploration, development and operation of oil and gas properties and the development, production and sale of oil and natural gas, 2) providing oil field services for wells which it operates and for third parties and 3) the marketing and trading of third party natural gas (which activity has not been actively conducted since 1999). The Company's activities are located primarily in the Rocky Mountain region of the United States, which is one geographic area.

The information below presents the operating segment data for the Company on the basis used by management in deciding how to allocate resources and in assessing performance. The following table sets forth revenues, operating earnings before income taxes, identifiable assets, depreciation, depletion and amortization expense and capital expenditures for the years ended December 31, 2001, 2000 and 1999. This information is presented on the basis used by management, which is the same basis used in the preparation of the Company's consolidated financial statements.

	2001	2000	1999
Revenues			
Oil & gas (including gains on derivative instruments)	$ 50,983,000	$ 44,437,000	$ 20,644,000
Oilfield services	12,207,000	9,912,000	6,764,000
Marketing and trading	0	0	2,318,000
	63,190,000	54,349,000	29,726,000
Corporate revenues	1,214,000	1,464,000	1,286,000
Intersegment sales	(4,117,000)	(3,634,000)	(1,790,000)
Per financial statements	$ 60,287,000	$ 52,179,000	$ 29,222,000
Operating Earnings			
Oil & gas (including gains on derivative instruments)	$ 34,913,000	$ 32,243,000	$ 12,217,000
Oilfield services	2,083,000	844,000	984,000
Marketing and trading	0	0	(511,000)
	36,996,000	33,087,000	12,690,000
Corporate earnings	(3,189,000)	(1,657,000)	(628,000)
Per financial statements	$33,807,000	$ 31,430,000	$ 12,062,000
Identifiable Assets			
Oil & gas	$ 100,200,000	$ 72,747,000	$ 44,321,000
Oilfield services	7,218,000	6,044,000	6,184,000
	107,418,000	78,791,000	50,505,000
Corporate assets	28,026,000	26,109,000	22,160,000
Per financial statements	$ 135,444,000	$ 104,900,000	$ 72,665,000
Depreciation, Depletion and Amortization Expense			
Oil & gas	$ 9,190,000	$ 6,150,000	$ 4,650,000
Oilfield services	1,284,000	982,000	750,000
	10,474,000	7,132,000	5,400,000
Corporate	85,000	72,000	67,000
Per financial statements	$ 10,559,000	$ 7,204,000	$ 5,467,000
Capital Expenditures			
Oil & gas	$ 35,248,000	$ 31,952,000	$ 18,617,000
Oilfield services	1,866,000	1,524,000	2,819,000
	37,114,000	33,476,000	21,436,000
Corporate	92,000	89,000	38,000
Per financial statements	$ 37,206,000	$ 33,565,000	$ 21,474,000

Total revenue by operating segment includes both sales to unaffiliated customers, as reported in the Company's consolidated income statement, and intersegment sales, which are oilfield services provided to Company-owned wells, which are eliminated in consolidation. Oilfield services revenue is priced and accounted for consistently for both unaffiliated and intersegment sales.

Identifiable assets by operating segment are those assets that are used in the Company's operations in each segment. Corporate assets are principally cash, cash equivalents and available for sale securities.

Following is a table summarizing the percentage of sales made to each customer that accounted for over 10% of the Company's consolidated revenues. Although the loss of any of these customers could have a material adverse effect on the Company, the Company believes it would be able to locate other customers for the purchase of its production and may be able to secure additional marketing opportunities.

	2001	2000	1999
Oil and Gas:			
Duke Energy Field Services, Inc.	31%	36%	28%
Valero Energy (formerly Ultramar Diamond Shamrock)	16	21	15

7. COMMITMENTS AND CONTINGENCIES

The Company entered into a seven-year office space lease, effective December 1, 2000. Office lease expense totaled $282,000, $187,000 and $155,000 for the years ended December 31, 2001, 2000 and 1999, respectively. Future minimum annual rentals under the non-cancelable operating lease for the remainder of the seven-year term are as follows:

Year ending December 31, 2002	$ 285,000
Year ending December 31, 2003	288,000
Year ending December 31, 2004	317,000
Year ending December 31, 2005	317,000
Year ending December 31, 2006	317,000
Year ending December 31, 2007	290,000
	$ 1,814,000

From time to time the Company may be involved in litigation that arises in the normal course of business operations. As of the date of this report, the Company is not a party to any litigation that it believes could reasonably be expected to have a material adverse effect on the business or results of operations.

8. BENEFIT PLANS

Employee Stock Option Plan

Under the Prima Energy Corporation 1993 Stock Incentive Plan and the Prima Energy Corporation 2001 Stock Incentive Plan, 2,650,000 shares of Prima's common stock are reserved for issuance to key employees at fair market value on the date of grant. Options granted to date under the plan vest ratably over three to five years, and expire ten years from the date of grant. At December 31, 2001, options to acquire 1,037,950 shares of the Company's common stock were outstanding. The exercise prices, which equaled the market price of the stock on the date of grant, range from $3.93 to $33.25 per share, with a weighted average price of $11.14 per share. No options were granted in 2000. As of December 31, 2001, the weighted average remaining contractual life of the options outstanding is 5 years, 4 months. A summary of options granted, exercised and outstanding during the three years ended December 31, 2001 is as follows:

	Number of Shares	Weighted Average Exercise Prices
Balance at December 31, 1998	1,182,375	$ 5.15
Granted during 1999	30,375	9.39
Exercised	(208,125)	4.06
Outstanding at December 31, 1999	1,004,625	5.50
Exercised in 2000	(92,650)	5.62
Outstanding at December 31, 2000	911,975	5.57
Granted during 2001	216,000	32.55
Exercised	(86,425)	5.26
Forfeited	(3,600)	14.08
Outstanding at December 31, 2001	1,037,950	11.14
Exercisable at December 31, 1999	622,350	4.48
Exercisable at December 31, 2000	654,125	4.70
Exercisable at December 31, 2001	652,225	5.03

Non-Employee Directors' Stock Option Plan

Under the Prima Energy Corporation Non-Employee Directors' Stock Option Plan 225,000 shares of Prima's common stock are reserved for issuance to non-employee directors at fair market value on the date of grant of a stock option. Upon the effective date of the plan, or upon election as a non-employee director, 22,500 options are granted each non-employee director. On each anniversary date of the initial grant, an additional 5,625 options are granted to each non-employee director for as long as they continue to serve on the Board. Options vest ratably over five years, and expire ten years from the date of grant. At December 31, 2001, options to acquire 135,000 shares of the Company's common stock were outstanding under the plan, at exercise prices ranging from $6.67 to $32.33 per share. As of December 31, 2001, the weighted average remaining contractual life of the options outstanding is eight years. A summary of options granted, exercised and outstanding during the three years ended December 31, 2001 is as follows:

	Number of Shares	Weighted Average Exercise Prices
Balance at December 31, 1998	90,000	$ 6.67
Granted during 1999	22,500	9.83
Outstanding at December 31, 1999	112,500	7.30
Granted during 2000	61,875	24.96
Exercised during 2000	(4,500)	6.67
Forfeited during 2000	(23,625)	7.42
Outstanding at December 31, 2000	146,250	14.77
Granted during 2001	22,500	25.45
Exercised during 2001	(10,125)	7.02
Forfeited during 2001	(23,625)	7.46
Outstanding at December 31, 2001	135,000	18.15
Exercisable at December 31, 1999	18,000	6.67
Exercisable at December 31, 2000	30,375	7.02
Exercisable at December 31, 2001	42,750	12.26

Summary of Outstanding Options

The following table summarizes information about stock options outstanding at December 31, 2001 on a combined basis for the employee and non-employee directors' plans:

	Stock Options Outstanding			Stock Options Exercisable	
Range of Share Prices	Number Outstanding at 12/31/01	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at 12/31/01	Weighted-Average Exercise Price
$ 3.93 – 4.41	476,750	2.4	$ 4.14	476,750	$ 4.14
6.67 – 9.83	401,450	6.7	7.26	206,375	7.06
21.75 – 24.75	61,875	8.8	23.08	9,000	22.75
29.90 – 33.25	232,875	9.2	32.46	2,850	32.08
	1,172,950	5.5	11.83	694,975	5.36

Recognition of Compensation Expense

Prima has adopted the disclosure-only provisions of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" ("SFAS 123"). Accordingly, no compensation costs have been recognized for the Employee Stock Option Plan or the Non-Employee Directors' Stock Option Plan. For disclosure purposes, the fair value of options is measured at the date of grant using the Black-Scholes option valuation model, which was developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. Such option valuation models also require the input of highly subjective assumptions, including the projected life of the options and expected stock price volatility. Because the Company's employee and directors' stock options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the estimated fair value, these valuation models do not necessarily provide a reliable measure of the fair value of such stock options.

The following assumptions were utilized to estimate the fair values on the dates of grant of options issued during the three years ended December 31, 2001, using the Black-Scholes Valuation Model:

	2001	2000	1999
Expected dividend yield	0%	0%	0%
Expected price volatility	43%	76%	37%
Risk free interest rate	5.1%	6.1%	6.8%
Expected life of options (in years)	6	9	9

Based on the above, the estimated weighted average fair values of employee stock options granted during 2001 and 1999 were $16.04 and $5.54, respectively. No employee stock options were granted in 2000. The weighted average fair values of non-employee directors' options granted during 2001, 2000 and 1999 were $12.49, $20.47 and $5.54, respectively.

For purposes of pro forma disclosures, the estimated fair values of option grants are amortized to expense over the options' vesting periods. Had compensation expense been determined based on the estimated fair values at the grant dates for options awarded through December 31, 2001, consistent with the provisions of SFAS 123, the Company's net income and net income per share would have been adjusted to the pro forma amounts indicated below.

	2001	2000	1999
Net Income			
As reported	$23,768,000	$21,895,000	$9,027,000
Pro forma	23,359,000	21,585,000	8,750,000
Basic net income per share			
As reported	$1.87	$1.72	$0.70
Pro forma	$1.83	$1.69	$0.68
Diluted net income per share			
As reported	$1.80	$1.65	$0.69
Pro forma	$1.77	$1.62	$0.67

Employee Stock Ownership Plan

The Company has an Employee Stock Ownership Plan ("ESOP"), which is administered pursuant to a Trust Agreement. The ESOP is qualified under Section 401(a) of the Internal Revenue Code of 1986, as amended, and is for the benefit of all eligible employees of the Company. Allocations to participants are made annually as of the last day of the plan's year, September 30, and are allocated among the participants in proportion to their eligible compensation for the year. Contributions are payable at a minimum rate of 5% of eligible salaries. Through September 30, 1993, the ESOP provided for contributions to be made quarterly and to be used to purchase Prima common stock on the open market. Effective October 1, 1993, the ESOP was amended to allow fully vested employees the option to direct the Trustees to diversify a portion of their investments by selling a limited percent of Prima common stock and investing the proceeds, as well as their contributions, in various diversified investment options. The ESOP benefits all full-time employees and provides for vesting in increments over six years. For the years ended December 31, 2001, 2000 and 1999, the Company expensed $316,000, $283,000 and $224,000, respectively, of Company contributions to the Plan.

9. TRANSACTIONS WITH RELATED PARTIES

The Company is a 6% limited partner in a real estate limited partnership that owns approximately 22 acres of undeveloped land in Phoenix, Arizona for investment and capital appreciation. The partnership owns the 22 acres free and clear. One of the general partners of the partnership is a company controlled by a brother of the Company's president. The Company participated on the same basis as the other limited partners. This transaction was approved by the disinterested members of the Company's Board of Directors. The carrying value of this investment at December 31, 2001 and 2000 was $257,000. During the three years ended December 31, 2001, the Company did not make any capital contributions to the partnership, nor did it receive any distributions therefrom.

Certain of the Company's directors and officers have participated, either individually or through entities which they control, in oil and gas properties in which the Company has an interest. These participations, which have been on a working interest basis, have been in prospects or properties originated or acquired by the Company. In some cases, the interests sold to affiliated and non-affiliated participants were sold on a promoted basis requiring these participants to pay a disproportionate share of well costs. Each of the participations by directors and officers has been on terms no less favorable to the Company than it could have obtained from non-affiliated participants. It is expected that joint participations with the Company will continue to occur from time to time in the future. All participations by the officers and directors have and will continue to be approved by the disinterested members of the Company's Board of Directors.

At any point in time, there are receivables and payables with officers and directors that arise in the ordinary course of business as a result of participations in jointly held oil and gas properties. Amounts due to or from officers and directors resulting from billings of joint interest costs or receipts of production revenues on these properties are handled on terms pursuant to standard industry joint operating agreements which are no more or less favorable than similar transactions with unrelated parties.

The Company acquired oil and gas leases covering 26,680 net undeveloped acres in June 2000 from a company controlled by a director of Prima for a negotiated price of $12 per net acre, or a total of $320,000. Additional acreage in the same general area were subsequently acquired from this director at cost. The aggregate amounts paid for these property interests, including the initial acquisition totaled $290,000 in 2001 and $376,000 in 2000. All leases acquired were subject to an overriding royalty reserved by the director or entities controlled by him of 3% or less, depending on the net revenue interest of the leases, proportionately reduced to the working interest acquired. The disinterested members of the Board of Directors approved the transactions.

10. SUBSEQUENT EVENT

On March 5, 2002, the Company sold all of its producing wells in the Stone's Throw CBM project in the northern Powder River Basin, along with associated gathering system facilities and approximately 35,000 net undeveloped acres in the Stone's Throw area. Net proceeds from the transaction totaled $13,539,000 after normal closing adjustments. Approximately $11,746,000 of the proceeds were closed into an escrow account with a qualified intermediary, to preserve the opportunity to consummate a tax-free like-kind exchange if suitable properties to acquire can be identified within 45 days and purchased within six months. If a tax-free exchange is not consummated, the Company's current income taxes for 2002 could increase by up to $1,400,000.

11. SUPPLEMENTARY OIL AND GAS INFORMATION

The Company's oil and gas operations are conducted entirely in the United States, primarily in the Rocky Mountain region. Certain information concerning these activities follows:

Costs Incurred – Costs incurred in oil and gas property acquisition, exploration and development activities and related depletion per equivalent unit-of-production were as follows:

	2001	2000	1999
Acquisition costs:			
Unproved properties	$ 2,114,000	$ 1,741,000	$ 3,347,000
Proved properties	400,000	237,000	123,000
Exploration costs	1,620,000	642,000	1,731,000
Development costs	31,114,000	29,332,000	13,416,000
Total	$35,248,000	$31,952,000	$18,617,000
Amortization per equivalent Mcf of production	$0.77	$0.54	$0.51

Costs Not Being Amortized – Oil and gas property costs not being amortized at December 31, 2001 consisted of $13,132,000 of leasehold costs. The Company anticipates that substantially all unevaluated costs will be classified as evaluated costs within five years.

Results of Operations -- Results of operations for oil and gas producing activities were as follows:

	2001	2000	1999
Revenues			
Oil and gas sales	$44,548,000	$44,437,000	$20,644,000
Gains on derivative instruments, net	6,435,000	0	0
	50,983,000	44,437,000	20,644,000
Expenses			
Depletion of oil and gas properties	9,190,000	6,150,000	4,650,000
Lease operating expense	3,295,000	2,623,000	2,012,000
Ad valorem and production taxes	3,344,000	3,421,000	1,765,000
Impairment of natural gas swap	241,000	0	0
	16,070,000	12,194,000	8,427,000
Income before income taxes	34,913,000	32,243,000	12,217,000
Income tax expense	10,998,000	9,770,000	3,079,000
Income from oil and gas producing activities	$23,915,000	$22,473,000	$ 9,138,000

Supplemental Oil and Gas Reserve Information (Unaudited)

The reserve information presented below is based on estimates of net proved reserves as of December 31, 2001 that were prepared by the Company's engineers and audited by Netherland, Sewell and Associates, Inc., independent petroleum engineers, and estimates at the end of 2000 and 1999 that were prepared or audited in part by Netherland, Sewell and Associates, Inc. and in part by Ryder Scott Company, independent petroleum engineers. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures. Oil and gas reserve engineering must be recognized as a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimates is a function of the quality of available data and engineering and geological interpretation and judgment. Results of drilling, testing and production after the date of the estimate may require revisions. Accordingly, reserve estimates are often materially different from the quantities of oil and natural gas that are ultimately produced.

Proved oil and gas reserves are 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. Proved developed oil and gas reserves are those proved reserves expected to be recovered through existing wells with existing equipment and operating methods.

Analyses of Changes in Proved Reserves – The following table sets forth information regarding the Company's estimated net total proved and proved developed oil and gas reserve quantities:

	2001		2000		1999	
	Oil (MBBLS)	Gas (MMCF)	Oil (MBBLS)	Gas (MMCF)	Oil (MBBLS)	Gas (MMCF)
Proved reserves:						
Beginning of year	3,729	154,172	3,268	124,111	2,826	71,207
Purchases of oil and gas reserves in place	-	2,388	1	5	8	167
Net exchanges of oil and gas reserves in place	10	(2,051)	14	125	8	153
Revisions of previous estimates	(611)	(44,495)	(259)	(5,969)	(83)	(2,604)
Extensions, discoveries and other additions	697	14,485	1,145	44,583	862	68,160
Production	(431)	(9,277)	(440)	(8,683)	(322)	(7,163)
Sales of oil and gas reserves in place	-	-	-	-	(31)	(5,809)
End of year	3,394	115,222	3,729	154,172	3,268	124,111
Proved developed reserves:						
Beginning of year	2,945	77,385	2,521	54,079	2,305	51,538
End of year	2,949	69,168	2,945	77,385	2,521	54,079

Year-End Oil and Gas Prices -- Oil and natural gas prices in effect at each year end used in calculating reserve estimates were as follows:

	2001	2000	1999
Natural gas (per Mcf)	$ 1.94	$ 7.51	$ 1.90
Oil (per barrel)	19.71	26.48	24.68

Standardized Measure – The following table presents the standardized measure of discounted future net cash flows related to proved oil and gas reserves.

	2001	2000	1999
Future cash inflows	$ 290,303,000	$1,256,037,000	$ 316,417,000
Future production costs	(90,816,000)	(218,269,000)	(90,302,000)
Future development costs	(42,863,000)	(61,828,000)	(36,107,000)
Future net cash flows	156,624,000	975,940,000	190,008,000
10% discount factor	(64,719,000)	(399,888,000)	(81,457,000)
Discounted future income taxes	(25,104,000)	(204,931,000)	(33,085,000)
Standardized measure of discounted future net cash flows	$ 66,801,000	$ 371,121,000	$ 75,466,000

A summary of changes in the standardized measure of discounted future net cash flows is as follows:

	2001	2000	1999
Standardized measure of discounted future net cash flows, beginning of year	$ 371,121,000	$ 75,466,000	$ 51,426,000
Sales of oil and gas, net of production costs and taxes	(34,057,000)	(38,392,000)	(16,867,000)
Net changes in prices and production costs	(469,638,000)	358,936,000	23,719,000
Extensions, discoveries, and improved recovery, less related costs	8,680,000	169,062,000	42,530,000
Development costs incurred during the year	19,920,000	12,128,000	6,373,000
Changes in estimated future development	11,381,000	922,000	2,267,000
Revisions of previous quantity estimates	(46,997,000)	(29,713,000)	(3,901,000)
Purchases of reserves in place	1,088,000	349,000	244,000
Net exchanges of reserves in place	(7,429,000)	3,409,000	233,000
Sales of reserves in place	0	0	(12,885,000)
Other	(4,207,000)	(16,747,000)	(3,624,000)
Accretion of discount	37,112,000	7,547,000	5,143,000
Net changes in future income taxes	179,827,000	(171,846,000)	(19,192,000)
Standardized measure of discounted future net cash flows, end of year	$ 66,801,000	$ 371,121,000	$ 75,466,000

12. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited financial data for each quarter for the years ended December 31, 2001 and 2000.

	Three Months Ended			
	3/31/01	6/30/01	9/30/01	12/31/01
Year Ended December 31, 2001				
Revenues	$18,470,000	$14,188,000	$17,175,000	$10,454,000
Gross profit	11,638,000	7,948,000	10,005,000	3,002,000
Income before income tax and cumulative effect of change in accounting principle	11,975,000	8,221,000	10,242,000	3,369,000
Net income	8,676,000	5,671,000	7,067,000	2,354,000
Basic net income per share	0.68	0.45	0.56	0.18
Diluted net income per share	0.65	0.43	0.54	0.18

	Three Months Ended			
	3/31/00	6/30/00	9/30/00	12/31/00
Year Ended December 31, 2000				
Revenues	$10,677,000	$12,081,000	$13,264,000	$16,157,000
Gross profit	5,483,000	6,470,000	7,609,000	10,404,000
Net income	4,184,000	4,811,000	5,569,000	7,331,000
Basic net income per share	0.33	0.38	0.44	0.57
Diluted net income per share	0.32	0.36	0.42	0.55

SIGNATURES

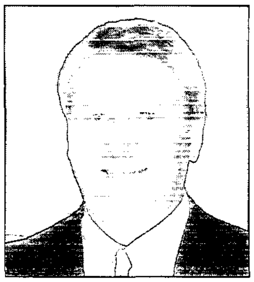
Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Prima Energy Corporation has duly caused this Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized, in Denver, Colorado on the 19th day of March, 2002.

PRIMA ENERGY CORPORATION

By: /s/ Richard H. Lewis
Richard H. Lewis, President

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report on Form 10-K has been signed below by the following persons in the capacities indicated and on the dates indicated.

Signature	Title	Date
/s/ Richard H. Lewis Richard H. Lewis	Chairman of the Board, President, Treasurer, (Principal Executive Officer)	March 19, 2002
/s/ Neil L. Stenbuck Neil L. Stenbuck	Executive Vice President - Finance (Principal Financial Officer) and Director	March 19, 2002
/s/ Sandra J. Irlando Sandra J. Irlando	Vice President - Accounting (Principal Accounting Officer)	March 19, 2002
/s/ James R. Cummings James R. Cummings	Director	March 19, 2002
/s/ Douglas J. Guion Douglas J. Guion	Director	March 19, 2002
/s/ Catherine James Paglia Catherine James Paglia	Director	March 19, 2002
/s/ George L. Seward George L. Seward	Director	March 19, 2002



Richard Lewis

BOARD OF DIRECTORS

RICHARD H. LEWIS
Chairman
Chief Executive Officer

JAMES R. CUMMINGS
Independant Consultant

DOUGLAS J. GUION
Oil and Gas Producer
Private Investor

CATHERINE JAMES PAGLIA
Director, Enterprise Asset Management

GEORGE L. SEWARD
President, Seward Land and Cattle Company

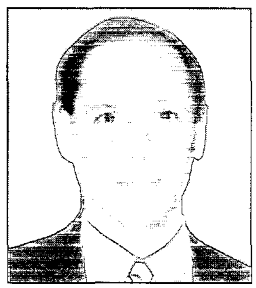
NEIL L. STENBUCK
Chief Financial Officer

James Cummings

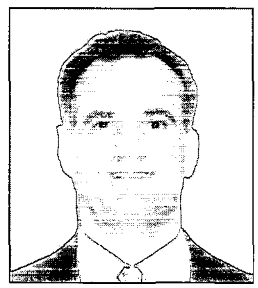
Douglas Guion

Catherine Paglia

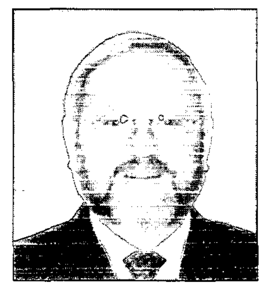
George Seward



Neil Stenbuck



Michael Kennedy



Michael McGuire

MANAGEMENT

RICHARD H. LEWIS
President and
Chief Executive Officer

NEIL L. STENBUCK
Executive Vice President and Chief Financial Officer

MICHAEL R. KENNEDY
Executive Vice President of Engineering and Operations

MICHAEL J. MCGUIRE
Executive Vice President of Exploration

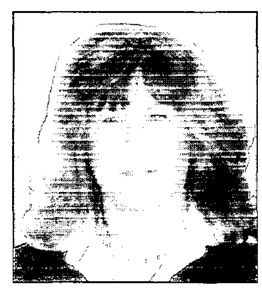
JOHN H. CARPENTER
Vice President of Marketing

SANDRA J. IRLANDO
Vice President of Accounting
and Secretary

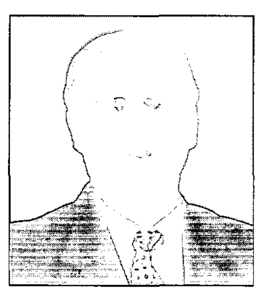
G. WALTER LUNSFORD
Vice President of Land

GREGORY R. VIGIL
Vice President of Corporate Development

John Carpenter



Sandra Irlando



Walter Lunsford

Gregory Vigil

TRANSFER AGENT
Computershare Investor Services
Golden, Colorado
(303) 262-0600

AUDITORS
Deloitte & Touche LLP
Denver, Colorado

LEGAL COUNSEL
Baker & Hostetler LLP
Denver, Colorado

BANK
Wells Fargo Bank West, N.A.
Denver, Colorado

SUBSIDIARIES
Prima Oil & Gas Company
Action Oilfield Services, Inc.
Action Energy Services
Prima Natural Gas Marketing, Inc.
Arete Gathering Company, LLC

ANNUAL MEETING
OF STOCKHOLDERS
3:00 p.m. Wednesday
May 15, 2002
Oxford Hotel
Grand Ballroom
1600 17th Street
Denver, Colorado

STOCK TRADED
Nasdaq National Market
Nasdaq Symbol: PENG

EXECUTIVE OFFICES
1099 18th Street
Suite 400
Denver, Colorado 80202
(303) 297-2100

PROXY STATEMENT
A copy of the Company's definitive Proxy Statement, as filed with the Securities and Exchange Commission, is available without charge to stockholders upon written request to the Secretary of the Company.

FORWARD-LOOKING STATEMENTS
This 2001 Annual Report contains "forward-looking statements" which are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. These statements include, without limitation, statements relating to the drilling and completion of wells, well operations, reserve estimates (including estimates for future net revenues associated with such reserves and the present value of such future net reserves), business strategies and other plans and objectives of Prima management for future operations and activities and other such matters. The words "believe," "expect," "plan," "budget," or "intend" and similar expressions identify forward-looking statements. Prima does not undertake to update, revise or correct any of the forward-looking information. Readers are cautioned that such forward-looking statements should be read in connection with Prima's disclosures under the heading: "Cautionary Statement for the Purposes of the 'Safe Harbor' Provisions of the Private Securities Litigation Reform Act of 1995" beginning on page 19 of the 2001 Form 10-K included herein.

Prima Energy Corporation

1099 18th Street ◦ Suite 400 ◦ Denver, Colorado 80202