PLAINS RESOURCES INC
Form 10-K/A
April 28, 2004


# UNITED STATES

# SECURITIES AND EXCHANGE COMMISSION

**Washington, D. C. 20549**

# FORM 10-K/A

**Amendment No. 1**

**FOR ANNUAL AND TRANSITION REPORTS PURSUANT TO SECTION 13 OR 15(d)**

**OF THE SECURITIES EXCHANGE ACT OF 1934**

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE**

**SECURITIES EXCHANGE ACT OF 1934**

**For the fiscal year ended December 31, 2003**

**OR**

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE**

**SECURITIES EXCHANGE ACT OF 1934**

**Commission file number: 0-9808**

# PLAINS RESOURCES INC.

**(Exact name of registrant as specified in its charter)**

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

**700 Milam Street, Suite 3100**

**Houston, Texas 77002**

**(Address of principal executive offices)**

**(Zip Code)**

**(832) 239-6000**

**(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 _ü_ No ____

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2).

Yes _ü_ No ____

The aggregate market 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 $243 million on June 30, 2003, the last business day of the registrant s most recently completed second fiscal quarter (based on $14.15 per share, the last sale price of the Common Stock as reported on the New York Stock Exchange on such date).

On February 29, 2004, there were 23.8 million shares of the registrant s Common Stock outstanding.

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**PLAINS RESOURCES INC.**

**AMENDMENT NO. 1 TO ANNUAL REPORT ON FORM 10K/A**

**FOR THE YEAR ENDED DECEMBER 31, 2003**

## Introductory Note and Table of Contents

Plains Resources Inc. hereby amends its Annual Report on Form 10-K for the fiscal year ended December 31, 2003 (originally filed on March 5, 2004) to include Items 10, 11, 12 and 13, which were not included in the original filing and to revise Item 7 and Item 9A. No other changes have been made to the Annual Report.

**Part IV**



This Form 10-K/A does not reflect events occurring after the filing of the original Form 10-K, and does not modify or update the disclosures therein in any other way other than as required to reflect the amendments described above and as set forth below.

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**STATEMENT REGARDING FORWARD-LOOKING STATEMENTS**

This Annual Report on Form 10-K includes forward-looking statements based on our current expectations and projections about future events. Statements that are predictive in nature, that depend upon or refer to future events or conditions, or that include words such as will , would , should , plans , likely , expects , anticipates , intends , believes , estimates , thinks , may expressions, are forward-looking statements. These statements involve known and unknown risks, uncertainties, and other factors that may cause our actual results and performance to be materially different from any future results or performance expressed or implied by these forward-looking statements. These factors include, among other things:

the future profitability of Plains Resources;

the uncertainty of the market for the midstream activities of marketing, gathering, transporting, terminalling, and storage of crude oil that Plains Resources engages in through its significant equity ownership in Plains All American Pipeline, L.P., or PAA;

the risks associated with the finding and developing of upstream oil and gas reserves associated with Plains Resources Florida oil and gas operations;

the seasonality of Plains Resources financial results;

the favorable resolution of pending and future litigation;

the operating and financial performance of PAA;

the consequences of our and Plains Exploration & Production Company s, or PXP, officers and employees providing services to both us and PXP and not being required to spend any specified percentage or amount of time on our business;

risks, uncertainties and other factors that could have an impact on PAA, which could in turn impact the value of our holdings in PAA (for a discussion of these risks, uncertainties and other factors, see PAA s filings with the Securities and Exchange Commission, or SEC);

the effects of our indebtedness, which could adversely restrict our ability to operate, could make us vulnerable to general adverse economic and industry conditions, could place us at a competitive disadvantage compared to our competitors that have less debt, and could have other adverse consequences;

uncertainties inherent in the development and production of oil and gas and in estimating reserves;

unexpected future capital expenditures (including the amount and nature thereof);

impact of oil and 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 effective indemnity or insurance, and
- general economic, market, industry or business conditions.

All forward-looking statements in this report are made as of the date hereof, and you should not place undue certainty on these statements without also considering the risks and uncertainties associated with these statements and our business that are discussed in this report. Moreover,

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although we believe the expectations reflected in the forward-looking statements are based upon reasonable assumptions, we can give no assurance that we will attain these expectations or that any deviations will not be material. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information. See Items 1 & 2. Business and Properties Risk Factors and 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 this report for additional discussions of risks and uncertainties.

## AVAILABLE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document we file at the SEC s Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the SEC s Public Reference Room. Our SEC filings are also available to the public at the SEC s web site at *www.sec.gov*. No information from such web site is incorporated by reference herein. Our web site is *www.plainsresources.com*. You may also obtain copies of our annual, quarterly and current reports, proxy statements and certain other information filed with the SEC, as well as amendments thereto, free of charge from our web site. These documents are posted to our web site as soon as reasonably practicable after we have filed or furnished these documents with the SEC.

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**GLOSSARY OF OIL AND GAS TERMS**

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and this Form 10-K:

*API gravity.* A system of classifying oil based on its specific gravity, whereby the greater the gravity, the lighter the oil.

*Bbl.* One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

*BOE.* One stock tank barrel equivalent of oil, calculated by converting gas volumes to equivalent oil volumes based on relative heat content, at a ratio of 6 Mcf to 1 Bbl of oil.

*Developed acreage.* The number of acres which are allocated or assignable to producing wells or wells capable of production.

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

*Differential.* An adjustment to the price of oil from an established spot market price to reflect differences in the quality and/or location of oil.

*Exploratory well.* A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

*Gas*. Natural gas.

*Gross acres.* The total acres in which a person or entity has a working interest.

*Gross oil and gas wells.* The total wells in which a person or entity owns a working interest.

*LPG.* Liquefied petroleum gas.

*MBbl.* One thousand barrels of oil or other liquid hydrocarbons.

*MBOE.* One thousand BOE.

*Mcf.* One thousand cubic feet of gas.

*Midstream.* The portion of the oil and gas industry focused on marketing, gathering, transporting and storing oil.

*MMBbl.* One million barrels of oil or other liquid hydrocarbons.

*MMBOE.* One million BOE.

*MMcf.* One million cubic feet of gas.

*Net acres.* Gross acres multiplied by the percentage working interest.

*Net oil and gas wells.* Gross wells multiplied by the percentage working interest.

*Net production.* Production that is owned, less royalties and production due others.

*Net revenue interest.* Our share of petroleum after satisfaction of all royalty and other non-cost-bearing interests.

*NYMEX*. New York Mercantile Exchange.

*Oil.* Crude oil, condensate and natural gas liquids.

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*Operator.* The individual or company responsible for the exploration and/or exploitation and/or production of an oil or gas well or lease.

*PV-10.* The pre-tax present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying sales prices in effect as of the dates of such estimates and held constant throughout the productive life of the reserves (except for consideration of price changes to the extent provided by contractual arrangements), and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on current costs and assuming continuation of existing economic conditions).

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

*Proved reserves.* Per Article 4-10(a)(2) of Regulation S-X, the SEC defines proved oil and gas reserves as the estimated quantities of oil, gas and gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes: (i) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (ii) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved reserves do not include: (i) oil that may become available from known reservoirs but is classified separately as indicated additional reserves ; (ii) oil, gas, and gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (iii) oil, gas, and gas liquids, that may occur in undrilled prospects; and (iv) oil, gas, and gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

*Proved reserve additions.* The sum of additions to proved reserves from extensions, discoveries, improved recovery, acquisitions and revisions of previous estimates.

*Proved undeveloped reserves.* Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be

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attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

*Reserve life.* A measure of the productive life of an oil and gas property or a group of properties, expressed in years. Reserve life is calculated by dividing proved reserve volumes at year-end by production for that year.

*Reserve replacement cost.* The cost per BOE of reserves added during a period calculated by using a fraction, the numerator of which equals the costs incurred for the relevant property acquisition, exploration, exploitation and development and the denominator of which equals changes in proved reserves due to revisions of previous estimates, extensions, discoveries, improved recovery and other additions and purchases of reserves in-place.

*Reserve replacement ratio.* The proved reserve additions for the period divided by the production for the period.

*Royalty.* An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner s royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

*Standardized measure.* The present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying sales prices in effect as of the dates of such estimates and held constant throughout the productive life of the reserves (except for consideration of price changes to the extent provided by contractual arrangements), and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on current costs and assuming continuation of existing economic conditions). Future income taxes are 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.

*Undeveloped acreage.* Acreage held under lease, permit, contract or option that is not in a spacing unit for a producing well.

*Upstream.* The portion of the oil and gas industry focused on acquiring, exploiting, developing, exploring for and producing oil and gas.

*Working interest.* An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

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

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## PART I

### Items 1 and 2. BUSINESS and PROPERTIES.

#### General

We are an independent energy company. We are principally engaged in the midstream activities of marketing, gathering, transporting, terminaling, and storage of oil through our equity ownership in Plains All American Pipeline, L.P., or PAA. PAA is a publicly traded master limited partnership actively engaged in the midstream energy markets. As of February 29, 2004 we owned 44% of the general partner of PAA and 12.4 million, or 21%, of the limited partnership units of PAA, which represented approximately 22% aggregate ownership interest in PAA. See Plains All American Pipeline, L.P. . We also participate in the upstream activities of acquiring, exploiting, developing, exploring for and producing oil through our wholly-owned subsidiary, Calumet Florida L.L.C. ( Calumet ), which has producing properties in the Sunniland Trend in south Florida.

The book value of our ownership interest in PAA represents 57% of our total assets as of December 31, 2003, the book value of our Florida oil properties represents 30% and other assets (including $5 million of restricted cash) represent 13% of our total assets. As of December 31, 2003, the present value of our proved oil reserves was approximately $77.5 million (see Oil Production Operations ). The present value of our oil reserves as of December 31, 2003 as determined in accordance with SEC requirements is based on prices, costs and assumptions in effect on that date. The price in effect at December 31, 2003 was $32.52 per barrel before adjustment for location and quality differential. This present value does not necessarily represent the actual value of such reserves since actual future prices and costs may be significantly higher or lower than the prices and costs on December 31, 2003. We currently own 11.1 million common units and 1.3 million Class B common units of PAA. The closing price of publicly traded PAA common units, as reported on the New York Stock Exchange, was $31.91 on December 31, 2003. The Class B common units are not publicly traded but do receive cash distributions from PAA. PAA s financial performance directly impacts our financial performance and the market value performance of PAA s limited partnership interests directly impacts the value of our assets. As a result, we encourage you to review PAA s SEC filings, including its Annual Report on Form 10-K for the year ended December 31, 2003, to review and assess, among other things, PAA s financial performance and financial condition, PAA s business, operations, and competition, and risk factors associated with PAA s business.

Our Board of Directors has authorized the repurchase of up to eight million shares of our common stock. Through December 31, 2003, we had repurchased a total of 4.9 million shares at a total cost of approximately $100.4 million.

#### Offer to Acquire Plains Resources

On November 19, 2003 we received a proposal from Vulcan Capital, Inc., our Chairman, James C. Flores, and our CEO and President, John T. Raymond, or the Vulcan Group, to acquire all of our outstanding stock for $14.25 per share in cash (the Original Vulcan Proposal ). Vulcan Capital is the investment arm of Seattle-based investor Paul G. Allen. The offer indicated that commitments for all of the financing necessary to complete the transaction had been received.

In response to receipt of the Original Vulcan Proposal, the Board of Directors established a special committee comprised of board members William C. O  Malley and William M. Hitchcock. The special committee was authorized to review, evaluate, negotiate and make recommendations to the full Board of Directors with respect to the Original Vulcan Proposal. In addition, the special committee was authorized to review and evaluate alternative proposals that may be developed or received from other parties relating to a transaction with the Company. The special committee retained Petrie Parkman &

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Co. as its financial advisor and Baker Botts L.L.P. and Morris, Nichols, Arsht & Tunnell as its legal counsel.

On January 22, 2004 the special committee, after a thorough review with its independent financial and legal advisors, announced that, after careful consideration, it had determined that the Original Vulcan Proposal was inadequate and not in the best interests of our stockholders. The Special Committee said it was prepared to enter into discussions or negotiations with the Vulcan Group or other parties relating to a transaction with the Company.

Following discussions and negotiations with the Vulcan Group and other interested parties, on February 18, 2004 the Special Committee voted unanimously to recommend to the PLX Board of Directors and to Plains Resources stockholders a $16.75 per share proposal from the Vulcan Group (the Revised Vulcan Proposal ). Our Board of Directors, excluding Mr. Flores, has unanimously approved the merger agreement negotiated in connection with the Revised Vulcan Proposal and recommends that stockholders vote in favor of the transactions contemplated thereby.

The merger agreement contains customary fiduciary termination rights. If the merger agreement is terminated, under specified circumstances, we have agreed to reimburse all of the Vulcan Group s reasonable out-of-pocket expenses. In addition, in certain circumstances we have agreed to pay a termination fee of $15 million. In all other circumstances, each party must pay all fees and expenses it incurs relating to the merger. The closing of the merger is subject to approval by the stockholders of Plains Resources and other customary closing conditions. The Company plans to hold a special meeting of stockholders to vote on the proposed transaction as soon as practicable. Completion of the transaction is expected during the second quarter of 2004. If the merger is consummated, Plains Resources will become a privately held company. Accordingly, upon closing, the registration of the Company s common stock under the Securities Exchange Act of 1934 will terminate and the Company will cease filing reports with the SEC.

Plains Resources has filed a preliminary proxy statement for the special meeting of stockholders to vote on the proposed transaction, and the Vulcan Group will file other relevant documents with the SEC concerning the proposed transaction.

**Spin-off of Plains Exploration & Production Company**

Prior to December 18, 2002 PXP was our wholly owned subsidiary. On December 18, 2002 we distributed the issued and outstanding shares of PXP common stock to the holders of record of our common stock as of the close of business on December 11, 2002. Each of our stockholders received one share of PXP common stock for each share of our common stock held. Prior to the spin-off, we made an aggregate of $52.2 million in cash contributions to PXP and transferred certain assets and liabilities to PXP, primarily related to land, unproved oil and gas properties, office equipment and compensation obligations.

In contemplation of the spin-off, under the terms of a Master Separation Agreement between us and PXP, on July 3, 2002 we contributed to PXP 100% of the capital stock of our wholly owned subsidiaries that own oil and gas properties in offshore California and Illinois. As a result, PXP indirectly owned our offshore California and Illinois properties and directly owned our onshore California properties. We also contributed $256.0 million of intercompany receivables that PXP and its subsidiaries owed to us. On July 3, 2002 PXP issued $200 million of 8.75% Senior Subordinated Notes due 2012, or the 8.75% notes, and entered into a $300 million revolving credit facility. PXP distributed to us the net proceeds of $195.3 million from the 8.75% notes and $116.7 million of initial borrowings under the credit facility. We used such amounts to redeem our 10.25% senior subordinated notes on August 2, 2002 ($287.0 million) and to repay amounts outstanding under our credit facility ($25.0 million).

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We received a letter ruling from the IRS on May 22, 2002, as supplemented on November 5, 2002, to the effect that the spin-off qualifies as a tax-free distribution. A letter ruling from the IRS, while generally binding on the IRS, may under certain circumstances be retroactively revoked or modified by the IRS. A letter ruling is based on the facts and representations presented in the request for that ruling. Generally, an IRS letter ruling will not be revoked or modified retroactively if there has been no misstatement or omission of material facts, the facts at the time of the transaction are not materially different from the facts upon which the IRS letter ruling was based, and there has been no change in the applicable law. We are not aware of any facts or circumstances that would cause the representations in the ruling request to be untrue or incomplete in any material respect.

As a result of the spin-off the historical results of the operations of PXP are reflected in our financial statements as discontinued operations . Except as noted, discussions in this Form 10-K with respect to oil and gas operations relate to our activities other than the discontinued operations of PXP. In connection with the spin-off, we entered into certain agreements with PXP, see Spin-off Agreements .

**Our June 2001 Strategic Restructuring**

In a series of transactions in June 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% of the subordinated units of PAA 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. In addition, in September 2001 PAA management exercised an option to acquire an additional 2% ownership interest in the general partner of PAA by paying us $1.5 million in cash and notes.

**Plains All American Pipeline, L.P**.

As of February 29, 2004, our aggregate ownership in PAA was approximately 22%, which was comprised of (1) a 44% interest in the general partner of PAA, (2) 19%, or 11.1 million, of the common units and (3) all of the 1.3 million class B common units.

*Operations*

PAA is a publicly traded master limited partnership that is engaged in the marketing, gathering, transporting terminalling and storage of oil and the gathering, marketing and storage of liquefied petroleum gas and other petroleum products. Terminals are facilities where 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 oil production.

PAA s operations are concentrated in Texas, Oklahoma, California and Louisiana and in the Canadian provinces of Alberta and Saskatchewan, and can be categorized into two primary business activities:

*Oil Pipeline Transportation Operations.* PAA owns and operates approximately 7,000 miles of gathering and mainline oil pipelines located throughout the United States and Canada. Its activities from pipeline operations generally consist of transporting oil for a fee, third party leases of pipeline capacity, barrel exchanges and buy/sell arrangements.

*Gathering, Marketing, Terminalling and Storage Operations*. PAA owns and operates approximately 24.0 million barrels of above-ground oil terminalling and storage facilities, including tankage associated with its pipeline systems. These facilities include an oil terminalling and storage facility at Cushing, Oklahoma. Cushing is one of the largest oil market hubs in the United States and the designated delivery point for NYMEX oil futures contracts. PAA s terminalling and storage operations generate revenue through a combination of storage and throughput charges to third parties. PAA also utilizes its storage tanks to counter-cyclically balance its gathering and marketing operations and to execute different hedging strategies to stabilize profits and reduce the negative impact of oil market volatility. PAA s gathering and marketing operations include:

the purchase of oil at the wellhead and the bulk purchase of oil at pipeline and terminal facilities;

the transportation of oil on trucks, barges and pipelines;

the subsequent resale or exchange of oil at various points along the oil distribution chain; and

the purchase of LPG from producers, refiners and other marketers, and the sale of LPG to wholesalers, retailers and industrial end users.

*PAA Cash Distributions*

PAA s partnership agreement requires that it distribute 100% of available cash within 45 days after the end of each quarter to unitholders of record and to its general partner. Available cash is generally defined as all cash and cash equivalents on hand at the end of each quarter less reserves established by PAA s general partner for future requirements.

Prior to the fourth quarter of 2003 PAA had outstanding 10.0 million subordinated units, of which we owned 4.5 million units. The subordinated units were not publicly traded and were subordinated in the right to distributions. Common units accrue arrearages with respect to distributions for any quarter during the subordination period and subordinated units do not accrue any arrearages. PAA met certain financial requirements and 25% of the subordinated units converted to common units in the fourth quarter of 2003. The remaining subordinated units converted to common units in February 2004.

Class B common units are initially pari passu with common units with respect to distributions, and are convertible into common units upon approval of a majority of the common unitholders. If we request that PAA call a meeting of common unitholders to consider approval of the conversion of Class B units into common units and the approval is not obtained within 120 days, each Class B common unitholder will be entitled to receive distributions, on a per unit basis, equal to 110% of the amount of distributions paid on a common unit, with such distribution right increasing to 115% if such approval is not secured within 90 days after the end of the 120-day period. Except for the vote to approve the conversion, Class B common units have the same voting rights as the common units.

PAA s general partner is entitled to receive incentive distributions if the amount distributed with respect to any quarter exceeds levels specified in PAA s partnership agreement. Generally, the general partner is entitled, without duplication, to 15% of amounts PAA distributes in excess of $0.45 per unit, 25% of the amounts PAA distributes in excess of $0.495 per unit and 50% of amounts PAA distributes in excess of $0.675 per unit.

Based on PAA s $0.5625 per unit distribution paid in the first quarter of 2004 ($2.25 per unit annualized), we would receive an annual distribution from PAA of approximately $32.6 million for 2004, including $4.1 million for our general partner distribution (including $2.9 million for the general partner incentive distribution).

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**Oil Production Operations**

Calumet has a 100% working interest in five producing fields in the Sunniland Trend in south Florida. Calumet acquired 50% of its interest in these fields in 1993 and the remaining 50% in 1994. In 2003 net production from these properties averaged 2,315 barrels of oil per day and proved reserves were 14.5 MMBbls at December 31, 2003. In 2003 we spent $3.3 million on capital projects, primarily facility enhancements and abandonment of inactive wells. In 2004 we expect to spend $3.5 million on artificial lift projects, facility upgrades and idle well abandonments.

The following tables set forth certain information with respect to the reserves of our Florida properties based upon reserve reports prepared by the independent petroleum consulting firm of Netherland, Sewell & Associates, Inc. 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. The amounts presented for 2002 and 2001 exclude reserves attributable to discontinued operations. See Spin Off of Plains Exploration & Production Company and Note 2 to the consolidated financial statements.

| | As of or for the Year Ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | | Oil (MBbls) | |
| **Proved Reserves** | | | |
| Beginning balance | 16,313 | 17,343 | 18,775 |
| Revision of previous estimates | (921) | (60) | (2,470) |
| Extensions, discoveries, improved recovery and other additions | | | 1,992 |
| Production | (845) | (970) | (954) |
| Ending balance | 14,547 | 16,313 | 17,343 |
| **Proved Developed Reserves** | | | |
| Beginning balance | 14,499 | 15,456 | 17,853 |
| Ending balance | 12,730 | 14,499 | 15,456 |
| **PV-10 ($/000s) (1)** | | | |
| Proved developed | $ 60,936 | $ 73,656 | $ 21,124 |
| Proved undeveloped | 16,517 | 14,258 | 5,421 |
| Total Proved | $ 77,453 | $ 87,914 | $ 26,545 |
| Standardized measure | $ 65,558 | $ 73,339 | $ 26,545 |
| Average year-end realized oil price, per Bbl (2) | $ 20.78 | $ 20.25 | $ 9.82 |
| December 31 NYMEX WTI spot price, per Bbl | $ 32.52 | $ 31.20 | $ 19.84 |

(1) The PV-10 and standardized measure have been reduced to reflect applicable abandonment costs. PV-10 represents the standardized measure before deducting estimated future income taxes.

(2) Price in effect at year end with adjustments based on location and quality of oil.

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 oil 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

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quantities of oil and gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil 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 PV-10 and standardized measure shown above represents estimates only and should not be construed as the current value of the estimated oil 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 oil 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 oil price in effect at December 31, 2003 is based on the year-end oil price with variations based on location and quality of oil. The overall average year-end price used in the reserve report as of December 31, 2003 was $20.78 per barrel of oil. See Product Markets and Major Customers . Historically, the prices for oil 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, 2002, we have not filed any estimates of total proved net oil reserves with any federal authority or agency other than the SEC.

**Productive Wells and Acreage**

As of December 31, 2003, we had working interests in 16 gross (16 net) active producing oil wells. At December 31, 2003 we had working interests in 12,025 gross, 12,025 net, developed acres and 73,427 gross, 71,524 net, undeveloped acres, all located in the state of Florida. Less than 10% of total net undeveloped acres are covered by leases that expire in the next five years.

**Drilling Activities**

No wells were drilled in 2003 or 2002. In 2001 we participated in 1 gross (0.5 net) dry exploratory well on a property outside Florida.

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**Production and Sales**

The following table presents certain information with respect to oil production and sales attributable to our properties, average sales prices received and average production costs during the three years ended December 31, 2003, 2002 and 2001.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| Production (MBbls) | 845 | 970 | 954 |
| Sales (MBbls) | 926 | 869 | 1,060 |
| Sales Price per Bbl | | | |
| Average NYMEX price | $ 30.99 | $ 26.15 | $ 26.01 |
| Differential | (7.06) | (3.97) | (9.77) |
| | 23.93 | 22.18 | 16.24 |
| Hedging | (0.33) | (0.71) | (1.11) |
| | 23.60 | 21.47 | 15.13 |
| Derivative cash settlements | (2.57) | | |
| | 21.03 | 21.47 | 15.13 |
| Costs and Expenses per Bbl | | | |
| Production expenses | 7.99 | 6.72 | 6.63 |
| Production and ad valorem taxes | 1.22 | 0.67 | 0.35 |
| Oil transportation expenses | 4.22 | 4.34 | 4.20 |

**Product Markets and Major Customers**

Our revenues are highly dependent upon the prices of, and demand for, oil. Historically, the markets for oil have been volatile, and are likely to continue to be volatile in the future. The prices we receive for our oil production and the levels of such production are subject to wide fluctuations and depend on numerous factors beyond our control, including the condition of the United States and world economies (particularly the manufacturing sector), foreign imports, political conditions in other oil-producing countries, the actions of the Organization of Petroleum Exporting Countries and domestic government regulation, legislation and policies. Decreases in the prices of oil 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 .

To manage our exposure to commodity price risks, we utilize various derivative instruments to hedge our exposure to price fluctuations on oil sales. Our hedging arrangements provide us protection on the hedged volumes if 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. See Item 7A Quantitative and Qualitative Disclosures about Market Risks .

Substantially all of our 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 production.

PAA is the exclusive purchaser of all of our equity oil production. If we were to lose PAA as the exclusive purchaser of our equity production, we believe such loss would not have a material adverse

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effect on our results of operations. We believe PAA could be replaced by other purchasers under contracts with similar terms and conditions.

We recommend you review PAA s Annual Report on Form 10-K for the year ended December 31, 2003, and other applicable SEC filings by PAA, for a discussion of PAA s major customers.

**Competition**

Competitors of our upstream activities include major integrated oil and gas companies, and numerous independent oil and gas companies, individuals and drilling and income programs. Many of our larger upstream competitors possess and employ financial and personnel resources substantially greater than those available to us. Such companies are able to pay more for productive oil and 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 gas industry.

We recommend you review PAA s Annual Report on Form 10-K for the year ended December 31, 2003, and other applicable SEC filings by PAA, for a discussion of PAA s competition.

**Regulation**

We recommend you review PAA s Annual Report on Form 10-K for the year ended December 31, 2003, and other applicable SEC filings by PAA, for a discussion of regulations related to the midstream business. Our discussion on regulation below relates primarily to our upstream business.

Our upstream 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 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 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 we maintain certain information about hazardous materials used or produced in our operations and that we provide this information to our 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 oil and 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 State of Florida has regulations governing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from oil and gas wells and the regulation of the spacing, plugging and abandonment of wells. Florida also has the right to restrict production to the market demand for oil and gas. Moreover, Florida imposes an ad valorem, production or severance tax with respect to production and sale of oil and gas within its jurisdiction.

*Pipeline Regulation*

In our upstream business, we have pipelines to deliver our production to sales points. Our pipelines are subject to certain regulations of the U.S. Department of Transportation, or DOT. 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. We believe that our pipeline operations are in substantial compliance with applicable requirements.

*Environmental*

Our operations and properties are subject to extensive and changing federal, state and local laws and regulations relating to safety, health and environmental protection, including the generation, storage, handling, emission, and transportation of materials and discharge of materials into the environment. 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. 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 the oil and gas industry generally, our compliance with existing and anticipated laws and regulations increases our overall cost of business, including our capital costs to construct, maintain, upgrade and close 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 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. If a person violates these environmental laws and regulations and any related permits, they may be subject to significant administrative, civil and criminal penalties, injunctions and construction bans or delays. If we were to discharge hydrocarbons or hazardous substances into the environment, we could, to the extent the event is not insured, incur 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 when we acquired our properties in the Sunniland Trend, and we believe that such properties have been operated in accordance with standard oil field practices, 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.

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.

**Other Business Matters**

Without successful drilling, acquisition or exploitation operations, our oil and gas reserves and revenues will decline. Drilling activities are subject to numerous risks, including the risk that no commercially viable oil or 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 Production Operations . 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 oil production also depends on a number of factors, including the demand for and supply of oil and the proximity of reserves to pipelines or trucking and terminal facilities. See Product Markets and Major Customers .

Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and gas, including blowouts, cratering, oil spills and fires, each of which could result in damage to or destruction of oil and gas wells, production facilities or other property, or injury to persons.

Our upstream properties 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 upstream operations and properties. The insurance covers all of our upstream 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 our operations. 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.

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We believe that we have generally satisfactory title to or rights in all of our producing properties. As is customary in the oil and 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 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.

**Spin-off Agreements**

In connection with the spin-off we entered into certain agreements with PXP, including a master separation agreement; an intellectual property agreement; the Plains Exploration & Production transition services agreement; the Plains Resources transition services agreement; and a technical services agreement. For the year ended December 31, 2003, PXP billed us $0.5 million for services provided to us under these agreements and we billed PXP $0.1 million for services we provided under these agreements.

The master separation agreement provides that for a period of three years, (1) we and our subsidiaries will be prohibited from engaging in or acquiring any business engaged in any of the upstream activities of acquiring, exploiting, developing, exploring for and producing oil and gas in any state in the United States (except Florida), and (2) PXP will be prohibited from engaging in any of the midstream activities of marketing, gathering, transporting, terminalling and storing oil and gas (except to the extent any such activities are ancillary to, or in support of, any of PXP s upstream activities).

The technical services agreement provides that PXP will provide services with respect to the operations of Calumet until (1) Calumet is no longer our subsidiary, (2) Calumet transfers substantially all of its assets to a person that is not a subsidiary of us, (3) the third anniversary of the date of this agreement or (4) when all the services are terminated as provided in the agreement. We may terminate the agreement as to some or all of the services at any time by giving PXP at least 90 days written notice.

**Employees**

As of February 29, 2004, we had 12 full-time employees (not including our Chief Executive Officer, Chief Financial Officer and General Counsel, who also devote time and efforts to PXP), none of whom is represented by any labor union. All of our full-time employees are field personnel involved in oil and gas producing activities.

**Risk Factors**

You should carefully consider the following risk factors in addition to the other information included in this report. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock.

***We are highly dependent upon the earnings and distributions of PAA.***

In 2003, we had oil revenues from our upstream operations of $21.9 million while distributions received from PAA attributable to our general and limited partner interests totaled $30.9 million.

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PAA s financial performance will directly affect our financial performance and the market value performance of PAA s limited partner interests will directly impact the value of our assets. A significant decline in PAA s earnings would have a corresponding negative impact on our earnings. Likewise, a significant decline in the value of PAA s common units would have a corresponding negative impact on the value of our assets.

In addition, cash from PAA distributions on its general partner and limited partner interests is one of our primary sources of our liquidity. If PAA could not, for any reason, make its minimum quarterly distribution payments on its limited partner and general partner interests, this would impair our ability to meet our short and long-term cash needs, including normal recurring operating needs, debt service obligations, contingencies and capital expenditures.

We have also entered into an oil marketing agreement with PAA under which PAA is the exclusive purchaser of all of our net oil production. We generally do not require letters of credit or other collateral from PAA to support our trade receivables. Accordingly, a material adverse change in PAA s financial condition could adversely impact our ability to collect our receivables from PAA and thereby affect our financial condition.

We urge you to review PAA s SEC filings, including its Annual Report on Form 10-K for the year ended December 31, 2003, for risks associated with PAA s business.

***Our levels of indebtedness may limit our financial and operating flexibility.***

We have a substantial amount of debt and the ability to incur substantially more debt. We have a secured term loan facility, of which $50.0 million was outstanding at December 31, 2003. The term loan is collateralized by a pledge of the equity of our subsidiaries and 5.2 million of our PAA common units. We also delivered mortgages on Calumet s oil and gas properties to secure the loan. The term loan is repayable in 12 quarterly installments of $5.0 million that commenced on August 31, 2003 with a final maturity on May 31, 2006.

We and all of our subsidiaries must comply with various covenants contained in our secured term loan facility, which, among other things, limit the ability of us and our subsidiaries to:

- incur additional debt or liens;
- enter into leases;
- sell assets;
- make loans or investments;

- change the nature of our business or operations;
- guarantee other indebtedness;
- enter into certain types of hedge agreements;
- enter into take-or-pay arrangements;
- merge or consolidate; and
- enter into transactions with affiliates.

If the Revised Vulcan Proposal is consummated, our credit facility will terminate and the amount outstanding would be paid in full. In addition, if an event of default exists, the term loan prohibits us from paying dividends or repurchasing or redeeming shares of any class of our capital stock.

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Our substantial debt could have important consequences to you. For example, it could:

- increase our vulnerability to general adverse economic and industry conditions;
- limit our ability to fund future working capital and capital expenditures, to engage in future acquisitions or development activities, or to otherwise realize the value of our assets and opportunities fully because of the need to dedicate a substantial portion of our cash flow to payments on our debt or to comply with any restrictive terms of our debt;
- limit our flexibility in planning for, or reacting to, changes in the industry in which we operate; and
- place us at a competitive disadvantage as compared to our competitors that have less debt.

In addition, if we fail to comply with the terms of our debt, our lenders will have the right to accelerate the maturity of that debt and foreclose upon the collateral securing that debt. Realization of any of these factors could adversely affect our financial condition.

***Volatile oil and gas prices could adversely affect our financial condition and results of operations.***

Revenues from our upstream operations are largely dependent on oil prices, which are extremely volatile. Any substantial or extended decline in the price of oil below current levels will have a material adverse effect on our business operations and future revenues. Moreover, oil prices depend on factors we cannot control, such as:

- supply and demand for oil and expectations regarding supply and demand;
- weather;
- actions by the Organization of Petroleum Exporting Countries, or OPEC;
- political conditions in other oil-producing countries including the possibility of insurgency or war in such areas;
- general economic conditions in the United States and worldwide; and
- governmental regulations.

Prices of oil will affect:

- our revenues, cash flows and earnings;
- our ability to attract capital to finance our operations and the cost of such capital;
- the amount that we are allowed to borrow; and
- the value of our oil and gas properties.

***Any prolonged, substantial reduction in the demand for oil, or distribution problems in meeting this demand, could adversely affect our business.***

Our success in our upstream business is materially dependent upon the demand for oil. The availability of a ready market for our oil production depends on a number of factors beyond our control, including the demand for and supply of oil and gas, the availability of alternative energy sources, the proximity of reserves to, and the capacity of oil and gas gathering systems, pipelines or trucking and terminal facilities. We may also have to shut-in some of our wells temporarily due to a lack of market or adverse weather conditions including hurricanes. If the demand for oil diminishes, our financial results would be negatively impacted.

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In addition, there are limitations related to the methods of transportation for our production. Substantially all of our oil production is transported by pipelines, barges and trucks 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 production, any of which could have a negative impact on our results of operation and cash flows.

***The war in Iraq, recent terrorist activities and the potential for other global events could adversely affect our business.***

The war in Iraq and recent terrorist attacks of unprecedented scope have caused instability in the world financial markets and may generate global economic instability. The continued threat of terrorism and the impact of military or other action have led to and will likely lead to increased volatility in prices for oil and gas and could affect the markets for our operations. Further, the United States government has issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. These developments have subjected our operations to increased risk and, depending on the ultimate magnitude, could have a material adverse affect on our business.

***If we do not replace the reserves that we have produced, our reserves and revenues will decline.***

The future success of our upstream business depends in part on our ability to find, develop and acquire additional oil and gas reserves that are economically recoverable which, in itself, is dependent on oil and gas prices. Without continued successful exploitation, acquisition or exploration activities, our reserves and revenues will decline as a result of our current reserves being depleted by production. We may not be able to find or acquire additional reserves at acceptable costs.

***Estimates of oil and gas reserves depend on many assumptions that may be inaccurate. Any material inaccuracies could adversely affect the quantity and value of our oil and gas reserves.***

The proved oil reserve information included in this document represents only estimates. These estimates are based on reports prepared by independent petroleum engineers. The estimates were calculated using oil prices in effect on the date indicated in the reports. Any significant price changes will have a material effect on the quantity and present value of our reserves.

Petroleum engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including:

- historical production from the area compared with production from other comparable producing areas;
- the assumed effects of regulations by governmental agencies;

assumptions concerning future oil and gas prices; and

assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating reserves:

the quantities of oil and gas that are ultimately recovered;

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- the timing of the recovery of oil and gas reserves;
- the production and operating costs incurred; and
- the amount and timing of future development expenditures.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. Actual production, revenues and expenditures with respect to reserves will vary from estimates and the variances may be material.

The discounted future net revenues included in this document should not be considered as the market value of the reserves attributable to our properties. As required by the SEC, the estimated discounted future net revenues from proved reserves are generally based on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net revenues will also be affected by factors such as:

- the amount and timing of actual production;
- supply and demand for oil and gas; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor, which the SEC requires to be used to calculate discounted future net revenues for reporting purposes, is not necessarily the most appropriate discount factor based on the cost of capital in effect from time to time and risks associated with our business and the oil and gas industry in general.

***The geographic concentration and lack of marketable characteristics of our oil reserves may have a greater effect on our ability to sell our oil compared to other companies.***

All of our oil reserves are located in Florida. Because our reserves are not as diversified geographically as many of our competitors, our business is more subject to local conditions than other, more diversified companies. Any regional events, including price fluctuations, natural disasters, and restrictive regulations that increase costs, reduce availability of equipment or supplies, reduce demand or limit our production may impact our operations more than if our reserves were more geographically diversified.

Our crude oil produced in Florida has a high sulfur content which limits its use in certain refineries and therefore limits its marketability.

***Operating hazards, natural disasters or other interruptions of our operations could result in potential liabilities, which may not be fully covered by our insurance.***

The oil and gas business involves certain operating hazards such as:

- well blowouts;
- cratering;
- explosions;
- uncontrollable flows of oil, gas or well fluids;
- fires;
- pollution; and
- releases of toxic gas.

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Any of these operating hazards could cause serious injuries, fatalities or property damage, which could expose us to liabilities. The payment of any of these liabilities could reduce, or even eliminate, the funds available for exploration, development, and acquisition, or could result in a loss of our properties.

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. Our insurance might be inadequate to cover our liabilities. The insurance market in general and the energy insurance market in particular have been difficult markets over the past several years. We have increased deductibles and decreased or eliminated certain types of coverages to mitigate cost increases. Insurance costs are expected to continue to increase over the next few years and we may decrease coverage and retain more risk to mitigate future cost increases. If we incur substantial liability and the damages are not covered by insurance or are in excess of policy limits, or if we incur liability at a time when we are not able to obtain liability insurance, then our business, results of operations and financial condition could be materially adversely affected.

***Governmental agencies and other bodies, including those in Florida, might impose regulations that increase our costs and may terminate or suspend our operations.***

Our business is subject to federal, state and local laws and regulations as interpreted by governmental agencies and other bodies, including those in Florida, vested with much authority relating to the exploration for, and the development, production and transportation of, oil and gas, as well as environmental and safety matters. Existing laws and regulations could be changed, and any changes could increase costs of compliance and costs of operating drilling equipment or significantly limit drilling activity.

***Environmental liabilities could adversely affect our financial condition.***

The oil and gas business is subject to environmental hazards, such as oil spills, gas leaks and ruptures and discharges of petroleum products and hazardous substances, and historic disposal activities. These environmental hazards could expose us to material liabilities for property damages, personal injuries or other environmental harm, including costs of investigating and remediating contaminated properties. In addition, we also may be liable for environmental damages caused by the previous owners or operators of properties we have purchased or are currently operating. A variety of stringent federal, state and local laws and regulations govern the environmental aspects of our business and impose strict requirements for, among other things:

- well drilling or workover, operation and abandonment;
- waste management;
- land reclamation; and
- controlling air, water and waste emissions.

Any noncompliance with these laws and regulations could subject us to material administrative, civil or criminal penalties or other liabilities. Additionally, our compliance with these laws may, from time to time, result in increased costs to our operations or decreased production, and may affect our costs of acquisitions.

In addition, environmental laws may, in the future, cause a decrease in our production or cause an increase in our costs of production, development or exploration. Pollution and similar environmental risks generally are not fully insurable.

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***Acquisitions could fail or present unanticipated problems for our business in the future, which could adversely affect our ability to complete acquisitions or realize anticipated benefits of those acquisitions.***

Our strategy may include acquiring midstream and upstream businesses and properties. We may not be able to identify suitable acquisition opportunities or finance and complete any particular acquisition successfully. Furthermore, acquisitions involve a number of risks and challenges, including:

- diversion of management s attention;
- the need to integrate acquired operations;
- potential loss of key employees of the acquired companies;
- potential lack of operating experience in a geographic market of the acquired business; and
- an increase in our expenses and working capital requirements.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows from the acquired businesses or realize other anticipated benefits of those acquisitions.

***Our ability to make upstream acquisitions is limited by our spin-off agreements.***

Under the spin-off agreements, until July 3, 2005, we are prohibited from acquiring any upstream business or properties in the United States outside of Florida. Thus, until after July 3, 2005, our upstream acquisition prospects are limited to Florida and outside of the United States.

***We intend to continue hedging a portion of our production, which may result in our making cash payments or prevent us from receiving the full benefit of increases in prices for oil and gas.***

We reduce our exposure to the volatility of oil prices by actively hedging a portion of our production. Hedging also prevents us from receiving the full advantage of increases in oil prices above the fixed amount specified in the hedge agreement. In a typical hedge transaction, we have the right to receive from the hedge counterparty the excess of the fixed price specified in the hedge agreement over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we must pay the counterparty this difference multiplied by the quantity hedged even if we had insufficient production to cover the quantities specified in the hedge agreement. Accordingly, if we have less production than we have hedged when the floating price exceeds the fixed price, we must make payments against which there are no offsetting sales of production. If these payments become too large, the remainder of our business may be adversely affected. In addition, our hedging agreements expose us to risk of financial loss if the counterparty to a hedging contract defaults on its contract obligations.

***Loss of key executives and failure to attract qualified management could limit our growth and negatively impact our operations.***

Successfully implementing our strategies will depend, in part, on our management team. The loss of members of our management team could have an adverse effect on our business. Our exploration and exploitation success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced engineers, geoscientists and other professionals. Competition for experienced professionals is extremely intense. If we cannot attract or retain experienced technical personnel, our ability to compete could be harmed.

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***We and PXP share and, therefore will compete for, the time and effort of our personnel who provide services to PXP, including directors and officers.***

Because certain of our officers and directors provide services to PXP, conflicts of interest could arise between PXP, on the one hand, and us, on the other. Additionally, some of these officers and directors own and are awarded from time to time shares, or options to purchase shares, or stock appreciation rights of PXP. Accordingly, their financial interests may not always be aligned with ours and could create, or appear to create, potential conflicts of interest when these officers and directors are faced with decisions that could have different implications for us and PXP.

***To preserve the tax-free status of the spin off, we may be limited in taking future actions.***

If we experience a change of control, fail to continue the active conduct of our trade or business or fail to comply with the representations underlying our tax ruling or supplemental tax ruling relating to the spin-off, the tax-free treatment of the spin off might be lost. If there are any corporate level taxes incurred by us as a result of the spin-off for any other reason, we would be responsible for 50% of any such liability and PXP would be responsible for the remaining 50%. The amount of any tax payments would be substantial and may result in events of default under our loan facility. As a result, we likely would not have sufficient financial resources to achieve our growth strategy or, possibly, repay our indebtedness after making these payments.

As a result of the tax principles discussed above, we may be highly limited in our ability to take the following steps in the future:

- issue equity in public or private offerings;
- issue equity as part of the consideration in acquisitions of additional assets; or
- undergo a change of control.

**Item 3. LEGAL PROCEEDINGS**

***PLX Stockholder Suits***

Beginning November 21, 2003, six putative class action lawsuits were filed against Plains Resources, our directors and Mr. Raymond, in the Court of Chancery in the State of Delaware, in and for New Castle County, seeking to enjoin the sale of Plains Resources. The lawsuits, and dates of filing, are as follows:

No. 071-N, *Twist Partners LLP v. Flores et al.* (filed Nov. 21, 2003)

No. 073-N, *Klein v. Flores et al.* (filed Nov. 21, 2003)

No. 074-N, *Levy v. Flores et al.* (filed Nov. 21, 2003)

No. 075-N, *Lanza v. Flores et al.* (filed Nov. 21, 2003)

No. 076-N, *Burt v. Flores et al.* (filed Nov. 21, 2003)

No. 143-N, *South Broadway Capital v. Flores et al.* (filed Dec. 30, 2003)

Four of the complaints (*Twist Partners*, *Klein*, *Levy*, and *South Broadway Capital*) also named Vulcan Capital as a defendant. Each complaint alleged that the $14.25 per share Vulcan Capital proposal would be inadequate compensation. The *Twist Partners* complaint alleged that our stock traded as high as $23.05 per share as recently as December 2002 and as high as $14.75 per share as recently as June 2003. It further alleged that the downward trend of the price of our stock reflects temporary market conditions in our industry, and that Mr. Flores and Mr. Raymond recognized a strong likelihood that the price would soon rebound to the levels at which it traded in 2003 and late 2002. The complaint further alleged that Mr. Flores, Mr. Raymond, and Vulcan Capital determined to usurp this hidden value for themselves, thereby allegedly denying our minority stockholders the opportunity to obtain fair value for their equity interest. The *Twist Partners* November 21, 2003 complaint alleged that all individual defendants breached fiduciary duties of due care and loyalty to our stockholders. Vulcan Capital was alleged to have aided and abetted these alleged breaches of fiduciary duty. The complaint alleged, among other things, that the November 20, 2003 announcement of a November 19, 2003 buyout offer represented a paltry premium of 7.6 percent to Plains current trading price and . . . a very significant discount to what it had traded at earlier in the year. As of the November 21, 2003 filing of the complaint, Twist Partners alleged that the individually named defendants had failed to auction the Company, had failed to conduct an active market check, had not appointed an independent person to negotiate on behalf of our stockholders.

The relief sought by Twist Partners includes certification of a class action, an injunction preventing consummation of the buyout offer (or rescinding it if consummated), compensatory and/or rescissory damages to the class, interest, attorneys fees, expert fees, and other costs, along with such other relief as the Court might find just and proper.

Substantially the same allegations and prayer for relief were made in each of the first five suits which was filed (*Twist Partners*, *Klein*, *Levy*, *Lanza*, and *Burt*). (Klein, Lanza, and Levy additionally alleged that Mr. Flores and Mr. Raymond dominated and controlled the rest of our Board of Directors.) The *Klein* complaint was subsequently amended to name and seek relief from Vulcan Energy rather than Vulcan Capital. These five cases were consolidated on December 11, 2003 under the action No. 071-N, *In re Plains Resources Inc. Shareholders Litigation*, and defendants are not required to respond to the originally filed complaints.

On December 30, 2003, a sixth complaint was filed by South Broadway Capital alleging substantially the same allegations and prayer for relief as the complaints consolidated under No. 071-N, *In re Plains Resources Inc. Shareholders Litigation*. Plaintiff s Delaware counsel of record for South Broadway Capital are also plaintiff s counsel of record in No. 071-N, *In re Plains Resources Inc. Shareholders Litigation*. The defendants expect that the *South Broadway Capital* action will be consolidated with the other five shareholder suits.

On February 24, 2004, the first amended consolidated complaint was filed in No. 071-N, *In re Plains Resources Inc. Shareholders Litigation*. That complaint makes additional factual allegations. It alleges that the $14.25 per share Vulcan Capital proposal failed to adequately reflect the value of certain assets and results of the transaction, including:

- the resulting controlling interest in PAA (for which plaintiffs allege the fair market value of the premium for such control is between $360 and $540 million);
- incentive distribution rights in Plains AAP (for which plaintiffs allege an estimated present value of $54.4 million);
- limited partner interest in PAA;
- our proved oil reserves (of which plaintiffs allege the market value is 15% higher than our standardized measure);
- certain unspecified tax credits not reflected on our balance sheet; and

other unspecified assets, net of liabilities.

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The amended consolidated complaint also alleges that:

- Mr. O Malley has significant business and/or personal relationships with Mr. Flores and Mr. Raymond and is not capable of being a truly independent member of the special committee;

- the Leucadia proposal was rejected without adequate consideration by the special committee;

- the special committee s January 22, 2004 statement that it was prepared to enter into discussions or negotiations with . . . other parties relating to a transaction was materially false and misleading, and that the special committee never intended to entertain proposals from anyone other than Vulcan and/or the Company s directors ;

- the Vulcan Capital proposal is not the result of a full and fair auction process or active market check, that the $16.75 per share price was reached without a full and thorough investigation, that the price and process are intrinsically unfair and inadequate; and

- our directors failed to make an informed decision with respect to the Vulcan Capital proposal.

Also on February 24, 2004, Donald Gilbert filed a putative class action lawsuit against Plains Resources, our directors, Mr. Raymond and Vulcan Capital in the 157th District Court for Harris County, Texas (No. 2004-10509, *Gilbert v. Plains Resources Inc. et al.*). The petition has not been served at this time. Its factual allegations repeat some but not all of those made in the consolidated amended complaint filed in *In re Plains Resources Inc. Shareholders Litigation* in Delaware. The Texas suit particularly alleges that members of the Class will be irreparably harmed in that they will not receive fair value for Plains Resources assets and business and will be prevented from obtaining the real value of their equity ownership in the Company, and that unless an injunction is entered, Vulcan Capital and Messrs. Flores and Raymond will continue to aid and abet a process that inhibits the maximization of shareholder value. For purported causes of action, the Texas lawsuit alleges that our directors breached fiduciary duties of loyalty and due care by allegedly failing to (1) inform themselves of our market value before taking action, (2) act in the best interest of our shareholders, (3) maximize shareholder value, (4) obtain the best financial and unspecified other terms when our independent existence will be materially altered by a transaction, and (5) act in accordance with their fundamental duties of due care and loyalty. It further alleges that Vulcan Capital and Messrs. Flores and Raymond aided and abetted our directors alleged breaches of fiduciary duties. The relief sought includes (1) declaration of a class action, (2) declaration that the proposed merger agreement was entered into in breach of the fiduciary duties of our directors, (3) injunction prohibiting us from proceeding with and consummating the proposed merger, (4) injunction requiring the implementation of procedures to obtain the highest price, (5) injunction requiring our directors to exercise their fiduciary duties to obtain a transaction which is in the best interests of shareholders until the process for the sale or auction of the Company is completed and the highest possible price is obtained, (6) unspecified appropriate damages, (7) costs and disbursements, including reasonable attorneys and experts fees, and (8) other and further relief which the Court may deem just and proper.

***PAA Suit***

On December 18, 2003, Alfons Sperber filed suit in the Court of Chancery in the State of Delaware, in and for New Castle County against Plains Resources, PAA, Plains AAP, L.P. ( Plains AAP ), PAA GP LLC, and several individual defendants (No. 123-N, *Sperber v. Plains Resources, Inc. et al.*). The *Sperber* suit was putatively brought on behalf of all limited partners and unit holders in PAA and alleges (1) breach of the fiduciary duties owed to PAA and its unit holders and limited partners by PAA; Plains AAP, L.P.; PAA GP, L.L.C.; and the individually named directors of PAA GP, L.L.C.; and (2) breach of the fiduciary duties owed to PAA and its unit holders and limited partners by Plains Resources Inc. and its individually named directors as controlling stockholder of PAA GP, L.L.C.

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Sperber s factual allegations concerning the buyout proposal are substantially the same as those alleged in the consolidated Plains Resources stockholders litigation. In addition, Sperber alleged that as a result of the buyout proposal, Mr. Flores and Mr. Raymond will effectively control PAA. Sperber alleged that PAA had made no disclosure concerning the buyout proposal, and that no actions had been taken to protect the interests of PAA, its limited partners, or its unitholders with respect to the Plains Resources buyout proposal. Sperber specifically alleged that defendants have breached their contractual and/or fiduciary duties by failing to seek, pursuant to their respective governing documents, to acquire Plains Resources or the PAA units and general partnership interests held by Plains Resources; failing to amend the PAA GP Amended and Restated Limited Liability Company Agreement and/or PAA s Amended and Restated Limited Partnership Agreement to limit the power of Messrs. Flores and Raymond and Vulcan Capital over selection of five of the seven members of the PAA GP board and the chief executive officer of PAA GP, failing to ensure that the transaction does not adversely affect PAA s interests under the Crude Oil Marketing Agreement, dated as of November 23, 1998, by and among Plains Resources, Plains Illinois Inc., Stocker Resources, LP, Calumet Florida, Inc., and Plains Marketing, LP and the Omnibus Agreement among Plains Resources, PAA, Plains Marketing, LP, All American Pipeline, LP and Plains All American Inc., dated as of November 23, 1998, or to obtain fair value for any waiver of those interests; failing to convene the conflicts committee to determine whether the proposed transaction is fair and reasonable to PAA; and failing to appoint a special committee of independent directors to consider the effects of the transaction. Sperber alleged that all defendants to that action owe fiduciary duties to PAA, its limited partners, and its unitholders which allegedly have been breached by the failure to take actions to protect the interests of PAA, its limited partners, and its unitholders.

The *Sperber* complaint requests the following relief: certification of a class action, an injunction preventing consummation of the buyout offer (or rescinding it if consummated), an injunction requiring PAA and Plains AAP to act to protect the interest of PAA, its limited partners, and its unitholders, a declaration that the individual defendants breached their fiduciary duties to the plaintiff and the putative class, an accounting of all assets, money, and other value improperly received from Plains Resources, disgorgement and imposition of a constructive trust on all property and profits defendants received as a result of wrongful conduct, damages to the class, interest, attorneys fees, and other costs, along with such other relief as the Court might find just and proper. Pursuant to an agreement among counsel, no response to the *Sperber* complaint is required until March 10, 2004.

***Other***

The previously reported lawsuit regarding the termination of an electric services contract with Commonwealth Energy Corporation was settled in January 2004 by Plains Exploration under its indemnity obligation to us. All claims of the lawsuit have been released.

In the ordinary course of our business, we are a claimant or defendant in various legal proceedings. We do not believe that the outcome of any pending legal proceedings, individually or in the aggregate, will have a material 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.

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**Directors and Executive Officers of Plains Resources**

Listed below are our directors and executive officers, their age as of February 29, 2004, and their business experience for the last five years.

*Directors*

*James C. Flores*, age 44, Chairman of the Board since December 2002. He was our Chairman of the Board and Chief Executive Officer from May 2001 to December 2002. He was Co-founder and Chairman from inception of Ocean Energy, Inc., an oil and gas company, and, at various times, President and Chief Executive Officer from 1992 until March 1999. In March 1999 Ocean Energy, Inc. was merged with Seagull Energy Corporation where Mr. Flores served as Chairman of the Board of the new Ocean Energy, Inc. from March 1999 until January 2000, and as Vice Chairman from January 2000 until January 2001. From January 2001 to May 2001 Mr. Flores managed various private investments. Mr. Flores has been Chairman of the Board, Chief Executive Officer and a Director of PXP since September 2002 and became President in March 2004.

*William M. Hitchcock*, age 64, Director since 1977. Mr. Hitchcock is a partner and has been President since 1996 of Pembroke Financial Partners LLC, a NASD investment firm. In addition, he is Chief Executive Officer of Camelot Oil & Gas, a private oil and gas company. He is also a director of Maxx Petroleum Ltd., an oil and gas company, Thoratec Corporation, a medical device company, and Luna Imaging, Inc., a digital imaging company. From 1992 to 1995, Mr. Hitchcock served as President of Plains Resources International Inc., which was formerly one of our wholly-owned subsidiaries. In addition, he was our Chairman of the Board from August 1981 to October 1992, except for the period from April 1987 to October 1987, when he served as our Vice Chairman.

*William C. O Malley*, age 66, Director since April 2003. Mr. O Malley is a director (since 1994) of and former Chairman of the Board of Tidewater Inc., a public offshore marine transportation, shipyard facilities and containerized shipping company. He was Tidewater Inc. s Chief Executive Officer from 1994 to 2002 and served as its President from 1994 to 2001. Mr. O Malley has been a director of Hibernia Corporation, the holding company for Hibernia National Bank, since 1995. He is also a director of BE&K Inc., an engineering and construction contractor. Mr. O Malley is a certified public accountant and a former partner with Arthur Young, a predecessor accounting firm to Ernst & Young LLP.

*D. Martin Phillips*, age 50, Director since June 2001. Mr. Phillips has been a Managing Director and principal of EnCap Investments L.P., or EnCap, a funds management and investment banking firm that focuses exclusively on the oil and gas industry, since November 1989. From 1978 to when he joined EnCap, Mr. Phillips served as Senior Vice President in the Energy Banking Group of NCNB Texas National Bank in Dallas, Texas. From 1999 to June 2003, Mr. Phillips served as a director of 3TEC Energy Corporation. Mr. Phillips also currently serves as a director of seven privately held EnCap portfolio companies and Small Steps Nurturing Center. He formerly served as president of the Houston Producers Forum.

*Robert V. Sinnott*, age 54**,** Director since 1994. Mr. Sinnott has been Senior Vice President of Kayne Anderson Investment Management, Inc., an investment management firm, since 1992. He is also a director of Glacier Water Services, Inc., a vended water company, and Plains All American GP LLC, the general partner of Plains AAP, L.P., which is in turn the general partner of PAA. Mr. Sinnott was Vice President and Senior Securities Officer of the Investment Banking Division of Citibank from 1986 to 1992.

*J. Taft Symonds*, age 64, 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,

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Inc., an international marketing firm, since 1978. He is also Chairman of the Board of Tetra Technologies, Inc., an oilfield services company, and a director of Plains All American GP LLC, the general partner of Plains AAP LP, which is in turn the general partner of PAA.

*Executive Officers*

*John T. Raymond*, age 33, Chief Executive Officer since December 2002. Mr. Raymond served as our President and Chief Operating Officer from November 2001 to December 2002 and as Executive Vice President and Chief Operating Officer from May 2001 to November 2001. In addition, 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., an energy investment company, from 1992 to April 1998. In addition, Mr. Raymond is a director of Plains All American GP LLC, the general partner of Plains AAP LP, which is in turn the general partner of PAA. Mr. Raymond served as President and Chief Operating Officer of PXP from September 2002 to March 2004.

*Stephen A. Thorington*, age 48, Executive Vice President and Chief Financial Officer since February 2003. He served as Acting Executive Vice President and Chief Financial Officer from December 2002 to February 2003 when he was appointed to his current position. Mr. Thorington has been Executive Vice President and Chief Financial Officer of PXP since September 2002. Mr. Thorington was Senior Vice President  Finance and Corporate Development of Ocean Energy, Inc. from July 2001 to September 2002 and Senior Vice President  Finance, Treasury and Corporate Development of Ocean Energy, Inc. from March 1999 to July 2001. He also served as Vice President, Finance and Treasurer of Seagull Energy Corporation from May 1996 to March 1999.

*John F. Wombwell*, age 42, has been Executive Vice President, General Counsel and Secretary of our company and of PXP since September 2003. Prior to joining Plains Resources, Mr. Wombwell was General Counsel of ExpressJet Airlines, Inc. from April 2002 to September 2003 and Integrated Electrical Services, Inc. from January 1998 to April 2002. Prior to that time, Mr. Wombwell was a partner at the law firm of Andrews & Kurth L.L.P., where he practiced law in the area of corporate and securities matters, representing a variety of public companies.

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PART II

**Item 5. MARKET FOR REGISTRANT S COMMON STOCK, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES**

**Price Range of Common Stock**

Our common stock is listed and traded on the New York Stock Exchange under the symbol PLX . The number of stockholders of record of our common stock as of February 29, 2004 was 933.

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 |
|---|---|---|
| **2003** | | |
| 1st Quarter | $ 12.70 | $ 10.41 |
| 2nd Quarter | 14.50 | 10.90 |
| 3rd Quarter | 14.54 | 12.45 |
| 4th Quarter | 16.10 | 12.55 |
| **2002** | | |
| Before Spin-off | | |
| 1st Quarter | 24.99 | 22.35 |
| 2nd Quarter | 27.75 | 24.60 |
| 3rd Quarter | 26.95 | 21.92 |
| 4th Quarter | 25.88 | 20.18 |
| After Spin-off | | |
| 4th Quarter | 12.51 | 11.85 |

**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 our loan facility.

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**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. As a result of the spin-off, the historical results of the operations of PXP are reflected in our financial statements as discontinued operations . As a result of the reduction in our ownership interest in PAA in 2001, our ownership interest 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. This 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, | | | | |
|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2000 | 1999 |
| **Revenues** | | | | | |
| Crude oil sales to PAA | $ 22,164 | $ 19,275 | $ 17,211 | $ 17,213 | $ 16,136 |
| Hedging | (307) | (613) | (1,181) | (6,570) | (3,658) |
| Marketing, transportation, storage and terminalling | | | | 6,425,644 | 10,796,998 |
| Gain on sale of assets (1) | | | | 48,188 | 16,457 |
| | 21,857 | 18,662 | 16,030 | 6,484,475 | 10,825,933 |
| **Costs and Expenses** | | | | | |
| Production expenses | 8,532 | 6,421 | 7,397 | 5,912 | 5,118 |
| Oil transportation expenses | 3,906 | 3,775 | 4,449 | 3,752 | 3,740 |
| Other operating expenses | 137 | 115 | | | |
| General and administrative | 6,973 | 5,747 | 11,083 | 44,468 | 27,035 |
| Marketing, transportation, storage and terminalling | | | | 6,292,615 | 10,689,308 |
| Unauthorized trading losses and related expenses (2) | | | | 7,963 | 166,440 |
| Depreciation, depletion, amortization and accretion | 4,995 | 4,139 | 4,816 | 28,362 | 23,669 |
| | 24,543 | 20,197 | 27,745 | 6,383,072 | 10,915,310 |
| **Other Income (Expense)** | | | | | |
| Equity in earnings of PAA | 15,073 | 18,807 | 18,540 | | |
| Gains on PAA unit transactions and public offerings (3) | 33,237 | 14,512 | 170,157 | | 9,787 |
| Loss on debt extinguishment | | (10,319) | | (15,148) | (1,545) |
| Gain (loss) on derivatives | (6,728) | | | | |
| Interest expense | (2,222) | (5,866) | (8,974) | (39,943) | (31,466) |
| Interest and other income | 97 | 239 | (312) | 7,068 | 1,150 |
| Minority interest in PAA | | | | (35,565) | 40,911 |
| Income tax expense | (16,464) | (6,106) | (67,072) | (5,628) | 26,104 |
| **Income (Loss) From Continuing Operations** | 20,307 | 9,732 | 100,624 | 12,187 | (44,436) |
| Income from discontinued operations, net of tax | | 27,800 | 54,693 | 28,749 | 19,105 |
| Cumulative effect of accounting changes, net of tax | 933 | | (1,986) | (121) | |
| **Net Income** | 21,240 | 37,532 | 153,331 | 40,815 | (25,331) |
| Cumulative preferred dividends (4) | (603) | (1,400) | (27,245) | (14,725) | (10,026) |
| **Income Available to Common Stockholders** | $ 20,637 | $ 36,132 | $ 126,086 | $ 26,090 | $ (35,357) |
| **Income From Continuing Operations Per Share** | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| Basic | $ 0.88 | $ 0.35 | $ 3.48 | $ (0.14) | $ (3.16) |
| Diluted | $ 0.86 | $ 0.34 | $ 2.81 | $ (0.14) | $ (3.16) |
| **Balance Sheet Data** | | | | | |
| Working capital (deficit) | $ (19,455) | $ (11,971) | $ (9,969) | $ 20,289 | $ 115,867 |
| Ownership interest in PAA | 100,536 | 70,042 | 64,626 | | |
| Total assets | 176,048 | 161,412 | 648,788 | 1,394,329 | 1,689,560 |
| Long-term debt | 30,000 | 27,000 | 282,061 | 626,376 | 676,703 |
| Redeemable preferred stock | | | | 50,000 | 138,813 |
| Stockholders equity | 100,904 | 105,509 | 254,852 | 137,140 | 40,619 |
| **Distributions from PAA** | 30,930 | 29,063 | 31,553 | 30,134 | 29,472 |

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(1) Relates to the sale of assets by PAA.
(2) Relates to losses resulting from unauthorized trading activity by a former employee of PAA.
(3) Amounts in 2003 relate to public offerings of PAA units and the conversion of certain subordinated units. Amounts in 2002 and 1999 relate to public offerings of PAA units. Amount in 2001 relates to sale of a portion of our interest in PAA and public offering of PAA units.
(4) 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.

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

The following information should be read in connection with the information contained in the consolidated financial statements and notes thereto included elsewhere in this report.

### Overview

We are an independent energy company. Our current business operations are focused in two areas of the energy business midstream and upstream.

*Midstream.*

Our midstream activities are carried out through our equity ownership in Plains All American Pipeline, L.P., or PAA, a public master limited partnership. PAA markets, gathers, transports, terminals, and stores oil. As of February 29, 2004 we owned 44% of the general partner of PAA and 12.4 million, or 21%, of the limited partnership units of PAA, which represented approximately 22% aggregate ownership interest in PAA. See Plains All American Pipeline, L.P. The book value of our ownership interest in PAA represents 57% of our total assets as of December 31, 2003.

During 2003, we received $30.9 million in partnership distributions from PAA. PAA partnership distributions generate relatively stable cash flows to the Company with relatively minimal future capital requirements from us. Our equity in the earnings of PAA was $15.1 million and we also recognized $33.2 million in gains on PAA unit transactions and public offerings. These numbers reflect lower PAA earnings and a decrease in our ownership of PAA as a result of 2003 equity offerings. PAA s financial performance directly impacts our financial performance and the market value performance of PAA s limited partnership interests directly impacts the value of our assets. Changes to PAA s income or asset values because of business or market factors affecting PAA will directly affect our reported income and asset values and could affect the amount of distributions we receive. As a result, we encourage you to review PAA s SEC filings, including its Annual Report on Form 10-K for the year ended December 31, 2003, to review and assess, among other things, PAA s financial performance and financial condition, PAA s business, operations, and competition, and risk factors associated with PAA s business.

*Upstream.*

We participate in the upstream activities of acquiring, exploiting, developing, exploring for and producing oil through our wholly owned subsidiary, Calumet Florida L.L.C., or Calumet, which owns producing properties in the Sunniland Trend in south Florida.

The book value of our upstream assets represents 30% of our total assets as of December 31, 2003. The present value of our oil reserves as of December 31, 2003, approximately $77.5 million, was determined in accordance with SEC requirements is based on prices, costs and assumptions in effect on that date. The price in effect at December 31, 2003 was $32.52 per barrel before adjustment for location and quality differential. This present value does not necessarily represent the actual value of such reserves since actual future prices and costs may be significantly higher or lower than the prices and costs on December 31, 2003.

Our revenues from the sale of oil during 2003 were $21.9 million. Our revenues from upstream operations are dependent on the price of oil, which is historically volatile. We manage our exposure to price risk by hedging a substantial portion of our oil production through the use of derivative instruments. We manage our upstream operations to provide a steady cash flow through our hedging and by controlling operating expenses of the properties. We could be adversely affected by a material change in oil prices for which we have not effectively hedged or increases in operating expenses such as electricity or transportation. Our production volumes will decline if we do not invest capital in new wells or reworking of existing wells.

*Proposed Merger Transaction*

As further described in Items 1 and 2 Business and Properties, the Company has entered into a merger agreement with the Vulcan Group as approved by the Special Committee and our board of directors. In the proposed merger, the Vulcan Group would acquire all of our outstanding stock for $16.75 per share in cash. We have filed a preliminary proxy statement for the special meeting of stockholders to vote on the proposed transaction. If the merger is consummated, Plains Resources will become a privately held company. Accordingly, upon closing, the registration of the Company s common stock under the Securities Exchange Act of 1934 will terminate and the Company will cease filing reports with the SEC.

**Spin-off of Plains Exploration & Production Company**

Prior to December 18, 2002 Plains Exploration & Production Company, or PXP, was our wholly owned subsidiary. On December 18, 2002 we distributed the issued and outstanding shares of PXP common stock to the holders of record of our common stock as of the close of business on December 11, 2002. Each of our stockholders received one share of PXP common stock for each share of our common stock held. Prior to the spin-off, we made an aggregate of $52.2 million in cash contributions to PXP and transferred certain assets and liabilities to PXP, primarily related to land, unproved oil and gas properties, office equipment and compensation obligations.

In contemplation of the spin-off, under the terms of a Master Separation Agreement between us and PXP, on July 3, 2002 we contributed to PXP 100% of the capital stock of our wholly owned subsidiaries that own oil and gas properties in offshore California and Illinois. As a result, PXP indirectly owned our offshore California and Illinois properties and directly owned our onshore California properties. We also contributed $256.0 million of intercompany receivables that PXP and its subsidiaries owed to us. On July 3, 2002 PXP issued $200 million of 8.75% Senior Subordinated Notes due 2012, or the 8.75% notes, and entered into a $300 million revolving credit facility. PXP distributed to us the net proceeds of $195.3 million from the 8.75% notes and $116.7 million of initial borrowings under the credit facility. We used such amounts to redeem our 10.25% senior subordinated notes on August 2, 2002 ($287.0 million) and to repay amounts outstanding under our credit facility ($25.0 million).

We received a letter ruling from the IRS on May 22, 2002, as supplemented on November 5, 2002, to the effect that the spin-off qualifies as a tax-free distribution. A letter ruling from the IRS, while generally binding on the IRS, may under certain circumstances be retroactively revoked or modified by the IRS. A letter ruling is based on the facts and representations presented in the request for that ruling. Generally, an IRS letter ruling will not be revoked or modified retroactively if there has been no misstatement or omission of material facts, the facts at the time of the transaction are not materially different from the facts upon which the IRS letter ruling was based, and there has been no change in the applicable law. We are not aware of any facts or circumstances that would cause the representations in the ruling request to be untrue or incomplete in any material respect.

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As a result of the spin-off the historical results of the operations of PXP are reflected in our financial statements as discontinued operations . Except where noted, discussions in this Form 10-K with respect to oil and gas operations relate to our activities other than the discontinued operations.

**General**

*Upstream Operations*

We follow the full cost method of accounting whereby all costs associated with property acquisition, exploration, exploitation and development activities are capitalized. Our revenues are derived from the sale of oil. We recognize revenues when our production is sold and title is transferred. Our revenues are highly dependent upon the prices of, and demand for oil. 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 our levels of production are subject to wide fluctuations and depend on numerous factors beyond our control, including supply and demand, economic conditions, foreign imports, the actions of OPEC, political conditions in other oil-producing countries, and governmental regulation, legislation and policies. Under the SEC s full cost accounting rules, we review the carrying value of our proved oil and gas properties each quarter. 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 to determine a ceiling value of our properties. The rules require a write-down if our capitalized costs exceed the allowed ceiling. We have had no write-downs due to these ceiling test limitations since 1998. Given the volatility of oil prices, it is likely that our estimate of discounted future net revenues from proved oil and gas reserves will fluctuate in the near term. If oil prices decline in the future, write-downs of our oil and gas properties could occur. Write-downs required by these rules do not directly impact our cash flows from operating activities. Decreases in oil and gas prices have had, and will likely have in the future, an adverse effect on the carrying value of our proved reserves and our revenues, profitability and cash flow.

To manage our exposure to commodity price risks, we use various derivative instruments to hedge our exposure to oil sales price fluctuations. Our hedging arrangements provide us protection on the hedged volumes if oil prices decline below the prices at which these hedges are set. However, if oil prices increase, ceiling prices in our hedges may cause us to receive lower revenues on the hedged volumes than we would receive in the absence of hedges. Gains and losses from hedging transactions are recognized as revenues when the associated production is sold.

Our oil production expenses include salaries and benefits of field personnel, electric costs, maintenance costs, production, ad valorem and severance taxes, and other costs necessary to operate our producing properties. Depletion of capitalized costs of producing oil and gas properties is provided using the units of production method based upon proved reserves. For the purposes of computing depletion, proved reserves are redetermined as of the end of each year and on an interim basis when deemed necessary. General and administrative expenses consist primarily of salaries and related benefits of administrative personnel, office rent, systems costs and other administrative costs.

*Midstream Operations*

We account for our ownership interest in PAA using the equity method of accounting. We record equity in earnings of PAA based on our aggregate ownership interest, as adjusted for general partner incentive distributions. Equity in earnings for our general partner interest is based on our 44% share of 2% of PAA s net income plus the amount of the general partner incentive distribution.

Equity in earnings for our limited partner units is based on our ownership percentage of limited partner units (21% at December 31, 2003) multiplied by 98% of PAA s net income less the general partner incentive distribution. Increased earnings attributable to the general partner incentive distributions will be somewhat offset because of our ownership of limited partner units. Cash distributions received from PAA are not reflected in earnings, but are reflected as a reduction in our ownership interest in PAA on the balance sheet.

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When PAA sells additional limited partner units and we do not purchase additional units, our ownership interest in PAA is reduced, creating an implied sale of a portion of our ownership interest. We have recognized gains from PAA equity issuances representing the difference between our carrying cost and the fair value of the interest deemed sold.

**Results of Operations**

In 2003 our net income was $21.2 million. We had revenues from oil sales of $21.9 million and costs and expenses totaled $24.5 million. Our equity in the earnings of PAA was $15.1 million and we recognized $33.2 million in gains on PAA unit transactions and public offerings. Our derivative transactions resulted in a $4.3 million fair value loss and $2.4 million in settlement losses and we had $2.2 million in interest expense. Income tax expense for the year was $16.5 million. We also recognized a $0.9 million gain on the adoption of a new accounting policy related to our accounting for asset retirement obligations.

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| Production (MBbls) | 845 | 970 | 954 |
| Sales (MBbls) | 926 | 869 | 1,060 |
| Sales Price per Bbl | | | |
| Average NYMEX price | $ 30.99 | $ 26.15 | $ 26.01 |
| Differential | (7.06) | (3.97) | (9.77) |
| | 23.93 | 22.18 | 16.24 |
| Hedging | (0.33) | (0.71) | (1.11) |
| | 23.60 | 21.47 | 15.13 |
| Derivative cash settlements | (2.57) | | |
| | 21.03 | 21.47 | 15.13 |
| Costs and Expenses per Bbl | | | |
| Production expenses | 7.99 | 6.72 | 6.63 |
| Production and ad valorem taxes | 1.22 | 0.67 | 0.35 |
| Oil transportation expenses | 4.22 | 4.34 | 4.20 |
| DD&A (oil & gas properties) | 4.78 | 3.73 | 2.74 |

In the first quarter of 2003, the NYMEX oil price and the price we receive for our Florida oil production did not correlate closely enough for our hedges to qualify for hedge accounting under the applicable accounting rules. As a result, we were required to discontinue hedge accounting effective February 1, 2003 and reflect the mark-to-market value of the derivatives in earnings prospectively from that date. The $2.1 million ($1.0 million, net of tax) net loss in Other Comprehensive Income ( OCI ) at January 31, 2003 ($0.3 million, $0.2 million net of tax at December 31, 2003) related to these hedges will be recognized in earnings as the related production is delivered. In 2003 the hedging amount presented in the above table relates only to oil sold in January 2003. None of our current derivatives qualify for hedge accounting. Derivative instruments that we enter into in the future may or may not qualify for hedge accounting.

**Comparison of Year Ended December 31, 2003 to Year Ended December 31, 2002**

Net income was $21.2 million for 2003 compared to income from continuing operations of $9.7 million for 2002. Including income from discontinued operations, net income was $37.5 million for 2002.

*Oil revenues.* Oil revenues, excluding the effect of hedging, increased 15%, or $2.9 million, from $19.3 million for 2002 to $22.2 million for 2003. Our average sales price for oil excluding hedging

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increased 8%, or $1.75, to $23.93 per Bbl for 2003 from $22.18 per Bbl for 2002. An increase in the NYMEX price to $30.99 per Bbl was partially offset by an increase in the average differential for location and quality from $3.97 per Bbl in 2002 to $7.06 in 2003. Including the effect of hedging, our average realized price for 2002 was $21.47 per Bbl and our average realized price for 2003 was $23.60 per Bbl. After deducting our $2.57 per Bbl loss on cash settlements of derivatives, our average realized price for 2003 period was $21.03 per Bbl.

Reported sales volumes from our Florida properties were 926 MBbls in 2003 compared to 869 MBbls in 2002. In accordance with SEC Staff Accounting Bulletin 101 we reflect revenue from oil production in the period it is sold as opposed to when it is produced. Oil volumes decreased 13% on an as produced basis, with production volumes of 845 MBbls in 2003 compared to 970 MBbls in 2002. The location of our Florida properties and the timing of the barges that transport the oil to market cause reported sales volumes to differ from production volumes. Actual timing of sales volumes is difficult to predict. The Florida oil is typically sold in shipments that range from approximately 110 MBbls to 140 MBbls and typically occurs every 30-50 days. In addition, our Florida properties consist of a relatively low number of higher volume wells and downtime due to equipment failures and other operational issues can cause production from this area to be volatile.

*Production expenses.* Production expenses increased 27%, or $1.6 million, to $7.4 million ($7.99 per Bbl) for 2003 from $5.8 million ($6.72 per Bbl) for 2002. The increase is primarily attributable to increased fuel and electricity costs and higher costs for maintenance and repairs.

*Production and ad valorem taxes*. Production and ad valorem taxes increased $0.5 million, to $1.1 million for 2003 from $0.6 million for 2002 primarily due to increased sales volumes and the expiration of severance tax exemptions for several wells in the second quarter of 2002. Unit production and ad valorem taxes were $1.22 per Bbl for 2003 compared to $0.67 per Bbl in 2002.

*Oil transportation expenses*. Gathering and transportation expenses increased 3%, or $0.1 million, from $3.8 million in 2002 to $3.9 million in 2003. On a per Bbl basis, oil transportation expenses decreased from $4.34 per Bbl in 2002 to $4.22 per Bbl in 2003.

*General and administrative expenses.* General and administrative expenses, or G&A expense, increased 23%, or $1.3 million, from $5.7 million in the 2002 to $7.0 million in 2003, primarily from costs incurred in connection with a buyout proposal received during 2003 and non-cash compensation expense related to restricted stock awards.

*Depreciation, depletion, amortization and accretion, or DD&A.* DD&A expense increased 22%, or $0.9 million, to $5.0 million for the year ended December 31, 2003 from $4.1 million for 2002. The increase is primarily due to higher sales volumes in 2003 versus 2002 and an increase in our average DD&A rate from $3.73 per Bbl in 2002 to $4.78 per Bbl in 2003. Accretion expense for 2003 was $0.2 million. Accretion expense represents the adjustment of our asset retirement obligation to its present value at the end of the period.

*Other operating expenses.* Other operating expenses for 2003 and 2002 include $0.1 million losses on the disposition of materials and supplies inventory.

*Equity in earnings of Plains All American Pipeline, L.P.* Our equity in earnings of PAA decreased $3.7 million to $15.1 million for 2003 from $18.8 million for 2002 due to lower PAA earnings and a decrease in our ownership in PAA as a result of its 2003 equity offerings. PAA had net income of $59.4 million for 2003 compared to $65.3 million in 2002. Our equity in earnings of PAA was reduced by approximately $7.7 million pre-tax as a result of a $28.8 million compensation accrual by PAA

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associated with PAA s assessment of the probable vesting in 2004 of restricted unit grants pursuant to PAA s long term incentive plan and a noncash loss on debt refinancing of $3.3 million recognized by PAA in 2003. Our ownership interest in PAA was 22% at December 31, 2003 and 25% at December 31, 2002.

*Gain on Plains All American Pipeline, L.P. unit offerings and subordinated unit conversion.* In the years ended December 31, 2003 and 2002 we recognized noncash gains totaling $23.5 million and $14.5 million, respectively related to PAA s public equity offerings in these periods. The gains are recognized to reflect our proportionate share of the increase in the underlying net assets of PAA resulting from the equity offerings. In the fourth quarter of 2003 we recognized a noncash gain of $9.7 million related to the conversion of one fourth of our PAA subordinated units to common units. The gain is recognized to reflect our proportionate share of the increase in the underlying net assets of PAA resulting from the conversion.

*Gain (loss) on derivatives*. As previously discussed, we were required to discontinue hedge accounting effective February 1, 2003. As a result, in the year ended December 31, 2003 we recorded a $6.7 million loss on derivatives that consisted of a $4.3 million loss in fair value and $2.4 million in settlement losses.

*Loss on debt extinguishment.* In 2002 we incurred a $10.3 million loss from the early retirement of $267.5 million of outstanding 10.25% notes. The expense included a call premium of 3.4167% on the outstanding principal amount of the 10.25% notes, or $9.1 million, and approximately $1.2 million related to unamortized premiums on the 10.25% notes and unamortized issue costs on the 10.25% notes and our credit facility.

*Interest expense.* Interest expense decreased $3.7 million, to $2.2 million for 2003 from $5.9 million for 2002, primarily reflecting lower outstanding debt.

*Income tax expense.* Income tax expense increased $10.4 million to $16.5 million for 2003 from $6.1 million for 2002. The increase was primarily due to higher pre-tax income from continuing operations as well as an increase in our effective tax rate, from 39% in 2002 to 45% in 2003.

Our effective tax rate reflects the Canadian taxes attributable to our share of PAA s earnings related to their Canadian operations. Since, for U.S. federal income tax purposes, we utilize net operating loss carryforwards, or NOLs, to reduce our currently payable taxes, we receive a deduction rather than a credit for Canadian income taxes. As a result of the double taxation of such Canadian earnings, our effective tax rate is higher than would normally be expected. Current income tax expense for 2003 and 2002 includes benefits of approximately $2.0 million and $2.9 million, respectively, representing tax paid in prior periods that was refunded to us as the result of certain legislation that allowed us to offset 100% of alternative minimum taxable income with NOLs. Previously, we could only offset 90% of AMT income with NOLs. The current income tax benefit is offset by a corresponding charge to deferred income tax expense. This change in the regulations did not change our overall effective tax rate and had no effect on net income.

*Cumulative effect of accounting change*. In the first quarter of 2003 we recognized a $0.9 million net of tax gain related to the adoption of Statement of Accounting Standards, or SFAS, No. 143, Accounting for Asset Retirement Obligations . See Recent Accounting Pronouncements for a discussion of the adoption of SFAS No. 143.

*Income from discontinued operations.* Income from discontinued operations of $27.8 million in 2002 reflects the net after tax earnings of PXP, which was spun off in the fourth quarter of 2002.

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**Comparison of Year Ended December 31, 2002 to Year Ended December 31, 2001**

In 2002, we reported net income of $37.5 million compared to net income of $153.3 million in 2001. Income from continuing operations was $9.7 million in 2002 compared to $100.6 million for 2001. Results for 2001 were affected by special items including $170.2 million of pre-tax gains related to the sale of a portion of our ownership interest in PAA and PAA s equity offerings.

*Oil revenues.* Our oil revenues increased 17%, or $2.7 million, to $18.7 million for the year ended December 31, 2002 from $16.0 million for the year ended December 31, 2001. The increase was primarily due to higher realized oil prices that increased revenues by $6.8 million in 2002 versus 2001. This increase was offset by lower sales volumes that decreased revenues by $4.1 million in 2002.

We reported sales volumes from our Florida properties of 869 MBbls in 2002 compared to 1,060 MBbls in 2001. In accordance with SEC Staff Accounting Bulletin 101, or SAB 101, we reflect revenue from oil production in the period it is sold as opposed to when it is produced. Oil volumes increased 2% on an as produced basis, with production volumes of 970 MBbls in 2002 compared to 954 MBbls in 2001.

Our average realized price for oil excluding transportation costs increased 42%, or $6.34, to $21.47 per Bbl for the year ended December 31, 2002 from $15.13 per Bbl for the prior year. The increase is primarily attributable to an improvement in the location and quality differential to NYMEX, which was $3.97 per Bbl in 2002 versus $9.77 per Bbl in 2001. The average NYMEX oil price increased slightly to $26.15 per Bbl in 2002 compared to $26.01 per Bbl in 2001. Hedging had the effect of decreasing our average price per Bbl by $0.71 in 2002 and $1.11 in 2001.

*Production expenses.* Our production expenses decreased 17%, or $1.2 million, to $5.8 million for the year ended December 31, 2002 from $7.0 million for 2001 primarily due to lower reported sales volumes. Unit production expenses for 2002 were $6.72 per Bbl compared to $6.63 in 2001.

*Production and ad valorem taxes*. Production and ad valorem taxes increased $0.2 million, to $0.6 million for 2002 from $0.4 million for 2001 primarily due to the expiration of severance tax exemptions for several wells. Unit production and ad valorem taxes were $0.67 per Bbl for 2002 compared to $0.35 per Bbl in 2001.

*Oil transportation expenses.* Our oil transportation costs decreased 14% to $3.8 million in 2002 from $4.4 million in 2001 primarily reflecting lower sales volumes.

*General and administrative expense.* Our general and administrative, or G&A expense, decreased 49%, or $5.4 million, to $5.7 million for the year ended December 31, 2002 from $11.1 million for the prior year. The decrease primarily reflects the $8.7 million of nonrecurring costs in 2001 related to our June 2001 strategic restructuring, partially offset by a lower amount of G&A expenses being capitalized in 2002.

*Depreciation, depletion, amortization and accretion, or DD&A*. DD&A expense decreased 15%, or $0.7 million, to $4.1 million for the year ended December 31, 2002 from $4.8 million for 2001. The decrease is primarily due to lower sales volumes in 2002 versus 2001. Our average DD&A rate for 2002 was $3.73 per Bbl compared to $2.74 per Bbl in 2001.

*Equity in earnings of Plains All American Pipeline, L.P.* Our equity in earnings of PAA increased slightly to $18.8 million for the year ended December 31, 2002 from $18.5 million for the 2001. Although PAA s net income increased from $44.2 million in 2001 to $65.3 million in 2002, our overall effective ownership was reduced to approximately 25% as of December 31, 2002 from 54% in January 2001. The reduced ownership interest is a result of the sale of a portion of our interest in June 2001 and PAA s subsequent equity offerings.

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*Gain on PAA units.* In 2002 we recognized a noncash gain of $14.5 million due to 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 public equity offering.

The 2001 gain on PAA units reflects: (i) $129.4 million in gains related to the sale of a portion of our ownership interest 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.

*Loss on debt extinguishment.* We incurred a $10.3 million loss on debt extinguishment in 2002 primarily from the early retirement of $267.5 million of outstanding 10.25% senior subordinated notes. The loss consisted of a call premium of 3.4167% on the outstanding principal amount of the 10.25% notes, or $9.1 million, and $3.1 million of unamortized issue costs on the 10.25% notes and our revolving credit facility, net of $1.9 million of unamortized issue premium on the 10.25% notes.

*Interest expense.* Our interest expense decreased $3.1 million, to $5.9 million for the year ended December 31, 2002 from $9.0 million for 2001. The decrease is due to the redemption of the 10.25% notes and the repayment of amounts outstanding under our revolving credit facility on July 3, 2002. From this date through early December 2002, when we borrowed $45 million under our tem loan facility, we had no outstanding debt. Outstanding debt during this period was debt of PXP and accordingly, interest expense for this period is reflected in discontinued operations.

*Income tax expense.* Our income tax expense decreased $61.0 million to $6.1 million for the year ended December 31, 2002. The decrease was primarily due to lower pre-tax income from continuing operations. Pre-tax income from continuing operations was significantly higher in 2002 as a result of the gains related to the sale of the PAA interest.

*Income from discontinued operations.* Income from discontinued operations decreased from $54.7 million in 2001 to $27.8 million in 2002, primarily reflecting lower revenues due to lower realized prices partially offset by higher sales volumes, higher costs and expenses, and expenses related to a terminated public equity offering.

**Liquidity and Capital Resources**

*General*

At December 31, 2003 we had negative working capital of $19.5 million. Cash generated from our upstream operations and PAA distributions are our primary sources of liquidity. We believe that we have sufficient liquid assets and cash from operations and PAA distributions to meet our short term and long-term normal recurring operating needs, debt service obligations, contingencies and anticipated capital expenditures.

If PAA could not, for any reason, make its minimum quarterly distribution payments on its limited partnership interests, this would impair our cash flows and our ability to meet our short and long-term cash needs. Thus, PAA s financial and operational performance directly affects our financial and operational performance. We encourage you to review PAA s SEC filings, including its Annual Report on Form 10-K for the year ended December 31, 2003.

*PAA Cash Distributions*

PAA s partnership agreement requires that it distribute 100% of available cash within 45 days after the end of each quarter to unitholders of record and to its general partner. Available cash is generally defined as all cash and cash equivalents on hand at the end of each quarter less reserves established by PAA s general partner for future requirements.

Prior to the fourth quarter of 2003 PAA had outstanding 10.0 million subordinated units, of which we owned 4.5 million units. The subordinated units were not publicly traded and were subordinated in the right to distributions. Common units accrue arrearages with respect to distributions for any quarter during the subordination period and subordinated units do not accrue any arrearages. PAA met certain financial requirements and 25% of the subordinated units converted to common units in the fourth quarter of 2003. The remaining subordinated units converted to common units in February 2004.

We own 1.3 million Class B common units. Class B common units are initially pari passu with common units with respect to distributions, and are convertible into common units upon approval of a majority of the common unitholders. If we request that PAA call a meeting of common unitholders to consider approval of the conversion of Class B units into common units and the approval is not obtained within 120 days, each Class B common unitholder will be entitled to receive distributions, on a per unit basis, equal to 110% of the amount of distributions paid on a common unit, with such distribution right increasing to 115% if such approval is not secured within 90 days after the end of the 120-day period. Except for the vote to approve the conversion, Class B common units have the same voting rights as the common units.

PAA s general partner is entitled to receive incentive distributions if the amount distributed with respect to any quarter exceeds levels specified in its partnership agreement (the MQD ). Generally the general partner is entitled, to 15% of amounts PAA distributes in excess of $0.450 per unit, 25% of the amounts PAA distributes in excess of $0.495 per unit and 50% of amounts PAA distributes in excess of $0.675 per unit.

Based on PAA s $0.5625 per unit distribution paid in the first quarter of 2004 ($2.25 per unit annualized), we would receive an annual distribution from PAA of approximately $32.6 million for 2004, including $4.1 million for our general partner distribution (including $2.9 million for the general partner incentive distribution).

Cash distributions on PAA s outstanding common units and Class B common units and the portion of the distributions representing an excess over the MQD for 2003, 2002 and 2001 were as follows:

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2003 | | 2002 | | 2001 | |
| | Distribution | Excess over MQD | Distribution | Excess over MQD | Distribution | Excess over MQD |
| First Quarter | $ 0.5375 | $ 0.0875 | $ 0.5250 | $ 0.0750 | $ 0.4750 | $ 0.0250 |
| Second Quarter | $ 0.5500 | $ 0.1000 | $ 0.5375 | $ 0.0875 | $ 0.5000 | $ 0.0500 |
| Third Quarter | $ 0.5500 | $ 0.1000 | $ 0.5375 | $ 0.0875 | $ 0.5125 | $ 0.0625 |
| Fourth Quarter | $ 0.5500 | $ 0.1000 | $ 0.5375 | $ 0.0875 | $ 0.5125 | $ 0.0625 |

*Financing Activities*

At December 31, 2003, $50.0 million was outstanding under the secured term loan facility. The term loan is repayable in twelve quarterly installments of $5.0 million each, that commenced on August 31, 2003 with a final maturity of May 31, 2006. Amounts outstanding under the term loan bear an annual interest rate, at our election, equal to either the Base Rate (as defined in the agreement) plus 1.5%, or LIBOR plus 3%. The term loan requires that we maintain $5.0 million on deposit in a debt service reserve account with one of the lending banks. Our average borrowing rate for 2003 was 4.3% (4.2% at December 31, 2003).

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To secure the term loan, we pledged 100% of the shares of stock of our subsidiaries, pledged 5.2 million of our PAA common units and delivered mortgages on Calumet s oil and gas properties. To the extent the outstanding principal under the term loan exceeds the balance in the debt service reserve account plus 50% of the fair market value of the pledged common units, we are required to repay the excess. The fair market value of the pledged units is determined based on the closing price of PAA common units as reported on the New York Stock Exchange.

The term loan contains covenants that limit our ability, as well as the ability of our subsidiaries, to incur additional debt, make investments, create liens, enter into leases, sell assets, change the nature of our business or operations, guarantee other indebtedness, enter into certain types of hedge agreements, enter into take-or-pay arrangements, merge or consolidate and enter into transactions with affiliates. In addition, if an event of default exists, the term loan prohibits us from paying dividends or repurchasing or redeeming shares of any class of capital stock. The term loan requires us to maintain a minimum consolidated tangible net worth (as defined) and a consolidated debt service coverage ratio (as defined in the agreement) of 1.0 to 1.0. At December 31, 2003, we were in compliance with the covenants contained in the term loan facility.

*Cash Flows from Continuing Operations*

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | | (in millions) | |
| Cash provided by (used in): | | | |
| Operating activities | $ 27.0 | $ 7.6 | $ 3.3 |
| Investing activities | (5.4) | (7.3) | 96.5 |
| Financing activities | (25.9) | (235.4) | (90.7) |

*Operating Activities*. Net cash provided by operating activities in 2003 totaled $27.0 million compared to $7.6 million in 2002. The increase primarily reflects the absence of debt extinguishment costs in 2003 and the negative effect in 2002 of the decrease in current liabilities reflecting the payment of costs incurred in prior periods. Net cash provided by operating activities in 2002 totaled $7.6 million compared to $3.3 million in 2001. The net increase is primarily attributable to higher realized oil prices and increased sales volumes.

*Investing Activities*. In 2003 net cash used in investing activities totaled $5.4 million. Additions to oil and gas properties and equipment used $3.1 million in cash, and we made capital contributions to PAA of $2.3 million to maintain our proportionate general partner share interest as a result of equity offerings by PAA. In 2002 net cash used in investing activities totaled $7.3 million. Additions to oil and gas properties and equipment used $5.9 million in cash, and we made capital contributions to PAA of $1.3 million to maintain our proportionate general partner share interest as a result of equity offerings by PAA. In 2001 net cash provided by investing activities was $96.5 million. Additions to oil and gas properties and equipment used $6.0 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. These uses of cash were offset by $106.9 million in cash proceeds received as a result of our June 2001 strategic restructuring.

*Financing activities*. Cash used in financing activities in 2003 included a net increase in long-term debt of $5.0 million, $2.8 million in proceeds from issuances of our common stock, $23.3 million to retire our outstanding Series D preferred stock, $9.0 million in treasury stock purchases and $0.6 million in preferred stock dividends. Cash used in financing activities in 2002 included a net reduction in long-term debt of $234.0 million, $5.2 million in proceeds from issuances of our common stock, and $1.4 million in preferred stock dividends. Cash used in financing activities in 2001 included a net

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reduction in long-term debt of $23.4 million, expenditures of $67.7 million for our repurchase of 2.8 million shares of our common stock, $9.2 million in proceeds from issuances of our common stock, and $8.7 million in preferred stock dividends.

*Capital Expenditures*

We have made and will continue to make capital expenditures with respect to our oil properties. We intend to make aggregate capital expenditures of approximately $3.5 million in 2004 for exploitation of our existing properties. These expenditures will be funded with cash from operations and PAA distributions.

When PAA issues equity, the general partner is required to contribute cash to maintain its 2% general partner interest. In 2003 PAA issued units in public equity offerings and we were required to make cash capital contributions to the general partner of PAA totaling $2.3 million for our 44% interest in the general partner. If PAA issues equity in the future, we will be required to make additional cash capital contributions.

Our Board of Directors has authorized the repurchase of up to eight million shares of our common stock. Through December 31, 2003, we had repurchased a total of 4.9 million shares at a total cost of approximately $100.4 million.

*Contractual Obligations*

At December 31, 2003, the aggregate amounts of contractually obligated payment commitments for the next five years are as follows (in thousands):

| | 2004 | 2005 | 2006 | 2007 | 2008 | Total |
|---|---|---|---|---|---|---|
| Long-term debt | $ 20,000 | $ 20,000 | $ 10,000 | $ | $ | $ 50,000 |
| Operating leases | 23 | 23 | 6 | | | 52 |
| | $ 20,023 | $ 20,023 | $ 10,006 | $ | $ | $ 50,052 |

Of such amounts, $20.0 million is due in less than one year and the total amount is due in one to three years.

**Commitments and Contingencies**

In connection with the reorganization and the spin-off we entered into certain agreements with PXP, including a master separation agreement; an intellectual property agreement; the Plains Exploration & Production transition services agreement; the Plains Resources transition services agreement; and a technical services agreement. See Items 1 and 2. Business and Properties Spin-off Agreements .

*Environmental Matters*. As discussed under Business & Properties Regulation Environmental. 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. Typically when producing oil and gas assets are purchased, one assumes the obligation to plug and abandon wells that are part of such assets. We have established policies for continuing compliance with environmental laws and regulations. Also, we maintain insurance coverage for environmental matters, which we believe is customary in the industry, but we are not fully insured against all environmental risks. 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.

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*Plugging, Abandonment and Remediation Obligations.* Consistent with normal industry practices, our oil and 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. Typically when producing oil and gas assets are purchased, one assumes the obligation to plug and abandon wells that are part of such assets. We have estimated that at December 31, 2003 the costs to perform these tasks will be approximately $8.1 million, net of salvage value.

*Operating risks and insurance coverage*. Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and gas, including well blowouts, cratering, explosions, spills of oil, gas or well fluids, fires, pollution and releases of toxic gas, each of which could result in damage to or destruction of oil and gas wells, production facilities or other property, or injury to persons. Although we maintain insurance coverage considered to be customary in the industry, we are not fully insured against all risks, 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.

*Other commitments and contingencies*. 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 oil and gas properties and the marketing, transportation, terminalling and storage of 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.

As discussed under Legal Proceedings , in the ordinary course of business, we are a claimant or defendant in various legal proceedings. In particular, we are a defendant in a number of lawsuits related to the sale of the Company. See Item 3. Legal Proceedings.

The previously reported lawsuit regarding the termination of an electric services contract with Commonwealth Energy Corporation was settled in January 2004 by Plains Exploration under its indemnity obligation to us. All claims of the lawsuit have been released.

*PAA s Commitments and Contingencies*

For a discussion of PAA s commitments and contingencies, we recommend you review PAA s Annual Report on Form 10-K for the year ended December 31, 2003, and other applicable SEC filings by PAA.

**Material Related Party Transactions**

*Governance of PAA*

We, along with Sable Investments, L.P. (which is owned by Mr. Flores, our Executive Chairman, and Mr. Raymond, our Chief Executive Officer), Kafu Holdings, L.P. (which is controlled by Kayne Anderson Capital Advisors, L.P. and Kayne Anderson Investment Management, Inc., of which Mr. Sinnott is Senior Vice President), and E-Holdings III, L.P. (which is controlled by EnCap Investments L.L.C. and of which Mr. Phillips is a managing director and principal) are parties to agreements governing Plains All American GP LLC, which is the general partner of Plains AAP, L.P., and Plains AAP, L.P., which is the general partner of PAA. These agreements govern the ongoing management of PAA.

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In addition, the general partner of PAA is owned as follows:

| | |
|---|---|
| Plains Resources | 44.00% |
| Sable Investments, L.P. | 20.00% |
| Kafu Holdings, L.P. | 16.42% |
| E-Holdings, L.P. | 9.00% |
| Others | 10.58% |
| | 100.00% |

Also, each of we, Sable Investments, Kafu Holdings, and E-Holdings may appoint one member of the Plains All American GP LLC board of directors. Under a Voting and Designation Agreement dated December 18, 2003, we have the right to direct Sable Investments to appoint the person we designate as director of Plains All American GP LLC.

*Our Relationship with PAA*

We have ongoing relationships with PAA, including:

- a marketing agreement that provides that PAA will purchase all of our equity oil production at market prices for a fee of $.20 per barrel. In 2003, PAA paid us $26.2 million for such equity production, including the royalty share of production, and we paid PAA $0.2 million in marketing fees;

- a separation agreement 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.

*Our Relationship with PXP*

In connection with the spin-off we entered into certain agreements with PXP, including a master separation agreement; an intellectual property agreement; the Plains Exploration & Production transition services agreement that expires June 16, 2004; the Plains Resources transition services agreement that expires June 8, 2004; and a technical services agreement that expires July 2005. For the year ended December 31, 2003, PXP billed us $0.5 million for services provided to us under these agreements and we billed PXP $0.1 million for services we provided under these agreements.

**Industry Concentration**

Financial instruments which potentially subject us to concentrations of credit risk consist principally of accounts receivable with respect to our oil 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.

There are a limited number of alternative methods of transportation for our production. Substantially all of our oil production is transported by pipelines, trucks and barges owned by third

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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 production which could have a negative impact on future results of operations or cash flows.

The contract counterparties for our derivative commodity contracts are all major financial institutions with Standard & Poor s ratings of A or better.

**Critical Accounting Policies and Factors That May Affect Future Results**

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

*Commodity pricing and risk management activities*. Prices for oil have historically been volatile. Decreases in oil 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 collars and purchased puts and calls. While the use of these types of hedging instruments limits our downside risk to adverse price movements, we 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 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 standardized measure (including, for this test only, the effect of any related hedging activities); plus
- the lower of cost or fair value of unproved properties not included in the costs being amortized (net of related tax effects).

These rules generally require that we price our future oil production at the 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 prices, it is likely that our estimate of discounted future net revenues from proved oil reserves will change in the near term. If oil prices decline in the future, even if only for a short period of time, write-downs of our oil and gas properties could occur. Write-downs required by these rules do not directly impact our cash flows from operating activities.

Based on the book value of our proved oil and gas properties (including related deferred income taxes) and our proved reserve reports as of December 31, 2003, we believe that we would have a write-down under the full cost ceiling test rules at a net realized price for our oil production of approximately $17.00 to $19.00 per barrel. Based on an estimated oil differential at December 31, 2003 of $11.75 per barrel, we would have a write-down at a NYMEX oil index price of $28.75 to $30.75 per barrel.

*Oil and gas reserves*. The proved reserve information included herein was based on estimates prepared by an outside engineering firm. Estimates prepared by others may be higher or lower than these estimates.

Estimates of proved reserves may be different from the actual quantities of oil and gas recovered because such estimates depend on many assumptions and are based on operating conditions and results at the time the estimate is made. The actual results of drilling and testing, as well as changes in production rates and recovery factors, can vary significantly from those assumed in the preparation of reserve estimates. As a result, such factors have historically, and can in the future, cause significant upward and downward revisions to proved reserve estimates.

You should not assume that the present value of future net cash flows is the current value of our estimated proved oil and gas reserves. In accordance with SEC requirements, we base the estimated discounted future net revenues 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.

All of our reserve base is comprised of oil properties that are sensitive to oil price volatility. Historically, we have experienced significant upward and downward revisions to our reserves volumes and values as a result of changes in year-end oil and gas prices and the corresponding adjustment to the projected economic life of such properties. Prices for oil and gas are likely to continue to be volatile, resulting in future downward and upward revisions to our reserve base.

Our rate of recording DD&A is dependent upon our estimate of proved reserves including future development and abandonment costs as well as our level of capital spending. If the estimates of proved reserves decline, the rate at which we record DD&A expense increases, reducing our net income. This decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields. The decline in proved reserve estimates may impact the outcome of the ceiling test discussed above. In addition, increases in costs required to develop our reserves would increase the rate at which we record DD&A expense. We are unable to predict changes in future development costs as such costs are dependent on the success of our exploitation and development program, as well as future economic conditions.

*PAA s Critical Accounting Policies.* For a discussion of PAA s critical accounting policies, we recommend you review PAA s Annual Report on Form 10-K for the year ended December 31, 2003, and other applicable SEC filings by PAA.

**Recent Accounting Pronouncements**

The Financial Accounting Standards Board (FASB) issued Financial Interpretation No. 46 (FIN 46), Consolidation of Variable Interest Entities in January 2003. FIN 46 addresses the consolidation of variable interest entities (VIEs) by business enterprises that are the primary beneficiaries. A VIE is an entity that does not have sufficient equity investment at risk to permit it to finance its activities without additional subordinated financial support, or whose equity investors lack the characteristics of a controlling financial interest. The primary beneficiary of a VIE is the enterprise that has the majority of the risks or rewards associated with the VIE. In December 2003, the FASB issued a revision to FIN 46, Interpretation No. 46R (FIN 46R), to clarify some of the provisions of FIN 46, and to exempt certain entities from its requirements. Application of FIN 46R is required in financial statements of public entities that have interests in structures that are commonly referred to as special-purpose entities for periods ending after December 15, 2003. Application for all other types of VIEs is required in financial statements for periods ending after March 15, 2004. We do not believe we participate in any arrangement that would be subject to the provisions of FIN 46R.

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**Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS**

We are exposed to various market risks, including volatility in 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.

We have entered into various derivative instruments to reduce our exposure to fluctuations in the market price of oil. The derivative instruments consist of oil swaps entered into with financial institutions. Derivative instruments are accounted for in accordance with SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities as amended, or 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. 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 our stockholders equity, to the extent the hedge is effective. Gains and losses on oil hedging instruments related to OCI and adjustments to carrying amounts on hedged volumes are included in oil revenues in the period that the related volumes are delivered.

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 at least 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.

In the first quarter of 2003, the NYMEX oil price and the price we received for our Florida oil production did not correlate closely enough for the hedges to qualify for hedge accounting. As a result, we were required to discontinue hedge accounting effective February 1, 2003 and reflect the mark-to-market value of the hedges in earnings prospectively from that date. In 2003, we recorded a $6.7 million loss on derivatives that consisted of a $4.3 million loss for the decrease in the fair value of our derivatives and a $2.4 million loss on cash settlements of such derivatives. In addition a $0.3 million loss on cash settlements for January 2003 is reflected as a reduction of revenues. None of our current hedges qualify for hedge accounting.

At December 31, 2003, Accumulated OCI consisted of unrealized losses of $0.3 million ($0.2 million, net of tax) on our oil hedging instruments generated prior to the discontinuation of hedge accounting, unrealized losses of $0.5 million ($0.3 million, net of tax) related to pension liabilities and an unrealized gain of $7.0 million ($3.9 million, net of tax) related to our equity in the OCI gains of PAA. At December 31, 2003, the liability related to our open oil derivative instruments was included in current liabilities ($2.8 million), other long-term liabilities ($1.8 million), and deferred income taxes (a tax benefit of $0.1 million).

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As of December 31, 2003, $0.3 million ($0.2 million, net of tax) of deferred net losses on our oil derivative instruments recorded in OCI are expected to be reclassified to earnings during the following twelve month period as the hedged volumes are produced and sold.

*Commodity Price Risk*. At February 29, 2004, we had the following open oil derivative positions:

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| Swaps | | | |
| Average price $25.01/bbl | 1,500 | | |
| Average price $24.70/bbl | | 1,000 | |
| Average price $24.43/bbl | | | 1,000 |

Assuming our fourth quarter 2003 production volumes are held constant in subsequent periods, these positions result in our hedging approximately 66%, 44% and 44% of oil production in 2004, 2005 and 2006, respectively. Location and quality differentials attributable to our properties are not included in the foregoing prices. Because of the quality and location of our oil production, these adjustments will reduce our net price per barrel.

The fair value of outstanding oil 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, | | | |
|---|---|---|---|---|
| | 2003 | | 2002 | |
| | Fair Value | Effect of 10% Price Decrease | Fair Value | Effect of 10% Price Decrease |
| Swaps and options contracts | $ (1.0) | $ 3.6 | $ (0.4) | $ 1.9 |

The fair value of the swaps is 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 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.

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 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. The contract counterparties for our current derivative commodity contracts are all major financial institutions with Standard & Poor s ratings of A or better.

*Interest Rate Risk.* Our debt instruments are sensitive to market fluctuations in interest rates. At December 31, 2003 we had $50.0 million outstanding under our credit facility, repayable $20.0 million in 2004, $20.0 million in 2005 and $10.0 million in 2006. Our credit facility bears interest at a base rate (as defined) or LIBOR plus the applicable margin (4.2% at December 31, 2003). The carrying value of our credit facility debt approximates fair value because interest rates are variable, based on prevailing market rates.

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## 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.

The financial statements, including the notes thereto, of PAA are incorporated herein by reference to pages F-1 through F-36 of PAA s Annual Report on Form 10-K for the year ended December 31, 2003 (as may be amended from time to time). The PAA financial statements were prepared by PAA.

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

None.

## Item 9A. CONTROLS AND PROCEDURES

Under the supervision and with the participation of our management, including our Chief Executive Officer (our principal executive officer) and our Chief Financial Officer (our principal financial officer), we evaluated the effectiveness of our disclosure controls and procedures (as defined under Rule 13a-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act )). Based on this evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures as of December 31, 2003 are effective to ensure that information we are required to disclose in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms.

During our fourth fiscal quarter ended December 31, 2003, there was no change in our internal control over financial reporting that has materially affected or is reasonably likely to materially affect our internal control over financial reporting.

# PART III

## Item 10. EXECUTIVE OFFICERS OF THE REGISTRANT

### Identification

Our directors and executive officers are identified and the business experience of each is given in Item 4 Submission of Matters to a Vote of Security Holders above.

**Board of Directors and Committees**

Plains board has established a Policy Concerning Corporate Ethics and Conflicts of Interest. This policy applies to all our employees, including our chief executive officer, chief financial officer and principal accounting officer. Any shareholder may request a copy of Plains Corporate Governance Guidelines and/or Policy Concerning Corporate Ethics and Conflicts of Interest, free of charge, by sending a request to Corporate Secretary, Plains Resources Inc., 700 Milam, Suite 3100, Houston, Texas 77002.

Plains non-management directors intend to meet periodically in executive session. There is not one single non-management director who has been chosen to preside over executive sessions of Plains board of directors.

Plains board has established an audit committee, an organization and compensation committee and a nominating and corporate governance committee. Plains board may establish other committees

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from time to time to facilitate Plains management. During 2003 Plains board held five meetings. No director attended fewer than 75% of the total number of meetings of the meetings of Plains board and committees on which he served.

Plains audit committee currently consists of Messrs. O Malley, Hitchcock, Phillips, Sinnott and Symonds, with Mr. O Malley acting as chairman. Plains audit committee selects Plains independent auditors to be engaged by Plains, reviews the plan, scope and results of Plains annual audit and discusses with the independent auditor any significant matters regarding internal controls over financial reporting that have come to their attention during the audit. Plains audit committee has adopted a written audit committee charter. The Audit Committee s charter, as amended, was attached to the Company s 2003 proxy statement. During 2003, Plains audit committee held six meetings. All of the members of Plains audit committee are non-employee directors. Plains board of directors, in its business judgment, has determined that all current members of Plains audit committee are independent as defined in the NYSE governance rules (and Item 7(d)(3)(iv) of Schedule 14A under the Exchange Act) and are financially literate in compliance with the NYSE listing standards as the Plains board of directors interprets that designation. In addition, the Plains board of directors has determined that Mr. O Malley is an audit committee financial expert as defined in Item 401(h)(2) of Regulation S-K. In making its determination, the board recognized Mr. O Malley s experience in public accounting and as a chief executive officer directly supervising the principal financial officer.

Plains organization and compensation committee currently consists of Messrs. Hitchcock, O Malley and Symonds, with Mr. Hitchcock acting as chairman. Plains organization and compensation committee reviews and sets the chief executive officer s compensation, establishes guidelines and standards relating to the determination of executive compensation, reviews executive compensation policies and recommends to Plains entire board compensation for Plains executive officers other than the chief executive officer and key employees. Plains organization and compensation committee also administers Plains equity compensation plan and determines the number of shares covered by, and terms of, grants to executive officers and key employees. All of the members of Plains compensation committee are non-employee directors. During 2003, Plains organizational and compensation committee held two meetings.

Plains nominating and corporate governance committee currently consists of Messrs. Sinnott, O Malley, Hitchcock, Phillips, and Symonds, with Mr. Sinnott acting as chairman. Plains nominating and corporate governance committee identifies and evaluates candidates for election as directors, nominates the slate of directors for election by Plains stockholders, and develops and recommends to Plains board Plains corporate governance principles. During 2003, Plains nominating and corporate governance committee held no meetings.

**Section 16(A) Beneficial Ownership Reporting Compliance**

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires the Company s directors and executive officers, and persons who own more than ten percent of a registered class of Plains equity securities, to file with the SEC and any exchange or other system on which such securities are traded or quoted, initial reports of ownership and reports of changes in ownership of Plains common stock and other equity securities. Officers, directors and greater than ten percent stockholders are required by the SEC s regulations to furnish Plains with copies of all Section 16(a) forms they filed with the SEC.

To the Company s knowledge, based solely on a review of the copies of such reports furnished to Plains and written representations that no other reports were required, the Company believes that all reporting obligations of the Company s officers, directors and greater than ten percent stockholders under Section 16(a) were satisfied during the first six months of the year ended December 31, 2003,

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except that (i) a Form 4 covering one transaction for the grant of restricted stock units related to 15,000 shares of the Company s common stock to Franklin R. Bay was filed late, (ii) two Forms 4 covering one transaction each for the grant of common stock in accordance with a 2001 agreement and for the grant of restricted stock units related to 20,000 shares of the Company s common stock to James C. Flores were filed late, (iii) a Form 4 covering one transaction for the exercise of a stock option by William M. Hitchcock was filed late, (iv) two Forms 4 covering one transaction each for the acquisition of 163 and 155 shares, respectively, of the Company s common stock in lieu of director s fees by William C. O Malley were filed late; (v) a Form 4 covering one transaction for the grant of restricted stock units related to 10,000 shares of the Company s common stock to D. Martin Phillips was filed late; (vi) a Form 4 covering one transaction for the grant of restricted stock units related to 40,000 shares of the Company s common stock to John T. Raymond was filed late, (vi) three Forms 4 covering one transaction each for the acquisition of 375, 172 and 338 shares, respectively, of the Company s common stock in lieu of director s fees by Robert V. Sinnott were filed late, and (vii) a Form 4 covering one transaction for the grant of restricted stock units related to 20,000 shares of the Company s common stock to Stephen A. Thorington was filed late. No forms were filed late after June 12, 2003.

**Item 11. EXECUTIVE COMPENSATION**

**Summary Compensation Table**

The following table shows certain compensation information for our chief executive officer and the two highly compensated executive officers whose 2003 salary and bonus exceeded $100,000, or named executive officers, for services rendered in all capacities during the fiscal years ended December 31, 2003, 2002 and 2001.

| | | | | Long Term Compensation | | | |
|---|---|---|---|---|---|---|---|
| | | | | Awards | | Payouts | |
| | | Annual Compensation | | | | | |
| Name and Principal Position | Year | Salary ($) | Bonus ($) | Restricted Stock Award(s) ($)(2) | Securities Underlying Options/ SARs (#) | LTIP Payouts ($) | All Other Compensation ($)(3) |
| James C. Flores | 2003 | 100,000 | 50,000(4) | 210,000(5) | 0 | 0 | 0 |
| Chairman of the Board(1) | 2002 | 4,167 | 100,000 | 750,600(6) | 475,000 | 0 | 11,000 |
| | 2001 | 0 | 325,000 | | 1,000,000(7) | 0 | 0 |
| John T. Raymond | 2003 | 150,000 | 75,000(4) | 420,000(5) | 0 | 0 | 0 |
| President and Chief | 2002 | 389,584 | 150,000 | 938,250(9) | 425,000 | 0 | 11,000 |
| Executive Officer(8) | 2001 | 187,500 | 788,000 | 0 | 300,000 | 0 | 0 |
| Stephen A. Thorington | 2003 | 100,000 | 50,000(4) | 210,000(5) | 0 | | 0 |
| Executive Vice President and | 2002 | 91,667 | 33,333 | 1,059,750(11) | 0 | 0 | 0 |
| Chief Financial Officer(10) | | | | | | | |

(1) Mr. Flores joined us as Chairman of the Board and Chief Executive Officer in May 2001 and became Executive Chairman of the Board in December 2002.

(2)

These dollar amounts represent the closing price of a share of our common stock on the restricted stock or restricted stock unit grant date as reported on the New York Stock Exchange multiplied by the number of restricted shares or units granted on such date.

(3) We match 100% of an employee s contribution to our 401(k) plan, subject to certain limitations in the plan, with matching contributions being made (i) before October 1, 2002, 50% in cash and 50% in our common stock (the number of shares for the stock match being based on the market value of our common stock at the time the shares are issued), and (ii) starting on October 1, 2002, 100% in cash.

(4) An additional bonus equal to this amount was awarded and was deferred until after the resolution of any open issues relating to the sale of the Company.

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(5) These amounts represent an award of restricted stock units on March 12, 2003 under our 2001 Stock Incentive Plan (calculated as described in footnote 2 above). The award vests on the third anniversary of the grant date, provided that if the closing price of shares of our common stocks equals or exceeds 150% of the of the shares on the grant date ($12.50), then the award will vest 18 months after the grant date.

(6) This was a restricted stock award under our 2001 Stock Incentive Plan. The fair market value at the time of the award was $750,600 (calculated as described in footnote 2 above). The fair market value of this award as of December 31, 2002 (calculated by multiplying the closing price per share of our common stock on December 31, 2002 as reported on the NYSE by the number of restricted shares) was $711,000. The award vests in three equal, annual installments beginning on December 19, 2003. Dividends will be paid on the shares covered by the award and will be held in custody by us until the restricted shares vest.

(7) Pursuant to Mr. Flores original employment agreement with us, we granted Mr. Flores a number of shares of our common stock with a value equal to $1 million. This grant is payable in five equal installments as of each anniversary of May 8, 2001, which is the date of his original employment agreement, in the form of a direct grant of shares of our common stock, the number of which will equal the annual dollar payment amount ($200,000) divided by the fair market value of a share on the applicable anniversary date. The first two installments of this grant were paid on May 8, 2002 and 2003 in the amount of 7,407 shares and 16,625 shares, respectively, of our common stock.

(8) Mr. Raymond joined us in May 2001 and became Chief Executive Officer in December 2002.

(9) This was a restricted stock award under our 2001 Stock Incentive Plan. The fair market value at the time of the award was $938,250 (calculated as described in footnote 2 above). The fair market value of this award as of December 31, 2002 (calculated by multiplying the closing price per share of our common stock on December 31, 2002 as reported on the NYSE by the number of restricted shares) was $888,750. The award vests in three equal, annual installments beginning on December 19, 2003. Dividends will be paid on the shares covered by the award and will be held in custody by us until the restricted shares vest.

(10) Mr. Thorington joined us in December 2002.

(11) This was a restricted stock award under our 2001 Stock Incentive Plan. The fair market value at the time of the award was $1,059,750 (calculated as described in footnote 2 above). The fair market value of this award as of December 31, 2002 (calculated by multiplying the closing price per share of our common stock on December 31, 2002 as reported on the NYSE by the number of restricted shares) was $533,250. The award vests in three equal, annual installments beginning on September 3, 2003. Dividends will be paid on the shares covered by the award and will be held in custody by us until the restricted shares vest.

**Option Grants in 2003**

There were no stock options or stock appreciation rights granted to any named executive officer.

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**Aggregated Option Exercises in 2003 and Year-End Option Values**

The following table sets forth certain information for each named executive officer concerning option exercises during 2003 and all unexercised options held at December 31, 2003.

| Name | Shares Acquired on Exercise (#) | Value Realized ($) |
|---|---|---|