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PLAINS
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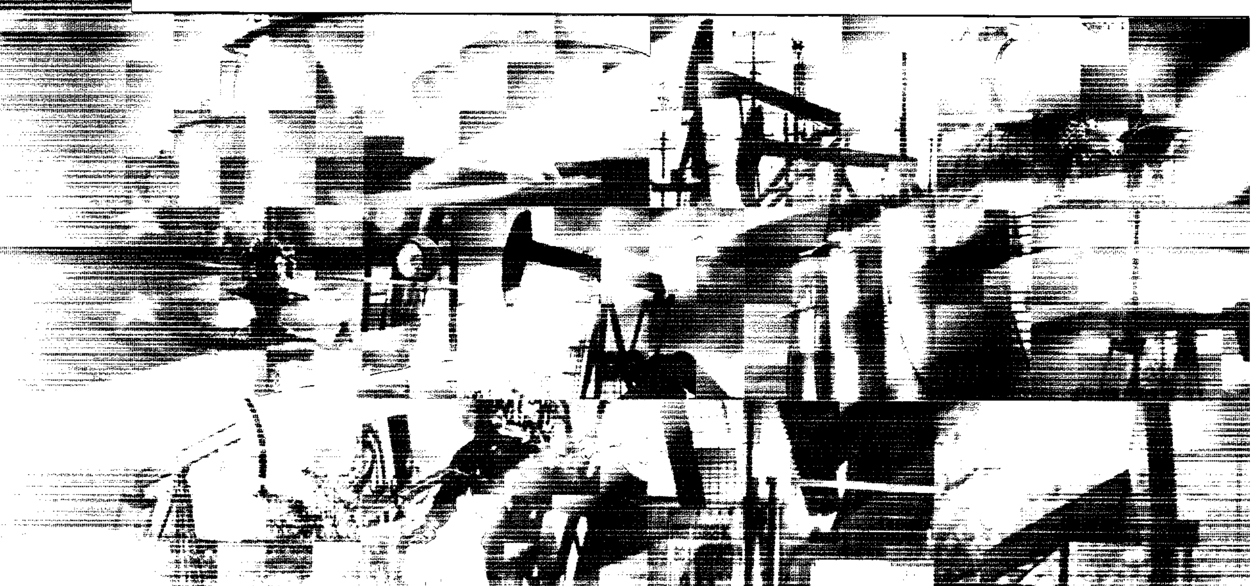
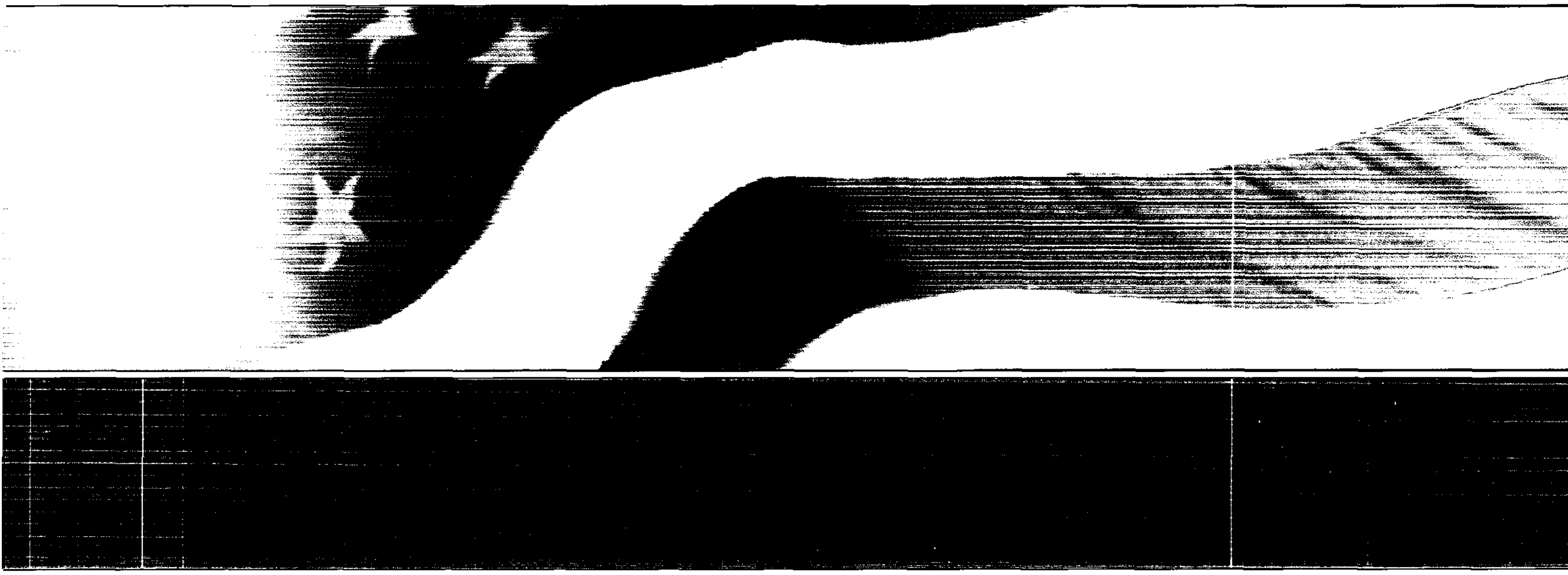


PLAINS RESOURCES ANNUAL REPORT
2001



CORPORATE PROFILE

Plains Resources Inc (NYSE:PLX), headquartered in Houston, Texas, is a dynamic energy company actively involved in the upstream and midstream sectors of the energy industry. In the upstream sector, the Company is engaged in the acquisition, development and exploitation of long-lived crude oil properties primarily located in California. The Company's proven reserves are 94% oil and 6% gas. With a reserve life in excess of 25 years, a healthy inventory of development projects and a sound cash flow profile, Plains is well-positioned to deliver solid performance in 2002. The Company is exposed to the growth potential in the midstream sector through its significant equity ownership in Plains All American Pipeline, L.P. (NYSE:PAA). PAA is a publicly traded master limited partnership actively engaged in the midstream (pipelines, terminals, storage) energy markets via the ownership of 3,000 miles of pipelines and 11.5 million barrels of storage assets. Plains Resources owns 44% of the general partner of PAA and 12.4 MM limited partnership units of PAA, which currently represents about 29% of the total units outstanding.

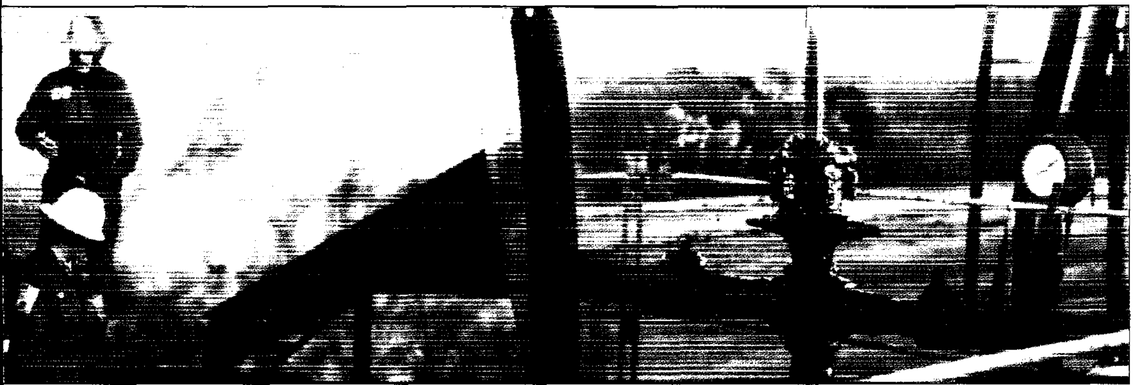
Plains Resources is focused on a value creation strategy in the upstream and midstream sectors with its long-lived oil and gas reserves, strong balance sheet, free cash flow, experienced management team, and ownership in PAA.

(in thousands, except per share and percentage information)

	2001	2000	1999	1998	1997
RESERVE DATA:					
Total oil reserves (barrels)	240,636	223,162	218,922	120,208	151,627
Total gas reserves (Mcf)	96,217	93,486	90,873	86,781	60,350
Total barrels of oil equivalent (BOE)	256,673	238,743	234,068	134,672	161,685
Percentage proved developed volume	56%	55%	55%	62%	65%
Estimated future net revenue	$ 1,677,429	$ 2,906,181	$ 2,846,524	$ 438,848	$ 1,060,745
Present value at 10% of estimated future net revenue	$ 669, 764	$ 1,345,392	$ 1,246,049	$ 226,943	$ 510,993
Percentage proved developed value	71%	76%	58%	82%	76%
OPERATING DATA:					
Oil sales (barrels)	9,279	8,355	8,016	7,575	6,900
Average oil price (per barrel)	$ 20.10	$ 15.96	$ 13.85	$ 13.03	$ 15.21
Gas sales (Mcf)	3,355	3,042	3,162	3,001	2,873
Average gas price (per Mcf)	$ 8.58	$ 5.26	$ 1.61	$ 1.36	$ 1.54
BOE sales	9,838	8,862	8,543	8,075	7,379
Average BOE price	$ 21.88	$ 16.85	$ 13.61	$ 12.73	$ 14.83
Production expense per BOE	$ 7.24	$ 7.01	$ 6.51	$ 6.29	$ 6.16
Gross margin per BOE	$ 14.64	$ 9.84	$ 7.10	$ 6.44	$ 8.67
SELECTED FINANCIAL DATA: [1]					
Oil and gas sales revenues	$ 215,247	$ 149,342	$ 116,223	$ 102,754	$ 109,403
Marketing, transportation and storage revenues [1]	$ —	$ 6,425,644	$ 10,796,998	$ 3,454,635	$ 2,732,043
Income (loss) before extraordinary items and *cumulative effect of accounting changes*	$ 155,317	$ 45,924	$ (24,787)	$ (62,346)	$ 14,259
Net income (loss)	$ 153,331	$ 40,815	$ (25,331)	$ (62,346)	$ 14,259
Net income (loss) per common and common equivalent share:					
Basic	$ 5.98	$ 1.46	$ (2.05)	$ (3.99)	$ 0.85
Diluted	$ 4.75	$ 1.39	$ (2.05)	$ (3.99)	$ 0.77
EBITDA [2]					
Upstream EBITDA	$ 136,769	$ 75,564	$ 51,172	$ 46,446	$ 59,106
Distributions from PAA	$ 31,553	$ 30,134	$ 29,472	$ —	$ —
Combined EBITDA	$ 168,322	$ 105,698	$ 80,644	$ 46,446	$ 59,106
Total assets	$ 648,788	$ 1,394,329	$ 1,689,560	$ 972,838	$ 556,819
Long-term debt	$ 282,061	$ 626,376	$ 676,703	$ 431,983	$ 285,728
Redeemable preferred stock	$ —	$ 50,000	$ 138,813	$ 88,487	$ —
Total stockholders' equity	$ 254,852	$ 137,140	$ 40,619	$ 69,170	$ 133,193

[1] Plains All American Pipeline LP ("PAA") is included in the Company's financial statements on the equity method of accounting in 2001 and on a consolidated basis in prior periods.

[2] *EBITDA means earnings before interest, income taxes, depletion, depreciation and amortization. Upstream EBITDA also excludes the results of operations of PAA, noncash* compensation, interest and other income, general and administrative costs related to our June 2001 corporate restructuring and amortization of option premiums. PAA distributions reflects amounts we received from PAA subsequent to its initial public offering in 1998.



we have created an identity of interests between each and every employee of PLX and the shareholder via stock ownership.

As noted earlier, your company delivered a very solid performance in 2001. Further to that point, net income for the year totaled $153.3 million, or $4.75 per diluted share. On a recurring basis, net income was $59.9 million, or $2.20 per diluted share as compared to $40.8 million, or $1.39 per diluted share, on the same recurring basis in the prior year. Upstream EBITDA, a key financial metric, increased 81% to $136.8 million in 2001. Upstream cash flow increased 119% to $107.6 million in 2001. Production increased 8% for the year as the Company reported volumes on an 'as produced' basis of 9.7 million barrels of oil equivalents, also a record. The Company received a record $31.6 million dollars from its ongoing interests in PAA.

We look to the future optimistically. Today, we have a solid hedge position in place as approximately 3/4 of 2002's and 1/2 of 2003's oil volumes are price protected at favorable levels with quality counterparties. We have a long-term predictable asset base characterized by a 25 year reserve life with a 5-year inventory of ready to execute organic projects. The expense side of the equation is perhaps the area with the greatest degree of variability. This is a dimension that we at a minimum control at expected levels, and via the relentless pursuit for further efficiency, will continue to attack and improve upon.

Of paramount importance is the human talent necessary to achieve our performance objectives. In this vein, we have a high quality employee base capable of executing our business in a disciplined, honest, prudent fashion well into the future. As always, we are grateful for the continuing efforts and support from all of our partners, shareholders and most especially our employees.

James C. Flores, Chairman and CEO
John T. Raymond, President and COO

DIRECTORS/OFFICERS

DIRECTORS:

James C. Flores
Chairman and Chief Executive Officer
Plains Resources Inc

Jerry L. Dees
Retired, Senior Vice President,
Exploration and Land
Vastar Resources, Inc

Tom H. Delimitros
General Partner
AMT Venture Funds

William M. Hitchcock
President
Pembroke Capital, L.L.C.

John H. Lollar
Managing Partner
Newgulf Exploration, L.P.

D. Martin Phillips
Managing Director and Principal
EnCap Investments L.L.C.

Robert V. Sinnott
Vice President
Kayne Anderson Investment
Management, Inc.
Director
Plains All American GP LLC

J. Taft Symonds
Chairman of the Board
Tetra Technologies, Inc.
Director
Plains All American GP LLC

OFFICERS:

James C. Flores
Chairman and Chief Executive Officer

John T. Raymond
President and Chief Operating Officer
Director
Plains All American GP LLC

Jere C. Overdyke, Jr.
Executive Vice President and
Chief Financial Officer

Timothy T. Stephens
Executive Vice President and
General Counsel

Franklin R. Bay
Senior Vice President
Corporate Development

Cynthia A. Feeback
Senior Vice President
Accounting and Treasurer

Thomas M. Gladney
Senior Vice President
Operations

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2001

OR

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

Commission file number: 0-9808

PLAINS RESOURCES INC.

(Exact name of registrant as specified in its charter)

Delaware	13-2898764
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

500 Dallas Street, Suite 700
Houston, Texas 77002
(Address of principal executive offices)
(Zip Code)

(713) 739-6700
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.10 per share	New York Stock Exchange

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

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

On February 28, 2002, there were 23,649,537 shares of the registrant's Common Stock outstanding. The aggregate value of the Common Stock held by non-affiliates of the registrant (treating all executive officers and directors of the registrant, for this purpose, as if they may be affiliates of the registrant) was approximately $498,176,000 on February 28, 2002 (based on $22.50 per share, the last sale price of the Common Stock as reported on the New York Stock Exchange on such date).

DOCUMENTS INCORPORATED BY REFERENCE: The information required in Part III of the Annual Report on Form 10-K is incorporated by reference to the registrant's definitive proxy statement to be filed pursuant to Regulation 14A for the registrant's 2002 Annual Meeting of Stockholders.

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

PLAINS RESOURCES INC.

2001 FORM 10-K ANNUAL REPORT

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FORWARD-LOOKING STATEMENTS

All statements, other than statements of historical fact, included in this Annual Report on Form 10-K are forward-looking statements, including, but not limited to, statements identified by the words "anticipate," "believe," "estimate," "expect," "plan," "intend" and "forecast" and similar expressions and statements regarding our business strategy, plans and objectives of our management for future operations. These statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions. These statements, however, are subject to certain risks, uncertainties and assumptions, including, but not limited to:

- uncertainties inherent in the exploration for and development and production of oil and gas and in estimating reserves;
- unexpected future capital expenditures (including the amount and nature thereof);
- impact of crude oil and natural gas price fluctuations;
- the effects of competition;
- the success of our risk management activities;
- the availability (or lack thereof) of acquisition or combination opportunities;
- the impact of current and future laws and governmental regulations;
- environmental liabilities that are not covered by an indemnity or insurance, and
- general economic, market or business conditions.

If one or more of these risks or uncertainties materialize, or if any of our underlying assumptions prove incorrect, our actual results may vary materially from those in the forward-looking statements. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information. See Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Factors That May Affect Future Results" for an additional discussion of these risks and uncertainties.

CERTAIN DEFINITIONS

As used herein, the following terms have specific meanings as set forth below:

Oil	crude oil, condensate and natural gas liquids
Gas	natural gas
Bbl	barrel
MBbl	thousand barrels
MMBbl	million barrels
B/d	barrels per day
Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
MMBtu	million British thermal units
BOE	barrel of oil equivalent, with gas volumes converted to oil barrels at a ratio of 6.0 Mcf of gas to 1.0 barrel of oil
MBOE	thousand barrels of oil equivalent
MMBOE	million barrels of oil equivalent
NYMEX	New York Mercantile Exchange

Upstream	the portion of the oil and gas business that acquires, exploits, develops, explores for and produces oil and gas
Midstream	the portion of the oil and gas business that markets, gathers, transports and stores oil
Proved Reserve Additions	the sum of additions from extensions, discoveries, improved recovery, acquisitions and revisions of previous estimates
Reserve Replacement Cost	cost per BOE of reserves added during a period calculated by using a fraction, of which the numerator is equal to the costs incurred for property acquisition, exploration, exploitation and development and of which the denominator is equal to proved reserve additions
Reserve Replacement Ratio	proved reserve additions for the period divided by production for the period
Working Interest	a cost-bearing interest under an oil and gas lease that gives the holder the right to develop and produce minerals under the lease
Net Revenue Interest	the lessee's share of production after satisfaction of all royalty and other non cost-bearing interests
Gross Acre	an acre of land in which an interest is owned
Net Acres	the sum of the fractional working interests owned in gross acres
Gross Oil and Gas Well	a well in which an interest is owned
Net Oil and Gas Well	obtained by multiplying the gross oil and gas well by the working interest owned in the applicable property
Present Value of Proved Reserves	the pre-tax present value (discounted at 10%) of estimated future cash inflows from proved oil and gas reserves reduced by estimated future operating expenses, development expenditures and abandonment costs (net of salvage value) associated therewith
Standardized Measure	the present value of proved reserves reduced by the present value (discounted at 10%) of estimated future income taxes

References herein to "Plains Resources", "Plains", the "Company", "we", "us" and "our" mean Plains Resources Inc.

PART I

Items 1 and 2. BUSINESS and PROPERTIES.

General

We are an independent energy company primarily engaged in the "upstream" activities of acquiring, exploiting, developing, exploring for and producing crude oil and natural gas in the United States. In addition, through our ownership in Plains All American Pipeline, L.P., or PAA, we have interests in the "midstream" activities of marketing, gathering, transporting, terminalling and storing crude oil. See "—Plains All American Pipeline, L.P.".

Our core areas of operations are in (i) the Los Angeles Basin, the Arroyo Grande field and the Mt. Poso field onshore California; (ii) the Point Arguello field offshore California; (iii) the Illinois Basin in southern Illinois; and (iv) the Sunniland Trend in south Florida. Our acquisition and exploitation efforts are concentrated on mature but underdeveloped crude oil producing properties that meet our targeted criteria. Generally, the properties that we consider acquiring and exploiting consist of entire fields where major integrated or large independent oil and natural gas companies own 100% or the controlling interest. Typically these fields have produced significant volumes since initial discovery, exhibit complex reservoir and geologic conditions and, as a result thereof, are likely to have significant estimated remaining reserves in place. Our management believes that it has developed a proven record in acquiring and exploiting underdeveloped crude oil properties where we can make substantial reserve additions and cash flow increases by implementing improved production practices and recovery techniques and by relatively low risk development drilling. An integral component of our exploitation effort is to increase unit operating margins, and therefore cash flow, by reducing unit production expenses and increasing wellhead price realizations.

We seek to complement these efforts by committing a minor portion of our capital to pursue higher risk exploration opportunities that offer potentially higher rewards in areas synergistic to our acquisition and exploitation activities. As part of our business strategy, we periodically evaluate selling, and from time to time have sold, certain of our mature producing properties that we consider to be non-strategic or fully valued. These sales enable us to focus on our core properties, maintain our financial flexibility, control our overhead and re-deploy the sales proceeds to activities that have potentially higher financial returns.

At December 31, 2001 proved oil and gas reserves totaled 256.7 MMBOE, comprised of 240.6 MMBbls of oil and 96.2 Bcf of gas. In 2001 we drilled 169 development wells, 168 of which were successful. In 2001 aggregate acquisition, exploitation, development, and exploration expenditures totaled $136.5 million, resulting in proved reserve additions of approximately 27.8 MMBOE, at a reserve replacement cost of $4.92 per BOE. During 2001 approximately 98% of our expenditures were on exploitation and development activities.

During the five-year period ended December 31, 2001, we incurred aggregate acquisition, exploitation, development, and exploration costs of approximately $518.7 million, resulting in proved reserve additions of 177.7 MMBOE, at a reserve replacement cost of $2.92 per BOE. During this period approximately 98% of our expenditures were on acquisitions, exploitation and development activities.

To manage our exposure to commodity price risk, we routinely hedge a portion of our crude oil production. For 2002 and 2003, we have entered into various arrangements, using a combination of swaps and purchased puts and calls. We intend to continue maintaining hedging arrangements for a significant portion of our production. See Item 7A. — "Quantitative and Qualitative Disclosures about Market Risks".

Plains All American Pipeline, L.P.

PAA is a publicly-traded master limited partnership that is engaged in the marketing, transportation and terminalling of crude oil and marketing liquefied petroleum gas. Terminals are facilities where crude oil is transferred to or from storage or a transportation system, such as a pipeline, to another transportation system, such as trucks or another pipeline. The operation of these facilities is called "terminalling". PAA is the exclusive purchaser/marketer of all of our equity crude oil production.

The principal business of PAA consists of: gathering crude oil from the fields where the crude oil is produced; interstate and intrastate transportation of crude oil through pipelines, trucks or barges; storing crude oil in storage tanks; transferring crude oil from pipelines and storage tanks to trucks, barges or other pipelines through terminals; the purchase of crude oil at the well and the bulk purchase of crude oil at pipeline and terminal facilities; and the subsequent resale or exchange of crude oil at various points along the crude oil distribution chain.

PAA owns and operates over 3,000 miles of gathering and mainline crude oil pipelines located throughout the United States and Canada. In connection with its terminalling and storage activities, PAA owns and operates approximately 11.5 million barrels of above-ground crude oil terminalling and storage facilities, including a 3.1 million barrel crude oil terminalling and storage facility in Cushing, Oklahoma, the largest crude oil trading hub in the United States and the designated delivery point for the NYMEX. PAA recently announced plans to expand the Cushing facility by 2.2 million barrels, with 1.1 million barrels of the expansion expected to be completed in mid-2002 and 1.1 million barrels expected to be completed in late 2002 or early 2003. PAA's operations are concentrated in Texas, Oklahoma, California and Louisiana and in the Canadian provinces of Alberta, Saskatchewan and Manitoba.

Our June 2001 Strategic Restructuring

On June 8, 2001, we sold a portion of our interests in PAA to a group of investors and management of PAA for approximately $155.2 million. The assets we sold in this restructuring included 52%, or approximately 5.2 million, of the subordinated units of PAA, at $22 per unit, and an aggregate 54% ownership interest in the general partner of PAA. We received approximately $110 million in cash and 23,108 shares of our series F preferred stock value at $45.2 million as consideration for the sale. We recognized a pre-tax gain of $128.3 million in connection with this sale. In connection with our strategic restructuring, the holders of the remaining shares of our series F preferred stock converted their shares into 2.2 million shares of our common stock and received from us a cash payment of approximately $2.5 million, equal to, with respect to each share of our series F preferred stock converted, the accrued dividends on each share from June 8, 2001 until the first date on which we could cause conversion of the shares, plus a 20% premium on the amount of the accrued dividends. Also, in connection with our strategic restructuring, holders of our series H preferred stock converted an aggregate of 132,022 shares into approximately 4.4 million shares of our common stock. We also granted management of PAA an option to acquire an additional 2% ownership interest in the general partner of PAA, which PAA management exercised in September 2001 by paying us $1.5 million in cash and notes. As a result of this exercise we recognized a gain of $1.1 million.

As a result of our strategic restructuring, all of our series F preferred stock and all but approximately 36,000 shares of our series H preferred stock were retired or converted. The remaining outstanding shares of our series H preferred stock were converted into 1.2 million shares of our common stock during the third quarter of 2001.

The excess of the fair value of our Series F preferred stock redeemed as consideration over the carrying value of such series F preferred stock ($21.4 million) is deemed to be a dividend to our preferred stockholders. As a result, for purposes of determining our basic and diluted earnings per share, we deducted this amount in determining our income available to our common stockholders.

In exchange for the significant value we received for the subordinated units (which are subordinated in right to distributions from PAA and are not publicly traded) relative to the then current market price of the publicly traded common units, we entered into a value assurance agreement with each of the purchasers of the subordinated units. The value assurance agreements require us to pay to the holders an amount per fiscal year, payable on a quarterly basis, equal to the difference between $1.85 per unit and the actual amount distributed during that period. The value assurance agreements will expire upon the earlier of the conversion of the subordinated units to common units, or June 8, 2006.

Also in connection with our strategic restructuring:

- we appointed James C. Flores as our Chairman of the Board and Chief Executive Officer and we appointed a new Chief Operating Officer, Chief Financial Officer, and General Counsel and Secretary;
- certain of our employees received transaction-related bonuses and other payments and vested in benefits in accordance with the terms of our employee benefit plans;

- we entered into a separation agreement with PAA whereby, among other things, (1) we agreed to indemnify PAA, its general partner, and its subsidiaries against (a) any claims related to the upstream business, whenever arising, and (b) any claims related to federal or state securities laws or the regulations of any self-regulatory authority, or other similar claims, resulting from alleged acts or omissions by us, our subsidiaries, PAA, or PAA's subsidiaries occurring on or before June 8, 2001, and (2) PAA agreed to indemnify us and our subsidiaries against any claims related to the midstream business, whenever arising;
- we entered into a pension and employee benefits assumption and transition agreement pursuant to which we and the general partner of PAA agreed to the transition of certain employees to the general partner, our provision of certain benefits with respect to the transfer, and our provision of transition-related services;
- with respect to certain of our employees who transferred to the general partner of PAA and who held in-the-money but unvested stock options to acquire our common stock, which were subject to forfeiture due to the transfer of employment, we agreed to substitute for the unvested options a total contingent grant of 51,000 subordinated units with a value equal to the discounted present value of the spread on the unvested options, to vest on the same vesting schedule as the options, as a result of which we recognized $0.5 million in noncash compensation expense; and
- we agreed to contribute 287,500 subordinated units to the general partner of PAA to be used for performance option grants to officers and key employees of the general partner.

As a result of our reduced ownership of PAA and our inability to control PAA's operations, our minority interest in PAA is accounted for using the equity method of accounting effective January 1, 2001. Under this method, we no longer consolidate the assets, liabilities and operating activities of PAA. Rather, we record our proportionate share of PAA's net assets and results of operations.

As of December 31, 2001, our aggregate ownership interest in PAA was approximately 29%, which was comprised of (1) a 44% interest in the general partner of PAA, (2) 45%, or approximately 4.5 million, of the subordinated units and (3) 24%, or approximately 7.9 million, of the common units, including approximately 1.3 million class B common units.

Based on PAA's current annual distribution rate of $2.05 per unit, we would receive an annual distribution from PAA of approximately $27.6 million, including $1.0 million for our 44% of the general partner incentive distribution. The general partner of PAA is entitled to receive incentive distributions if the amount PAA distributes with respect to any quarter exceeds levels specified in PAA's partnership agreement. Under the quarterly incentive distribution provisions, generally the general partner is entitled to 15% of distributions in excess of $0.45 per unit, 25% of distributions in excess or $0.495 per unit and 50% of distributions in excess of $0.675 per unit. Based on the current $2.05 annual distribution level ($0.5125 quarterly) and the current units outstanding, the general partner's incentive distribution is forecast to be approximately $2.2 million, of which we would receive 44%.

Unauthorized Trading Losses

In November 1999, we discovered that a former employee of PAA had engaged in unauthorized trading activity, resulting in a loss of approximately $174.0 million, which includes associated costs and legal expenses. A full investigation into the unauthorized trading activities by outside legal counsel and independent accountants and consultants determined that the vast majority of the losses occurred from March through November 1999, and the impact warranted a restatement of previously reported financial information for 1999 and 1998. Approximately $7.1 million of the unauthorized trading losses was recognized in 1998 and the remainder in 1999. In 2000, we recognized an additional $8.0 million charge for litigation related to the unauthorized trading losses.

The unauthorized trading and associated losses resulted in a default of certain covenants under PAA's then-existing credit facilities and significant short-term cash and letter of credit requirements. In December 1999, PAA executed amended credit facilities and obtained default waivers from all of its lenders. PAA paid approximately $13.7 million to its lenders in connection with the amended credit facilities. In connection with the amendments, we loaned approximately $114.0 million to PAA. We financed the $114.0 million that we loaned PAA with: the issuance of a new series of our Series F preferred stock for proceeds of $50.0 million; cash distributions of approximately $9.0 million received from PAA in November 1999; and $55.0 million of borrowings under our revolving credit facility. In May 2000, PAA entered into new bank credit agreements to refinance their existing bank debt and repay the $114.0 million owed to us.

After the public announcement of the trading losses, class actions were filed against us and PAA. Derivative lawsuits have also been filed in the United States District Court of the Southern District of Texas and the Delaware Chancery Court, Newcastle County. Agreements have been reached to settle all of the class actions and the Delaware and Texas derivative actions. The securities class actions settlement and the Delaware derivative action settlement have been approved by the courts. The Texas derivative action settlement, which does not contemplate any cash payment by us, is pending court approval. See Item 3.—"Legal Proceedings".

Oil and Gas Reserves

The following tables set forth certain information with respect to our reserves based upon reserve reports prepared by the independent petroleum consulting firms of Netherland, Sewell & Associates, Inc. and Ryder Scott Company in 2001 and H.J. Gruy and Associates, Inc., Netherland, Sewell & Associates, Inc., and Ryder Scott Company in 2000 and 1999. The reserve volumes and values were determined under the method prescribed by the Securities and Exchange Commission, or SEC, which requires the application of year-end prices for each year, held constant throughout the projected reserve life.

	As of or for the Year Ended December 31,					
	2001		2000		1999	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
Proved Reserves						
Beginning balance	223,162	93,486	218,922	90,873	120,208	86,781
Revision of previous estimates	(15,457)	(5,485)	(9,834)	(3,597)	62,895	(8,234)
Extensions, discoveries, improved recovery and other additions	42,210	11,571	22,429	9,252	37,393	15,488
Sale of reserves in-place	—	—	—	—	—	—
Purchase of reserves in-place	—	—	—	—	6,442	—
Production	(9,279)	(3,355)	(8,355)	(3,042)	(8,016)	(3,162)
Ending balance	240,636	96,217	223,162	93,486	218,922	90,873
Proved Developed Reserves						
Beginning balance	123,532	52,184	120,141	49,255	73,264	58,445
Ending balance	134,704	59,101	123,532	52,184	120,141	49,255

The following table sets forth the Present Value of Proved Reserves at December 31, 2001, 2000 and 1999.

	2001	2000	1999
		(in thousands)	
Proved developed	$475,219	$1,020,023	$ 721,151
Proved undeveloped	194,545	325,369	524,898
Total Proved	$669,764	$1,345,392	$1,246,049

There are numerous uncertainties inherent in estimating quantities and values of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reservoir engineering is a subjective process of estimating the recovery from underground accumulations of crude oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Because all reserve estimates are to some degree speculative, the quantities of crude oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future crude oil and natural gas sales prices may all differ from those assumed in these estimates. In addition, different reserve engineers may make different estimates of reserve quantities and cash flows based upon the same available data. Therefore, the Present Value of Proved Reserves shown above represents estimates only and should not be construed as the current market value of the estimated crude oil and natural gas reserves attributable to our properties. The information set forth in the preceding tables includes revisions of reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions reflect additional information from subsequent exploitation and development activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in product prices. See Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Factors That May Affect Future Results".

In accordance with the SEC guidelines, the reserve engineers' estimates of future net revenues from our properties and the present value thereof are made using crude oil and natural gas sales prices in effect as of the dates of such estimates and are held constant throughout the life of the properties, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. The crude oil price in effect at December 31, 2001 is based on the year-end crude oil price with variations based on location and quality of crude oil. The overall average prices used in the reserve reports as of December 31, 2001 were $14.91 per barrel of oil and $2.56 per Mcf of gas. See "Product Markets and Major Customers". Historically, the prices for oil and gas have been volatile and are likely to continue to be volatile in the future. See Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Factors That May Affect Future Results".

Since December 31, 2000, we have not filed any estimates of total proved net oil or gas reserves with any federal authority or agency other than the SEC.

The following table sets forth certain information with respect to our reserves over the last five years.

	As of or for the Year Ended December 31,				
	2001	2000	1999	1998	1997
	(in thousands, except ratios and per unit amounts)				
Present Value of Proved Reserves(1)	$669,764	$1,345,392	$1,246,049	$226,943	$510,993
Proved Reserves					
Oil (MBbls)	240,636(1)	223,162	218,922	120,208	151,627
Gas (MMcf)	96,217	93,486	90,873	86,781	60,350
MBOE	256,673	238,743	234,068	134,672	161,685
Reserve Replacement Ratio	282%	153%	1,263%	(229)%(2)	603%
Reserve Replacement Cost per BOE	$ 4.92	$ 5.98	$ 0.68	$ (5.46)(2)	$ 2.71
Capital costs incurred	$136,475	$ 80,928	$ 72,979	$100,935	$127,378
Percentage of total capital costs					
Acquisition	1%	3%	5%	10 %	34%
Development	98%	96%	89%	88 %	65%
Exploration	1%	1%	6%	2 %	1%
Average year-end realized oil price, per Bbl(3)	$ 14.91	$ 21.02	$ 20.94	$ 7.96	$ 13.91
Average year-end realized gas price, per Mcf	$ 2.56	$ 14.63	$ 2.77	$ 1.68	$ 2.13
December 31 NYMEX WTI spot price	$ 19.84	$ 26.80	$ 25.60	$ 12.05	$ 18.34

(1) We have reduced the pre-tax present value of proved reserves and the future net revenues of certain properties to reflect applicable abandonment costs and, with respect to the LA Basin properties, a net profits interest owned by a third party. Approximately 8.8 MMBOE of our proved reserves in the L.A. Basin at December 31, 2001 are subject to a 50% net profits interest.

(2) The reserve replacement ratio and reserve replacement cost per BOE for 1998 are negative due to a negative volume revision related to low crude oil prices at December 31, 1998.

(3) The average year-end oil price is based on the price in effect at year-end with adjustments based on the location and quality of the oil.

Acquisition and Exploitation Activities

Acquisition and Exploitation Strategy

We are continually engaged in the exploitation and development of our existing property base and the evaluation and pursuit of additional underdeveloped properties for acquisition. We generally focus on mature but underdeveloped producing crude oil properties in areas where we believe substantial reserve additions and cash flow increases can be made through relatively low-risk drilling, improved production practices and recovery techniques and improved operating margins. We seek to improve a property's operating margin by reducing costs, investing capital to increase production rates and enhancing the marketing arrangements of the crude oil production.

We seek to acquire a majority interest in the properties we have identified and to act as operator of those properties. When we purchase properties, we then implement our exploitation plan by enhancing product price realizations, optimizing production practices, realigning and expanding injection processes, drilling wells, and performing stimulations, recompletions, artificial lift upgrades and other operating margin and reserve enhancements. After the initial acquisition, we may also seek to increase our interest in the properties through acquisitions of offsetting acreage, farmout drilling arrangements and the purchase of minority interests in the properties.

By implementing our exploitation plan, we seek to increase cash flows and enhance the value of our asset base. The results of these activities are reflected in additions and revisions to proved reserves. During the five-year period ending December 31, 2001, additions to proved reserves totaled 120.4 MMBOE or approximately 282% of cumulative net production for this period. These reserves were added at an aggregate average cost of $3.80 per BOE. This activity excludes reserves added as a result of our acquisition activities. Reserve additions related solely to our acquisition activities totaled 57.3 MMBOE and were added at an aggregate average cost of $1.08 per BOE.

We believe that our properties in our four core areas hold potential for additional increases in production, reserves and cash flow. However, our ability to achieve such increases could be adversely affected by future decreases in the demand for crude oil and natural gas, operating risks, unavailability of capital, adverse changes in governmental regulations or other currently unforeseen developments. Accordingly, we can give no assurance that such increases will be achieved.

During 2002, we expect to spend approximately $77 million on the development and exploitation of our crude oil and natural gas properties. Approximately $52 million of these capital expenditures are for exploitation projects in onshore California. Activities to be conducted include development drilling and a variety of primary and secondary recovery projects that we believe will expand our proved developed reserve base, offset normal production decline and potentially generate a year-over-year production increase of approximately 3-5%. The 2002 capital program incorporates the results of various analyses and field studies and includes the drilling of approximately 82 total wells, including 10 injection wells and numerous injection realignment related workovers.

Exploitation Projects

The following table sets forth certain information with respect to our crude oil and gas properties (dollars in millions):

	California Properties						
	LA Basin	**Montebello**	**Arroyo Grande**	**Mt. Poso**	**Sunniland Trend**	**Illinois Basin**	**Point Arguello**
Year(s) Acquired	1992	1997	1997	1998	1993/1994	1995	1999
Year(s) Discovered	1924-1966	1917	1906	1926	1943-1978	1905	1981
Proved reserves at acquisition—MMBOE	17.7	23.3	19.9	7.7	5.0	17.3	6.4
Year Ended December 31, 2001							
Capital Expenditures	$ 74.7	$ 13.0	$ 10.6	$10.3	$ 6.9	$12.5	$ 5.6
Sales—MMBOE	4.1	0.8	0.6	0.8	1.1	1.0	1.4
Gross Margin(1)	$ 78.5	$ 11.1	$ 7.1	$13.4	$ 5.4	$14.5	$15.4
As of December 31, 2001:							
Proved Reserves—MMBOE	114.0(2)	27.6	60.8	9.3	17.3	21.1	5.0
Proved Developed Reserves—MMBOE	79.9	15.5	12.0	4.6	15.5	13.3	3.8
Future Net Revenues	$806.3	$185.7	$413.2	$45.1	$34.7	$55.7	$ 6.9
Present Value of Proved Reserves	$357.7	$ 71.4	$126.1	$22.5	$26.5	$10.5	$ 6.9

(1) Revenues less production expenses. Excludes $0.9 million ($0.09 per BOE) of hedging losses.

(2) Approximately 8.8 MMBOE of our proved reserves at December 31, 2001 are subject to a 50% net profits interest.

(3) We have reduced the pre-tax present value of proved reserves and the future net revenues of certain properties to reflect applicable abandonment costs and, with respect to the LA Basin properties, a net profits interest owned by a third party.

Onshore California. In 1992, we acquired Stocker Resources, a sole purpose company formed in 1990 to acquire substantially all of Chevron USA's producing crude oil properties in the LA Basin. These interests included the Inglewood, East Beverly Hills, San Vicente and South Salt Lake fields. Following the initial acquisition, we expanded our holdings in this area by acquiring additional interests within the existing fields, including all of Texaco Exploration and Production, Inc.'s interest in the Vickers lease which further consolidated our holdings in the Inglewood field. We refer to all of our properties in the LA Basin acquired before 1997 collectively as the "LA Basin properties". We hold a 100% working interest in the LA Basin properties.

The LA Basin properties consist of crude oil reserves discovered at various times between 1924 and 1966. We have performed various exploitation activities, including drilling additional production and injection wells, returning previously marginal wells to economic production, optimizing pre-existing waterflood operations, initiating new waterfloods, optimizing artificial lift, increasing the capacity and efficiency of facilities, upgrading facilities to maintain regulatory compliance, reducing unit production expenses and improving marketing margins. Additionally, we continuously update and perform technical studies to identify new investment opportunities on these properties. Through these acquisition and exploitation activities, our net average daily production from this area has increased from approximately 6,700 BOE per day in 1992 to an average of approximately 14,000 BOE per day during the fourth quarter of 2001.

In 2001 we spent $74.7 million on capital projects on the LA Basin properties, the most significant of which were the drilling of 42 production and 15 injection wells. In 2002 we expect to spend $38 million on capital projects which will include drilling 22 production wells and 4 injection wells, performing numerous recompletions and workovers, and modifying various production and injection facilities.

In March 1997, we expanded our operations in the LA Basin with the acquisition of Chevron's interest in the Montebello field. We acquired a 100% working interest (99.2% net revenue interest) in 55 producing crude oil wells and related facilities and approximately 450 acres of surface fee land. Our net average daily production from this field has increased from approximately 930 BOE per day at the time of acquisition to approximately 2,400 BOE per day during the fourth quarter of 2001. Since the acquisition, we have drilled a total of 48 producing wells and 22 injection wells. During 2000, we evaluated the field reservoir information and prepared a comprehensive waterflood development plan. In 2001 we spent $13.0 million on capital projects in the Montebello field, the most significant of which were the drilling of 17 production and 6 injection wells. In 2002 we expect to spend $11 million on capital projects which include the drilling of 12 production wells and 6 injection wells, performing numerous workovers and increasing the capacity of the production and injection facilities.

In November 1997, we acquired a 100% working interest (97% net revenue interest) in the Arroyo Grande field located in San Luis Obispo County, California from subsidiaries of Shell Oil Company ("Shell"). We also acquired surface and related development rights to approximately 1,000 acres included in the 1,500-acre producing unit. The field is primarily under continuous steam injection and at the acquisition date, was producing approximately 1,600 BOE per day (approximately 1,500 BOE net to our interest) of 14 degree API gravity crude oil from 70 wells. Since acquiring this property we have drilled additional wells to downsize the injection patterns in the currently developed area from 5 acres to 1.25 acres to accelerate recoveries, and realigned steam injection within these areas to increase the efficiency of the recovery process. It is also noteworthy that steam injection was curtailed by about 50% immediately following the acquisition due to low crude prices. Although crude prices subsequently rebounded, injection was maintained at this low rate pending analysis of the saturation inputs provided by the infill drilling program, and in 2001 due to excessive natural gas fuel costs. As a result, base volumes declined considerably, but this decline was offset by the contributions from producing wells drilled to downsize the injection patterns.

In 2001 we spent $10.6 million on capital projects in the Arroyo Grande field, the most significant of which were the drilling of 19 production and 11 injection wells and the installation of a gas processing facility to reduce third-party fuel gas purchases. In 2002 we expect to spend $2 million on capital projects which include the recompletion of 5 wells. Although no capital is required and little upward volume impact is expected in 2002, we also plan to increase steam injection to near pre-acquisition levels in early 2002. Our net average daily production from this field was approximately 1,900 BOE per day during the fourth quarter of 2001.

During 1998, we acquired the Mt. Poso field from Aera Energy LLC. The field is located near Bakersfield, California, in Kern County. At acquisition, the field was producing 900 BOE per day of 15 to 17 degree API gravity crude and added 7.7 MMBOE to our proved reserves. Since acquisition, we have undertaken an aggressive recompletion and drilling program targeting the Pyramid Hills formation. In 2001 we spent $10.3 million on capital projects in the Mt. Poso field, the most significant of which were the drilling of 43 production wells and recompletion of 38 wells. In 2002 we expect to spend $1 million on capital projects to optimize the producing infrastructure. Our net average daily production from this field was approximately 2,000 BOE per day during the fourth quarter of 2001.

South Florida. Our properties in the Sunniland Trend in south Florida produced an average of approximately 2,900 MBbls of oil per day in 2001 and accounted for 11% of our total sales volumes. In 2001 we spent $6.9 million on capital projects in the Sunniland Trend, primarily facility enhancements and abandonment of inactive wells. In 2002 we expect to spend $6 million on well abandonments and infrastructure projects.

Illinois Basin. Our properties in the Illinois Basin produced an average of approximately 2,700 MBbls of oil per day in 2001 and accounted for 11% of our total sales volumes. In 2001 we spent $12.5 million on capital projects in the Illinois Basin, the most significant of which were the drilling of 42 production and 9 injection wells and various water injection realignment projects. In 2002 we expect to spend $9 million on capital projects which include drilling 38 production wells.

Offshore California. In July 1999 we acquired Chevron's 26.3% working interest in the Point Arguello Unit and the various partnerships owning the associated transportation, processing and marketing infrastructure and a 26.3% right to participate in the adjacent Rocky Point Unit. We assumed Chevron's 26.3% share of costs related to: (1) plugging and abandoning all existing well bores; (2) removing conductors; (3) flushing hydrocarbons from all lines and vessels; and (4) removing/abandoning all structures, fixtures and conditions created subsequent to closing. Chevron retained the obligation for all other abandonment costs, including but not limited to (1) removing, dismantling and disposing of the existing offshore platforms; (2) removing and disposing of all existing pipelines; and (3) removing, dismantling, disposing and remediation of all existing onshore facilities. We are the operator of record for both the Point Arguello Unit and the Rocky Point Unit.

In 2001 we spent $5.6 million on capital projects in the Point Arguello Unit, the most significant of which were the drilling of 6 production wells and a number of recompletion and stimulation workovers. In 2002 we expect to spend $4 million on capital projects which include converting 5 wells to electric submersible lift systems, and various recompletions and stimulations. We are currently seeking regulatory approval to allow near-term development of the adjacent Rocky Point Unit by drilling extended-reach wells from the Point Arguello platforms. While several critical regulatory permits and other agreements remain to be finalized among the working interest owners, and a larger rig must be procured, we believe the resolution of these issues may potentially allow drilling of Rocky Point to occur in 2003.

At acquisition our net average daily production from this unit was 5,200 BOE per day. During the fourth quarter of 2001 our net average daily production was approximately 4,400 BOE per day.

Productive Wells and Acreage

As of December 31, 2001, we had working interests in 2,071 gross (2,045 net) active producing oil wells. The following table sets forth certain information with respect to our developed and undeveloped acreage as of December 31, 2001.

	December 31, 2001			
	Developed Acres(1)		Undeveloped Acres(2)	
	Gross	Net	Gross	Net(3)
Onshore California	8,889	8,844	8,928	5,296
Offshore California(4)	15,326	4,033	41,720	1,449
Florida	12,025	12,025	75,034	72,581
Illinois	16,622	14,628	13,737	5,500
Indiana	1,155	854	1,280	575
Kansas	—	—	48,147	37,647
Kentucky	—	—	1,321	521
Louisiana	—	—	4,875	4,858
Total	54,017	40,384	195,042	128,427

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

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

(3) Less than 10% of total net undeveloped acres are covered by leases that expire from 2002 through 2004.

(4) Does not include 6,200 acres under an option agreement, in which we have the right to acquire a 26.315% interest.

Drilling Activities

Certain information with regard to our drilling activities during the years ended December 31, 2001, 2000 and 1999 is set forth below:

	Year Ended December 31,					
	2001		2000		1999	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Oil	—	—	—	—	—	—
Natural gas	—	—	—	—	—	—
Dry	1.0	0.5	—	—	1.0	0.5
Total	1.0	0.5	—	—	1.0	0.5
Development Wells:						
Oil	168.0	163.4	158.0	156.0	105.0	105.0
Natural gas	—	—	—	—	—	—
Dry	1.0	1.0	2.0	2.0	—	—
Total	169.0	164.4	160.0	158.0	105.0	105.0
Total Wells:						
Oil	168.0	163.4	158.0	156.0	105.0	105.0
Natural gas	—	—	—	—	—	—
Dry	2.0	1.5	2.0	2.0	1.0	0.5
Total	170.0	164.9	160.0	158.0	106.0	105.5

See "—Acquisition and Exploitation Activities" and "—Productive Wells and Acreage" for additional information regarding exploitation activities, including waterflood patterns, workovers and recompletions.

Production and Sales

The following table presents certain information with respect to crude oil and natural gas production attributable to our properties, the revenue derived from the sale of such production, average sales prices received and average production costs during the three years ended December 31, 2001, 2000 and 1999.

	Year Ended December 31,		
	2001	2000	1999
	(in thousands except as noted)		
Sales:			
Oil (MBbls)	9,279	8,355	8,016
Gas (MMcf)	3,355	3,042	3,163
MBOE	9,838	8,862	8,543
Revenue:			
Oil	$186,476	$133,325	$111,128
Gas	28,771	16,017	5,095
	$215,247	$149,342	$116,223
Average sales price (in dollars):			
Oil			
Average NYMEX price per bbl	*$ 26.01*	*$ 30.25*	*$ 19.25*
Average hedge gain (loss) per bbl	(0.10)	(9.66)	(1.39)
Average differential per bbl	(5.81)	(4.63)	(4.00)
Average realized price per bbl	20.10	15.96	13.86
Gas			
Average price per Mcf	8.58	5.26	1.61
Average price per BOE	21.88	16.85	13.61
Production expenses ($/BOE)	7.24	7.01	6.51

Pursuant to a crude oil marketing agreement, PAA is the exclusive purchaser of all of our equity oil production.

Product Markets and Major Customers

Our revenues are highly dependent upon the prices of, and demand for, oil and gas. Historically, the markets for oil and gas have been volatile, and are likely to continue to be volatile in the future. The prices we receive for our oil and gas production and the levels of such production are subject to wide fluctuations and depend on numerous factors beyond our control, including seasonality, the condition of the United States and world economies (particularly the manufacturing sector), foreign imports, political conditions in other oil-producing and gas-producing countries, the actions of the Organization of Petroleum Exporting Countries and domestic government regulation, legislation and policies. Decreases in the prices of oil and gas have had, and could have in the future, an adverse effect on the carrying value of our proved reserves and our revenues, profitability and cash flow. See Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Factors That May Affect Future Results".

Certain of our operations in California that have interruptible electrical contracts from time to time have been adversely impacted by electrical service interruptions. We estimate that our oil and gas production for 2000 and 2001 was adversely affected by approximately 43,000 BOE and 60,000 BOE, respectively, as a result of such interruptions. Although under recent regulatory rulings we believe that our operations will only be affected if rolling blackouts occur, and we have made operational changes to mitigate the effects of electrical interruptions, there can be no assurance that our operations will not be adversely impacted in the future by the California power market. Although we are not currently experiencing any significant involuntary curtailment of our crude oil or natural gas production, market, logistic, economic and regulatory factors may in the future materially affect our ability to sell our production.

To manage our exposure to commodity price risks, we utilize various derivative instruments to hedge our exposure to price fluctuations on crude oil sales. Our hedging arrangements provide us protection on the hedged volumes if crude oil prices decline below the prices at which these hedges are set, however, ceiling prices in our hedges may cause us to receive less revenue on the hedged volumes than we would receive in the absence of hedges. We do not currently have any natural gas hedges. See Item 7A—"Quantitative and Qualitative Disclosures about Market Risks".

Substantially all of our and gas production is transported by pipelines, trucks and barges owned by third parties. The inability or unwillingness of these parties to provide transportation services to us for a reasonable fee could result in our having to find transportation alternatives, increased transportation costs or involuntary curtailment of a significant portion of our oil and gas production.

Deregulation of gas prices has increased competition and volatility of natural gas prices. Prices received for our natural gas are subject to seasonal variations and other fluctuations. All of our gas production is currently sold under various arrangements at spot indexed prices.

PAA is the exclusive purchaser of all of our equity oil production. The following table reflects for the years ended December 31, 2000 and 1999, during which periods PAA was consolidated in our financial statements, customers accounting for more than 10% of consolidated sales (excluding hedging effects):

	Percentage of Consolidated Sales	
	Year Ended December 31,	
Customer	2000	1999
Marathon Ashland Petroleum(1)	12%	—
Sempra Energy Trading Corporation(1)	—	22%
Koch Oil Company(1)	—	18%
	Percentage of Oil and Gas Sales(2)	
Chevron	43%	39%
Equiva Trading Company	23%	—
Tosco Refining Company	—	19%
Conoco Inc.	—	11%
Marathon Ashland Petroleum	13%	16%

(1) These customers pertain to the operations of PAA. Represents percentage of oil and gas sales revenues, plus marketing, transportation, storage and terminalling revenues.

(2) These percentages represent the entities that purchased our equity crude production from PAA.

If we were to lose PAA as the exclusive purchaser of our equity production, we believe such loss would not have a material adverse effect on our results of operations. We believe PAA could be replaced by other purchasers under contracts with similar terms and conditions.

Competition

Our competitors include major integrated oil and natural gas companies, and numerous independent oil and natural gas companies, individuals and drilling and income programs. Many of our larger competitors possess and employ financial and personnel resources substantially greater than those available to us. Such companies are able to pay more for productive crude oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, there is substantial competition for capital available for investment in the oil and natural gas industry.

Regulation

Our operations are subject to extensive regulations. Many federal, state and local departments and agencies are authorized by statute to issue and have issued laws and regulations binding on the oil and natural gas industry and its individual participants. The failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability. However, we do not believe that we are affected in a significantly different manner by these laws and regulations than are our competitors. Due to the myriad of complex federal, state and local regulations that may affect us, directly or indirectly, you should not rely on the following discussion of certain laws and regulations as an exhaustive review of all regulatory considerations affecting our operations.

OSHA

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended, or OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard, the U.S. Environmental Protection Agency, or EPA, community-right-to-know regulations, and similar state statutes require that certain information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with OSHA requirements, including general industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances.

Regulation of Production

The production of crude oil and natural gas is subject to regulation under a wide range of federal and state statutes, rules, orders and regulations. State and federal statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. The states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from crude oil and natural gas wells and the regulation of the spacing, plugging and abandonment of wells. Many states also restrict production to the market demand for oil and natural gas and several states have indicated interest in revising applicable regulations. The effect of these regulations is to limit the amount of oil and natural gas we can produce from our wells and to limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes an ad valorem, production or severance tax with respect to production and sale of crude oil, natural gas and natural gas liquids within its jurisdiction.

Pipeline Regulation

We have pipelines to deliver our production to sales points. Our pipelines are subject to regulation by the U.S. Department of Transportation, or DOT, with respect to the design, installation, testing, construction, operation, replacement, and management of pipeline facilities. In addition, we must permit access to and copying of records, and must make certain reports and provide information as required by the Secretary of Transportation. Comparable regulation exists in the states in which we conduct pipeline operations. Some of our pipelines related to the Point Arguello Unit are also subject to regulation by the Federal Energy Regulatory Commission, or FERC. We believe that our pipeline operations are in substantial compliance with applicable requirements.

Sale of Natural Gas

The FERC regulates interstate natural gas pipeline transportation rates and service conditions. Although the FERC does not regulate natural gas producers such as us, the agency's actions are intended to foster increased competition within all phases of the natural gas industry. To date, the FERC's pro-competition policies have not materially affected our business or operations. It is unclear what impact, if any, future rules or increased competition within the natural gas industry will have on our gas sales efforts.

Additional proposals and/or proceedings that might affect the natural gas industry may be considered by the FERC, the U.S. Congress, or state regulatory bodies. We cannot predict when or if any of these proposals may become effective or what effect, if any, they may have on our operations. We do not believe, however, that our operations will be affected any differently than other gas producers with which we compete.

Environmental Regulation

General

Numerous federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to the protection of the environment affect our operations and costs. In particular, our activities in connection with storage and transportation of crude oil and other liquid hydrocarbons and our use of facilities for treating, processing or otherwise handling hydrocarbons and wastes are subject to stringent environmental laws and regulations. Our operations and properties are subject to extensive and changing federal, state and local laws and regulations relating to environmental protection, including the generation, storage, handling, emission, transportation and discharge of materials into the environment, and relating to safety and health. These laws and regulations may require the acquisition of a permit or other authorization before construction or drilling commences and for certain other activities; limit or prohibit construction, drilling and other activities on certain lands lying within wilderness or wetlands and other protected areas; and impose substantial liabilities for pollution resulting from our operations. The permits required for various of our operations are subject to revocation, modification and renewal by issuing authorities.

As with our industry generally, compliance with existing and anticipated laws and regulations increases our overall cost of business, including our capital costs to construct, maintain and upgrade equipment and facilities. Although these regulations affect our capital expenditures and earnings, we believe that they do not affect our competitive position because our competitors that comply with such laws and regulations are similarly affected. Environmental laws and regulations have historically been subject to change, and we are unable to predict the ongoing cost to us of complying with these laws and regulations or the future impact of such laws and regulations on our operations. Violation of these environmental laws and regulations and any associated permits can result in the imposition of significant administrative, civil and criminal penalties, injunctions and construction bans or delays. A discharge of hydrocarbons or hazardous substances into the environment could, to the extent such event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and claims made by neighboring landowners and other third parties for personal injury and property damage.

Although we obtained environmental studies on our properties in California, the Sunniland Trend and the Illinois Basin, and we believe that such properties have been operated in accordance with standard oil field practices, certain of the fields have been in operation for more than approximately 90 years, and current or future local, state and federal environmental laws and regulations may require substantial expenditures to remediate the properties or to otherwise comply with such rules and regulations. In December 1995, we negotiated an agreement with Chevron, a prior owner of certain of the LA Basin properties, to remediate sections of the properties impacted by prior drilling and production operations. Under this agreement, Chevron agreed to investigate and potentially remediate specific areas contaminated with hazardous components, such as volatile organic substances and heavy metals, and we agreed to excavate and remediate nonhazardous crude oil contaminated soils. We are obligated to construct and operate (for the next 10 years) a minimum of five acres of bioremediation cells for crude oil contaminated soils designated for excavation and treatment by Chevron. Although we believe that we do not have any material obligations for operations conducted before our acquisition of the properties from Chevron, other than our obligation to plug existing wells and those normally associated with customary oil field operations of similarly situated properties (such as the Chevron agreement described above), there can be no assurance that current or future local, state or federal rules and regulations will not require us to spend material amounts to comply with such rules and regulations or that any portion of such amounts will be recoverable from Chevron, either under the December 1995 agreement or the limited indemnity from Chevron contained in the original purchase agreement.

A portion of our Sunniland Trend properties is located within the Big Cypress National Preserve and our operations therein are subject to regulations administered by the National Park Service, or NPS. Under such regulations, a master plan of operations has been approved by the Regional Director of the NPS. The master plan of operations is a comprehensive plan of practices and procedures for our drilling and production operations designed to minimize the effect of such operations on the environment. We must modify the master plan of operations and secure permits from the NPS for new wells that require the use of additional land for drilling operations. The master plan of operations also requires that we restore the surface property affected by drilling and production operations upon cessation of these activities. We do not anticipate that expenditures required to comply with such regulations will have a material adverse effect on our operations.

Approximately 183 acres of our 450 acres in the Montebello Field have been designated as California Coastal Sage Scrub, a known habitat for the gnatcatcher, a species of bird designated as a federal threatened species under the Endangered Species Act, or ESA. Approximately 40 pairs of gnatcatchers are believed to inhabit the property. In addition, our 450 acres have been or will shortly be committed to the Natural Community Conservation Program/Coastal Sage Scrub Project, a voluntary conservation program. A variety of existing laws, rules and guidelines govern activities that can be conducted on properties that contain coastal sage scrub and gnatcatchers. These laws, rules and guidelines generally limit the scope of operations that can be conducted on such properties to those activities that do not materially interfere with such vegetation, the gnatcatcher or its habitat. The ESA provides for criminal penalties for willful violations of the ESA. Other statutes that provide protection to animal and plant species and which may apply to our operations include, but are not necessarily limited to, the Marine Mammal Protection Act, the Marine Protection, Research and Sanctuaries Act, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. Although there can be no assurance that the presence of coastal sage scrub and gnatcatchers on the Montebello Field and existing or future laws, rules and guidelines will not prohibit or limit our operations and our planned activities or future commercial and/or residential development, we believe that we will be able to operate the existing wells and realize the reserve potential identified in our acquisition analysis without undue restrictions or prohibitions.

Water

The Oil Pollution Act, as amended, or OPA, was enacted in 1990 and amends provisions of the Federal Water Pollution Control Act of 1972, as amended, or FWPCA, and other statutes as they pertain to prevention and response to oil spills. The OPA subjects owners of facilities to strict, joint and potentially unlimited liability for containment and removal costs, natural resource damages, and certain other consequences of an oil spill, where such spill is into navigable waters (broadly defined), along shorelines or in the exclusive economic zone of the U.S. The OPA establishes a liability limit for onshore facilities of $350.0 million; however, a party cannot take advantage of this liability limit if the spill is caused by gross negligence or willful misconduct or resulted from a violation of a federal safety, construction, or operating regulation. If a party fails to report a spill or cooperate in the cleanup, the liability limits likewise do not apply. In the event of an oil spill into navigable waters, substantial liabilities could be imposed upon us. States in which we operate have also enacted similar laws. Regulations have been or are currently being developed under OPA and state laws that may also impose additional regulatory burdens on our operations.

The FWPCA imposes restrictions and strict controls regarding the discharge of produced waters and other oil and gas wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters. The FWPCA provides for civil, criminal, and administrative penalties for unauthorized discharges, and, along with OPA, imposes substantial potential liability for the costs of removal, remediation and damages. We believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition or results of operations. In addition, the Coastal Zone Management Act authorizes state implementation and development of programs of management measures for non-point source pollution to restore and protect coastal waters.

Pursuant to the FWPCA, the United States Corps of Engineers, with oversight by the EPA, administers a complex program that regulates activities in wetland areas. Some of our operations may be in areas that have been designated as wetlands and, as such, would be subject to permitting requirements. Failure to properly obtain a permit or violation of permit terms could result in the issuance of compliance orders, restorative injunctions and a host of civil, criminal and administrative penalties. We believe that we are currently in substantial compliance with these permitting requirements.

Some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. We believe that we are in substantial compliance with these state requirements.

Air Emissions

Our operations are subject to the federal Clean Air Act, as amended, and comparable state and local statutes. We believe that our operations are in substantial compliance with these statutes in all states in which we operate.

Amendments to the federal Clean Air Act enacted in late 1990 required most industrial operations in the U.S. to incur capital expenditures in order to meet air emission control standards developed by the EPA and state environmental agencies. In addition, these amendments included a new operating permit for major sources, which applied to some of our facilities. Implementation of these amendments has not had a material adverse effect on our financial condition or results of operations.

Solid Waste

We generate wastes, including hazardous wastes, that are subject to the requirements of the federal Resource Conservation and Recovery Act, or RCRA and comparable state statutes. The EPA is considering the adoption of stricter disposal standards for non-hazardous wastes, including oil and gas wastes. We are not currently required to comply with a substantial portion of the RCRA requirements because our operations generate minimal quantities of hazardous wastes. However, it is possible that additional wastes, which could include wastes currently generated as non-hazardous wastes during operations, will in the future be designated as "hazardous wastes." Hazardous wastes are subject to more rigorous and costly treatment, storage, transportation and disposal requirements than are non-hazardous wastes. On August 8, 1998, the EPA added four petroleum refining wastes to the list of RCRA hazardous wastes. While the full impact of this new rule has yet to be determined, the rule may impose increased expenditures and operating expenses on us, which may require us to assume additional obligations relating to the treatment, storage, transportation and disposal of certain petroleum refining wastes that were not previously regulated as hazardous waste. Additional changes in the regulations could result in additional capital expenditures or operating expenses for us as well as the industry in general.

Hazardous Substances

The Comprehensive Environmental Response, Compensation and Liability Act, as amended, or CERCLA, also known as "Superfund," and comparable state laws impose liability, without regard to fault or the legality of the original act, on certain classes of persons that contributed to the release or threatened release of a "hazardous substance" into the environment. These persons include the current and past owners or operators of the site or sites where the release occurred and companies that disposed or transported or arranged for the disposal or transportation of the hazardous substances found at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In the course of our ordinary operations, we may generate waste that falls within CERCLA's definition of a "hazardous substance." We may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which such hazardous substances have been disposed of or released into the environment. We may be subject to third party lawsuits seeking damages for hazardous substances released into the environment.

We currently own or lease, and have in the past owned or leased, properties where hydrocarbons are being or have been handled. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes were not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination.

Hazardous Materials Transportation Requirements

The DOT regulations affecting pipeline safety require pipeline operators to implement measures designed to reduce the environmental impact of oil discharge from onshore oil pipelines. These regulations require operators to maintain comprehensive spill response plans, including extensive spill response training for pipeline personnel. In addition, DOT regulations contain detailed specifications for pipeline operation and maintenance. We believe our operations are in substantial compliance with such regulations.

Other Business Matters

We must continually acquire, explore for, develop or exploit new crude oil and natural gas reserves to replace those produced or sold. Without successful drilling, acquisition or exploitation operations, our crude oil and natural gas reserves and revenues will decline. Drilling activities are subject to numerous risks, including the risk that no commercially viable crude oil or natural gas production will be obtained. Our decision to purchase, explore, exploit or develop an interest or property will depend in part on the evaluation of data obtained through geophysical and geological analyses and engineering studies, the results of which are often inconclusive or subject to varying interpretations. See "—Oil and Gas Reserves". The cost of drilling, completing and operating wells is often uncertain. Drilling may be curtailed, delayed or canceled as a result of many factors, including title problems, weather conditions, compliance with government permitting requirements, shortages of or delays in obtaining equipment, reductions in product prices or limitations in the market for products. The availability of a ready market for our crude oil and natural gas production also depends on a number of factors, including the demand for and supply of crude oil and natural gas and the proximity of reserves to pipelines or trucking and terminal facilities. See "—Product Markets and Major Customers". Natural gas wells may be shut in for lack of a market or due to inadequacy or unavailability of natural gas pipeline or gathering system capacity.

Substantially all of our oil and gas production is transported by pipelines, trucks and barges owned by third parties. The inability or unwillingness of these parties to provide transportation services to us for a reasonable fee could cause us to seek transportation alternatives, which in turn could result in increased transportation costs to us or involuntary curtailment of a significant portion of our oil and gas production.

Our operations are subject to all of the risks normally incident to the exploration for and the production of crude oil and natural gas, including blowouts, cratering, oil spills and fires, each of which could result in damage to or destruction of crude oil and natural gas wells, production facilities or other property, or injury to persons. The relatively deep drilling conducted by us from time to time involves increased drilling risks of high pressures and mechanical difficulties, including stuck pipe, collapsed casing and separated cable. Our operations in California, including transportation of crude oil by pipelines within the city of Los Angeles, are especially susceptible to damage from earthquakes and involve increased risks of personal injury, property damage and marketing interruptions because of the population density of the area. Although we maintain insurance coverage considered to be customary in the industry, we are not fully insured against certain of these risks, including, in certain instances, earthquake risk in California, either because such insurance is not available or because of high premium costs.

A pipeline may experience damage as a result of an accident or other natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damages and suspension of operations. We maintain insurance of various types that we consider to be adequate to cover our operations and properties. The insurance covers all of our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences.

The occurrence of a significant event not fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe that we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable.

Title to Properties

Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interferes with the use of such properties in the operation of our business.

We believe that we have generally satisfactory title to or rights in all of our producing properties. As is customary in the oil and natural gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. Title investigation is made and title opinions of local counsel are generally obtained only before commencement of drilling operations. We believe that we have satisfactory title to all of our other assets. Although title to such properties are subject to encumbrances in certain cases, such as customary interests generally retained in connection with acquisition of real property, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens and minor easements, restrictions and other encumbrances to which the underlying properties were subject at the time of acquisition by us, we believe that none of such burdens will materially detract from the value of such properties or from our interest therein or will materially interfere with their use in the operation of our business.

Federal and Foreign Taxation

At December 31, 2001, we had remaining federal income tax net operating loss, or NOL, carryforwards of approximately $51.8 million and approximately $34.1 million of alternative minimum tax, or AMT, net operating loss carryforwards available as a deduction against future AMT income. In addition, we had approximately $3.8 million of enhanced oil recovery credits, $5.1 million of AMT credits and $7.0 million of statutory depletion carryforwards at December 31, 2001. The NOL carryforwards expire in 2019. The value of these carryforwards depends on our ability to generate federal taxable income. In addition, for AMT purposes, only 90% of AMT income in any given year may be offset by AMT NOLs.

Our ability to utilize NOL carryforwards to reduce our future federal taxable income and federal income tax is subject to various limitations under the Internal Revenue Code of 1986, as amended, or the Code. The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the issuance or exercise of rights to acquire stock, the purchase or sale of stock by 5% stockholders, as defined in the Treasury Regulations, and our offering of stock during any three-year period resulting in an aggregate change of more than 50%, which we will refer to as an ownership change, in our beneficial ownership.

In the event of an ownership change, Section 382 of the Code imposes an annual limitation on the amount of a corporation's taxable income that can be offset by these carryforwards. The limitation is generally equal to the product of (1) the fair market value of our equity multiplied by (2) a percentage approximately equivalent to the yield on long-term tax-exempt bonds during the month in which an ownership change occurs. In addition, the limitation is increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains (as defined in the Code) inherent in the assets sold. Although no assurances can be made, we do not believe that an ownership change has occurred as of December 31, 2001. Equity transactions after the date hereof by us or by 5% stockholders (including relatively small transactions and transactions beyond our control) could cause an Ownership Change and therefore a limitation on the annual utilization of NOLs.

In the event of an ownership change, the amount of our NOLs available for use each year will depend upon future events that cannot currently be predicted and upon interpretation of complex rules under Treasury Regulations. If less than the full amount of the annual limitation is utilized in any given year, the unused portion may be carried forward and may be used in addition to successive years' annual limitation.

As a result of PAA's operations in Canada, beginning in 2001 we became subject to Canadian federal and provincial income taxes. Our currently payable Canadian income taxes for 2001 totaled $2.1 million.

Employees

As of February 1, 2002, we had 314 full-time employees, none of whom is represented by any labor union. Of such full-time employees, 187 are field personnel involved in oil and gas producing activities.

Item 3. LEGAL PROCEEDINGS

Texas Securities Litigation. In November and December of 1999, class action lawsuits were filed in the United States District Court for the Southern District of Texas alleging that PAA and certain of the general partner's officers and directors violated federal securities laws, primarily in connection with unauthorized trading by a former employee. The consolidated class action filed by purchasers of our common stock and options is captioned Koplovitz v. Plains Resources Inc., et al. The consolidated action filed by purchasers of PAA's common units is captioned Di Giacomo v. Plains All American Pipeline, L.P., et al.

We and PAA reached an agreement with representatives for the plaintiffs for the settlement of all of the class actions, and in January 2001, PAA deposited approximately $30.0 million under the terms of the settlement agreement. The total cost of the settlement to us and PAA, including interest and expenses and after insurance reimbursements, was $14.9 million. Of that amount, $1.0 million was allocated to us by agreement between special independent committees of our board of directors and the board of directors of Plains Holdings Inc. (fka Plains All American Inc.), the then general partner of PAA. The settlement has received final approval by the court. The settlement agreement does not affect the Texas Derivative Litigation and Delaware Derivative Litigation described below.

Delaware Derivative Litigation. Beginning December 3, 1999 derivative lawsuits were filed in the Delaware Chancery Court, New Castle County naming Plains Holdings Inc., the then general partner of PAA, its directors and certain of its officers as defendants alleging that the defendants breached the fiduciary duties that they owed to PAA and its unitholders by failing to monitor properly the activities of its employees. The court has consolidated all of the cases under the caption In Re Plains All American Inc. Shareholders Litigation. A motion to dismiss was filed on behalf of the defendants on August 11, 2000.

An agreement has been reached with the plaintiffs to settle the Delaware litigation by PAA making an aggregate payment of approximately $1.1 million. On March 6, 2002, the Delaware court approved this settlement.

Texas Derivative Litigation. On July 11, 2000, a derivative lawsuit was filed in the United States District Court for the Southern District of Texas entitled Fernandez v. Plains All American Inc., et al., naming Plains Holdings Inc., the then general partner of PAA, its directors and certain of its officers as defendants. This lawsuit contains the same claims and seeks the same relief as the Delaware derivative litigation described above. A motion to dismiss was filed on behalf of the defendants on August 14, 2000. PAA has reached an agreement in principle to settle the Texas derivative litigation. The settlement, which is subject to court approval, contemplates a payment of $112,500 by PAA and does not contemplate any payment by us.

We, in the ordinary course of business, are a claimant and/or defendant in various other legal proceedings. Our management does not believe that the outcome of these legal proceedings, individually and in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

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

No matters were submitted to a vote of the security holders, through solicitation of proxies or otherwise, during the fourth quarter of the fiscal year covered by this report.

Directors and Executive Officers of Plains Resources

Listed below are our directors and executive officers and their business experience for the last five years.

Directors

James C. Flores, age 42, Chairman of the Board and Chief Executive Officer and Director since May 2001. Mr. Flores served as Chairman of the Board of Ocean Energy, Inc. from March 1999 until January 2000, and as Vice Chairman from January 2000 until January 2001. Before its merger into Seagull Energy Corporation he was President and Chief Executive Officer of Ocean Energy, Inc. from July 1995 until March 1999 and a director from 1992 until March 1999.

Jerry L. Dees, age 62, Director since 1997. Mr. Dees retired in 1996 as Senior Vice President, Exploration and Land, for Vastar Resources, Inc. (previously ARCO Oil and Gas Company), a position he had held since 1991

Tom H. Delimitros, age 61, Director since 1988. Mr. Delimitros has been General Partner of AMT Venture Funds, a venture capital firm, since 1989.

William M. Hitchcock, age 62, Director since 1977. Mr. Hitchcock is a partner and has been President, since December 1996, of Pembroke Capital LLC, an investment firm. In addition, he is Chief Executive Officer of Camelot Oil & Gas, an oil and gas company.

John H. Lollar, age 63, Director since 1995. Mr. Lollar has been the Managing Partner of Newgulf Exploration L.P. since December 1996.

D. Martin Phillips, age 48, Director since June 2001. Mr. Phillips has been a Managing Director and principal of EnCap Investments L.L.C., a funds management and investment banking firm that focuses exclusively on the oil and gas industry, since November 1989.

Robert V. Sinnott, age 52, Director since 1994. Mr. Sinnott has been Senior Vice President of Kayne Anderson Investment Management, Inc., an investment management firm, since 1992.

J. Taft Symonds, age 62, Director since 1987. Mr. Symonds has been Chairman of the Board of Symonds Trust Co. Ltd., an investment firm, and Chairman of the Board of Maurice Pincoffs Company, Inc., an international marketing firm, since 1978.

Executive Officers

Franklin R. Bay, age 44, Senior Vice President of Corporate Development, since January 2002. Prior to joining Plains, Mr. Bay served in various capacities with Enron Corp. for approximately five years, including Vice President of Commercial Affairs for Northern Natural Gas Pipeline Company, General Counsel of the Gas Pipeline Group and Head of Broadband Services Emerging Business Group.

Cynthia A. Feeback, age 44, Senior Vice President—Accounting and Treasurer since July 2001. She was our Vice President—Accounting and Assistant Treasurer from May 1999 to July 2001, and our Controller and Assistant Treasurer from May 1998 to May 1999. Previously, Ms. Feeback served as our Controller from 1993 to 1998.

Thomas M. Gladney, age 50, Senior Vice President of Operations since November 2001. He was President of Arguello, Inc., a subsidiary of ours from December 1999 to November 2001. From January 1992 to December 1998, he was Offshore Operations Manager for Oryx Energy Company.

Jere C. Overdyke, Jr., age 50, Executive Vice President and Chief Financial Officer, since May 2001. From 1991 to March 2001, he served in various capacities with Enron Corp., including Managing Director of Enron Global Markets, Enron North America, Enron International and Enron Capital and Trade Resources.

John T. Raymond, age 31, President and Chief Operating Officer since November 2001. He was our Executive Vice President and Chief Operating Officer from May 2001 to November 2001. Mr. Raymond served as Director of Corporate Development of Kinder Morgan, Inc. from January 2000 to May 2001, and as Vice President of Corporate Development of Ocean Energy, Inc. from April 1998 to January 2000. Mr. Raymond also served as Vice President of Howard Weil Labouisse Friedrichs, Inc. from 1992 to April 1998.

Timothy T. Stephens, age 50, Executive Vice President—Administration, Secretary and General Counsel since May 2001. From March 2000 to May 2001, Mr. Stephens practiced as a private business consultant to various clients. He served as Chairman, President and Chief Executive Officer of Abacan Resources Corporation from February 1998 until March 2000. Mr. Stephens was President of Seven Seas Petroleum from February 1995 to May 1997, and Vice President of Enron Capital & Trade Resources Corp. from July 1991 to February 1995.

PART II

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

Price Range of Common Stock

Our common stock is listed and traded on the New York Stock Exchange under the symbol "PLX". Prior to December 21, 2001 our common stock was traded on the American Stock Exchange. The number of stockholders of record of our common stock as of February 28, 2002 was 1,077.

The following table sets forth the range of high and low closing sales prices for our common stock as reported on the applicable Stock Exchange Composite Tapes for the periods indicated below.

	High	Low
2001:		
1st Quarter	$23.65	$19.44
2nd Quarter	26.80	19.89
3rd Quarter	29.50	22.76
4th Quarter	27.70	22.20
2000:		
1st Quarter	$14.75	$10.50
2nd Quarter	17.00	11.00
3rd Quarter	20.13	13.81
4th Quarter	21.75	16.88

Dividend Policy

We have not paid cash dividends on shares of our common stock since our inception and do not anticipate paying any cash dividends on our common stock in the foreseeable future. In addition, the amount of dividends we can pay is restricted by provisions of the indentures governing the issue of $275.0 million of 10.25% Senior Subordinated Notes Due 2006, or 10.25% notes, and the agreement with respect to our $225.0 million revolving credit facility.

Recent Sales of Unregistered Securities

On June 8, 2001, the holders of the remaining 26,892 shares of our series F preferred stock outstanding converted their shares of our series F preferred stock into 2,236,639 shares of our common stock plus a cash payment equal to, with respect to each share of our series F preferred stock converted, the accrued dividends on each share from June 8, 2001 until the first date on which we could cause conversion of the shares, plus a 20% premium on the amount of the accrued dividends. This conversion was exempt from registration pursuant to Section 3(a)(9) of the Securities Act of 1933, as amended.

In the second quarter of 2001, certain holders of our series H preferred stock converted an aggregate of 132,022 shares into 4,439,788 shares of our common stock. This conversion was exempt from registration pursuant to Section 3(a)(9) of the Securities Act of 1933, as amended.

In the third quarter of 2001, pursuant to the terms of our series H preferred stock, the remaining shares of our series H preferred stock outstanding were converted into 1,212,600 shares of our common stock. This conversion was exempt from registration pursuant to Section 3(a)(9) of the Securities Act of 1933, as amended.

Item 6. SELECTED FINANCIAL DATA

The following selected financial information was derived from, and is qualified by reference to, our consolidated financial statements, including the notes thereto, appearing elsewhere in this report. The selected financial data should be read in conjunction with the consolidated financial statements, including the notes thereto, and "Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations" (in thousands, except per share information).

	Year Ended December 31,				
	2001(1)	2000	1999	1998	1997
Statement of Operations Data:					
Revenues:					
Oil and natural gas sales	$215,247	$ 149,342	$ 116,223	$ 102,754	$ 109,403
Other operating revenues	473	—	—	—	—
Marketing, transportation, storage and terminalling revenues	—	6,425,644	10,796,998	3,454,635	2,732,043
Gain on sale of assets(2)	—	48,188	16,457	—	—
	215,720	6,623,174	10,929,678	3,557,389	2,841,446
Expenses:					
Production expenses	71,192	62,140	55,645	50,827	45,486
Marketing, transportation, storage and terminalling expenses	—	6,292,615	10,689,308	3,416,274	2,719,563
Unauthorized trading losses and related expenses(3)	—	7,963	166,440	7,100	—
General and administrative(4)	21,293	50,776	31,402	10,778	8,340
Depreciation, depletion and amortization	28,921	47,221	36,998	31,020	23,778
Reduction of carrying cost of oil and natural gas properties(5)	—	—	—	173,874	—
	121,406	6,460,715	10,979,793	3,689,873	2,797,167
Income from Operations	94,314	162,459	(50,115)	(132,484)	44,279
Equity in earnings of PAA(1)	18,540	—	—	—	—
Gain on PAA unit offerings(6)	170,157	—	9,787	60,815	—
Interest expense	(26,385)	(55,828)	(46,378)	(35,730)	(22,012)
Interest and other income(7)	151	7,411	1,237	834	319
Income (loss) before income taxes, minorityinterest, extraordinary item and cumulative effect of accounting change	256,777	114,042	(85,469)	(106,565)	22,586
Minority interest	—	(42,535)	40,203	(786)	—
Income tax (expense) benefit					
Current	(9,947)	(1,020)	7	(862)	(352)
Deferred	(91,513)	(24,563)	20,472	45,867	(7,975)
Income (loss) before extraordinary item and cumulative effect of accounting change	155,317	45,924	(24,787)	(62,346)	14,259
Extraordinary item, net of tax benefit and minority interest(8)	—	(4,988)	(544)	—	—
Cumulative effect of accounting change, net of tax benefit(9)	(1,986)	(121)	—	—	—
Net income (loss)	153,331	40,815	(25,331)	(62,346)	14,259
Less: cumulative preferred stock dividends(10)	(27,245)	(14,725)	(10,026)	(4,762)	(163)
Net income (loss) applicable to common shareholders	$126,086	$ 26,090	$ (35,357)	$ (67,108)	$ 14,096
Income (loss) per common share—basic:					
Before extraordinary item	$ 6.07	$ 1.75	$ (2.02)	$ (3.99)	$ 0.85
Extraordinary item	—	(0.28)	(0.03)	—	—
Cumulative effect of accounting change	(0.09)	(0.01)	—	—	—
	$ 5.98	$ 1.46	$ (2.05)	$ (3.99)	$ 0.85
Income (loss) per common share—diluted:					
Before extraordinary item	$ 4.82	$ 1.56	$ (2.02)	$ (3.99)	$ 0.77
Extraordinary item	—	(0.17)	(0.03)	—	—
Cumulative effect of accounting change	(0.07)	—	—	—	—
	$ 4.75	$ 1.39	$ (2.05)	$ (3.99)	$ 0.77

Table and footnotes continued on following page

	Year Ended December 31,				
	2001	2000	1999	1998	1997
Cash Flow Data:					
Net cash provided by (used in) operating activities	$120,128	$ 35,860	$ (75,964)	$ 37,630	$ 30,307
Net cash provided by (used in) investing activities	(29,383)	130,183	(266,396)	(483,422)	(107,634)
Net cash provided by (used in) financing activities	(91,221)	(229,191)	404,044	448,622	78,524
EBITDA (11):					
Upstream EBITDA	123,235	74,594	51,172	46,446	59,106
Adjusted Upstream EBITDA	136,769	75,564	51,172	46,446	59,106
PAA Distributions	31,553	30,134	29,472	—	—
Combined EBITDA	168,322	105,698	80,644	46,446	59,106

	As of December 31,				
	2001	2000	1999	1998	1997
Balance Sheet Data:					
Cash and cash equivalents	$ 1,179	$ 5,080	$ 68,228	$ 6,544	$ 3,714
Working capital (deficit)(12)	(9,969)	20,289	115,867	(21,041)	(6,011)
Property and equipment, net	507,425	844,274	787,653	661,726	413,308
Total assets	648,788	1,394,329	1,689,560	972,838	556,819
Long-term debt	282,061	626,376	676,703	431,983	285,728
Other long-term liabilities and deferred income taxes	49,183	3,422	21,107	10,253	5,107
Redeemable preferred stock	—	50,000	138,813	88,487	—
Non-redeemable preferred stock, common stock and other stockholders' equity	254,852	137,140	40,619	69,170	133,193

(1) As a result of the reduction in our ownership interest in PAA, our investment in PAA is accounted for using the equity method of accounting effective January 1, 2001. In prior periods, PAA is included on a consolidated basis. See Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations—General".

(2) Relates to the sale of assets by PAA.

(3) Relates to losses resulting from unauthorized trading activity by a former employee of PAA. See Items 1 and 2—"Business and Properties—Unauthorized Trading Losses".

(4) Expense for 2001 included $8.7 million in costs related to our strategic restructuring and expense for 2000 includes a $5.0 million charge to reserve for potentially uncollectible accounts receivable of PAA.

(5) Represents a noncash charge related to a writedown of the capitalized costs of our proved crude oil and natural gas properties due to low crude oil prices at December 31, 1998.

(6) Gains in 2001 relate to the Transactions and PAA's public offerings of common units. Gains in 1999 relate to PAA's public offering of common units and the gain in 1998 relates to the formation of PAA.

(7) Amount for 2000 includes $4.4 million of previously deferred net gains from terminated interest rate swaps recognized as a result of debt extinguishment.

(8) Relates to the early redemption and refinancing of PAA debt.

(9) The amount for 2001 is the cumulative effect of adopting Statement of Financial Accounting Standards No. 133—"Accounting for Derivative Instruments and Hedging Activities". The amount for 2000 is the cumulative effect adjustment as a result of the adoption of SEC Staff Accounting Bulletin 101—"Revenue Recognition in Financial Statements".

(10) Amount for 2001 includes a $21.4 million deemed dividend and a $2.5 million cash payment related to the redemption and conversion of series F preferred stock in connection with our strategic restructuring. See Items 1 and 2—"Business and Properties—Our June 2001 Strategic Restructuring".

(11) EBITDA means earnings before interest, income taxes, depletion, depreciation and amortization. Upstream EBITDA excludes the results of operations of PAA. Adjusted upstream EBITDA also excludes noncash compensation, interest and other income, general and administrative costs related to the June 2001 strategic restructuring and amortization of option premiums. PAA distributions reflects amounts we received from PAA subsequent to its initial public offering in 1998. Combined EBITDA reflects adjusted upstream EBITDA plus distributions received from PAA. EBITDA is not a measurement presented in accordance with generally accepted accounting principles, or GAAP, and is not intended to be used in lieu of GAAP representations of results of operations and cash provided by operating activities. EBITDA is commonly used by debt holders and financial statement users as a measurement to determine the ability of an entity to meet its interest obligations.

(12) At December 31, 1999, working capital includes $37.9 million and $103.6 million related to pipeline linefill and a segment of the All American Pipeline, respectively, both of which were sold in the first quarter of 2000.

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

General

Before the second quarter of 2001 we were engaged in two related lines of business within the energy industry. The first line of business, referred to as "upstream", acquires, exploits, develops, explores and produces crude oil and natural gas. The second line of business, referred to as "midstream", engaged in the marketing, transportation and terminalling of crude oil. Our midstream business was conducted through our majority ownership in PAA. For financial statement purposes, for the years prior to 2001, the assets, liabilities and earnings of PAA were included in our consolidated financial statements, with the public unitholders' interest reflected as a minority interest.

June 2001 Strategic Restructuring

On June 8, 2001, we sold a portion of our interests in PAA to a group of investors and management of PAA for approximately $155.2 million. The assets we sold in this restructuring included 52%, or approximately 5.2 million, of the subordinated units of PAA, at $22 per unit, and an aggregate 54% ownership interest in the general partner of PAA. We received approximately $110 million in cash and 23,108 shares of our series F preferred stock valued at $45.2 million as consideration for the sale. We recognized a pre-tax gain of $128.3 million in connection with this sale. In connection with our strategic restructuring, the holders of the remaining shares of our series F preferred stock converted their shares into 2.2 million shares of our common stock and received from us a cash payment of approximately $2.5 million, equal to, with respect to each share of our series F preferred stock converted, the accrued dividends on each share from June 8, 2001 until the first date on which we could cause conversion of the shares, plus a 20% premium on the amount of the accrued dividends. Also, in connection with our strategic restructuring, holders of our series H preferred stock converted an aggregate of 132,022 shares into approximately 4.4 million shares of our common stock. We also granted management of PAA an option to acquire an additional 2% ownership interest in the general partner of PAA, which PAA management exercised in September 2001 by paying us $1.5 million in cash and notes. As a result of this exercise we recognized a gain of $1.1 million.

As a result of our strategic restructuring, all of our series F preferred stock and all but approximately 36,000 shares of our series H preferred stock were retired or converted. The remaining outstanding shares of our series H preferred stock were converted into 1.2 million shares of our common stock during the third quarter of 2001.

The excess of the fair value of our Series F preferred stock redeemed as consideration over the carrying value of such series F preferred stock ($21.4 million) is deemed to be a dividend to our preferred stockholders. As a result, for purposes of determining our basic and diluted earnings per share, we deducted this amount in determining our income available to our common stockholders.

In exchange for the significant value we received for the subordinated units (which are subordinated in right to distributions from PAA and are not publicly traded) relative to the then current market price of the publicly traded common units, we entered into a value assurance agreement with each of the purchasers of the subordinated units. The value assurance agreements require us to pay to the holders an amount per fiscal year, payable on a quarterly basis, equal to the difference between $1.85 per unit and the actual amount distributed during that period. The value assurance agreements will expire upon the earlier of the conversion of the subordinated units to common units, or June 8, 2006.

Also in connection with our strategic restructuring:

- we appointed James C. Flores as our Chairman of the Board and Chief Executive Officer and we appointed a new Chief Operating Officer, Chief Financial Officer, and General Counsel and Secretary;

- certain of our employees received transaction-related bonuses and other payments and vested in benefits in accordance with the terms of our employee benefit plans;
- we entered into a separation agreement with PAA whereby, among other things, (1) we agreed to indemnify PAA, its general partner, and its subsidiaries against (a) any claims related to the upstream business, whenever arising, and (b) any claims related to federal or state securities laws or the regulations of any self-regulatory authority, or other similar claims, resulting from alleged acts or omissions by us, our subsidiaries, PAA, or PAA's subsidiaries occurring on or before June 8, 2001, and (2) PAA agreed to indemnify us and our subsidiaries against any claims related to the midstream business, whenever arising;
- we entered into a pension and employee benefits assumption and transition agreement pursuant to which we and the general partner of PAA agreed to the transition of certain employees to the general partner, our provision of certain benefits with respect to the transfer, and our provision of transition-related services;
- with respect to certain of our employees who transferred to the general partner of PAA and who held in-the-money but unvested stock options to acquire our common stock, which were subject to forfeiture due to the transfer of employment, we agreed to substitute for the unvested options a total contingent grant of 51,000 subordinated units with a value equal to the discounted present value of the spread on the unvested options, to vest on the same vesting schedule as the options, as a result of which we recognized $0.5 million in noncash compensation expense; and
- we agreed to contribute 287,500 subordinated units to the general partner of PAA to be used for performance option grants to officers and key employees of the general partner.

As a result of our reduced ownership of PAA and our inability to control PAA's operations, our minority interest in PAA is accounted for using the equity method of accounting effective January 1, 2001. Under this method, we no longer consolidate the assets, liabilities and operating activities of PAA. Rather, we record our proportionate share of PAA's net assets and results of operations.

As of December 31, 2001, our aggregate ownership interest in PAA was approximately 29%, which was comprised of (1) a 44% interest in the general partner of PAA, (2) 45%, or approximately 4.5 million, of the subordinated units and (3) 24%, or approximately 7.9 million, of the common units, including approximately 1.3 million class B common units.

Based on PAA's current annual distribution rate of $2.05 per unit, we would receive an annual distribution from PAA of approximately $27.6 million, including $1.0 million for our 44% of the general partner incentive distribution. The general partner of PAA is entitled to receive incentive distributions if the amount PAA distributes with respect to any quarter exceeds levels specified in PAA's partnership agreement. Under the quarterly incentive distribution provisions, generally the general partner is entitled to 15% of distributions in excess of $0.45 per unit, 25% of distributions in excess or $0.495 per unit and 50% of distributions in excess of $0.675 per unit. Based on the current $2.05 annual distribution level ($0.5125 quarterly) and the current units outstanding, the general partner's incentive distribution is forecast to be approximately $2.2 million, of which we would receive 44%.

Results of Operations

As a result of the change to the equity method of accounting for our investment in PAA, our income statement presentation for 2001 is not comparable to our income statement presentations for 2000 and 1999. The following table reflects our 2001 income statement compared to proforma income statements for 2000 and 1999 adjusted to reflect PAA on the equity method of accounting. Our discussion of the results of operations will be based on the income statement presentation reflected herein.

	Year Ended December 31		
	2001	2000 ProForma	1999 ProForma
		(in thousands)	
Revenues			
Oil	$186,476	$131,672	$109,643
Gas	28,771	16,017	5,094
Other operating revenues	473	—	—
	215,720	147,689	114,737
Costs and Expenses			
Production costs	71,192	62,140	55,646
General and administrative	21,293	10,955	7,919
Depletion, depreciation and amortization	28,921	22,699	19,652
	121,406	95,794	83,217
Income from Operations	94,314	51,895	31,520
Other Income (Expense)			
Equity in earnings of PAA	18,540	50,115	(60,905)
Gain on PAA Unit transactions	170,157	—	—
Interest expense	(26,385)	(30,408)	(25,844)
Interest and other income and expense	151	(95)	10,671
Income (Loss) Before Income Taxes, Extraordinary Items and Cumulative Effect of Accounting Change	256,777	71,507	(44,558)
Income tax (expense) benefit			
Current expense	(9,947)	(1,020)	7
Deferred expense	(91,513)	(24,563)	20,765
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Change	155,317	45,924	(23,786)
Extraordinary item	—	(4,988)	(1,545)
Cumulative effect of accounting change	(1,986)	(121)	—
Net Income (Loss)	153,331	40,815	(25,331)
Preferred dividend requirement	(27,245)	(14,725)	(10,026)
Income (Loss) Attributable to Common Shares	$126,086	$ 26,090	$ (35,357)

The following table reflects the components of our oil and gas revenues and sets forth our revenues and costs and expenses on a BOE basis:

	Year Ended December 31		
	2001	2000 ProForma	1999 ProForma
Daily Average Sales Volumes			
Total			
Oil and liquids (Bbls)	25,422	22,828	21,962
Natural Gas (Mcf)	9,192	8,312	8,665
BOE	26,954	24,213	23,406
Oil and Liquids (Bbls)			
Onshore California	15,858	13,990	14,150
Offshore California	3,920	4,122	2,223
Illinois	2,739	2,799	3,029
Florida	2,905	1,917	2,560
	25,422	22,828	21,962
Natural Gas (Mcf)			
Onshore California	9,192	8,312	8,665
Unit Economics (in dollars)			
Average Liquids Sales Price ($/Bbl)			
Average NYMEX	$26.01	$30.25	$19.25
Hedging gain (loss)	(0.10)	(9.50)	(1.39)
Differential	(5.81)	(4.99)	(4.18)
Net realized(1)	$20.10	$15.76	$13.68
Average Gas Sales Price ($/Mcf)	$ 8.58	$ 5.26	$ 1.61
Average Sales Price per BOE	$21.88	$16.67	$13.43
Average Production Costs per BOE	(7.24)	(7.01)	(6.51)
Gross Margin per BOE	14.64	9.66	6.92
G&A per BOE(2)	(2.16)	(1.22)	(0.92)
Gross Profit per BOE	$12.48	$ 8.44	$ 6.00
DD&A per BOE (oil and gas properties)	$ 2.75	$ 2.25	$ 2.13

(1) Prices in 2000 and 1999 are proforma to include the $0.20/Bbl marketing fee paid to PAA that was eliminated in consolidation.

(2) Excludes costs associated with our strategic restructuring and noncash compensation expense.

Comparison of Year Ended December 31, 2001 to Year Ended December 31, 2000

We reported net income of $153.3 million for the year ended December 31, 2001, compared to net income of $40.8 million for the same period in 2000. Our adjusted EBITDA increased 59% in 2001, to $168.3 million from the $105.7 million reported in 2000.

Excluding certain unusual items, net income for 2001 was $59.9 million compared to $40.8 million in 2000. The unusual items in 2001 include: (i) $170.2 million of gains including (a) $129.4 million in gains related to the sale of a portion of our investment in PAA in connection with our June 2001 strategic restructuring, (2) $38.8 million of gains related to PAA's 2001 equity offerings, and (3) a $2.0 million gain related to the vesting of certain unit grants; (ii) $8.7 million of general and administrative expenses related to our June 2001 strategic restructuring, of which $4.3 million is noncash compensation cost associated with the vesting of performance-based stock options; (iii) a $1.9 million charge (net to our interest) included in equity in earnings of PAA related to our June 2001 strategic restructuring; (iv) a $0.9 million charge related to the termination of an interest rate swap, and (v) a $0.9 million noncash charge representing unamortized premiums for crude oil put options with a subsidiary of Enron Corp.

During the year ended December 31, 2001, our operating revenues from oil, natural gas and electricity sales increased by $68.0 million, from $147.7 million in 2000 to $215.7 million in 2001. The increase primarily reflects more favorable results of our hedging program and higher gas prices. Increased prices contributed $51.4 million in additional revenue, and increased sales volumes contributed $16.6 million.

Our oil sales volumes increased 11%, from 22.8 MBbls per day in 2000 to 25.4 MBbls per day in 2001. On an "as produced" basis, our oil volumes increased 8% from 23.2 MBbls per day in 2000 to 25.1 MBbls per day in 2001. Our gas sales volumes increased 11%, from 8.3 MMcf per day in 2000 to 9.2 MMcf per day in 2001. Production increases were primarily attributable to the continuing development of our onshore California properties.

The average realized price for crude oil and liquids increased 28%, from $15.76 per barrel in 2000 to $20.10 per barrel in 2001. Hedges that we put into place in the latter part of 1999, when crude oil prices were considerably lower, significantly impacted the 2000 realized price. The average realized price for natural gas increased 63%, from $5.26 per Mcf in 2000 to $8.58 per Mcf in 2001. This increase is reflective of the well-publicized high natural gas prices in California during the first half of 2001.

Our production costs increased by $9.1 million, from $62.1 million for the year ended December 31, 2000 to $71.2 million for the same period in 2001. The 2001 increase was primarily attributable to increased volumes, which accounted for $6.8 million of the increase. On a barrel equivalent basis, production costs increased 3%, from $7.01 per BOE in 2000 to $7.24 per BOE in 2001, primarily reflecting higher electricity costs in California during the year.

Our general and administrative, or G&A, expense increased $10.3 million, from $11.0 million for the year ended December 31, 2000 to $21.3 million for the same period in 2001. Included in 2001 G&A is approximately $8.7 million of nonrecurring costs associated with our June 2001 strategic restructuring, of which $4.3 million was noncash compensation cost primarily associated with the vesting of performance-based stock options in connection with our restructuring.

Our depreciation, depletion and amortization, or DD&A, expense increased $6.2 million, from $22.7 million for the year ended December 31, 2000 to $28.9 million for the same period in 2001. Oil and gas DD&A expense increased $7.2 million reflecting higher sales volumes and an increase in the rate per BOE. Our average oil and gas DD&A expense on a per barrel equivalent basis for 2000 was $2.25 per BOE as compared to $2.75 per BOE in 2001. Our oil and gas DD&A rate for the fourth quarter of 2001 and the first nine months of 2002, based on our year-end 2001 oil and gas reserves, is $3.10 per BOE.

Our equity in the earnings of PAA was $18.5 million for the year ended December 31, 2001, as compared to $50.1 million for the same period in 2000. The decrease was primarily attributable to decreases in our ownership interest in 2001 as well as nonrecurring gains included in PAA's 2000 earnings. At December 31, 2000 our ownership interest in PAA was approximately 54%. Primarily as a result of PAA's two public unit offerings during 2001, and our June 2001 strategic restructuring, our ownership interest was approximately 29% at December 31, 2001.

The gain on PAA units reflects: (i) $129.4 million in gains related to the sale of a portion of our investment in PAA in connection with our June 2001 strategic restructuring; (ii) $38.8 million of gains resulting from the increase in the book value of our equity in PAA to reflect our proportionate share of the increase in the underlying net assets of PAA resulting from PAA's 2001 public equity offerings, in which we did not participate; and (iii) a $2.0 million gain related to the vesting of certain unit grants. No similar transactions occurred in 2000.

Our interest expense decreased by $4.0 million, from $30.4 million to $26.4 million for the year ended December 31, 2001 compared to 2000, reflecting lower bank debt and lower interest rates on borrowings under our revolving credit facility.

Our income tax expense increased to $101.5 million for the year ended December 31, 2001 as compared to $25.6 million for the same period in 2000. The increase was primarily attributable to the gains on PAA units discussed above and an increase in our effective tax rate from 35.8% in 2000 to 39.5% in 2001. In 2001 we recognized a deferred tax provision of $91.5 million and a current tax provision of $10.0 million. The current tax provision is primarily attributable to the gain on the sale of PAA units. For 2000 we recognized a deferred tax provision of $24.6 million and a current tax provision of $1.0 million. At December 31, 2001 we have a net deferred tax liability of $44.3 million, primarily attributable to timing differences between the deductibility of certain costs for book and tax purposes.

The cumulative effects of accounting change recognized for the year ended December 31, 2001 is for the adoption of Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities", as amended. The amount in 2000 is for the adoption of SEC Staff Accounting Bulletin 101 "Revenue Recognition in Financial Statements".

Comparison of Year Ended December 31, 2000 to Year Ended December 31, 1999

We reported net income of $40.8 million for the year ended December 31, 2000, compared to a net loss of $25.3 million for the same period in 1999. Combined EBITDA increased 31% in 2000, to $105.7 million from the $80.6 million reported in 1999.

Our operating revenues from oil and natural gas sales were $147.7 million in 2000, an increase of $33.0 million over 1999 due to higher commodity prices and increased sales volumes, which contributed approximately $28.5 million and $4.5 million to the increase, respectively.

Our oil sales volumes increased from 22.0 MBbls per day in 1999 to 22.8 MBbls per day in 2000. The volume increase is primarily attributable to a full year of production from our offshore California property that was acquired in mid-1999. Our gas sales volumes decreased from 8.7 MMcf per day in 1999 to 8.3 MMcf per day in 2000.

The average realized price for oil increased 15%, from $13.68 per barrel in 1999 to $15.76 per barrel in 2000. The average NYMEX oil price increased from $19.25 per barrel in 1999 to $30.25 per barrel in 2000. We did not participate in the full amount of this increase as hedges that we put into place in the latter part of 1999, when oil prices were significantly lower, decreased our realized price by $9.50 per barrel. The average realized price for gas increased 227%, from $1.61 per Mcf in 1999 to $5.26 per Mcf in 2000. This increase is reflective of the well-publicized high gas prices in California during the latter half of 2000.

Our production costs were $62.1 million in 2000, an increase of $6.5 million over 1999 due to higher production costs and increased sales volumes, which contributed $4.4 million and $2.1 million to the increase, respectively. On a barrel equivalent basis, production costs increased 8%, from $6.51 per BOE in 1999 to $7.01 per BOE in 2000, primarily reflecting a full year of production from our offshore California property, increased gas fuel costs and upward pressure on costs throughout the service industry.

Our G&A expense increased $3.1 million, from $7.9 million for the year ended December 31, 1999 to $11.0 million for the same period in 2000. The increase primarily reflects higher personnel costs and expenses related to our corporate reorganization and $1.0 million in expenses related to PAA's unauthorized trading loss.

Our DD&A expense increased $3.0 million, from $19.7 million for the year ended December 31, 1999 to $22.7 million for the same period in 2000. Oil and gas DD&A expense increased $1.8 million, with $1.1 million of the increase from higher sales volumes. Our oil and gas DD&A expense on a per barrel equivalent basis for 1999 was $2.13 per BOE as compared to $2.25 per BOE in 2000.

Our equity in the earnings of PAA was $50.1 million for the year ended December 31, 2000, as compared to a loss of $60.9 million for the same period in 1999. The loss in 1999 was due to unauthorized trading losses of $166.4 million incurred by PAA in 1999.

Our interest expense increased by $4.6 million, from $25.8 million to $30.4 million for the year ended December 31, 2000 compared to 1999, reflecting higher bank debt.

Our income tax expense increased to $25.6 million for the year ended December 31, 2000 as compared to an income tax benefit of $20.8 million for the same period in 1999.

The extraordinary items in 2000 and 1999 relate to the early redemption and refinancing of PAA debt.

Liquidity and Capital Resources

General

Cash generated from our upstream operations, PAA distributions and our revolving credit facility are our primary sources of liquidity. At December 31, 2001 we had availability on our revolving credit facility of $212.9 million. We believe that we have sufficient liquid assets, cash from operations and, if necessary, borrowing capacity under our credit facility to meet our short term normal recurring operating needs, debt service obligations, contingencies and anticipated capital expenditures. We also believe that we have sufficient liquid assets, cash from operations and borrowing capacity under our credit facility to meet our long term normal recurring operating needs, contingencies and anticipated capital expenditures. In 2006, our approximately $267.5 million of 10.25% senior subordinated notes will mature. We believe that we will refinance the 10.25% senior subordinated notes before they mature, however, there can be no assurance that we will be able to do so.

Cash Flows

	Year Ended December 31,		
	2001	2000	1999
		(in millions)	
Cash provided by (used in):			
Operating activities	$120.1	$ 35.9	$ (76.0)
Investing activities	(29.4)	130.2	(266.4)
Financing activities	(91.2)	(229.2)	404.0

Operating Activities. Net cash provided by operating activities in 2001 totaled $120.1 million compared to net cash provided by operating activities of $35.9 million in 2000. The net increase is primarily attributable to higher realized oil and gas prices and increased sales volumes. Net cash used in operating activities in 1999 resulted from the unauthorized trading losses of PAA.

Investing Activities. In 2001 net cash used in investing activities was $29.4 million. Additions to oil and gas properties and equipment used $131.8 million in cash, and we made capital contributions to

PAA of $4.0 million to maintain our proportionate general partner share of equity offerings by PAA. To maintain its 2% general partner interest, the general partner of PAA is required to make a capital contribution each time PAA has a new equity offering. These uses of cash were offset by $106.9 million in cash proceeds received as a result of our June 2001 strategic restructuring. During 2000 investing activities provided cash of $130.2 million. Proceeds from PAA asset sales of $224.3 million were offset primarily by expenditures of $12.2 million for crude oil pipeline, gathering and terminal costs and $78.7 million for upstream acquisition, exploration and development costs. Net cash used in investing activities for 1999 included approximately $176.9 million for midstream acquisitions, primarily for the Scurlock and West Texas gathering system acquisitions, approximately $12.5 million for midstream capital costs and $77.9 for upstream acquisition, exploration, exploitation and development costs.

Financing Activities. Cash used in financing activities in 2001 included a net reduction in long-term debt of $23.9 million, expenditures of $67.7 million for our repurchase of 2.8 million shares of our common stock stock, $9.2 million in proceeds from new issuances of our common stock, and $8.7 million in preferred stock dividends. Cash used in financing activities in 2000 included a net reduction in long and short term debt of $158.0 million, expenditures of $23.6 million for our repurchase of 1.3 million shares of our common stock, $13.4 million in preferred stock dividends and $29.4 million in distributions to PAA unitholders. Cash provided by financing activities in 1999 was generated primarily from net issuances of $50.0 million of our series F preferred stock, $50.8 million in PAA common units and $325.2 million of short-term and long-term debt. Financing activities for 1999 also included dividend payments of approximately $4.2 million on our series E preferred stock and distributions to PAA unitholders of $22.2 million.

Our Board of Directors has authorized the repurchase of up to eight million shares of our common stock. During 2001 we repurchased 2.8 million shares for $67.7 million and in 2000 we repurchased 1.3 million shares for $23.6 million. Our average cost for the share purchases was $24.02 per share in 2001 and $18.34 per share in 2000.

Capital Expenditures

We have made and will continue to make substantial capital expenditures for the acquisition, exploitation, development, exploration and production of crude oil and natural gas reserves. Historically, we have financed these expenditures primarily with cash generated by operations, bank borrowings and the issuance of our common stock and our preferred stock. We intend to make aggregate capital expenditures, including capitalized G&A and interest, of approximately $77 million in 2002 for exploitation of our existing properties. In addition, we intend to continue to pursue the acquisition of underdeveloped producing properties. We will also be required to make capital contributions to the general partner of PAA for any PAA equity offerings. We believe that we will have sufficient cash from operating activities and borrowings under the revolving credit facility to fund our capital expenditures.

Commitments

At December 31, 2001, the aggregate amounts of contractually obligated payment commitments for the next five years are as follows (in thousands):

	2002	2003	2004	2005	2006	Thereafter
Long-term debt	511	1,949	6,261	4,313	267,450	—
Operating leases	616	593	595	573	143	—
	1,127	2,542	6,856	4,886	267,593	—

The long-term debt amounts consist principally of amounts due under our revolving credit facility and 10.25% senior subordinated notes. Historically, we have renewed and/or extended our revolving credit facility prior to commencing scheduled payments. There can be no assurance, however, that we will be able to do so in the future. We believe that we will refinance the 10.25% senior subordinated notes before they mature, however, there can be no assurance that we will be able to do so.

In connection with our June 2001 strategic restructuring, we entered into value assurance agreements with the purchasers of the subordinated units, under the terms of which we will pay the purchasers an amount per fiscal year, payable on a quarterly basis, equal to $1.85 per unit less the actual amount distributed during that year. The value assurance agreements will expire upon the earlier of (a) the conversion of all of the subordinated units to common units or (b) June 8, 2006. In the first quarter of 2002 PAA paid a quarterly distribution of $0.5125 per unit ($2.05 annualized).

Revolving Credit Facility

Amounts borrowed under our credit facilities were as follows at the dates indicated (in thousands):

	December 31,	
	2001	2000
Plains, excluding PAA		
Revolving credit facility	$11,500	$ 27,300
	11,500	27,300
PAA		
Revolving credit facility	—	320,000
Letter of credit and hedged inventory facility	—	1,300
	—	321,300
	$11,500	$348,600

We have a $225.0 million revolving credit facility with a group of banks. Our revolving credit facility is guaranteed by all of our upstream subsidiaries and is collateralized by our upstream oil and natural gas properties and those of the guaranteeing subsidiaries and the stock of all the upstream subsidiaries. The borrowing base under the revolving credit facility at December 31, 2001 was $225.0 million and is subject to redetermination from time to time by the lenders in good faith, in the exercise of the lenders' sole discretion, and in accordance with customary practices and standards in effect from time to time for crude oil and natural gas loans to borrowers similar to us. Our borrowing base may be affected from time to time by the performance of our oil and natural gas properties and changes in oil and natural gas prices. We incur a commitment fee of 3/8% per annum on the unused portion of the borrowing base. In addition, we pay a fee of 1 3/8% per annum of the face amount of letters of credit that are issued under our revolving credit facility. Our revolving credit facility terminates on July 1, 2003, at which time the remaining outstanding balance converts to a term loan, repayable in eight equal quarterly installments commencing October 1, 2003, with a final maturity of July 1, 2005. Our revolving credit facility bears interest, at our option, of either LIBOR plus 1 3/8% or the base rate (as defined in our facility). At December 31, 2001, letters of credit of $0.6 million were outstanding under the revolving credit facility.

Our revolving credit facility contains covenants which, among other things, limit the payment of cash dividends on our common stock, limit repurchases of our common stock, limit the amount of our consolidated debt, limit our ability to make certain loans and investments, and provide that we must maintain a specified relationship between current assets and current liabilities.

In October 2001 we amended the terms of our revolving credit facility to allow us to purchase any combination of our own common stock, our senior subordinated notes and PAA common units and pay cash dividends on our common stock (up to $30 million) up to a total of $150.0 million. At December 31, 2001 we had $117.5 million available under this provision of the credit facility.

As of December 31, 2001, we were in compliance with the covenants contained in our revolving credit facility and could have borrowed the full $225.0 million available under the facility.

10.25% Senior Subordinated Notes Due 2006

At December 31, 2001 we had $267.5 million principal amount of 10.25% Senior Subordinated Notes Due 2006, or 10.25% notes, outstanding, bearing a coupon rate of 10.25%. The 10.25% notes were issued in 1996 ($150.0 million), 1997 ($50.0 million) and 1999 ($75.0 million). In 2001 we repurchased $7.55 million of the 10.25% notes at 99.5% of par.

The 10.25% notes are redeemable, at our option, at 105.13% of the principal amount through March 15, 2002, at 103.42% on or after March 15, 2002, at 101.71% on or after March 15, 2003 and at 100% on or after March 15, 2004 plus, in each case, accrued interest to the date of redemption.

The indentures governing our 10.25% notes contain covenants that: (1) limit the incurrence of additional indebtedness; (2) limit certain investments; (3) limit restricted payments; (4) limit the disposition of assets; (5) limit the payment of dividends and other payment restrictions affecting subsidiaries; (6) limit transactions with affiliates; (7) limit the creation of liens; and (8) restrict mergers, consolidations and transfers of assets. In the event of a change of control and a corresponding rating decline under the indentures, we will be required to make an offer to repurchase the 10.25% notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of the repurchase.

The 10.25% notes are unsecured general obligations and are subordinated in right of payment to all our existing and future senior indebtedness and are guaranteed by certain of our subsidiaries on a full, unconditional, joint and several basis.

Contingencies

Following our announcement in November 1999 of PAA's losses resulting from unauthorized trading by a former employee, numerous class action lawsuits were filed against PAA, certain of its general partner's officers and directors and in some of these cases, its general partner and us alleging violations of the federal securities laws. In addition, derivative lawsuits were filed in the Delaware Chancery Court against PAA's general partner, its directors and certain of its officers alleging the defendants breached the fiduciary duties owed to PAA and its unitholders by failing to monitor properly the activities of its traders. These suits have been settled. See Item 3.—"Legal Proceedings."

Recent Accounting Pronouncements

The following Statements of Financial Accounting Standards, or SFAS's, were issued in June 2001: SFAS No. 141, Business Combinations, SFAS No. 142, Goodwill and Other Intangible Assets, and SFAS No. 143, Accounting for Asset Retirement Obligations. In August 2001, SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets was also issued. SFAS No. 141 requires the use of the purchase method of accounting for all business combinations. It applies to all business combinations initiated after June 30, 2001 and to all business combinations accounted for by the purchase method that are completed after June 30, 2001. SFAS No. 142 requires that goodwill as well as other intangible assets with indefinite lives not be amortized but be tested annually for impairment and is effective for fiscal years beginning after December 15, 2001. SFAS No. 144 addresses financial accounting and reporting for the impairment of long-lived assets and long-lived assets to be disposed of. It supersedes, with exceptions, SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of and is effective for fiscal years beginning after December 15, 2001. SFAS No. 141, No. 142 and No. 144 had no effect on our financial statements. We will account for all future business combinations and any related goodwill in accordance with the provisions of SFAS No. 141 and SFAS No. 142.

SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost will be allocated to expense using a systematic and rational method. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. We are currently assessing the impact of SFAS No. 143 and at this time cannot reasonably estimate the effect of this statement on our consolidated financial position, results of operations or cash flows.

In the fourth quarter of 2000, we adopted SEC Staff Accounting Bulletin 101, "Revenue Recognition in Financial Statements", or SAB 101. As a result, we record revenue from crude oil production in the period it is sold as opposed to when it is produced and carry any unsold production as inventory valued at historical cost. The total effect of implementing SAB 101 was to reduce reported sales volumes by 144,000 barrels for 2000 and net income for the year by $175,000, including a $121,000 reduction for the cumulative effect of prior years. The effect of this change in accounting for crude oil inventories on prior periods was deminimus.

Critical Accounting Policies and Factors That May Affect Future Results

Based on the accounting policies we have in place, which are discussed in Note 1 to the consolidated financial statements, certain factors may impact our future financial results. The most significant of these factors and their effect on certain of our accounting policies is discussed below.

Commodity Pricing and Risk Management Activities

Prices for oil and gas have historically been volatile. Decreases in oil and gas prices from current levels will adversely affect our revenues, results of operations, cash flows and proved reserves. If the industry experiences significant prolonged future price decreases, this could be materially adverse to our operations and our ability to fund planned capital expenditures

Periodically, we enter into hedging arrangements relating to a portion of our oil production to achieve a more predictable cash flow, as well as to reduce our exposure to adverse price fluctuations. Hedging instruments used are typically fixed price swaps and purchased puts and calls. While the use of these types of hedging instruments limits our downside risk to adverse price movements, they are subject to a number of risks, including instances in which the benefit to revenues is limited when commodity prices increase. For a further discussion concerning our risks related to oil and gas prices and our hedging programs, see Item 7A—Quantitative and Qualitative Disclosures About Market Risks.

Write-downs Under Full Cost Ceiling Test Rules

Under the SEC's full cost accounting rules we review the carrying value of our proved oil and gas properties each quarter. Under these rules, capitalized costs of proved oil and gas properties (net of accumulated depreciation, depletion and amortization, and deferred income taxes) may not exceed a "ceiling" equal to the present value of estimated future net cash flows from proved oil and gas reserves (including the effect of any related hedging activities), discounted at 10 percent, plus the lower of cost or fair value of unproved properties included in the costs being amortized (net of related tax effects). These rules generally require that we price our future oil and gas production at the oil and gas prices in effect at the end of each fiscal quarter and require a write-down if our capitalized costs exceed this "ceiling," even if prices declined for only a short period of time. We have had no write-downs due to these ceiling test limitations since 1998. Given the volatility of oil and gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline significantly in the future, even if only for a short period of time, it is possible that write-downs of our oil and gas properties could occur. Write-downs required by these rules do not impact cash flows from our operating activities.

Oil and Gas Reserves

The process of estimating quantities of proved reserves is inherently uncertain, and the reserve data included in this annual report are only estimates. Reserve engineering is a subjective process of estimating underground accumulations of natural gas and crude oil that cannot be measured in an exact manner. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgment of the persons preparing the estimate.

The proved reserve information included in this annual report is based on estimates prepared by outside engineering firms. Estimates prepared by others may be higher or lower than these estimates. Because these estimates depend on many assumptions, all of which may substantially differ from actual results, reserve estimates may be different from the quantities of natural gas and crude oil that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate.

You should not assume that the present value of future net cash flows is the current market value of our estimated proved natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate.

Our rate of recording DD&A is dependent upon our estimate of proved reserves. If the estimates of proved reserves declines, the rate at which we record DD&A expense increases, reducing net income. Such a decline may result from lower market prices, which may make it non-economic to drill for and produce higher cost fields. In addition, the decline in proved reserve estimates may impact the outcome of the "ceiling" test discussed above.

Operating Risks and Insurance Coverage

Our operations are subject to all of the risks normally incident to the exploration for and the production of crude oil and natural gas, including blowouts, cratering, oil spills and fires, each of which could result in damage to or destruction of crude oil and natural gas wells, production facilities or other property, or injury to persons. Our operations in California, including transportation of crude oil by pipelines within the city of Los Angeles, are especially susceptible to damage from earthquakes and involve increased risks of personal injury, property damage and marketing interruptions because of the population density of the area. Although we maintain insurance coverage considered to be customary in the industry, we are not fully insured against some risks, including earthquake risk in California, either because insurance is not available or because of high premium costs. The occurrence of a significant event that is not fully insured against could have a material adverse effect on our financial position. Our insurance does not cover every potential risk associated with operating our pipelines, including the potential loss of significant revenues. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences.

Environmental Matters

As an owner or lessee and operator of oil and gas properties, we are subject to various federal, state, and local laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liabilities on the lessee under an oil and gas lease for the cost of pollution clean-up resulting from operations, subject the lessee to liability for pollution damages, and require suspension or cessation of operations in affected areas. We maintain insurance coverage, which we believe is customary in the industry, although we are not fully insured against all environmental risks. We have established policies for continuing compliance with environmental laws and regulations and have made and will continue to make expenditures in our efforts to comply with these requirements, which we believe are necessary business costs in the oil and gas industry.

Although we obtained environmental studies on our properties in California, the Sunniland Trend and Illinois Basin, and we believe that such properties have been operated in accordance with standard oil field practices, certain of the fields have been in operation for approximately 90 years, and current or future federal, state and local environmental laws and regulations may require substantial expenditures to comply with such rules and regulations. While we do not believe that compliance with current federal, state or local environmental laws and regulations will have a material adverse effect on our capital expenditures, results of operations or competitive position; there is no assurance that changes in or additions to such laws or regulations will not have such an impact.

Consistent with normal industry practices, substantially all of our crude oil and natural gas leases require that, upon termination of economic production, the working interest owners plug and abandon non-producing wellbores, remove tanks, production equipment and flow lines and restore the wellsite. We have estimated that the cost to perform these tasks is approximately $17.0 million, net of salvage value and other considerations. Such estimated costs are amortized to expense through the unit-of-production method as a component of accumulated depreciation, depletion and amortization. Results from operations for 2001, 2000 and 1999 each include $0.5 million of expense associated with these estimated future costs.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

We are exposed to various market risks, including volatility in crude oil commodity prices and interest rates. To manage our exposure, we monitor current economic conditions and our expectations of future commodity prices and interest rates when making decisions with respect to risk management. We do not enter into derivative transactions for speculative trading purposes.

On January 1, 2001, we adopted SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities" as amended by SFAS 137 and SFAS 138, or SFAS 133. Under SFAS 133, all derivative instruments are recorded on the balance sheet at fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. To qualify for hedge accounting, the derivative must qualify either as a fair value hedge, cash flow hedge or foreign currency hedge. Currently, we use only cash flow hedges and the remaining discussion will relate exclusively to this type of derivative instrument. If the derivative qualifies for hedge accounting, the gain or loss on the derivative is deferred in accumulated Other Comprehensive Income, or OCI, a component of our stockholders' equity, to the extent the hedge is effective.

The relationship between the hedging instrument and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the contract and on an ongoing basis. Hedge accounting is discontinued prospectively when a hedge instrument becomes ineffective. Gains and losses deferred in OCI related to cash flow hedges that become ineffective remain unchanged until the related product is delivered. If it is determined that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument are recognized in earnings immediately.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. Hedge effectiveness is measured on a quarterly basis. This process includes specific identification of the hedging instrument and the hedged item, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. No amounts were excluded from the computation of hedge effectiveness. At December 31, 2001, all open positions qualified for hedge accounting.

Unrealized gains and losses on hedging instruments reflected in OCI and adjustments to carrying amounts on hedged volumes are included in oil and gas revenues in the period that the related volumes are delivered. Gains and losses of hedging instruments which represent hedge ineffectiveness as well as any amounts excluded from the assessment of hedge effectiveness are recognized currently in oil and gas revenues. Effective October 2001, we implemented Derivatives Implementation Group, or DIG, Issue G20, "Cash Flow Hedges: Assessing and Measuring the Effectiveness of a Purchased Option Used in a Cash Flow Hedge", which provides guidance for assessing the effectiveness on total changes in an option's cash flows rather than only on changes in the option's intrinsic value. Implementation of this DIG Issue G20 will reduce earnings volatility since it allows us to include changes in the time value of purchased options and collars in the assessment of hedge effectiveness. Time value changes were previously recognized in current earnings since we excluded time value changes from the assessment of hedge effectiveness. Oil and gas revenues for the year ended December 31, 2001 include a $3.4 million non-cash loss related to the ineffective portion of the cash flow hedges representing the fair value change in the time value of options for the nine months prior to the implementation of DIG Issue G20.

We utilize various derivative instruments to hedge our exposure to price fluctuations on crude oil sales. The derivative instruments consist primarily of cash-settled crude oil option and swap contracts entered into with financial institutions. We do not currently have any natural gas hedges. We also utilize interest rate swaps and collars to manage the interest rate exposure on our long-term debt. In October 2001 we entered into a three-year interest rate swap agreement, fixing at 5.29% the interest rate on $7.5 million of borrowing under our revolving credit facility.

On January 1, 2001, in accordance with the transition provisions of SFAS 133, we recorded a gain of $4.5 million in OCI representing the cumulative effect of an accounting change to recognize at fair value all cash flow derivatives, including our equity in the cash flow derivatives of PAA. We recorded cash flow hedge derivative assets and liabilities of $20.6 million and $18.1 million, respectively, and a net-of-tax non-cash charge of $2.0 million was recorded in earnings as a cumulative effect adjustment.

For the year ended December 31, 2001 net unrealized gains of $9.8 million were added to OCI and the fair value of open positions increased $16.2 million. At December 31, 2000, we had an interest rate swap arrangement to protect interest rate fluctuations on a portion of our outstanding debt. The position was terminated prior to maturity and as a result $0.6 million related to such position was relieved from OCI.

At December 31, 2001, net unrealized gains on our option and swap contracts included in OCI was $16.7 million. The related assets and liabilities were included in other current assets ($21.8 million), other assets ($5.7 million), and deferred income taxes ($10.8 million). Additionally, OCI includes our $2.3 million (net of tax) equity in the unrealized OCI losses of PAA. As of December 31, 2001, $13.2 million of deferred net gains on derivative instruments recorded in OCI are expected to be reclassified to earnings during the next twelve-month period.

Commodity Price Risk. At March 13, 2002, we had the following open crude oil hedge positions:

	Barrels Per Day	
	2002	2003
Puts		
Average price $20.00/bbl	2,000	—
Calls		
Average price $35.17/bbl	9,000	—
Swaps		
Average price $24.00/bbl	17,000	—
Average price $23.12/bbl	—	12,500

These positions provide for us to receive for the year ended December 31, 2002 an average minimum NYMEX price of approximately $23.58 per barrel on 19,000 barrels per day with full upside participation above $20.00 per barrel on 11% of those hedged barrels, and upside participation above $35.17 per barrel on 47% of those hedged barrels. For example, if the NYMEX index averages $20.00 during 2002, we will receive $23.58 per barrel; if the NYMEX index averages $25.00 per barrel, we will receive $24.11 per barrel; if the NYMEX index averages $30.00 per barrel, we will receive $24.63 per barrel; and if the NYMEX index average were to fall to $15.00 per barrel we would receive $23.58 per barrel, all on the hedged barrels. For 2003, we have entered into various arrangements that provide for us to receive an average fixed NYMEX price of $23.12 per barrel on 12,500 barrels per day regardless of the NYMEX index average. Location and quality differentials attributable to our properties and the cost of the hedges are not included in the foregoing prices. Because of the quality and location of our crude oil production, these adjustments will reduce our net price per barrel.

The agreements provide for monthly cash settlement based on the differential between the agreement price and the actual NYMEX price. Gains or losses are recognized in the month of related production and are included in crude oil and natural gas sales revenues. Such contracts resulted in a reduction of revenues of $0.9 million, $79.4 million and $11.1 million for the years ended December 31, 2001, 2000 and 1999, respectively. At December 31, 2001, we had an unrealized gain of $16.6 million (net of tax) with respect to such contracts. The estimated fair value of the hedges is included in our balance sheet at December 31, 2001.

The fair value of outstanding derivative commodity instruments and the change in fair value that would be expected from a 10 percent price decrease are shown in the table below (in millions):

	December 31,			
	2001		2000	
	Fair Value	Effect of 10% Price Decrease	Fair Value	Effect of 10% Price Decrease
Swaps and options contracts	$28.8	$18.5	$17.3	$(13.0)
Futures contracts	$ —	$ —	$ (9.4)	$ 6.0

The fair value of the swaps and option contracts are estimated based on quoted prices from independent reporting services compared to the contract price of the swap and approximate the gain or loss that would have been realized if the contracts had been closed out at year end. All hedge positions offset physical positions exposed to the cash market. None of these offsetting physical positions are included in the above table. Price-risk sensitivities were calculated by assuming an across-the-board 10 percent decrease in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of an actual 10 percent change in prompt month crude oil prices, the fair value of our derivative portfolio would typically change less than that shown in the table due to lower volatility in out-month prices.

In the fourth quarter of 2001 we terminated our open crude oil put options with Enron Risk Management Corp. and charged earnings for $0.9 million, representing unamortized premiums for such options. The contract counterparties for our current derivative commodity contracts are all major financial institutions with Standard & Poor's ratings of A or better. Three of the financial institutions are participating lenders in our revolving credit facility, with one such counterparty holding contracts that represent approximately 37% of the fair value of all open positions at December 31, 2001.

Our management intends to continue to maintain hedging arrangements for a significant portion of our production. These contracts may expose us to the risk of financial loss in certain circumstances. Our hedging arrangements provide us protection on the hedged volumes if crude oil prices decline below the prices at which these hedges are set, but ceiling prices in our hedges may cause us to receive less revenue on the hedged volumes than we would receive in the absence of hedges.

Interest Rate Risk. Our debt instruments are sensitive to market fluctuations in interest rates. The table below presents principal payments and the related weighted average interest rates by expected maturity dates and the estimated fair value for debt outstanding at December 31, 2001. Our variable rate debt bears interest at LIBOR or prime plus the applicable margin. The average interest rates presented below are based upon rates in effect at December 31, 2001. The carrying value of variable rate bank debt approximates fair value because interest rates are variable, based on prevailing market rates. The fair value of fixed rate debt was based on quoted market prices based on trades of subordinated debt.

	Expected Year of Maturity							
	2002	2003	2004	2005	2006	Thereafter	Total	Fair Value
	(dollars in millions)							
Long-term debt—variable rate	$ —	$ 1.4	$ 5.8	$ 4.3	$—	$ —	$ 11.5	$ 11.5
Average interest rate	—	5.10%	5.10%	5.10%	—	—	5.10%	
Long-term debt—fixed rate	$0.5	$ 0.5	$ 0.5	$ —	$—	$267.5	$269.0	$272.1
Average interest rate	8.00%	8.00%	8.00%	—	—	10.25%	10.24%	

Interest rate swaps are used to hedge underlying debt obligations. These instruments hedge specific debt issuances and qualify for hedge accounting. The interest rate differential is reflected as an adjustment to interest expense over the life of the instruments. At December 31, 2001, we had an interest rate swap for an aggregate notional principal amount of $7.5 million, for which we would receive approximately $0.03 million if such arrangement were terminated as of such date. The swap is based on LIBOR margins and provides for a fixed rate of 3.914% with an expiration date of October 2004. The adjustment to interest expense resulting from interest rate swaps for the years ended December 31, 2001 and 2000 was a $0.03 million loss and a $0.3 million gain, respectively.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required here is included in this report as set forth in the "Index to Financial Statements" on page F-1.

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

None.

PART III

Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Information regarding our directors and executive officers will be included in the proxy statement for the 2002 annual meeting of stockholders to be filed within 120 days after December 31, 2001, and is incorporated by reference to this report.

We have provided summary information with respect to our directors and executive officers following Item 4 in Part I of this report.

Item 11. EXECUTIVE COMPENSATION

Information regarding executive compensation will be included in the proxy statement and is incorporated by reference to this report.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information regarding beneficial ownership will be included in the proxy statement and is incorporated by reference to this report.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information regarding certain relationships and related transactions will be included in the proxy statement and is incorporated by reference to this report.

PART IV

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

(a) (1) and (2) Financial Statements and Financial Statement Schedules

See "Index to Consolidated Financial Statements" set forth on Page F-1.

(a) (3) Exhibits

2.1 Stock Purchase Agreement dated as of March 15, 1998, among Plains Resources Inc., Plains All American Inc. and Wingfoot Ventures Seven Inc. (incorporated by reference to Exhibit 2(b) to the Company's Annual Report on Form 10-K for the year ended December 31, 1997).

2.2 Unit Transfer and Contribution Agreement, dated as of May 8, 2001, among Sable Investments, L.P., Sable Holdings, L.P., James C. Flores, Plains Resources Inc., Plains Holdings Inc. (formerly known as Plains All American Inc.) and Plains Holdings LLC (formerly known as PAAI LLC) (incorporated by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K filed on May 10, 2001).

2.3 Unit Transfer and Contribution Agreement, dated as of May 8, 2001, among KAFU Holdings, LLC, Plains Resources Inc., Plains Holdings Inc. (formerly known as Plains All American Inc.), and Plains Holdings LLC (formerly known as PAAI LLC) (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K filed on May 10, 2001).

2.4 First Amendment, dated as of June 8, 2001, to Unit Transfer and Contribution Agreement, dated as of May 8, 2001, among KAFU Holdings, LLC, Plains Resources Inc., Plains Holdings Inc. (formerly known as Plains All American Inc.), and Plains Holdings LLC (formerly known as PAAI LLC) (incorporated by reference to Exhibit 99.9 to the Company's Current Report on Form 8-K filed on June 13, 2001).

2.5 Unit Transfer and Contribution Agreement, dated as of May 8, 2001, among E-Holdings III, L.P., Plains Resources Inc., Plains Holdings Inc. (formerly known as Plains All American Inc). and Plains Holdings LLC (formerly known as PAAI LLC) (incorporated by reference to Exhibit 99.4 to the Company's Current Report on Form 8-K filed on May 10, 2001).

2.6 First Amendment, dated as of June 8, 2001, to Unit Transfer and Contribution Agreement, dated as of May 8, 2001, among E-Holdings III, L.P., Plains Resources Inc., Plains Holdings Inc. (formerly known as Plains All American Inc.) and Plains Holdings LLC (formerly known as PAAI LLC) (incorporated by reference to Exhibit 99.10 to the Company's Current Report on Form 8-K filed on June 13, 2001).

2.7 Unit Transfer and Contribution Agreement, dated as of June 8, 2001, among Strome Hedgecap Fund, L.P., Plains Resources Inc., Plains Holdings Inc. (formerly known as Plains All American Inc.) and Plains Holdings LLC (formerly known as PAAI LLC) (incorporated by reference to Exhibit 99.5 to the Company's Current Report on Form 8-K filed on June 13, 2001).

2.8 Unit Transfer and Contribution Agreement, dated as of June 8, 2001, among Mark E. Strome, Plains Resources Inc., Plains Holdings Inc. (formerly known as Plains All American Inc.), and Plains Holdings LLC (formerly known as PAAI LLC) (incorporated by reference to Exhibit 99.6 to the Company's Current Report on Form 8-K filed on June 13, 2001).

2.9 Unit Transfer and Contribution Agreement, dated as of June 8, 2001, among John T. Raymond, Plains Resources Inc., Plains Holdings Inc. (formerly known as Plains All American Inc.) and Plains Holdings LLC (formerly known as PAAI LLC) (incorporated by reference to Exhibit 99.7 to the Company's Current Report on Form 8-K filed on June 13, 2001).

2.10 Contribution Agreement, dated as of June 8, 2001, among PAA Management, L.P., Plains Resources Inc., Plains Holdings Inc. (formerly known as Plains All American Inc.), and Plains Holdings LLC (formerly known as PAAI LLC) (incorporated by reference to Exhibit 99.8 to the Company's Current Report on Form 8-K filed on June 13, 2001).

3.1 Second Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3(a) to the Company's Annual Report on Form 10-K for the year ended December 31, 1995).

*3.2 Bylaws of the Company

3.3 Certificate of Designation, Preference and Rights of Series D Cumulative Convertible Preferred Stock (incorporated by reference to Exhibit 3(c) to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 1997).

3.4 First Amendment to the Plains Resources Inc. Bylaws. (incorporated by reference to Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

4.1 Indenture dated as of March 15, 1996, among the Company, the Subsidiary Guarantors named therein and Texas Commerce Bank National Association, as Trustee for the Company's 10¼% Senior Subordinated Notes due 2006, Series A and Series B (incorporated by reference to Exhibit 4(b) to the Company's Form S-3 (Registration No. 333-1851)).

4.2 Indenture dated as of July 21, 1997, among the Company, the Subsidiary Guarantors named therein and Texas Commerce Bank National Association, as Trustee for the Company's 10¼% Senior Subordinated Notes due 2006, Series C and Series D (incorporated by reference to Exhibit 4 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1997).

4.3 Specimen Common Stock Certificate (incorporated by reference to Exhibit 4 to the Company's Form S-1 Registration Statement (Reg. No. 33-33986)).

4.4 Warrant dated November 12, 1997, to Shell Land & Energy Company for the purchase of 150,000 shares of Common Stock (incorporated by reference to Exhibit 4(d) to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1997).

4.5 Indenture dated as of September 15, 1999, among Plains Resources Inc., the Subsidiary Guarantors named therein and Chase Bank of Texas, National Association, as Trustee (incorporated by reference to Exhibit 4(a) to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1999).

4.6 Registration Rights Agreement dated as of September 22, 1999, among Plains Resources Inc., the Subsidiary Guarantors named therein, J.P. Morgan Securities Inc. and First Union Capital Markets Corp. (incorporated by reference to Exhibit 4(b) to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1999).

4.7 Stock Purchase Agreement dated as of December 15, 1999, among Plains Resources Inc. and the purchasers named therein (incorporated by reference to Exhibit 4(g) to the Company's Annual Report on Form 10-K for the year ended December 31, 1999).

4.8 Amendment to Stock Purchase Agreement dated as of December 17, 1999, among Plains Resources Inc. and the purchasers named therein (incorporated by reference to Exhibit 4(h) to the Company's Annual Report on Form 10-K for the year ended December 31, 1999).

10.1 The Company's 1991 Management Options (incorporated by reference to Exhibit 4.1 to the Company's Form S-8 Registration Statement (Reg. No. 33-43788)).

10.2 The Company's 1992 Stock Incentive Plan (incorporated by reference to Exhibit 4.3 to the Company's Form S-8 Registration Statement (Reg. No. 33-48610)).

10.3 The Company's Amended and Restated 401(k) Plan (incorporated by reference to Exhibit 10(d) to the Company's Annual Report on Form 10-K for the year ended December 31, 1996).

10.4 The Company's 1996 Stock Incentive Plan (incorporated by reference to Exhibit 4 to the Company's Form S-8 Registration Statement (Reg. No. 333-06191)).

10.5 First Amendment to the Company's 1992 Stock Incentive Plan (incorporated by reference to Exhibit 10(n) to the Company's Annual Report on Form 10-K for the year ended December 31, 1996).

10.6 Second Amendment to the Company's 1992 Stock Incentive Plan (incorporated by reference to Exhibit 10(b) to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1997).

10.7 First Amendment to Plains Resources Inc. 1996 Stock Incentive Plan dated May 21, 1998 (incorporated by reference to Exhibit 10(z) to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1998)

10.8 Third Amendment to Plains Resources Inc. 1992 Stock Incentive Plan dated May 21, 1998 (incorporated by reference to Exhibit 10(aa) to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1998).

10.9 Purchase and Sale Agreement dated June 4, 1999, by and among the Company, Chevron U.S.A., Inc., and Chevron Pipe Line Company (incorporated by reference to Exhibit 10(h) to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1999).

10.10 Second Amendment to Plains Resources 1996 Stock Incentive Plan dated May 20, 1999 (incorporated by reference to Exhibit 10(q) to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1999).

10.11 Third Amendment to Plains Resources 1996 Stock Incentive Plan dated June 7, 2000 (incorporated by reference to Exhibit 10.23 to the Company's Annual Report on Form 10-K for the Year Ended December 31, 2000).

10.12 Forms of Officer Stock Option Agreement (incorporated by reference to Exhibits 4.1 and 4.2 to the Company's Form S-8 Registration Statement (Registration No. 333-45562).

10.13 Contribution, Conveyance and Assumption Agreement among Plains All American Pipeline, L.P. and certain other parties dated as of November 23, 1998 (incorporated by reference to Exhibit 10.03 to Annual Report on Form 10-K for the Year Ended December 31, 1998 for Plains All American Pipeline, L.P.).

10.14 Crude Oil Marketing Agreement among Plains Resources Inc., Plains Illinois Inc., Stocker Resources, L.P., Calumet Florida, Inc. and Plains Marketing, L.P. dated as of November 23, 1998 (incorporated by reference to Exhibit 10.07 to Annual Report on Form 10-K for the Year Ended December 31, 1998 for Plains All American Pipeline, L.P.).

10.15 Omnibus Agreement among Plains Resources Inc., Plains All American Pipeline, L.P., Plains Marketing, L.P., All American Pipeline, L.P., and Plains Holdings Inc. (formerly known as Plains All American Inc.) dated as of November 23, 1998 (incorporated by reference to Exhibit 10.08 to Annual Report on Form 10-K for the Year Ended December 31, 1998 for Plains All American Pipeline, L.P.).

10.16 First Amendment to Contribution, Conveyance and Assumption Agreement dated as of December 15, 1998 (incorporated by reference to Exhibit 10.13 to Annual Report on Form 10-K for the Year Ended December 31, 1998 for Plains All American Pipeline, L.P.).

10.17 Employment Agreement dated as of May 8, 2001 between Plains Resources Inc. and James C. Flores (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the three months ended March 31, 2001).

10.18 Performance Stock Option Agreement dated as of May 8, 2001 between Plains Resources Inc. and James C. Flores (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.19 Separation Agreement dated as of June 8, 2001 by and among Plains Resources Inc., Plains Holdings Inc. (formerly known as Plains All American Inc.), Plains All American GP LLC, Plains AAP, LP and Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.20 Pension and Employee Benefits Assumption and Transition Agreement, dated as of June 8, 2001, by and between Plains Resources Inc., Plains Holdings Inc. (formerly known as Plains All American Inc.) and Plains All American GP LLC (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.21 Value Assurance Agreement dated as of June 8, 2001 by and among Plains Resources Inc. and Sable Holdings L.P. and schedule of other Value Assurance Agreements substantially identical thereto (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.22 Contribution, Assignment and Amendment Agreement dated as of June 8, 2001, between Plains Holdings Inc. (formerly known as Plains All American Inc.), Plains AAP, LP and Plains All American GP LLC. (incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.23 Registration Rights Agreement dated as of May 8, 2001, among Plains Resources Inc. and James C. Flores. (incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.24 Registration Rights Agreement dated as of June 8, 2001, among Plains Resources Inc., Strome Hedgecap Fund L.P., Strome Series Fund 1, Strome Series Fund 2 and Mark E. Strome. (incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.25 Registration Rights Agreement dated as of June 8, 2001, among Plains All American Pipeline, L.P., Sable Holdings, L.P., E-Holdings III, L.P., KAFU Holdings, LP, PAA Management, L.P., Mark E. Strome, Strome Hedgecap Fund, L.P., John T. Raymond, and Plains Holdings Inc. (formerly known as Plains All American Inc.) (incorporated by reference to Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.26 Registration Rights Agreement dated as of June 8, 2001, among Plains Resources Inc. and EnCap Energy Capital Fund III, L.P., EnCap Energy Capital Fund III-B, L.P., BOCP Energy Partners, L.P. and Energy Capital Investment Company PLC. (incorporated by reference to Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.27 Registration Rights Agreement dated as of June 8, 2001, among Plains Resources Inc. and Kayne Anderson Capital Advisors, L.P. (incorporated by reference to Exhibit 10.11 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.28 Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC, dated as of June 8, 2001. (incorporated by reference to Exhibit 10.12 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.29 Amended and Restated Limited Partnership Agreement of Plains AAP, L.P, dated June 8, 2001. (incorporated by reference to Exhibit 10.13 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.30 Plains Resources Inc. 2001 Stock Incentive Plan. (incorporated by reference to Exhibit 10.15 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.31 Amendment and Transfer Agreement—Plains Resources Inc. 401(k) Plan and Trust and the Plains All American 401(k) Plan and Trust (incorporated by reference to Exhibit 10.16 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.32 Fifth Amended and Restated Credit Agreement dated as of October 5, 2001, by and among Plains Resources Inc., The Chase Manhattan Bank, as Co-Agent for the Lenders, First Union National Bank, as agent for the Lenders, and the Lenders named within, amending and restating the Original Agreement (incorporated by reference to Exhibit 2.1 to the Company's Quarterly Report on Form 10-Q for the three months ended September 30, 2001).

10.33 Letter Agreement dated as of October 23, 2001 by and between Plains Marketing, L.P. ("Plains Marketing") and Stocker Resources, L.P. ("Stocker"), regarding the Crude Oil Sales Agreement dated April 1, 2001 between Tosco Refining Co. and Plains Marketing for Stocker's Arroyo Grande Crude Oil (incorporated by reference to Exhibit 2.2 to the Company's Quarterly Report on Form 10-Q for the three months ended September 30, 2001).

*10.34 Value Assurance Agreement, dated as of August 17, 2001, by and among Plains Resources Inc. and First Union Investors, Inc.

*10.35 Employment Agreement dated June 7, 2001, between John T. Raymond and Plains Resources Inc.

*10.36 Combination Incentive Stock Option and Nonqualified Stock Option Agreement, dated as of June 7, 2001, between John T. Raymond and Plains Resources Inc.

*10.37 Performance Stock Option Agreement, dated as of June 7, 2001, between John T. Raymond and Plains Resources Inc.

*10.38 Employment Agreement dated June 7, 2001, between Jere C. Overdyke and Plains Resources Inc.

*10.39 Combination Incentive Stock Option and Nonqualified Stock Option Agreement, dated as of June 7, 2001, between Jere C. Overdyke and Plains Resources Inc.

*10.40 Performance Stock Option Agreement, dated as of June 7, 2001, between Jere C. Overdyke and Plains Resources Inc.

*10.41 Employment Agreement dated June 7, 2001, between Timothy T. Stephens and Plains Resources Inc.

*10.42 Combination Incentive Stock Option and Nonqualified Stock Option Agreement, dated as of June 7, 2001, between Timothy T. Stephens and Plains Resources Inc.

*10.43 Performance Stock Option Agreement, dated as of June 7, 2001, between Timothy T. Stephens and Plains Resources Inc.

*21.1 Subsidiaries of the Company

*23.1 Consent of PricewaterhouseCoopers LLP.

*23.2 Consent of H.J. Gruy and Associates, Inc.

*23.3 Consent of Netherland, Sewell and Associates, Inc.

*23.4 Consent of Ryder Scott Company.

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* Filed herewith

Reports on Form 8-K

On November 8, 2001 we filed a Form 8-K with respect to Item 9, Regulation FD Disclosures. The report discussed our fourth quarter 2001 estimates.

On December 19, 2001 we filed a Form 8-K with respect to Item 9, Regulation FD Disclosures. The report discussed our year 2002 estimates.

SIGNATURES

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

PLAINS RESOURCES INC.

Date: March 21, 2002

By: /s/ JERE C. OVERDYKE, Jr.
Jere C. Overdyke, Jr.
Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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

Signature	Title	Date
/s/ JAMES C. FLORES **James C. Flores**	Chairman of the Board and Chief Executive Officer (Principal Executive Officer)	March 21, 2002
/s/ JERRY L. DEES **Jerry L. Dees**	Director	March 21, 2002
/s/ TOM H. DELIMITROS **Tom H. Delimitros**	Director	March 21, 2002
/s/ WILLIAM M. HITCHCOCK **William M. Hitchcock**	Director	March 21, 2002
/s/ JOHN H. LOLLAR **John H. Lollar**	Director	March 21, 2002
/s/ D. MARTIN PHILLIPS **D. Martin Phillips**	Director	March 21, 2002
/s/ ROBERT V. SINNOTT **Robert V. Sinnott**	Director	March 21, 2002
/s/ J. TAFT SYMONDS **J. Taft Symonds**	Director	March 21, 2002
/s/ JERE C. OVERDYKE, Jr. **Jere C. Overdyke, Jr.**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 21, 2002
/s/ CYNTHIA A. FEEBACK **Cynthia A. Feeback**	Senior Vice President—Accounting and Treasurer (Principal Accounting Officer)	March 21, 2002

PLAINS RESOURCES INC.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

All other schedules are omitted because they are not applicable or the required information is shown in the financial statements or notes thereto.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and
Stockholders of Plains Resources Inc.

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Plains Resources Inc. 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. 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 of these statements in accordance with auditing standards generally accepted in the United States of America, which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for its crude oil inventories in connection with its adoption of Staff Accounting Bulletin No. 101, "Revenue Recognition in Financial Statements", effective January 1, 2000.

As discussed in Note 3 to the consolidated financial statements, the Company changed its method of accounting for derivative instruments and hedging activities in connection with its adoption of Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities", as amended effective January 1, 2001.

PricewaterhouseCoopers LLP

Houston, Texas
March 13, 2002

PLAINS RESOURCES INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in thousands of dollars)

	December 31, 2001	December 31, 2000
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,179	$ 5,080
Accounts receivable	20,039	357,790
Commodity hedging contracts and other derivatives	23,257	6,033
Inventory	6,721	54,844
Other current assets	1,527	11,662
	52,723	435,409
Property and Equipment, at cost		
Oil and natural gas properties—full cost method		
Subject to amortization	900,898	762,245
Not subject to amortization	40,506	42,581
Crude oil pipeline, gathering and terminal assets	—	470,460
Other property and equipment	4,003	6,453
	945,407	1,281,739
Less allowance for depreciation, depletion and amortization	(437,982)	(437,465)
	507,425	844,274
Investment in Plains All-American Pipeline, L.P.	64,626	—
Other Assets	24,014	114,646
	$ 648,788	$1,394,329
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and other current liabilities	$ 53,895	$ 399,773
Interest payable	8,286	13,536
Notes payable	511	1,811
	62,692	415,120
Long-Term Debt		
Bank debt	11,500	27,300
Bank debt of subsidiary	—	320,000
Subordinated debt	269,539	277,543
Other	1,022	1,533
	282,061	626,376
Other Long-Term Liabilities	4,889	3,422
Deferred Income Taxes	44,294	—
Commitments and Contingencies (Note 15)		
Minority Interest in Plains All American Pipeline, L.P.	—	162,271
Cumulative Convertible Preferred Stock, stated at liquidation preference	—	50,000
Non-redeemable Preferred Stock, Common Stock and Other Stockholders' Equity		
Series D Cumulative Convertible Preferred Stock, $1.00 par value, 46,600 shares authorized, issued and outstanding, at stated value	23,300	23,300
Series H Cumulative Convertible Preferred Stock, $1.00 par value, 175,000 shares authorized; nil and 169,571 shares issued and outstanding, at stated value	—	84,785
Common Stock, $0.10 par value, 50,000,000 shares authorized; 27,677,411 and 18,746,612 shares issued for 2001 and 2000	2,768	1,875
Additional paid-in capital	268,520	139,203
Retained earnings (deficit)	37,676	(88,410)
Accumulated other comprehensive income	13,930	—
Treasury stock, at cost	(91,342)	(23,613)
	254,852	137,140
	$ 648,788	$1,394,329

See notes to consolidated financial statements.

PLAINS RESOURCES INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	Year Ended December 31,		
	2001	2000	1999
Revenues			
Crude oil and liquids	$186,476	$ 133,325	$ 111,128
Natural gas	28,771	16,017	5,095
Marketing, transportation, storage and terminalling	—	6,425,644	10,796,998
Gain on sale of assets	—	48,188	16,457
Other operating revenues	473		
	215,720	6,623,174	10,929,678
Costs and Expenses			
Production expenses	71,192	62,140	55,645
General and administrative	21,293	50,776	31,402
Marketing, transportation, storage and terminalling	—	6,292,615	10,689,308
Unauthorized trading losses and related expenses	—	7,963	166,440
Depreciation, depletion and amortization	28,921	47,221	36,998
	121,406	6,460,715	10,979,793
Income (Loss) from Operations	94,314	162,459	(50,115)
Other Income (Expense)			
Equity in earnings of Plains All American Pipeline, L.P.	18,540	—	—
Gains on Plains All American Pipeline, L.P. unit transactions and public offerings	170,157	—	9,787
Interest expense	(26,385)	(55,828)	(46,378)
Interest and other income	151	7,411	1,237
Income (Loss) Before Income Taxes, Minority Interest, Extraordinary Items and Cumulative Effect of Accounting Changes	256,777	114,042	(85,469)
Minority interest in Plains All American Pipeline, L.P.	—	(42,535)	40,203
Income tax (expense) benefit:			
Current	(9,947)	(1,020)	7
Deferred	(91,513)	(24,563)	20,472
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	155,317	45,924	(24,787)
Extraordinary items, net of tax benefit and minority interest	—	(4,988)	(544)
Cumulative effect of accounting changes, net of tax benefit	(1,986)	(121)	—
Net Income (Loss)	153,331	40,815	(25,331)
Cumulative preferred dividends	(27,245)	(14,725)	(10,026)
Income (Loss) Available to Common Stockholders	$126,086	$ 26,090	$ (35,357)
Basic Earnings Per Share			
Income (loss) before extraordinary items and cumulative effect of accounting changes	$ 6.07	$ 1.75	$ (2.02)
Extraordinary items	—	(0.28)	(0.03)
Cumulative effect of accounting changes	(0.09)	(0.01)	—
Net income (loss)	$ 5.98	$ 1.46	$ (2.05)
Diluted Earnings Per Share			
Income (loss) before extraordinary items and cumulative effect of accounting changes	$ 4.82	$ 1.56	$ (2.02)
Extraordinary items	—	(0.17)	(0.03)
Cumulative effect of accounting changes	(0.07)	—	—
Net income (loss)	$ 4.75	$ 1.39	$ (2.05)

See notes to consolidated financial statements.

PLAINS RESOURCES INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2001	2000	1999
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$153,331	$ 40,815	$(25,331)
Items not affecting cash flows from operating activities:			
Depreciation, depletion and amortization	28,921	47,221	36,998
Equity in earnings of Plains All American Pipeline, L.P.	(18,540)	—	—
Distributions received from Plains All American Pipeline, L.P.	31,553	—	—
Noncash gains	(170,157)	(48,188)	(26,244)
Minority interest in income of a subsidiary	—	35,566	(40,203)
Loss on early extinguishment of debt, net of tax	—		
Deferred income taxes	91,513	21,297	(20,472)
Cumulative effect of adoption of SFAS 133	1,986	—	—
Change in derivative fair value	1,227	—	—
Noncash compensation expense	4,514	2,682	1,013
Allowance for doubtful accounts	—	5,000	—
Other noncash items	1,626	10,925	(61)
Change in assets and liabilities from operating activities:			
Accounts receivable and other	21,023	102,651	(226,438)
Inventory	1,133	(13,977)	33,930
Accounts payable and other current liabilities	(29,636)	(143,453)	171,974
Pipeline linefill	—	(16,679)	(3)
Other long-term liabilities	1,634	(8,000)	18,873
Net cash provided by (used in) operating activities	120,128	35,860	(75,964)
CASH FLOWS FROM INVESTING ACTIVITIES			
Acquisition, exploration and developments costs	(131,785)	(78,726)	(77,899)
Additions to other property and assets	(561)	(3,133)	(2,472)
Plains All American Pipeline, L.P. acquisitions and assets	—	(12,219)	(189,425)
Proceeds from the sale of Plains All American Pipeline, L.P. units	106,941	—	—
Investment in Plains All American Pipeline, L.P.	(3,978)	—	—
Proceeds from asset sales	—	224,261	3,400
Net cash provided by (used in) investing activities	(29,383)	130,183	(266,396)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from long-term debt	204,900	1,698,575	744,971
Proceeds from short-term debt	—	51,300	131,119
Proceeds from sale of common stock	9,169	2,301	5,542
Proceeds from issuance of preferred stock	—	—	50,000
Proceeds from issuance of common units, net	—	—	50,759
Purchase of senior subordinated notes	(7,550)	—	—
Principal payments of long-term debt	(221,211)	(1,799,186)	(449,332)
Principal payments of short-term debt	—	(108,719)	(82,150)
Purchase of common stock	(67,729)	(23,613)	—
Costs incurred in connection with financing arrangements	—	(6,748)	(19,448)
Preferred stock dividends	(8,698)	(13,409)	(4,245)
Distributions to Plains All American Pipeline, L.P. unitholders	—	(29,432)	(22,201)
Other	(102)	(260)	(971)
Net cash provided by (used in) financing activities	(91,221)	(229,191)	404,044
Net increase (decrease) in cash and cash equivalents	(476)	(63,148)	61,684
Decrease in cash due to deconsolidation of Plains All American Pipeline, L.P.	(3,425)	—	—
Cash and cash equivalents, beginning of year	5,080	68,228	6,544
Cash and cash equivalents, end of year	$ 1,179	$ 5,080	$ 68,228

See notes to consolidated financial statements.

PLAINS RESOURCES INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands)

	Year Ended December 31, 2001	2000	1999
Net Income (Loss)	$153,331	$40,815	$(25,331)
Other Comprehensive Income:			
Unrealized gains on derivatives:			
Cumulative effect of accounting change, net of taxes of $4,383	6,856	—	—
Unrealized gains arising during the year, net of taxes of $8,329	12,803	—	—
Reclassification adjustment for gains realized in net income, net of tax benefit of $1,921	(2,989)	—	—
	16,670	—	—
Minimum pension liability adjustment, net of tax benefit of $272	(421)	—	—
	16,249	—	—
Equity in other comprehensive income changes of Plains All American Pipeline, L.P.			
Cumulative effect of accounting change, net of tax benefit of $1,496	(2,340)	—	—
Change in fair value of open hedging positions, net of taxes of $5	21	—	—
	(2,319)	—	—
Other Comprehensive Income	13,930	—	—
Comprehensive Income (Loss)	$167,261	$40,815	$(25,331)

See notes to consolidated financial statements.

PLAINS RESOURCES INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN NON-REDEEMABLE PREFERRED STOCK, COMMON STOCK AND OTHER STOCKHOLDERS' EQUITY

(in thousands)

	2001		2000		1999	
	Shares	Amount	Shares	Amount	Shares	Amount
Series D Cumulative Convertible Preferred Stock						
Balance, beginning of year	47	$ 23,300	47	$ 23,300	47	$ 21,946
Preferred stock dividends	—	—	—	—	—	1,354
Balance, end of year	47	23,300	47	23,300	47	23,300
Series H Cumulative Convertible Preferred Stock						
Balance, beginning of year	170	84,785	—	—	—	—
Shares issued upon conversion of redeemable preferred stock	—	—	170	84,785	—	—
Conversion of preferred stock into common	(170)	(84,785)	—	—	—	—
Balance, end of year	—	—	170	84,785	—	—
Common Stock						
Balance, beginning of year	18,747	1,875	17,924	1,792	16,882	1,688
Common stock issued upon exercise of options, warrants and other	1,041	103	557	56	943	94
Conversion of preferred stock into common	7,889	790	266	27	99	10
Balance, end of year	27,677	2,768	18,747	1,875	17,924	1,792
Additional Paid-in Capital						
Balance, beginning of year		139,203		130,027		124,679
Common stock issued upon exercise of options, warrants and other		18,429		5,223		3,583
Conversion of preferred stock into common		110,888		3,958		1,765
Redemption of preferred stock		—		(5)		—
Balance, end of year		268,520		139,203		130,027
Retained Earnings (Deficit)						
Balance, beginning of year		(88,410)		(114,500)		(79,143)
Preferred stock dividends		(27,245)		(14,725)		(10,026)
Net income (loss)		153,331		40,815		(25,331)
Balance, end of year		37,676		(88,410)		(114,500)
Accumulated Other Comprehensive Income						
Balance, beginning of year		—		—		—
Other comprehensive income		13,930		—		—
Balance, end of year		13,930		—		—
Treasury Stock						
Balance, beginning of year	(1,291)	(23,613)	—	—	—	—
Purchase of common stock	(2,830)	(67,729)	(1,291)	(23,613)	—	—
Balance, end of year	(4,121)	(91,342)	(1,291)	(23,613)	—	—
Total		$254,852		$137,140		$ 40,619

See notes to consolidated financial statements.

Note 1—Organization and Significant Accounting Policies

Organization

The consolidated financial statements of Plains Resources Inc. ("Plains", "our", or "we") include the accounts of all wholly owned subsidiaries and for periods prior to January 1, 2001, Plains All American Pipeline, L.P. ("PAA"). As discussed in Note 2, in June 2001 we reduced our interest in PAA from 54% to 33% and as a result we no longer have the ability to exercise control over the operations of PAA. Accordingly, effective January 1, 2001, our minority interest investment in PAA is accounted for using the equity method of accounting. Under the equity method, we no longer consolidate the assets, liabilities and operating activities of PAA, but instead record our proportionate share of PAA's net assets and results of operations. For periods prior to January 1, 2001 the assets, liabilities and results of operations of PAA are consolidated in our financial statements.

All significant intercompany transactions have been eliminated. Certain reclassifications have been made to the prior year statements to conform to the current year presentation.

We are an independent energy company that is currently engaged in the "Upstream" oil and gas business. The Upstream business acquires, exploits, develops, explores for and produces crude oil and natural gas. Our Upstream activities are all located in the United States. Prior to the reduction in our interest in PAA, we also participated directly in the "Midstream" oil and gas business, which consists of the marketing, transportation and terminalling of crude oil. We continue to participate indirectly in the Midstream oil and gas business through our minority interest in PAA. All of PAA's Midstream activities are conducted in the United States and Canada.

Significant Accounting Policies

Oil and Gas Properties. We follow the full cost method of accounting whereby all costs associated with property acquisition, exploration, exploitation and development activities are capitalized. Such costs include internal general and administrative costs such as payroll and related benefits and costs directly attributable to employees engaged in acquisition, exploration, exploitation and development activities. General and administrative costs associated with production, operations, marketing and general corporate activities are expensed as incurred. These capitalized costs along with our estimate of future development and abandonment costs, net of salvage values and other considerations, are amortized to expense by the unit-of-production method using engineers' estimates of proved oil and natural gas reserves. The costs of unproved properties are excluded from amortization until the properties are evaluated. Interest is capitalized on oil and natural gas properties not subject to amortization and in the process of development. Proceeds from the sale of oil and natural gas properties are accounted for as reductions to capitalized costs unless such sales involve a significant change in the relationship between costs and the estimated value of proved reserves, in which case a gain or loss is recognized. Unamortized costs of proved properties are subject to a ceiling which limits such costs to the present value of estimated future cash flows from proved oil and natural gas reserves of such properties (including the effect of any related hedging activities) reduced by future operating expenses, development expenditures and abandonment costs (net of salvage values), and estimated future income taxes thereon.

Other Property and Equipment. Other property and equipment is recorded at cost and consists primarily of office furniture and fixtures and computer hardware and software. Acquisitions, renewals, and betterments are capitalized; maintenance and repairs are expensed. Depreciation is provided using the straight-line method over estimated useful lives of three to seven years. Net gains or losses on property and equipment disposed of are included in interest and other income in the period in which the transaction occurs.

Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates made by management include (1) crude oil and natural gas reserves, (2) depreciation, depletion and amortization, including future abandonment costs, (3) income taxes and related valuation allowance, (4) allowance for doubtful accounts receivable and (5) accrued liabilities. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Cash and Cash Equivalents. Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less. At December 31, 2001 and 2000, the majority of cash and cash equivalents is concentrated in two institutions and at times may exceed federally insured limits. We periodically assess the financial condition of the institutions and believe that any possible credit risk is minimal.

Accounts Receivable, Net. At December 31, 2000, PAA had an allowance for doubtful accounts receivable of $5.0 million that is reflected in the consolidated balance sheet as a reduction of certain accounts receivable which are included in Other Assets. At December 31, 2001 the allowance is reflected in our investment in PAA.

Inventory. Plains' crude oil inventories are carried at cost. Materials and supplies inventory is stated at the lower of cost or market with cost determined on an average cost method. PAA's crude oil inventories are carried at the lower of cost, adjusted for deferred gains or losses, or market value using an average cost method.

Inventory consists of the following (in thousands):

	December 31,	
	2001	2000
Plains, excluding PAA		
Crude oil	$ 1,467	$ 3,347
Materials and supplies	5,254	4,716
	6,721	8,063
PAA		
Crude oil	—	45,914
Materials and supplies	—	867
	—	46,781
	$ 6,721	$54,844

Other Assets. Other assets consists of the following (in thousands):

	December 31, 2001	December 31, 2000
Plains, excluding PAA		
Deferred tax asset	$ —	$ 47,974
Land	8,853	8,853
Commodity hedging contracts and other derivatives	5,661	—
Debt issue costs, net	3,566	7,249
Other	5,934	3,318
	24,014	67,394
PAA		
Pipeline linefill, at cost	—	34,312
Debt issue costs, net	—	7,259
Long-term receivable, net	—	5,000
Other	—	681
	—	47,252
	$24,014	$114,646

Costs incurred in connection with the issuance of long-term debt are capitalized and amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the "effective interest" method of amortization.

Federal and State Income Taxes. Income taxes are accounted for in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes ("SFAS 109"). SFAS 109 requires recognition of deferred tax liabilities and assets for the expected future tax consequences of events that have been included in the financial statements or tax returns. Under this method, deferred tax liabilities and assets are determined based on the difference between the financial statement and tax bases of assets and liabilities using tax rates in effect for the year in which the differences are expected to reverse. A valuation allowance is established to reduce deferred tax assets if it is more than likely than not that the related tax benefits will not be realized.

Revenue Recognition. Oil and gas revenue from our interests in producing wells is recognized when the production is delivered and the title transfers. Transportation costs incurred in connection with such operations, which are immaterial, are reflected as a reduction of sales revenues.

PAA's gathering and marketing revenues are accrued at the time title to the product sold transfers to the purchaser, which occurs upon receipt of the product by the purchaser, and purchases are accrued at the time title to the product purchased transfers to PAA, which occurs upon our receipt of the product. PAA's terminalling and storage revenues are recognized at the time service is performed and revenues for the transportation of crude oil are recognized based upon regulated and non-regulated tariff rates and the related transported volumes.

Derivative Financial Instruments (Hedging). We utilize various derivative instruments to reduce our exposure to decreases in the market price of crude oil. The derivative instruments consist primarily of crude oil swap and option contracts entered into with financial institutions. We also utilize interest rate swaps to manage the interest rate exposure on our long-term debt.

Stock Options. We have elected to follow Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees ("APB 25") and related interpretations in accounting for our employee stock options. Under APB 25, no compensation expense is recognized when the number of options to be issued is known and the exercise price of the options equals the fair value (market price) of the underlying stock on the date of grant.

Sale of Units by PAA. When PAA sells additional units to a third party, resulting in a change in our percentage ownership interest, we recognize a gain or loss in our consolidated statement of operations if the selling price per unit is more or less than our average carrying amount per unit.

Recent Accounting Pronouncements. The following Statements of Financial Accounting Standards ("SFAS's") were issued in June 2001: SFAS No. 141, Business Combinations, SFAS No. 142, Goodwill and Other Intangible Assets, and SFAS No. 143, Accounting for Asset Retirement Obligations. In August 2001, SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets was also issued. SFAS No. 141 requires the use of the purchase method of accounting for all business combinations. It applies to all business combinations initiated after June 30, 2001 and to all business combinations accounted for by the purchase method that are completed after June 30, 2001. SFAS No. 142 requires that goodwill as well as other intangible assets with indefinite lives not be amortized but be tested annually for impairment and is effective for fiscal years beginning after December 15, 2001. SFAS No. 144 addresses financial accounting and reporting for the impairment of long-lived assets and long-lived assets to be disposed of. It supersedes, with exceptions, SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of and is effective for fiscal years beginning after December 15, 2001. SFAS No. 141, No. 142 and No. 144 had no effect on our financial statements. We will account for all future business combinations and any related goodwill in accordance with the provisions of SFAS No. 141 and SFAS No. 142.

SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost should be allocated to expense using a systematic and rational method. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. The Company is currently assessing the impact of SFAS No. 143 and at this time cannot reasonably estimate the effect of this statement on its consolidated financial position, results of operations or cash flows.

In the fourth quarter of 2000, we adopted Securities and Exchange Commission ("SEC") Staff Accounting Bulletin 101, "Revenue Recognition in Financial Statements" ("SAB 101"). As a result, we record revenue from crude oil production in the period it is sold as opposed to when it is produced and carry any unsold production as inventory valued at historical cost. The total effect of implementing SAB 101 was to reduce reported sales volumes by 144,000 barrels for 2000 and net income for the year by $175,000, including a $121,000 reduction for the cumulative effect of prior years. The effect of this change in accounting for crude oil inventories on prior periods was deminimus.

Note 2—Investment in Plains All American Pipeline, L.P.

In a series of transactions on June 8, 2001, we sold a portion of our interest in PAA to a group of investors and certain members of PAA management for aggregate consideration of approximately $155.2 million (consisting of $110.0 million in cash and $45.2 million in Series F Cumulative Convertible Preferred Stock [the "Series F Preferred Stock"]) and recognized a pre-tax gain of $128.3 million in connection with this sale. In addition, certain holders of the Series F Preferred Stock and

Series H Convertible Preferred Stock (the "Series H Preferred Stock") converted their shares into shares of our common stock. We sold (i) 5.2 million Subordinated Units of PAA (the "Subordinated Units") for $69.5 million in cash and the redemption of 23,108 shares of Series F Preferred Stock, valued at $45.2 million; and (ii) an aggregate 54% ownership interest in the general partner of PAA for $40.5 million in cash. In addition, the investor group and certain other stockholders converted 26,892 shares of Series F Preferred Stock and 132,022 shares of Series H Preferred Stock into a total of 6.6 million shares of our common stock. On September 5, 2001, pursuant to an option granted as part of the June 8, 2001 transactions, certain members of the executive management of PAA acquired an aggregate additional 2% ownership interest in the general partner of PAA for $1.5 million in cash and notes, further reducing our ownership in the general partner of PAA to 44%. We recognized a gain of $1.1 million as a result of this transaction. These transactions in the aggregate are hereinafter referred to as "the Transactions".

As a result of the Transactions, all of the Series F Preferred Stock and all but approximately 36,000 shares of the Series H Preferred Stock were retired or converted. The remaining outstanding shares of the Series H Preferred Stock converted to 1.2 million shares of our common stock during the third quarter. Also as a result of the Transactions, certain of our employees received transaction-related bonuses and other payments and vested in benefits in accordance with the terms of certain of our employee benefit plans.

The excess of the fair value of the Series F Preferred stock as consideration for the PAA Units over the carrying value of the Series F Preferred Stock ($21.4 million) is deemed to be a dividend to preferred stockholders and is deducted in determining the income available to common stockholders for the purpose of determining basic and fully diluted earnings per share. In connection with the conversion of the Series F Preferred Stock into common stock, we made a $2.5 million inducement payment representing a 20% premium to the amount of dividends that would accrue on the Series F Preferred Stock between the closing of the Transactions and the first date we could potentially cause such conversion. Such amounts are included in preferred dividends.

The Subordinated Units are subordinated in right to distributions from PAA and are not publicly traded. However, PAA's partnership agreement provides that, if certain financial tests are met, the Subordinated Units (including those retained by us) will convert into common units on a one-for-one basis commencing in 2003. In connection with the Transactions, we entered into Value Assurance Agreements with such purchasers of the Subordinated Units under the terms of which we will pay the purchasers an amount per fiscal year, payable on a quarterly basis, equal to $1.85 per unit less the actual amount distributed during that year. The Value Assurance Agreements expire upon the earlier of (a) the conversion of the Subordinated Units to common units or (b) June 8, 2006. In the first quarter of 2002 PAA paid a distribution of $0.5125 per unit ($2.05 annualized).

Also in connection with the Transactions, we entered into a separation agreement with PAA pursuant to which, among other things, (a) we agreed to indemnify PAA, the general partner of PAA, and the subsidiaries of PAA against any losses or liabilities resulting from (i) the operation of the upstream business or (ii) federal or state securities laws, or the regulations of any self-regulatory authority, or other similar claims resulting from acts or omissions by us, our subsidiaries, PAA, or PAA's subsidiaries on or before the closing of the Transactions; and (b) PAA agreed to indemnify us and our subsidiaries against any losses or liabilities resulting from the operation of the midstream business. We also entered into a pension and employee benefits assumption and transition agreement pursuant to which the general partner of PAA and us agreed to the transition of certain employees to such general partner, the provision of certain benefits with respect to such transfer, and the provision of other transition services by us.

In addition, we agreed to contribute 287,500 of our Subordinated Units to PAA's general partner to be used for option grants to officers and key employees. These Subordinated Units are considered to be a contribution to the general partner and we will receive no reimbursement for such units. Also, at the time of the Transactions, certain of our employees, who are now employees of PAA's general partner, held "in-the-money" but unvested Plains stock options which were subject to forfeiture due to the transfer of employment. We agreed to substitute, based on the present value of such options, a contingent grant of 51,000 Subordinated Units that vest on the same schedule the stock options were to vest. In connection with these substitute options, we recognized $0.5 million in noncash compensation expense in 2001.

In May 2001, PAA issued 4.0 million common units in a public equity offering. We recognized a gain of $19.6 million resulting from the increase in the book value of our equity in PAA to reflect our proportionate share of the increase in the underlying net assets of PAA due to the sale of the units. In October 2001, PAA issued 4.5 million Common Units in a public offering. As a result of the offering, we made a general partner capital contribution of approximately $1.0 million, and our aggregate ownership interest in PAA was reduced to approximately 29%. We recognized a gain of approximately $19.2 million resulting from the increase in book value of our equity in PAA to reflect our proportionate share of the increase in the underlying net assets of PAA resulting from this public offering.

At March 31, 2001, our aggregate ownership interest in PAA was approximately 54%. Following the sale of common units by PAA in the aforementioned public equity offerings and the Transactions, our aggregate ownership interest in PAA was approximately 29%. At December 31, 2001, our aggregate 29% ownership in PAA consisted of: (i) a 44% ownership interest in the 2% general partner interest and incentive distribution rights, (ii) 45%, or approximately 4.5 million, of the Subordinated Units and (iii) 24% or approximately 7.9 million of the common units (including approximately 1.3 million Class B common units).

The following table presents summarized financial statement information of PAA (in thousands of dollars):

	Year Ended December 31, 2001
Revenues	$6,868,215
Cost of sales and operations	6,725,954
Gross margin	142,261
Operating income	71,368
Income before cumulative effect of accounting change	43,671
Net income	44,179
	At December 31, 2001
Current assets	$ 558,082
Property and equipment, net	604,919
Other assets	98,250
Total assets	1,261,251
Current liabilities	505,160
Long-term debt	351,677
Other long-term liabilities	1,617
Partners' capital	402,797
Total liabilities and partners' capital	1,261,251

Note 3—Derivative Instruments and Hedging Activities

On January 1, 2001, we adopted Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting for Derivative Instruments and Hedging Activities" as amended by SFAS 137 and SFAS 138 ("SFAS 133"). Under SFAS 133, all derivative instruments are recorded on the balance sheet at fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. To qualify for hedge accounting, the derivative must qualify either as a fair value hedge, cash flow hedge or foreign currency hedge. Currently, we use only cash flow hedges and the remaining discussion will relate exclusively to this type of derivative instrument. If the derivative qualifies for hedge accounting, the gain or loss on the derivative is deferred in accumulated Other Comprehensive Income ("OCI"), a component of Stockholders' Equity to the extent the hedge is effective.

The relationship between the hedging instrument and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the contract and on an ongoing basis. Hedge accounting is discontinued prospectively when a hedge instrument becomes ineffective. Gains and losses deferred in OCI related to cash flow hedges that become ineffective remain unchanged until the related product is delivered. If it is determined that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument are recognized in earnings immediately.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. Hedge effectiveness is measured on a quarterly basis. This process includes specific identification of the hedging instrument and the hedge transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. No amounts were excluded from the computation of hedge effectiveness. At December 31, 2001, all open positions qualified for hedge accounting.

Unrealized gains and losses on hedging instruments reflected in OCI and adjustments to carrying amounts on hedged volumes are included in oil and gas revenues in the period that the related volumes are delivered. Gains and losses from hedging instruments, which represent hedge ineffectiveness as well as any amounts excluded from the assessment of hedge effectiveness, are recognized currently in oil and gas revenues. Effective October 2001, we implemented Derivatives Implementation Group ("DIG") Issue G20, "Cash Flow Hedges: Assessing and Measuring the Effectiveness of a Purchased Option Used in a Cash Flow Hedge", which provides guidance for assessing the effectiveness on total changes in an option's cash flows rather than only on changes in the option's intrinsic value. Implementation of this DIG issue will reduce earnings volatility since it allows us to include changes in the time value of purchased options and collars in the assessment of hedge effectiveness. Time value changes were previously recognized in current earnings since we excluded time value changes from the assessment of hedge effectiveness. Oil and gas revenues for the year ended December 31, 2001 include a $3.4 million non-cash loss related to the ineffective portion of the cash flow hedges representing the fair value change in the time value of options for the nine months prior to the implementation of DIG Issue G20.

We utilize various derivative instruments to hedge our exposure to price fluctuations on crude oil sales. The derivative instruments consist primarily of cash-settled crude oil option and swap contracts entered into with financial institutions. We do not currently have any natural gas hedges. We also utilize interest rate swaps and collars to manage the interest rate exposure on our long-term debt. In October

2001 we entered into a three-year interest rate swap agreement, fixing at 5.29% the interest rate on $7.5 million of borrowing under our revolving credit facility. At December 31, 2001, we had the following open crude oil hedge positions:

	Barrels Per Day	
	2002	2003
Puts		
Average price $20.00/bbl	2,000	—
Calls		
Average price $35.17/bbl	9,000	—
Swaps		
Average price $24.00/bbl	17,000	—
Average price $23.16/bbl	—	7,500

On January 1, 2001, in accordance with the transition provisions of SFAS 133, we recorded a gain of $4.5 million in OCI, representing the cumulative effect of an accounting change to recognize at fair value all cash flow derivatives, including our equity in the cash flow derivatives of PAA. We recorded cash flow hedge derivative assets and liabilities of $20.6 million and $18.1 million, respectively, and a net-of-tax non-cash charge of $2.0 million was recorded in earnings as a cumulative effect adjustment.

For the year ended December 31, 2001, net unrealized gains of $9.8 million were added to OCI and the fair value of open positions increased $16.2 million. At December 31, 2000, we had an interest rate swap arrangement to protect interest rate fluctuations on a portion of our outstanding debt. The position was terminated prior to maturity and as a result $0.6 million related to such position was relieved from OCI when the debt was repaid in June 2001.

At December 31, 2001, net unrealized gains on our option and swap contracts included in OCI was $16.7 million. The related assets and liabilities were included in commodity hedging contracts and other derivatives ($21.8 million), other assets ($5.7 million), and deferred income taxes ($10.8 million). Additionally, OCI includes our $2.3 million net of tax equity in the unrealized OCI losses of PAA. As of December 31, 2001, $13.2 million of deferred net gains on derivative instruments recorded in OCI are expected to be reclassified to earnings during the next twelve-month period.

Note 4—Long-Term Debt and Credit Facilities

Short-term debt and long-term debt consists of the following at December 31, 2001 and 2000 (in thousands):

	2001		2000	
	Current	Long-Term	Current	Long-Term
Plains				
Revolving credit facility, bearing interest at 4.2% and 8.4%, at December 31, 2001 and 2000, respectively	$ —	$ 11,500	$ —	$ 27,300
10.25% Senior Subordinated Notes, due 2006, net of repurchased notes of $7.55 million and nil, and unamortized premium of $2.1 million and $2.5 million at December 31, 2001 and 2000, respectively	—	269,539	—	277,543
Other long-term debt	511	1,533	511	2,044
	511	282,572	511	306,887
PAA				
Letter of credit facility and hedged inventory facility, bearing interest at a weighted average interest rate of 8.4%	—	—	1,300	—
Plains Marketing, L.P. revolving credit facility, bearing interest at 9.2%, at December 31, 2000	—	—	—	320,000
	$511	$282,572	$1,811	$626,887

Aggregate total maturities of long-term debt in the next five years are as follows: 2002—$0.5 million; 2003—$1.9 million; 2004—$6.3 million; 2005—$4.3 million; and 2006—$267.5 million.

Plains Long-Term Debt and Credit Facilities

Revolving Credit Facility

We have a $225.0 million revolving credit facility with a group of banks. The revolving credit facility is guaranteed by all of our upstream subsidiaries and is collateralized by our upstream oil and natural gas properties and those of the guaranteeing subsidiaries and the stock of all the upstream subsidiaries. The borrowing base under the revolving credit facility at December 31, 2001, is $225.0 million and is subject to redetermination from time to time by the lenders in good faith, in the exercise of the lenders' sole discretion, and in accordance with customary practices and standards in effect from time to time for crude oil and natural gas loans to borrowers similar to our company. Our borrowing base may be affected from time to time by the performance of our oil and natural gas properties and changes in oil and natural gas prices. We incur a commitment fee of 3⁄8% per annum on the unused portion of the borrowing base. In addition, we pay a fee of 1 3⁄8% per annum of the face amount of letters of credit that are issued under our revolving credit facility. The revolving credit facility, as amended, terminates on July 1, 2003, at which time the remaining outstanding balance converts to a term loan, repayable in eight equal quarterly installments commencing October 1, 2003, with a final maturity of July 1, 2005. The revolving credit facility bears interest, at our option, of either LIBOR plus 1 3⁄8% or the Base Rate (as defined therein). At December 31, 2001, letters of credit of $0.6 million were outstanding under the revolving credit facility.

The revolving credit facility contains covenants which, among other things, limit the payment of cash dividends on common stock, limit repurchases of common stock, limit the amount of consolidated debt, limit our ability to make certain loans and investments and provide that we must maintain a specified relationship between current assets and current liabilities. At December 31, 2001 we were in compliance with such covenants and could have borrowed the full $225.0 million available under the facility.

Under the terms of the revolving credit facility we can purchase any combination of our own common stock, our senior subordinated notes and PAA common units and pay cash dividends on our common stock (up to $30.0 million) up to a total of $150.0 million. At December 31, 2001 we had $117.5 million remaining under this limit. The Board of Directors, subject to the $150.0 million limit, has authorized the purchase of up to eight million shares of our common stock, our senior subordinated notes and PAA units in the open market from time to time as market conditions are deemed favorable.

In October 2001 we entered into a three-year interest rate swap agreement, fixing the interest rate on $7.5 million of borrowing under our revolving credit facility at 5.29%

10.25% Senior Subordinated Notes Due 2006

At December 31, 2001 we had $267.5 million principal amount of 10.25% Senior Subordinated Notes Due 2006 (the "10.25% Notes") outstanding, bearing a coupon rate of 10.25%. In 1996 we issued $150.0 million principal amount at 99.38% of par to yield 10.35%. In 1997 $50.0 million principal amount was issued at approximately 107% of par and in 1999 $75.0 million principal amount was issued at approximately 101% of par. In 2001 we repurchased $7.5 million principal amount at 99.5% of par.

The 10.25% Notes are redeemable, at our option at 105.13% of the principal amount through March 15, 2002, at 103.42% on or after March 15, 2002, at 101.71% on or after March 15, 2003 and at 100% on or after March 15, 2004 plus, in each case, accrued interest to the date of redemption.

The Indenture contains covenants that include, but are not limited to, covenants that: (1) limit the incurrence of additional indebtedness; (2) limit certain investments; (3) limit restricted payments; (4) limit the disposition of assets; (5) limit the payment of dividends and other payment restrictions affecting subsidiaries; (6) limit transactions with affiliates; (7) limit the creation of liens; and (8) restrict mergers, consolidations and transfers of assets. In the event of a Change of Control and a corresponding Rating Decline, as both are defined in the Indenture, we will be required to make an offer to repurchase the 10.25% Notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of the repurchase.

The 10.25% Notes are unsecured general obligations and are subordinated in right of payment to all our existing and future senior indebtedness and are guaranteed by certain of our Upstream subsidiaries on a full, unconditional, joint and several basis.

PAA Credit Facilities

At December 31, 2000, PAA's bank credit agreements consisted of a $400.0 million senior secured revolving credit facility and a $300.0 million senior secured letter of credit and borrowing facility, both of which were secured by substantially all of PAA's assets. PAA's credit facilities were nonrecourse to us.

Note 5—Unauthorized Trading Losses

In November 1999, we discovered that a former employee of PAA had engaged in unauthorized trading activity, resulting in losses of approximately $174.0 million, including estimated associated costs and legal expenses. Approximately $7.1 million of the unauthorized trading losses were recognized in 1998 and the remainder in 1999. In 2000, we recognized an additional $8.0 million charge for litigation related to the unauthorized trading losses.

Note 6—PAA Acquisitions and Dispositions

Scurlock Acquisition

On May 12, 1999, PAA completed the acquisition of Scurlock Permian LLC ("Scurlock") and certain other pipeline assets from Marathon Ashland Petroleum LLC. Including working capital adjustments and closing and financing costs, the cash purchase price was approximately $141.7 million.

Financing for the Scurlock acquisition was provided through: (i) borrowings of approximately $92.0 million under a PAA bank facility; (ii) the sale to the general partner of 1.3 million Class B common units of PAA for a total cash consideration of $25.0 million, or $19.125 per unit, the price equal to the market value of PAA's common units on May 12, 1999; and (iii) a $25.0 million draw under PAA's existing revolving credit agreement.

The funds for the purchase of the Class B units by the general partner were provided by a capital contribution from us. We financed our capital contribution through our revolving credit facility.

The assets, liabilities and results of operations of Scurlock are included in our consolidated financial statements effective May 1, 1999. The Scurlock acquisition has been accounted for using the purchase method of accounting and the purchase price was allocated in accordance with Accounting Principles Board Opinion No. 16, Business Combinations ("APB 16") as follows (in thousands):

Crude oil pipeline, gathering and terminal assets	$125,120
Other property and equipment	1,546
Pipeline linefill	16,057
Other assets (debt issue costs)	3,100
Other long-term liabilities (environmental accrual)	(1,000)
Net working capital items	(3,090)
Cash paid	$141,733

Pro Forma Results for the Scurlock Acquisition

The following unaudited pro forma data is presented to show pro forma revenues, net loss and basic and diluted net loss per share for the year ended December 31, 1999 as if the Scurlock acquisition, which was effective May 1, 1999, had occurred on January 1, 1999 (in thousands, except per share data):

Revenues	$11,323,577
Net loss	$ (27,147)
Net loss per share available to common stockholders:	
Basic and diluted	$ (2.15)

All American Pipeline Linefill Sale and Asset Disposition

In March 2000, PAA sold the segment of the All American Pipeline that extends from Emidio, California to McCamey, Texas to a unit of El Paso Corporation for $129.0 million. PAA realized net proceeds of approximately $124.0 million after the associated transaction costs and estimated costs to remove some equipment. The proceeds from the sale were used to reduce the outstanding debt of PAA. PAA recognized a gain of approximately $20.1 million in connection with the sale.

PAA had suspended shipments of crude oil on this segment of the pipeline in November 1999. At that time, PAA owned approximately 5.2 million barrels of crude oil in the segment of the pipeline. PAA sold this crude oil from November 1999 to February 2000 for net proceeds of approximately $100.0 million and recognized gains of approximately $28.1 million and $16.5 million in 2000 and 1999, respectively, in connection with the sale of the linefill.

Note 7—Redeemable Preferred Stock

Series F Cumulative Convertible Preferred Stock

On December 14, 1999, we sold in a private placement 50,000 shares of Series F Preferred Stock for $50.0 million As discussed in Note 2, in conjunction with the Transactions we redeemed 23,108 shares of the Series F Preferred Stock and the remaining 26,892 shares were converted into 2.2 million shares of our common stock. Each share of the Series F Preferred Stock had a stated value of $1,000 per share and bore a dividend of 10% per annum. Dividends were payable semi-annually in either cash or additional shares of Series F Preferred Stock at our option and were cumulative from the date of issue. Dividends paid in additional shares of Series F Preferred Stock were limited to an aggregate of six dividend periods. Each share of Series F Preferred Stock was convertible into 81.63 shares of common stock (an initial effective conversion price of $12.25 per share). At December 31, 2000 there were 50,000 shares of Series F Preferred Stock outstanding.

The Series F Preferred Stock is stated at liquidation preference on the consolidated balance sheet at December 31, 2000. Liquidation preference represents the number of shares outstanding multiplied by the stated value of the shares. Any unpaid cash dividends are accrued in accounts payable and other current liabilities on the consolidated balance sheet.

Series E and Series G Convertible Preferred Stock

In July 1998 we issued $85.0 million of Series E Cumulative Convertible Preferred Stock (the "Series E Preferred Stock"). Each share of the Series E Preferred Stock had a stated value of $500 per share and bore a dividend of 9.5% per annum. Dividends were payable semi-annually in either cash or additional shares of Series E Preferred Stock at our option and were cumulative from the date of issue. Each share of Series E Preferred Stock was convertible into 27.78 shares of common stock (an initial effective conversion price of $18.00 per share). In February 2000 each outstanding share of the Series E Preferred Stock was exchanged for a share of a new Series G Cumulative Convertible Preferred Stock (the "Series G Preferred Stock") which had a conversion price of $15.00 per share. Other than the reduced conversion price, the terms of the Series G Preferred Stock were substantially identical to those of the Series E Preferred Stock

In December 2000, we exchanged or redeemed all of the shares of Series G Preferred Stock that had not been previously converted into shares of common stock. We exchanged 169,571 shares of Series G Preferred Stock for 169,571 shares of Series H Preferred Stock and in connection therewith paid $2.0 million, the amount equal to accrued dividends, and converted 1,825 shares of Series G Preferred Stock into 62,226 shares of common stock. The remaining 213 shares of the Series G Preferred Stock were redeemed at 105% of stated value in accordance with the original terms. In connection with that redemption, we paid $114,000 consisting of $112,000 for stated value and $2,000 for accrued and unpaid dividends.

Note 8—Common Stock and Non-Redeemable Preferred Stock

Common and Preferred Stock

We have authorized capital stock consisting of 50.0 million shares of common stock, $0.10 par value, and 2 million shares of preferred stock, $1.00 par value. At December 31, 2001 and 2000, there were 23.6 million shares and 17.5 million shares of common stock outstanding (net of treasury shares), respectively, and 46,600 and 266,171 shares of preferred stock outstanding.

Stock Warrants and Options

At December 31, 2001, we had a warrant outstanding which entitles the holder thereof to purchase an aggregate 150,000 shares of common stock at $25.00 per share expiring in 2002. We have various stock option plans for our employees and directors (see Note 14).

Series D Cumulative Convertible Preferred Stock

In November 1997, we issued 46,600 shares of Series D Cumulative Convertible Preferred Stock (the "Series D Preferred Stock"). The Series D Preferred Stock has an aggregate stated value of $23.3 million and is redeemable at our option at 140% of stated value. If not previously redeemed or converted, the Series D Preferred Stock will automatically convert into 932,000 shares of common stock in 2012. Each share of the Series D Preferred Stock has a stated value of $500 and is convertible into common stock at a ratio of $25.00 of stated value for each share of Common Stock to be issued. The Series D Preferred Stock bears an annual dividend of $30.00 per share.

Series H Convertible Preferred Stock

In December 2000, we exchanged 169,571 shares of Series G Preferred Stock for 169,571 shares of Series H Preferred Stock. The Series H Preferred Stock was convertible into the same number of shares of common stock as the Series G Preferred Stock (33.33 shares of common), but did not bear a dividend and did not contain a mandatory redemption feature. As discussed in Note 2, in conjunction with the Transactions, 132,022 shares of the Series H Preferred Stock were converted into 4.4 million shares of our common stock. In the third quarter of 2001 the remaining outstanding shares were converted into 1.2 million common shares.

Treasury Stock

Our Board of Directors has authorized the repurchase of up to eight million shares of our common stock. Ir 2001, we repurchased 2.8 million common shares at a cost of $67.7 million, and in 2000 we repurchased 1.: million common shares at a cost of $23.6 million.

Note 9—Earnings Per Share

The following is a reconciliation of the numerators and the denominators of the basic and diluted earning: per share computations for income (loss) from continuing operations before extraordinary items and the cumulative effect of accounting change for the years ended December 31, 2001, 2000 and 1999 (in thousands except per share amounts):

	For the Year Ended December 31,								
	2001			2000			1999		
	Income (Numerator)	Shares (Denominator)	Per Share Amount	Income (Numerator)	Shares (Denominator)	Per Share Amount	Income (Numerator)	Shares (Denominator)	Per Share Amoun
Income (loss) before extraordinary item and cumulative effect of accounting change . . .	$155,317			$45,924			$(24,787)		
Less: preferred stock dividends	(27,245)			(14,725)			(10,026)		
Income (loss) available to common stockholders	128,072	21,090	$6.07	31,199	17,845	$1.75	(34,813)	17,262	$(2.02
Effect of dilutive securities:									
Preferred Stock conversion	3,365	5,280		14,725	10,673				
Employee stock options and warrants	—	874		—	855		—	—	
Income (loss) available to common stockholders assuming dilution	$131,437	27,244	$4.82	$45,924	29,373	$1.56	$(34,813)	17,262	$(2.02

In 1999, we recorded a net loss and our options and warrants were not included in the computations o diluted earnings per share because their assumed conversion was antidilutive. In addition, our preferred stocl that was outstanding at December 31, 1999 was convertible into 7.0 million shares of common stock but was no included in the computation of diluted earnings per share in 1999 because the effect was antidilutive. See Note 14 for additional information concerning outstanding options and warrants.

Note 10—Income Taxes

Our deferred income tax assets and liabilities at December 31, 2001 and 2000 consist of the tax effect of income tax carryforwards and differences related to the timing of recognition of certain types of costs as follows (in thousands):

	December 31, 2001	December 31, 2000
U.S. Federal		
Deferred tax assets:		
Net operating losses	$ 18,142	$64,370
Percentage depletion	2,450	2,450
Tax credit carryforwards	8,988	4,662
Excess outside tax basis over outside book basis	9,979	24,504
Other	4,926	1,669
	44,485	97,655
Deferred tax liabilities:		
Net oil & gas acquisition, exploration and development costs	(63,693)	(42,946)
Commodity hedging contracts and other	(9,028)	—
Net deferred tax asset (liability)	(28,236)	54,709
Valuation allowance	(2,450)	(2,555)
	(30,686)	52,154
Foreign		
Excess outside tax basis over outside book basis	466	—
States		
Deferred tax liability	(14,074)	(4,180)
Net deferred tax assets (liability)	$(44,294)	$47,974

At December 31, 2001, we have carryforwards of approximately $51.8 million of regular tax net operating losses ("NOL"), $7.0 million of statutory depletion, $5.1 million of alternative minimum tax credits and $3.8 million of enhanced oil recovery credits. At December 31, 2001, we also had approximately $34.1 million of alternative minimum tax NOL carryforwards available as a deduction against future alternative minimum tax income. The NOL carryforwards expire in 2019.

Set forth below is a reconciliation between the income tax provision (benefit) computed at the United States statutory rate on income (loss) before income taxes and the income tax provision in the accompanying consolidated statements of operations (in thousands):

	Year Ended December 31, 2001	2000	1999
U.S. federal income tax provision at statutory rate	$ 89,872	$25,028	$(15,842)
State income taxes, net of federal benefit	10,050	2,018	(1,298)
Foreign income taxes, net of federal benefit	916	—	—
Full cost ceiling test limitation	—	—	(3,617)
Other	622	(1,463)	278
Income tax expense (benefit) on income before extraordinary item	101,460	25,583	(20,479)
Income tax benefit allocated to extraordinary item	—	(3,190)	(293)
Income tax benefit allocated to cumulative effect of accounting change	(1,270)	(76)	—
Income tax (benefit) provision	$100,190	$22,317	$(20,772)

In accordance with certain provisions of the Tax Reform Act of 1986, a change of greater than 50% of our beneficial ownership within a three-year period (an "Ownership Change") will place an annual limitation on our ability to utilize our existing tax carryforwards. Under the Final Treasury Regulations issued by the Internal Revenue Service, we do not believe that an Ownership Change has occurred as of December 31, 2001.

Note 11—Early Extinguishment of Debt

In 2000, PAA recognized a $15.2 million extraordinary loss ($5.0 million net of minority interest of $7.0 million and deferred income taxes of $3.2 million) consisting primarily of unamortized debt issue costs related to the refinancing of PAA's credit facilities. In addition, interest and other income for 2000 includes $4.4 million of previously deferred net gains from interest rate swaps terminated as a result of the debt extinguishment. In 1999, PAA recognized a $1.5 million extraordinary loss ($0.5 million net of minority interest of $0.7 million and deferred tax of $0.3 million) related to the write-off of certain debt issue costs and penalties associated with the prepayment of debt.

Note 12—Related Party Transactions

Reimbursement of Expenses of the General Partner and Its Affiliates

Prior to the Transactions, the general partner of PAA was a wholly-owned subsidiary of Plains. As a result of the Transactions another entity was named general partner and our ownership in that entity is 44%. Previously, we had sole responsibility for conducting PAA's business and managing its operations. We did not receive any management fee or other compensation in connection with the management of PAA's business, but were reimbursed for all direct and indirect expenses incurred on its behalf. For the period from January 1, 2001 to June 8, 2001, and for the years ended December 31, 2000 and 1999, we were reimbursed approximately $31.2 million, $63.8 million and $44.7 million, respectively, for direct and indirect expenses on PAA's behalf. The reimbursed costs consisted primarily of employee salaries and benefits. PAA does not employ any persons to manage its business. These functions are provided by employees of the general partner.

Crude Oil Marketing Agreement

PAA is the exclusive marketer/purchaser for all of our equity crude oil production. The marketing agreement provides that PAA will purchase for resale at market prices all of our equity crude oil production for which PAA charges a fee of $0.20 per barrel. For the years ended December 31, 2001, 2000 and 1999, we paid approximately $223.1 million, $244.9 million and $131.5 million, respectively, for the purchase of crude oil under the agreement, including the royalty share of production.

Financing

In December 1999, we loaned PAA $114.0 million, which was repaid in May 2000. Interest on the notes was $3.3 million and $0.6 million for the years ended December 31, 2000 and 1999, respectively.

Transaction Grant Agreements

In 1998, at no cost to PAA, we agreed to grant 400,000 of our PAA common units (including distribution equivalent rights attributable to such units) to certain key officers and employees of the general partner and its affiliates. The grants vested over a three year period subject to PAA paying distributions on common and subordinated units. Of these grants, 69,000 vested in 1999 and 133,000 vested in 2000. The remaining grants vested in 2001 as a result of the Transactions. PAA recognized noncash compensation expense related to the transaction grants of approximately $4.8 million, $2.7 million and $1.0 million in the years ended December 31, 2001, 2000, and 1999, respectively, and we reflected capital contributions of a similar amount. The noncash compensation is included in general and administrative expense in the Consolidated Statements of Operations for the years ended December 31, 2000 and 1999. Our share of this expense is included in our equity in the earnings of PAA in 2001.

Note 13—Benefit Plans

We have a nonqualified retirement plan (the "Plan") for certain of our officers. Benefits under the Plan are based on salary at the time of adoption, vest over a 15-year period and are payable over a 15-year period commencing at age 60. The Plan is unfunded.

Net pension expense for the years ended December 31, 2001, 2000 and 1999 is comprised of the following components (in thousands):

	Year Ended December 31,		
	2001	2000	1999
Service cost—benefits earned during the period	$156	$ 99	$109
Interest on projected benefit obligation	131	96	83
Amortization of prior service cost	31	37	37
Unrecognized loss	17	—	6
Net pension expense	$335	$232	$235

Summarized information of our retirement plan for the periods indicated is as follows (in thousands):

	December 31,	
	2001	2000
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 1,821	$ 1,233
Service cost	155	99
Interest cost	131	96
Settlement losses	271	—
Special termination benefits	—	175
Benefits paid	(67)	—
Settlement payments	(1,159)	—
Actuarial (gains) losses	755	218
Benefit obligation at end of year	$ 1,907	$ 1,821
Amounts recognized in the consolidated balance sheets:		
Projected benefit obligation for service rendered to date	$ 1,907	$ 1,821
Plan assets at fair value	—	—
Benefit obligation in excess of fair value of plan assets	(1,907)	(1,821)
Unrecognized (gain) loss	720	185
Unrecognized prior service costs	310	508
Adjustment to recognize minimum liability	(1,030)	(693)
Net amount recognized	$(1,907)	$(1,821)

The weighted-average discount rate used in determining the projected benefit obligation was 7.25% and 7.5% for the years ended December 31, 2001 and 2000, respectively.

We also maintain a 401(k) defined contribution plan whereby we match 100% of an employee's contribution (subject to certain limitations in the plan). Matching contributions are made 50% in cash and 50% in common stock of the Company, with the number of shares for the stock match based on the market value of the common stock at the time the shares are granted. For the years ended December 31, 2001, 2000 and 1999, defined contribution plan expense was $0.3 million, $1.4 million and $1.0 million, respectively. Such expense for 2000 and 1999 includes amounts attributable to employees of the general partner of PAA.

Note 14—Stock Compensation Plans

Stock Options

Historically, we have used stock options as a long-term incentive for our employees, officers and directors under various stock option plans. We have options outstanding under our 2001 and 1996 plans, under which a maximum of 5.6 million shares of common stock were reserved for issuance. Generally, the options are granted: (i) at an exercise price equal to or greater than the market price of the underlying stock on the date of grant; and (ii) with a pro rata vesting period of two to five years and an exercise period of five to ten years. Certain options have vesting provisions related to the market price of our common stock. If such options do not vest under such provisions, they vest at the end of a five-year period.

Performance options to purchase a total of 500,000 shares of common stock were granted to two executive officers in 1996. Terms of the options provided for an exercise price of $13.50, the market price on the date of grant, and were to vest if shares of our common stock traded at or above $24.00 per share for any 20 trading days in any 30 consecutive trading day period prior to August 2001, or upon a change in control if certain conditions were met. The performance options vested in the second quarter of 2001 and we recognized $4.0 million of noncash compensation expense, which is included in general and administrative expense.

In May 2001 we granted options on 2,250,000 shares under the terms of our 2001 plan subject to the approval of such plan by our board of directors. The market price of our common stock at the time the plan was approved in July 2001 exceeded the exercise price with respect to 1,450,000 of such options and, accordingly, we recognized noncash compensation with respect to such options. During 2001, $0.3 million in compensation expense with respect to such options is included in general and administrative expense.

A summary of the status of our stock options as of December 31, 2001, 2000, and 1999, and changes during the years ending on those dates are presented below (shares in thousands):

	2001		2000		1999	
Fixed Options	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	2,749	$12.11	2,811	$11.06	2,749	$10.53
Granted	2,464	24.02	419	13.91	237	15.09
Exercised	(1,431)	11.51	(444)	6.96	(158)	7.94
Forfeited	(115)	14.06	(37)	14.37	(17)	9.93
Outstanding at end of year	3,667	$20.30	2,749	$12.11	2,811	$11.06
Options exercisable at year-end	1,084	$13.32	1,708	$11.07	1,836	$ 9.50
Weighted-average fair value of options granted during the year	$10.12		$5.39		$5.40	

In October 1995, the Financial Accounting Standards Board issued SFAS 123, which established financial accounting and reporting standards for stock-based employee compensation. SFAS 123 defines a fair value based method of accounting for an employee stock option or similar equity instrument. SFAS 123 also allows an entity to continue to measure compensation cost for those instruments using the intrinsic value-based method of accounting prescribed by APB 25. We have elected to follow APB 25 and related interpretations in accounting for our employee stock options because, as discussed below, the alternative fair value accounting provided for under SFAS 123 requires the use of option valuation models that were not developed for use in valuing employee stock options. Under APB 25, because the exercise price of our employee stock options equals the market price of the underlying stock on the date of grant, no compensation expense has been recognized in the accompanying financial statements.

Pro forma information regarding net income (loss) and earnings per share is required by SFAS 123 and has been determined as if we had accounted for our employee stock options under the fair value method as provided therein. The fair value for the options was estimated at the date of grant using a Black-Scholes option pricing model with the following weighted average assumptions for grants in 2001, 2000 and 1999: risk-free interest rates of 2.5% for 2001, 6.3% for 2000, and 5.1% for 1999; a volatility factor of the expected market price of our common stock of .0.50 for 2001, 0.50 for 2000 and 0.50 for 1999; no expected dividends; and weighted average expected option lives of 5.3 years in 2001, 2.6 years in 2000 and 2.7 years in 1999. For purposes of pro forma disclosures, the estimated fair value of the options is amortized to expense over the options' vesting period.

The Black-Scholes option valuation model and other existing models were developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of and are highly sensitive to subjective assumptions including the expected stock price volatility. Because our employee stock options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, in management's opinion, the existing models do not provide a reliable single measure of the fair value of its employee stock options.

Set forth below is a summary of our net income (loss) before extraordinary item and earnings per share as reported and pro forma as if the fair value based method of accounting defined in SFAS 123 had been applied (in thousands, except per share data).

	Year Ended December 31,		
	2001	2000	1999
As Reported:			
Net income (loss) before extraordinary item and cumulative effect of accounting change	$155,317	$45,924	$(24,787)
Net income (loss) per common share, basic	6.07	1.75	(2.02)
Net income (loss) per common share, diluted	4.82	1.56	(2.02)
Pro Forma:			
Net income (loss) before extraordinary item and cumulative effect of accounting change	$152,335	$45,132	$(25,125)
Net income (loss) per common share, basic	5.93	1.70	(2.04)
Net income (loss) per common share, diluted	4.72	1.54	(2.04)

The following table summarizes information about stock options outstanding at December 31, 2001 (share amounts in thousands):

Range of Exercise Price	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
$ 6.25 to $14.19	702	2.4 years	$10.08	542	$ 8.97
14.31 to 21.12	508	1.9 years	16.39	461	16.43
23.00 to 23.00	1,000	9.4 years	23.00	—	—
23.74 to 25.30	1,457	5.0 years	24.74	81	24.73
$ 6.25 to $25.30	3,667	5.3 years	$20.30	1,084	$13.32

Share Grant

In May 2001, an officer was granted the right to receive an amount, payable in our common stock, equal to the excess of the "fair market value" (as defined in our 2001 plan) of a share of common stock on the effective date and $22.00, multiplied by one million. On the effective date, May 8, 2001, the closing price of our common stock was $23.00 and accordingly, the employee will receive $1.0 million, to be paid in five annual installments as of each anniversary of the effective date, in the form of a direct grant of shares of common stock. The number of shares is determined by dividing the annual installment by the fair market value of a share on the applicable anniversary date. We will recognize $1.0 million of noncash compensation expense ratably over the five-year period. General and administrative expense for 2001 includes $0.3 million in compensation expense with respect to this share grant.

Note 15—Commitments, Contingencies and Industry Concentration

Commitments and Contingencies

We lease certain real property, equipment and operating facilities under various operating leases. Future non-cancelable commitments related to these items at December 31, 2001, are summarized below (in thousands):

2002	$616
2003	593
2004	595
2005	573
2006	143
Thereafter	—

Total expenses related to these commitments for the years ended December 31, 2001, 2000 and 1999 were $0.7 million, $7.3 million and $9.3 million, respectively. Such amounts for 2000 and 1999 include $6.7 million and $8.8 million, respectively, attributable to PAA.

Under the amended terms of an asset purchase agreement with respect to certain of our onshore California properties, commencing with the year beginning January 1, 2000, and each year thereafter, we are required to plug and abandon 20% of the then remaining inactive wells, which currently aggregate approximately 149. To the extent we elect not to plug and abandon the number of required wells, we are required to escrow an amount equal to the greater of $25,000 per well or the actual average plugging cost per well in order to provide for the future plugging and abandonment of such wells. In addition, we are required to expend a minimum of $600,000 per year in each of the ten years beginning January 1, 1996, and $300,000 per year in each of the succeeding five years to remediate oil contaminated soil from existing well sites, provided there are remaining sites to be remediated. In the event we do not expend the required amounts during a calendar year, we are required to contribute an amount equal to 125% of the actual shortfall to an escrow account. We may withdraw amounts from the escrow account to the extent we expend excess amounts in a future year. Through December 31, 2001, we have not been required to make contributions to an escrow account.

In connection with the acquisition of our interest in the Point Arguello field, offshore California, we assumed our 26% share of (1) plugging and abandoning all existing well bores, (2) removing conductors, (3) flushing hydrocarbons from all lines and vessels and (4) removing/abandoning all structures, fixtures and conditions created subsequent to closing. The seller retained the obligation for all other abandonment costs, including but not limited to (1) removing, dismantling and disposing of the existing offshore platforms, (2) removing and disposing of all existing pipelines and (3) removing, dismantling, disposing and remediation of all existing onshore facilities.

Although we obtained environmental studies on our properties in California, Florida and Illinois and we believe that such properties have been operated in accordance with standard oil field practices, certain of the fields have been in operation for more than 90 years, and current or future local, state and federal environmental laws and regulations may require substantial expenditures to comply with such rules and regulations. In connection with the purchase of certain of our onshore California properties, we received a limited indemnity for certain conditions if they violate applicable local, state and federal environmental laws and regulations in effect on the date of such agreement. We believe that we do not have any material obligations for operations conducted prior to our acquisition of the properties, other than our obligation to plug existing wells and those normally associated with customary oil field operations of similarly situated properties, there can be no assurance that current or future local, state or federal rules and regulations will not require us to spend material amounts to comply with such rules and regulations or that any portion of such amounts will be recoverable under the indemnity.

Consistent with normal industry practices, substantially all of our crude oil and natural gas leases require that, upon termination of economic production, the working interest owners plug and abandon non-producing wellbores, remove tanks, production equipment and flow lines and restore the wellsite. We have estimated that the costs to perform these tasks is approximately $17.0 million, net of salvage value and other considerations. Such estimated costs are amortized to expense through the unit-of-production method as a component of accumulated depreciation, depletion and amortization. Results from operations for 2001, 2000 and 1999 each include $0.5 million of expense associated with these estimated future costs. For valuation and realization purposes of the affected crude oil and natural gas properties, these estimated future costs are also deducted from estimated future gross revenues to arrive at the estimated future net revenues and the Standardized Measure disclosed in Note 19.

As is common within the industry, we have entered into various commitments and operating agreements related to the exploration and development of and production from proved crude oil and natural gas properties and the marketing, transportation, terminalling and storage of crude oil. It is management's belief that such commitments will be met without a material adverse effect on our financial position, results of operations or cash flows.

Industry Concentration

Financial instruments which potentially subject us to concentrations of credit risk consist principally of accounts receivable with respect to our oil and gas operations and derivative instruments related to our hedging activities. PAA is the exclusive marketer/purchaser for all of our equity oil production. This concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that PAA may be affected by changes in economic, industry or other conditions. We do not believe the loss of PAA as the exclusive purchaser of our equity production would have a material adverse affect on our results of operations. We believe PAA could be replaced by other purchasers under contracts with similar terms and conditions. The contract counterparties for our derivative commodity contracts are all major financial institutions with Standard & Poor's ratings of A or better. Three of the financial institutions are participating lenders in our revolving credit facility, with one such counterparty holding contracts that represent approximately 37% of the fair value of all open positions at December 31, 2001.

There are a limited number of alternative methods of transportation for our production. Substantially all of our oil and gas production is transported by pipelines, trucks and barges owned by third parties. The inability or unwillingness of these parties to provide transportation services to us for a reasonable fee could result in our having to find transportation alternatives, increased transportation costs or involuntary curtailment of a significant portion of our oil and gas production which could have a negative impact on future results of operations or cash flows.

Note 16—Litigation

Texas Securities Litigation. In November and December of 1999, class action lawsuits were filed in the United States District Court for the Southern District of Texas alleging that PAA. and certain of the general partner's officers and directors violated federal securities laws, primarily in connection with unauthorized trading by a former employee. The consolidated class action filed by purchasers of our common stock and options is captioned Koplovitz v. Plains Resources Inc., et al. The consolidated action filed by purchasers of PAA's common units is captioned Di Giacomo v. Plains All American Pipeline, L.P., et al.

We and PAA reached an agreement with representatives for the plaintiffs for the settlement of all of the class actions, and in January 2001, PAA deposited approximately $30.0 million under the terms of the settlement agreement. The total cost of the settlement to us and PAA, including interest and expenses, and after insurance reimbursements, was $14.9 million. Of that amount, $1.0 million was allocated to us by agreement between special independent committees of our board of directors and the board of directors of Plains Holdings Inc. (formerly known as Plains All American Inc.), the then general partner of PAA. The settlement has received final approval by the court. The settlement agreement does not affect the Texas Derivative Litigation and Delaware Derivative Litigation described below.

Delaware Derivative Litigation. Beginning December 3, 1999 derivative lawsuits were filed in the Delaware Chancery Court, New Castle County naming Plains Holdings Inc., the then general partner of PAA, its directors and certain of its officers as defendants, alleging that the defendants breached the fiduciary duties they owed to PAA and its unitholders by failing to monitor properly the activities of its employees. The court has consolidated all of the cases under the caption In Re Plains All American Inc. Shareholders Litigation. A motion to dismiss was filed on behalf of the defendants on August 11, 2000.

An agreement has been reached with the plaintiffs to settle the Delaware litigation by PAA making an aggregate payment of approximately $1.1 million. On March 6, 2002 the Delaware court approved this settlement.

Texas Derivative Litigation. On July 11, 2000, a derivative lawsuit was filed in the United States District Court for the Southern District of Texas entitled Fernandez v. Plains All American Inc., et al., naming Plains Holdings Inc., the then general partner of PAA, its directors and certain of its officers as defendants. This lawsuit contains the same claims and seeks the same relief as the Delaware derivative litigation described above. A motion to dismiss was filed on behalf of the defendants on August 14, 2000. PAA has reached an agreement in principle to settle the Texas derivative litigation. The settlement, which is subject to court approval, contemplates a payment of $112,500 by PAA and does not contemplate any payment by the Company.

We, in the ordinary course of business, are a claimant and/or defendant in various other legal proceedings. Management does not believe that the outcome of these legal proceedings, individually and in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Note 17—Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of Statement of Financial Accounting Standards No. 107, Disclosures About Fair Value of Financial Instruments ("SFAS 107"). The estimated fair value amounts have been determined using available market information and valuation methodologies described below. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of items comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. Derivative financial instruments included in other assets are stated at fair value. The carrying amounts and fair values of our other financial instruments are as follows (in thousands):

	December 31,			
	2001		2000	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt:				
Bank debt	$11,500	$11,500	$27,300	$27,300
Subordinated debt	269,539	272,130	277,543	274,313
Other long-term debt	1,022	1,022	1,533	1,533

The carrying value of bank debt approximates its fair value, as interest rates are variable, based on prevailing market rates. The fair value of subordinated debt is based on quoted market prices based on trades of subordinated debt.

Note 18—Supplemental Disclosures of Cash Flow Information

Selected cash payments and noncash activities were as follows (in thousands):

	Year Ended December 31,		
	2001	2000	1999
Cash paid for interest (net of amount capitalized)	$27,939	$56,154	$44,329
Cash paid for taxes	$ 7,048	$ 987	$ 548
Noncash sources and (uses) of investing and financing activities:			
Series D Preferred Stock dividends	$ —	$ —	$ (1,354)
Exchange of preferred stock for common stock	$ —	$ 62	$ 71
Series E Preferred Stock dividends	$ —	$ —	$ (2,030)
Tax benefit from exercise of employee stock options	$ 6,990	$ 1,901	$ 440

Note 19—Crude Oil and Natural Gas Activities

Costs Incurred

Our oil and natural gas acquisition, exploration, exploitation and development activities are conducted in the United States. The following table summarizes the costs incurred during the last three years (in thousands).

	Year Ended December 31,		
	2001	2000	1999
Property acquisitions costs:			
Unproved properties	$ 44	$ 73	$ 879
Proved properties	1,798	2,433	2,880
Exploration costs	329	872	4,101
Exploitation and development costs	134,304	77,550	65,119
	136,475	$80,928	$72,979

Capitalized Costs

The following table presents the aggregate capitalized costs subject to amortization relating to our crude oil and natural gas acquisition, exploration, exploitation and development activities, and the aggregate related accumulated DD&A (in thousands).

	December 31,	
	2001	2000
Proved properties	$900,898	$762,245
Accumulated DD&A	(435,269)	(408,337)
	$465,629	$353,908

The DD&A rate per equivalent unit of production was $2.75, $2.25, and $2.13 for the years ended December 31, 2001, 2000, and 1999, respectively.

Costs Not Subject to Amortization

The following table summarizes the categories of costs comprising the amount of unproved properties not subject to amortization (in thousands).

	December 31,		
	2001	2000	1999
Acquisition costs	$30,038	$34,087	$42,261
Exploration costs	3,579	4,456	4,842
Capitalized interest	6,890	4,038	4,928
	$40,507	$42,581	$52,031

Unproved property costs not subject to amortization consist mainly of acquisition and lease costs and seismic data related to unproved areas. We will continue to evaluate these properties over the lease terms; however, the timing of the ultimate evaluation and disposition of a significant portion of the properties has not been determined. Costs associated with seismic data and all other costs will become subject to amortization as the prospects to which they relate are evaluated. Approximately 13%, 11% and 16% of the balance in unproved properties at December 31, 2001, related to additions made in 2001, 2000 and 1999, respectively.

During 2001, 2000 and 1999, we capitalized $3.6 million, $4.4 million and $4.4 million, respectively, of interest related to the costs of unproved properties in the process of development.

Supplemental Reserve Information (Unaudited)

The following information summarizes our net proved reserves of crude oil (including condensate and natural gas liquids) and natural gas and the present values thereof for the three years ended December 31, 2001. The following reserve information is based upon reports of the independent petroleum consulting firms of Netherland, Sewell & Associates, Inc., and Ryder Scott Company in 2001, and H.J. Gruy and Associates, Inc., Netherland, Sewell & Associates, Inc., and Ryder Scott Company in 2000 and 1999. The estimates are in accordance with regulations prescribed by the SEC.

In management's opinion, the reserve estimates presented herein, in accordance with generally accepted engineering and evaluation principles consistently applied, are believed to be reasonable. However, there are numerous uncertainties inherent in estimating quantities and values of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating the recovery from underground accumulations of crude oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Because all reserve estimates are to some degree speculative, the quantities of crude oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future crude oil and natural gas sales prices may all differ from those assumed in these estimates. In addition, different reserve engineers may make different estimates of reserve quantities and cash flows based upon the same available data. Therefore, the Standardized Measure shown below represents estimates only and should not be construed as the current market value of the estimated crude oil and natural gas reserves attributable to our properties. In this regard, the information set forth in the following tables includes revisions of reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions reflect additional information from subsequent exploitation and development activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in product prices.

Decreases in the prices of crude oil and natural gas have had, and could have in the future, an adverse effect on the carrying value of our proved reserves and our revenues, profitability and cash flow. Almost all of our reserve base (approximately 94% of year-end 2001 reserve volumes) is comprised of crude oil properties that are sensitive to crude oil price volatility.

Estimated Quantities of Crude Oil and Natural Gas Reserves (Unaudited)

The following table sets forth certain data pertaining to our proved and proved developed reserves for the three years ended December 31, 2001 (in thousands).

	As of or for the Year Ended December 31,					
	2001		2000		1999	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
Proved Reserves						
Beginning balance	223,162	93,486	218,922	90,873	120,208	86,781
Revision of previous estimates	(15,457)	(5,485)	(9,834)	(3,597)	62,895	(8,234)
Extensions, discoveries, improved recovery and other additions	42,210	11,571	22,429	9,252	37,393	15,488
Sale of reserves in-place	—	—	—	—	—	—
Purchase of reserves in-place	—	—	—	—	6,442	—
Production	(9,279)	(3,355)	(8,355)	(3,042)	(8,016)	(3,162)
Ending balance	240,636	96,217	223,162	93,486	218,922	90,873
Proved Developed Reserves						
Beginning balance	123,532	52,184	120,141	49,255	73,264	58,445
Ending balance	134,704	59,101	123,532	52,184	120,141	49,255

Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

The Standardized Measure of discounted future net cash flows relating to proved crude oil and natural gas reserves is presented below (in thousands):

	December 31,		
	2001	2000	1999
Future cash inflows	$3,833,456	$6,057,344	$4,837,010
Future development costs	(329,393)	(275,862)	(231,914)
Future production expense	(1,826,634)	(2,875,301)	(1,758,572)
Future income tax expense	(511,040)	(887,107)	(845,133)
Future net cash flows	1,166,389	2,019,074	2,001,391
Discounted at 10% per year	(742,981)	(1,099,413)	(1,073,591)
Standardized measure of discounted future net cash flows	$ 423,408	$ 919,661	$ 927,800

The Standardized Measure of discounted future net cash flows (discounted at 10%) from production of proved reserves was developed as follows:

1. An estimate was made of the quantity of proved reserves and the future periods in which they are expected to be produced based on year-end economic conditions.

2. In accordance with SEC guidelines, the engineers' estimates of future net revenues from our proved properties and the present value thereof are made using crude oil and natural gas sales prices in effect as of the dates of such estimates and are held constant throughout the life of the properties, except where such guidelines permit alternate treatment, including the use of

fixed and determinable contractual price escalations. We have entered into various arrangements to fix or limit the NYMEX crude oil price for a significant portion of our crude oil production. Arrangements in effect at December 31, 2001 are discussed in Note 3. Such arrangements are not reflected in the reserve reports. The overall average year-end prices used in the reserve reports as of December 31, 2001, were $14.91 per barrel of crude oil and $2.56 per Mcf of natural gas. Such prices as of December 31, 2000 were $21.02 per barrel of crude oil and $14.63 per Mcf of natural gas.

3. The future gross revenue streams were reduced by estimated future operating costs (including production and ad valorem taxes) and future development and abandonment costs, all of which were based on current costs.

4. The reports reflect the pre-tax Present Value of Proved Reserves to be $0.7 billion, $1.3 billion and $1.2 billion at December 31, 2001, 2000 and 1999, respectively. SFAS No. 69 requires us to further reduce these estimates by an amount equal to the present value of estimated income taxes which might be payable by us in future years to arrive at the Standardized Measure. Future income taxes were calculated by applying the statutory federal and state income tax rate to pre-tax future net cash flows, net of the tax basis of the properties involved and utilization of available tax carryforwards related to oil and gas operations.

The principal sources of changes in the Standardized Measure of the future net cash flows for the three years ended December 31, 2001, are as follows (in thousands):

	Year Ended December 31,		
	2001	2000	1999
Balance, beginning of year	$ 919,661	$ 927,800	$ 226,943
Sales, net of production expenses	(144,055)	(166,571)	(60,578)
Net change in sales and transfer prices, net of production expenses	(674,439)	96,104	516,097
Changes in estimated future development costs	(18,134)	(14,593)	(52,951)
Extensions, discoveries and improved recovery, net of costs	94,775	141,638	112,573
Previously estimated development costs incurred during the year	87,721	31,363	22,842
Purchase of reserves in-place	—	—	53,724
Revision of quantity estimates	(166,869)	(104,200)	404,705
Accretion of discount	145,375	115,605	22,694
Net change in income taxes	179,373	(107,485)	(318,249)
Balance, end of year	$ 423,408	$ 919,661	$ 927,800

Results of Operations for Oil and Gas Producing Activities

The results of operations from oil and gas producing activities below exclude non-oil and gas revenues, general and administrative expenses, interest charges, interest income and interest capitalized. Income tax (expense) or benefit was determined by applying the statutory rates to pretax operating results (in thousands).

	Year Ended December 31,		
	2001	2000	1999
Revenues from oil and gas producing activities	$215,247	$149,342	$116,223
Production costs	(71,192)	(62,140)	(55,645)
Depreciation, depletion and amortization	(27,009)	(19,953)	(18,177)
Income tax expense	(45,987)	(26,227)	(16,536)
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 71,059	$ 41,022	$ 25,865

PLAINS RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Note 20—Quarterly Financial Data (Unaudited)

The following table shows summary financial data for 2001 and 2000 (in thousands, except per share data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter(1)	Total
2001					
Revenues	$ 58,232	$ 58,424	$ 54,168	$ 44,896	$ 215,720
Operating profit	31,172	22,510	25,217	15,415	94,314
Income before cumulative effect of accounting change	20,952	100,102	15,154	19,109	155,317
Cumulative effect of accounting change	(1,986)	—	—	—	(1,986)
Net income	18,966	100,102	15,154	19,109	153,331
Basic EPS					
Income before cumulative effect of accounting change	1.11	3.83	0.63	0.79	6.07
Cumulative effect of accounting change	(0.11)	—	—	—	(0.09)
Net income	1.00	3.83	0.63	0.79	5.98
Diluted EPS					
Income before cumulative effect of accounting change	0.72	2.68	0.58	0.75	4.82
Cumulative effect of accounting change	(0.06)	—	—	—	(0.07)
Net income	0.66	2.68	0.58	0.75	4.75
2000					
Revenues	$2,087,685	$1,427,044	$1,542,463	$1,573,393	$6,630,585
Operating profit	53,502	54,400	48,706	55,660	212,268
Income before extraordinary item and cumulative effect of accounting change	21,268	8,992	7,026	8,638	45,924
Extraordinary item	(1,365)	(3,623)	—	—	(4,988)
Cumulative effect of accounting change	(121)	—	—	—	(121)
Net income	19,782	5,369	7,026	8,638	40,815
Basic EPS					
Income before extraordinary item and cumulative effect of accounting change	0.98	0.29	0.19	0.29	1.75
Extraordinary item	(0.08)	(0.20)	—	—	(0.28)
Cumulative effect of accounting change	—	—	—	—	(0.01)
Net income	0.90	0.09	0.19	0.29	1.46
Diluted EPS					
Income before extraordinary item and cumulative effect of accounting change	0.72	0.28	0.18	0.27	1.56
Extraordinary item	(0.05)	(0.19)	—	—	(0.17)
Cumulative effect of accounting change	—	—	—	—	—
Net income	0.67	0.09	0.18	0.27	1.39

(1) For 2000, includes a $5.0 million charge to reserve for potentially uncollectible accounts receivable.

Note 21—Operating Segments

Prior to completion of the Transactions , our operations consisted of two operating segments: (1) Upstream Operations—engages in the acquisition, exploitation, development, exploration and production of crude oil and natural gas and (2) Midstream Operations—engages in pipeline transportation, purchases and resales of crude oil at various points along the distribution chain and the leasing of certain terminalling and storage assets. As a result of the Transactions we no longer have a Midstream segment.

	Upstream	Midstream	Total
		(In thousands)	
2000			
Revenues:			
External customers	$149,342	$ 6,425,644	$ 6,574,986
Intersegment (a)	—	215,543	215,543
Gain on sale of assets	—	48,188	48,188
Interest and other income (expense)	(3,468)	10,879	7,411
Total revenues of reportable segments	$145,874	$ 6,700,254	$ 6,846,128
Segment gross margin (b)	$ 86,202	$ 126,066	$ 212,268
Segment gross profit (c)	76,297	85,195	161,492
Segment income (loss) before income taxes, extraordinary item and cumulative effect of accounting change	23,009	91,033	114,042
Interest expense	27,346	28,482	55,828
Depreciation, depletion and amortization	22,474	24,747	47,221
Income tax expense	6,503	19,080	25,583
Extraordinary item, net of tax and minority interest	—	(4,988)	(4,988)
Capital expenditures	81,475	12,603	94,078
Assets	458,678	935,651	1,394,329
1999			
Revenues:			
External customers	$116,223	$10,796,998	$10,913,221
Intersegment (a)	—	75,454	75,454
Gain on sale of assets	—	16,457	16,457
Interest and other income	241	10,783	11,024
Total revenues of reportable segments	$116,464	$10,899,692	$11,016,156
Segment gross margin (b)	$ 60,578	$ (58,750)	$ 1,828
Segment gross profit (c)	52,775	(82,349)	(29,574)
Segment income (loss) before income taxes and extraordinary item	8,132	(93,601)	(85,469)
Interest expense	25,298	21,080	46,378
Depreciation, depletion and amortization	19,586	17,412	36,998
Income tax benefit	1,635	18,844	20,479
Extraordinary item, net of tax and minority interest	—	(544)	(544)
Capital expenditures	77,899	189,286	267,185
Assets	445,921	1,243,639	1,689,560

(a) Intersegment revenues and transfers were conducted on an arm's-length basis.

(b) Gross margin is calculated as operating revenues less operating expenses.

(c) Gross profit is calculated as operating revenues less operating expenses and general and administrative expenses.

The following table reconciles segment revenues to amounts reported in our financial statements:

	For the Year Ended December 31,	
	2000	1999
Revenues of reportable segments	$6,846,128	$11,016,156
Intersegment	(215,543)	(75,454)
Net gain recorded upon the formation of PAA not allocated to reportable segments	—	—
Total company revenues	$6,630,585	$10,940,702

PAA is the exclusive purchaser of all of our equity oil production. The following table reflects for the years ended December 31, 2000 and 1999, during which periods PAA was included in our consolidated financial statements, customers accounting for more than 10% of consolidated sales (excluding hedging effects):

	Percentage of Consolidated Sales	
	Year Ended December 31,	
Customer	2000	1999
Marathon Ashland Petroleum (1)	12%	—
Sempra Energy Trading Corporation (1)	—	22%
Koch Oil Company (1)	—	18%
	Percentage of Oil and Gas Sales(2)	
Chevron	43%	39%
Equiva Trading Company	23%	—
Tosco Refining Company	—	19%
Conoco Inc.	—	11%
Marathon Ashland Petroleum	13%	16%

(1) These customers pertain to our midstream segment Represents percentage of oil and gas sales revenues plus marketing, transportation, storage and terminalling revenues.

(2) These percentages represent the entities that purchased our equity crude production from PAA.

We do not believe the loss of PAA as the exclusive purchaser of our equity production would have a material adverse effect on our results of operations. We believe PAA could be replaced by other purchasers under contracts with similar terms and conditions.

Note 22—Consolidating Financial Statements

The following financial information presents consolidating financial statements, which include:

- the parent company only ("Parent");
- the guarantor subsidiaries on a combined basis ("Guarantor Subsidiaries");
- the nonguarantor subsidiaries on a combined basis ("Nonguarantor Subsidiaries");
- elimination entries necessary to consolidate the Parent, the Guarantor Subsidiaries and the Nonguarantor Subsidiaries; and
- Plains Resources Inc. on a consolidated basis.

These statements are presented because the 10.25% Notes discussed in Note 4 are not guaranteed by all of our subsidiaries.

PLAINS RESOURCES INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING BALANCE SHEET (in thousands)

DECEMBER 31, 2001

ASSETS	Parent	Guarantor Subsidiaries	Nonguarantor Subsidiaries	Intercompany Eliminations	Consolidated
Current Assets					
Cash and cash equivalents	$ 1,013	$ 13	$ 153	$ —	$ 1,179
Accounts receivable and other	26,773	18,050	—	—	44,823
Current intercompany advances	—	13,662	(13,662)	—	—
Inventory	—	6,721	—	—	6,721
	27,786	38,446	(13,509)	—	52,723
Property and Equipment, at cost	243,969	701,587	—	(149)	945,407
Less allowance for depreciation, depletion and amortization	(217,801)	164,795)	—	(55,386)	(437,982)
	26,168	536,792	—	(55,535)	507,425
Investment in Subsidiaries and Intercompany Advances	467,837	(279,496)	178,202	(301,917)	64,626
Other Assets	10,313	13,769	383	(451)	24,014
	$ 532,104	$ 309,511	$165,076	$(357,903)	$ 648,788
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Accounts payable and other current liabilities	$ (68,896)	$ 42,581	$ 80,210	$ —	$ 53,895
Interest payable	8,286	—	—	—	8,286
Notes payable	—	511	—	—	511
	(60,610)	43,092	80,210	—	62,692
Long-Term Debt					
Bank debt	11,500	—	—	—	11,500
Subordinated debt	269,539	—	—	—	269,539
Other	—	1,022	—	—	1,022
	281,039	1,022	—	—	282,061
Other Long-Term Liabilities	3,013	1,413	463	—	4,889
Deferred Income Taxes	53,810	8,415	(17,931)	—	44,294
Non-redeemable Preferred Stock, Common Stock and Other Stockholders' Equity					
Series D Cumulative Convertible Preferred Stock	23,300	—	—	—	23,300
Common Stock	2,768	837	—	(837)	2,768
Additional paid-in capital	268,520	3,805	43,390	(47,195)	268,520
Retained earnings (accumulated deficit)	37,676	250,927	61,263	(312,190)	37,676
Accumulated other comprehensive income	13,930	—	(2,319)	2,319	13,930
Treasury stock, at cost	(91,342)	—	—	—	(91,342)
	254,852	255,569	102,334	(357,903)	254,852
	$ 532,104	$ 309,511	$165,076	$(357,903)	$ 648,788

PLAINS RESOURCES INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING BALANCE SHEET (in thousands)

DECEMBER 31, 2000

ASSETS	Parent	Guarantor Subsidiaries	Nonguarantor Subsidiaries	Intercompany Eliminations	Consolidated
Current Assets					
Cash and cash equivalents	$ 4	$ 597	$ 4,479	$ —	$ 5,080
Accounts receivable and other	12,193	15,596	347,696	—	375,485
Current intercompany advances	—	17,605	(17,605)	—	—
Inventory	—	8,063	46,781	—	54,844
	12,197	41,861	381,351	—	435,409
Property and Equipment, at cost	237,591	570,677	473,471	—	1,281,739
Less allowance for depreciation, depletion and amortization	(215,942)	(138,871)	(27,266)	(55,386)	(437,465)
	21,649	431,806	446,205	(55,386)	844,274
Investment in Subsidiaries and Intercompany Advances	389,467	(254,891)	(6,372)	(128,204)	—
Other Assets	8,151	16,005	90,490	—	114,646
	$ 431,464	$ 234,781	$911,674	$(183,590)	$1,394,329
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Accounts payable and other current liabilities	$ 7,105	$ 46,368	$359,823	$ 13	$ 413,309
Notes payable and other current obligations	—	511	1,300	—	1,811
	7,105	46,879	361,123	13	415,120
Long-Term Debt					
Bank debt	27,300	—	—	—	27,300
Bank debt of a subsidiary	—	—	320,000	—	320,000
Subordinated debt	277,543	—	—	—	277,543
Other	—	1,533	—	—	1,533
	304,843	1,533	320,000	—	626,376
Other Long-Term Liabilities	2,413	—	1,009	—	3,422
Minority Interest in PAA	(70,037)	—	232,216	92	162,271
Cumulative Convertible Preferred Stock, Stated at Liquidation Preference	50,000	—	—	—	50,000
Non-redeemable Preferred Stock, Common Stock and Other Stockholders' Equity					
Series D Cumulative Convertible Preferred Stock	23,300	—	—	—	23,300
Series H Cumulative Convertible Preferred Stock	84,785	—	—	—	84,785
Common Stock	1,875	78	—	(78)	1,875
Additional paid-in capital	139,203	3,951	43,393	(47,344)	139,203
Retained earnings (accumulated deficit)	(88,410)	182,340	(46,067)	(136,273)	(88,410)
Treasury stock, at cost	(23,613)	—	—	—	(23,613)
	137,140	186,369	(2,674)	(183,695)	137,140
	$ 431,464	$ 234,781	$911,674	$(183,590)	$1,394,329

PLAINS RESOURCES INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENT OF OPERATIONS (in thousands)

YEAR ENDED DECEMBER 31, 2001

	Parent	Guarantor Subsidiaries	Nonguarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues					
Crude oil and liquids	$ —	$186,476	$ —	$ —	$186,476
Natural gas	—	28,771	—	—	28,771
Other operating revenues	—	473	—	—	473
	—	215,720	—	—	215,720
Expenses					
Production expenses	—	71,192	—	—	71,192
General and administrative	10,023	11,260	10	—	21,293
Depreciation, depletion and amortization	1,502	27,419	—	—	28,921
	11,525	109,871	10	—	121,406
Income (Loss) from Operations	(11,525)	105,849	(10)	—	94,314
Other Income (Expense)					
Equity in earnings of subsidiary	176,527	—	18,540	(176,527)	18,540
Gain on PAA unit transactions and public offerings	—	—	170,157	—	170,157
Interest expense	(2,805)	(23,580)	—	—	(26,385)
Interest and other income	(312)	463	—	—	151
Income (Loss) Before Income Taxes and Cumulative Effect of Accounting Change	161,885	82,732	188,687	(176,527)	256,777
Income tax (expense) benefit:					
Current	44,749	—	(54,696)	—	(9,947)
Deferred	(51,175)	(13,532)	(26,806)	—	(91,513)
Income (Loss) Before Cumulative Effect of Accounting Change	155,459	69,200	107,185	(176,527)	155,317
Cumulative effect of accounting change, net of tax benefit	(2,128)	—	142	—	(1,986)
Net Income (Loss)	153,331	69,200	107,327	(176,527)	153,331
Cumulative preferred dividends	(27,245)	—	—	—	(27,245)
Income (Loss) Available to Common Stockholders	$126,086	$ 69,200	$107,327	$(176,527)	$126,086

PLAINS RESOURCES INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENT OF OPERATIONS (in thousands)

YEAR ENDED DECEMBER 31, 2000

	Parent	Guarantor Subsidiaries	Nonguarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues					
Crude oil and liquids	$ 4	$131,667	$ —	$ 1,654	$ 133,325
Natural gas	—	16,017	—	—	16,017
Marketing, transportation, storage and terminalling	—	—	6,641,187	(215,543)	6,425,644
Gain on sale of assets	—	—	48,188	—	48,188
	4	147,684	6,689,375	(213,889)	6,623,174
Expenses					
Production expenses	—	62,140	—	—	62,140
General and administrative	2,054	7,851	40,871	—	50,776
Marketing, transportation, storage and terminalling	—	—	6,506,504	(213,889)	6,292,615
Unauthorized trading losses and related expenses	1,000	—	6,963	—	7,963
Depreciation, depletion and amortization	3,068	19,406	24,747	—	47,221
	6,122	89,397	6,579,085	(213,889)	6,460,715
Income from Operations	(6,118)	58,287	110,290	—	162,459
Other Income (Expense)					
Equity in earnings of subsidiary	64,115	—	—	(64,115)	—
Interest expense	(9,581)	(20,827)	(28,482)	3,062	(55,828)
Interest and other income	(737)	331	10,879	(3,062)	7,411
Income (Loss) Before Income Taxes, Minority Interest, Extraordinary Item and Cumulative Effect of Accounting Change	47,679	37,791	92,687	(64,115)	114,042
Minority interest	—	—	(42,535)	—	(42,535)
Income tax (expense) benefit:					
Current	24,094	—	(25,114)	—	(1,020)
Deferred	(30,958)	361	6,034	—	(24,563)
Income (Loss) Before Extraordinary Item and Cumulative Effect of Accounting Change	40,815	38,152	31,072	(64,115)	45,924
Extraordinary item, net of tax benefit and minority interest	—	—	(4,988)	—	(4,988)
Cumulative effect of accounting change, net of tax benefit	—	(121)	—	—	(121)
Net Income (Loss)	40,815	38,031	26,084	(64,115)	40,815
Cumulative preferred dividends	(14,725)	—	—	—	(14,725)
Income (Loss) Available to Common Stockholders	$26,090	$ 38,031	$ 26,084	$(64,115)	$ 26,090

PLAINS RESOURCES INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENT OF OPERATIONS (in thousands)

YEAR ENDED DECEMBER 31, 1999

	Parent	Guarantor Subsidiaries	Nonguarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues					
Crude oil and liquids	$ —	$109,641	$ —	$ 1,487	$ 111,128
Natural gas	—	5,095	—	—	5,095
Marketing, transportation, storage and terminalling	—	—	10,872,452	(75,454)	10,796,998
Gain on sale of assets	—	—	16,457	—	16,457
	—	114,736	10,888,909	(73,967)	10,929,678
Expenses					
Production expenses	—	55,645	—	—	55,645
General and administrative	2,311	5,492	23,599	—	31,402
Depreciation, depletion and amortization	2,096	17,490	17,412	—	36,998
Marketing, transportation, storage and terminalling	—	—	10,763,275	(73,967)	10,689,308
Unauthorized trading losses and related expenses	—	—	166,440	—	166,440
	4,407	78,627	10,970,726	(73,967)	10,979,793
Income (Loss) from Operations	(4,407)	36,109	(81,817)	—	(50,115)
Other Income (Expense)					
Equity in earnings (loss) of subsidiary	(11,510)	—	—	11,510	—
Gain on PAA unit offering	—	—	9,787	—	9,787
Interest expense	(6,994)	(18,851)	(21,080)	547	(46,378)
Interest and other income	699	89	996	(547)	1,237
Income (Loss) Before Income Taxes, Minority Interest and Extraordinary Item	(22,212)	17,347	(92,114)	11,510	(85,469)
Minority interest in PAA	—	—	40,203	—	40,203
Income tax (expense) benefit:					
Current	338	—	(331)	—	7
Deferred	(3,457)	4,754	19,175	—	20,472
Income (Loss) Before Extraordinary Item	(25,331)	22,101	(33,067)	11,510	(24,787)
Extraordinary item, net of tax benefit and minority interest	—	—	(544)	—	(544)
Net Income (Loss)	(25,331)	22,101	(33,611)	11,510	(25,331)
Cumulative preferred dividends	(10,026)	—	—	—	(10,026)
Income (Loss) Available to Common Stockholders	$(35,357)	$ 22,101	$ (33,611)	$ 11,510	$ (35,357)

PLAINS RESOURCES INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS (in thousands)

YEAR ENDED DECEMBER 31, 2001

	Parent	Guarantor Subsidiaries	Nonguarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income (loss)	$ 153,331	$ 69,200	$107,327	$(176,527)	$ 153,331
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation, depletion, and amortization	1,502	27,419	—	—	28,921
Equity earnings in subsidiary	(176,527)	—	(18,540)	176,527	(18,540)
Distributions from subsidiary	—	—	31,553	—	31,553
Noncash gains	—	—	(170,157)	—	(170,157)
Deferred income tax	51,175	13,532	26,806	—	91,513
Cumulative effect of adoption of SFAS 123	2,128	—	(142)	—	1,986
Change in derivative fair value	1,227	—	—	—	1,227
Noncash compensation expense	4,514	—	—	—	4,514
Other noncash items	1,626	—	—	—	1,626
Change in assets and liabilities resulting from operating activities:					
Accounts receivable and other	(14,580)	(7,461)	43,064	—	21,023
Inventory	—	1,342	1,133	—	2,475
Accounts payable and other current liabilities	(76,001)	(3,787)	(1,486)	—	(81,274)
Other long-term liabilities	600	1,413	(546)	—	1,467
Advances from (payments to) affiliates	143,285	30,054	(122,876)	—	50,463
Net cash provided by (used in) operating activities	92,280	131,712	(103,864)	—	120,128
CASH FLOWS FROM INVESTING ACTIVITIES					
Acquisition, exploration and development costs	—	(131,785)	—	—	(131,785)
Additions to other property and assets	(561)	—	—	—	(561)
Proceeds from the sale of PAA units	—	—	106,941	—	106,941
Investment in PAA	—	—	(3,978)	—	(3,978)
Net cash provided by (used in) investing activities	(561)	(131,785)	102,963	—	(29,383)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from long-term debt	204,900	—	—	—	204,900
Proceeds from sale of capital stock, options and warrants	9,169	—	—	—	9,169
Proceeds from issuance of preferred stock	—	—	—	—	—
Purchase of senior subordinated notes	(7,550)	—	—	—	(7,550)
Principal payments of long-term debt	(220,700)	(511)	—	—	(221,211)
Purchase of treasury stock	(67,729)	—	—	—	(67,729)
Preferred stock dividends	(8,698)	—	—	—	(8,698)
Other	(102)	—	—	—	(102)
Net cash used in financing activities	(90,710)	(511)	—	—	(91,221)
Net decrease in cash and cash equivalents	1,009	(584)	(901)	—	(476)
Decrease in cash due to deconsolidation of PAA	—	—	(3,425)	—	(3,425)
Cash and cash equivalents, beginning of period	$ 4	$ 597	$ 4,479	$ —	5,080
Cash and cash equivalents, end of period	$ 1,013	$ 13	$ 153	$ —	$ 1,179

PLAINS RESOURCES INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS (in thousands)

YEAR ENDED DECEMBER 31, 2000

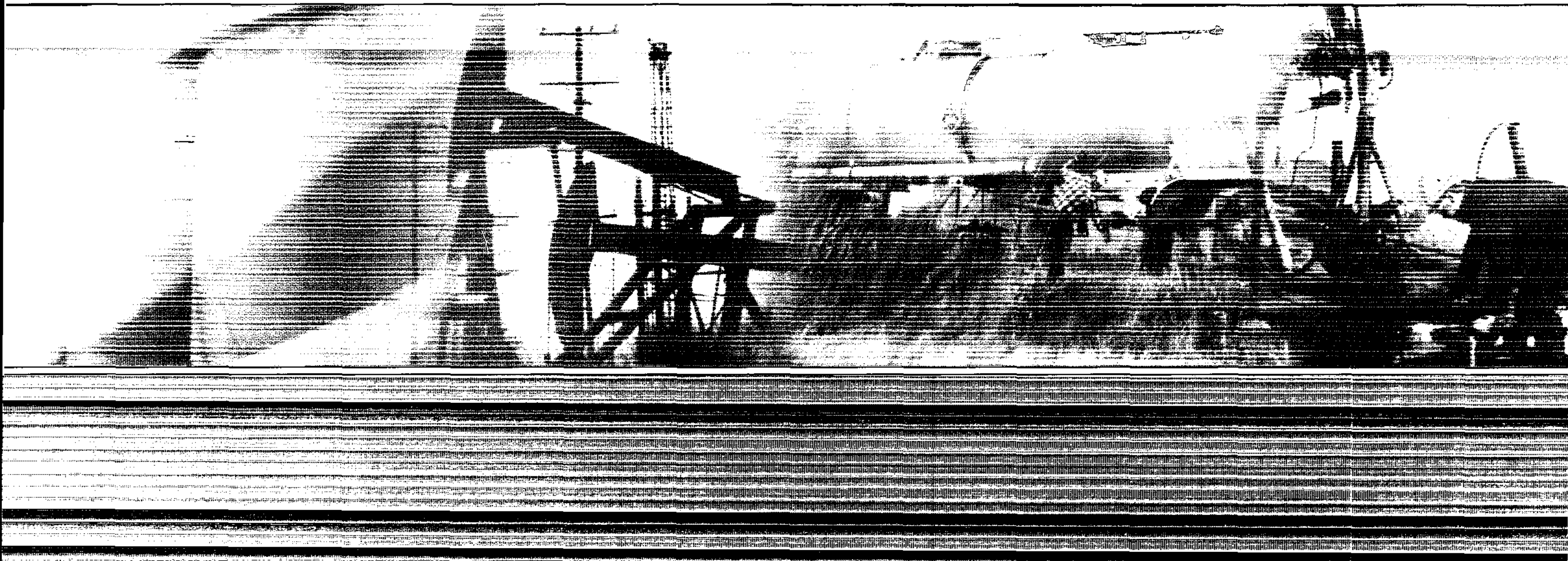
	Parent	Guarantor Subsidiaries	Nonguarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income (loss)	$ 40,815	$38,031	$ 26,084	$(64,115)	$ 40,815
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation, depletion, and amortization	3,068	19,406	24,747	—	47,221
Gain on sale of assets (Note 6)	—	—	(48,188)	—	(48,188)
Minority interest in income of a subsidiary	—	—	35,566	—	35,566
Equity earnings in subsidiary	(64,115)	—	—	64,115	—
Deferred income tax	30,958	(362)	(9,299)	—	21,297
Noncash compensation expense	(407)	—	3,089	—	2,682
Allowance for doubtful accounts	—	—	5,000	—	5,000
Other noncash items	6,351	—	4,574	—	10,925
Change in assets and liabilities resulting from operating activities:					
Accounts receivable and other	(10,385)	(7,461)	120,497	—	102,651
Inventory	—	(2,023)	(11,954)	—	(13,977)
Pipeline linefill	—	—	(16,679)	—	(16,679)
Accounts payable and other current liabilities	(16,595)	34,685	(161,543)	—	(143,453)
Other long-term liabilities	591	—	(8,591)	—	(8,000)
Advances from (payments to) affiliates	119,735	(9,889)	(109,846)	—	—
Net cash provided by (used in) operating activities	110,016	72,387	(146,543)	—	35,860
CASH FLOWS FROM INVESTING ACTIVITIES					
Payments for crude oil pipeline, gathering and terminal assets	—	—	(12,219)	—	(12,219)
Payments for acquisition, exploration, and development costs	(3,894)	(74,448)	(384)	—	(78,726)
Payments for additions to other property and assets	—	(2,476)	(657)	—	(3,133)
Proceeds from asset sales (Note 6)	—	—	224,261	—	224,261
Net cash provided by (used in) investing activities	(3,894)	(76,924)	211,001	—	130,183
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from long-term debt	264,825	—	1,433,750	—	1,698,575
Proceeds from short-term debt	—	—	51,300	—	51,300
Proceeds from sale of capital stock, options and warrants	2,301	—	—	—	2,301
Principal payments of long-term debt	(375,336)	—	(1,423,850)	—	(1,799,186)
Principal payments of short-term debt	—	—	(108,719)	—	(108,719)
Purchase of treasury stock	(23,613)	—	—	—	(23,613)
Costs incurred in connection with financing arrangements	—	—	(6,748)	—	(6,748)
Preferred stock dividends	(13,409)	—	—	—	(13,409)
Distribution to unitholders	30,133	—	(59,565)	—	(29,432)
Other	(260)	—	—	—	(260)
Net cash used in financing activities	(115,359)	—	(113,832)	—	(229,191)
Net decrease in cash and cash equivalents	(9,237)	(4,537)	(49,374)	—	(63,148)
Cash and cash equivalents, beginning of period	$ 9,241	$ 5,134	$ 53,853	$ —	68,228
Cash and cash equivalents, end of period	$ 4	$ 597	$ 4,479	$ —	$ 5,080

PLAINS RESOURCES INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS (in thousands)

YEAR ENDED DECEMBER 31, 1999

	Parent	Guarantor Subsidiaries	Nonguarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income (loss)	$ (25,331)	$ 22,101	$ (33,611)	$ 11,510	$ (25,331)
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation, depletion, and amortization	2,096	17,490	17,412	—	36,998
Noncash gains (Note 4 and 6)	—	—	(26,244)	—	(26,244)
Minority interest in income of a subsidiary	—	—	(40,203)	—	(40,203)
Equity in earnings of subsidiary	11,510	—	—	(11,510)	—
Deferred income tax	3,457	(4,754)	(19,175)	—	(20,472)
Noncash compensation expense	—	—	1,013	—	1,013
Other noncash items	(1,108)	—	1,047	—	(61)
Change in assets and liabilities resulting from operating activities:					
Accounts receivable and other	(970)	(1,287)	(224,181)	—	(226,438)
Inventory	—	(842)	34,772	—	33,930
Pipeline linefill	—	—	(3)	—	(3)
Accounts payable and other current liabilities	5,275	2,169	164,530	—	171,974
Other long-term liabilities	—	—	18,873	—	18,873
Net cash provided by (used in) operating activities	(5,071)	34,877	(105,770)	—	(75,964)
CASH FLOWS FROM INVESTING ACTIVITIES					
Payments for midstream acquisitions (See Note 6)	—	—	(176,918)	—	(176,918)
Payments for crude oil pipeline, gathering and terminal assets	—	—	(12,507)	—	(12,507)
Payments for acquisition, exploration, and development costs	(3,793)	(74,106)	—	—	(77,899)
Payments for additions to other property and assets	(267)	(2,137)	(68)	—	(2,472)
Proceeds from sale of pipeline linefill	—	—	3,400	—	3,400
Net cash provided by (used in) investing activities	(4,060)	(76,243)	(186,093)	—	(266,396)
CASH FLOWS FROM FINANCING ACTIVITIES					
Advances/investments with affiliates	(194,902)	46,306	148,396	200	—
Proceeds from long-term debt	341,250	—	403,721	—	744,971
Proceeds from short-term debt	—	—	131,119	—	131,119
Proceeds from sale of capital stock, options and warrants	5,542	—	—	—	5,542
Proceeds from issuance of preferred stock	50,000	—	—	—	50,000
Proceeds from issuance of common units (Note 4)	(25,000)	—	75,759	—	50,759
Principal payments of long-term debt	(180,711)	—	(268,621)	—	(449,332)
Principal payments of short-term debt	—	—	(82,150)	—	(82,150)
Costs incurred in connection with financing arrangements	(2,205)	—	(17,243)	—	(19,448)
Preferred stock dividends	(4,245)	—	—	—	(4,245)
Distribution to unitholders	29,472	—	(51,673)	—	(22,201)
Other	(971)	—	—	—	(971)
Net cash provided by financing activities	18,230	46,306	339,308	200	404,044
Net increase in cash and cash equivalents	9,099	4,940	47,445	200	61,684
Cash and cash equivalents, beginning of period	142	194	6,408	(200)	6,544
Cash and cash equivalents, end of period	$ 9,241	$ 5,134	$ 53,853	$ —	$ 68,228



DEAR FELLOW SHAREHOLDER,

By virtually any measure, your company had an outstanding 2001. We achieved records on many fronts as summarized in the following pages. These results were achieved in the midst of some very uncertain times, from both a business as well as a geopolitical perspective. While uncertainty, in our business, will continue to be a prevailing constant, the tragedies of September 11, 2001 have forced each and every one of us to further expand our defining parameters. History has taught us that uncertainty breeds volatility which ultimately manifests itself in the form of opportunity. This is a trend that has become increasingly true over time and it is one that is not likely to reverse itself anytime soon. To this end, one of the most significant achievements of 2001 was the separation of Plains Resources (PLX) from our affiliate company Plains All American Pipeline, L.P. (PAA). The mid year 2001 transaction that resulted in the deconsolidation created two distinct entities with separate management teams dedicated solely to the performance and growth of each respective entity. Plains Resources, in addition to benefiting from its ongoing participation in PAA, is structured to capture upstream opportunities given its healthy balance sheet coupled with its strong cash flow profile. The PAA platform is equally healthy as evidenced by its own solid 2001 performance in the midstream arena. The end result to our shareholders is direct economic participation in two separate platforms that are well positioned to exploit future opportunities in either the upstream or midstream segment of the energy business via PLX or PAA, respectively. Consistent with past practice, we continue to emphasize the unique leverage the PLX shareholder has to PAA. This dynamic remains very much intact. As part of the mid year deconsolidating transaction, the Company reduced its share count by approximately 3.2MM common shares. Additionally, we repurchased 1.5MM shares at other times during the year as part of our ongoing share repurchase program. This program will continue well into the future thereby further increasing your per share exposure to PAA.

In light of the current business climate we feel compelled to address a topic that is undoubtedly at the forefront of some of your thoughts, namely business integrity. Fortunately for all of us, this is a rather brief discussion when it comes to this Company. While there are volumes written in an attempt to define exactly what integrity means, in our minds, it means doing everything right and simultaneously doing the right thing. We go beyond the simple presentation of fact to ensure we are representing the truth to both ourselves as well as all others, whether it be our shareholders, partners, or employees. While we are appreciative of end results, we are equally appreciative of the means used to achieve them. In our view, the quality of the ends and the means must be symmetrical; if not, things will inevitably end in disappointment. We manage the Company with the core belief that success never comes at the expense of integrity. Henceforth, there are no compromises when it comes to integrity, ever. As the two top executives of PLX, a significant portion of our personal net worths are dependent upon the success of both PLX and PAA. Furthermore,

10K FINANCIAL DISCLAIMER

FORWARD-LOOKING STATEMENTS

All statements, other than statements of historical fact, included in this Annual Report on Form 10-K are forward-looking statements, including, but not limited to, statements identified by the words "anticipate," "believe," "estimate," "expect," "plan," "intend" and "forecast" and similar expressions and statements regarding our business strategy, plans and objectives of our management for future operations. These statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions. These statements, however, are subject to certain risks, uncertainties and assumptions, including, but not limited to:

- uncertainties inherent in the exploration for and development and production of oil and gas and in estimating reserves;
- unexpected future capital expenditures (including the amount and nature thereof);
- impact of crude oil and natural gas price fluctuations;
- the effects of competition;
- the success of our risk management activities;
- the availability (or lack thereof) of acquisition or combination opportunities;
- the impact of current and future laws and governmental regulations;
- environmental liabilities that are not covered by an indemnity or insurance, and
- general economic, market or business conditions.

If one or more of these risks or uncertainties materialize, or if any of our underlying assumptions prove incorrect, our actual results may vary materially from those in the forward-looking statements. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information. See Item 7. – "Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies and Factors That May Affect Future Results" in our Form 10-K for an additional discussion of these risks and uncertainties.

SHAREHOLDER INFORMATION

TICKER SYMBOL

NYSE: PLX

TRANSFER AGENT

American Stock Transfer & Trust
40 Wall Street
New York, New York 10005-2392

FORM 10-K

A copy of the Company's annual report on Form 10-K to the Securities and Exchange Commission for the year ended December 31, 2001, is available free of charge on request to:

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