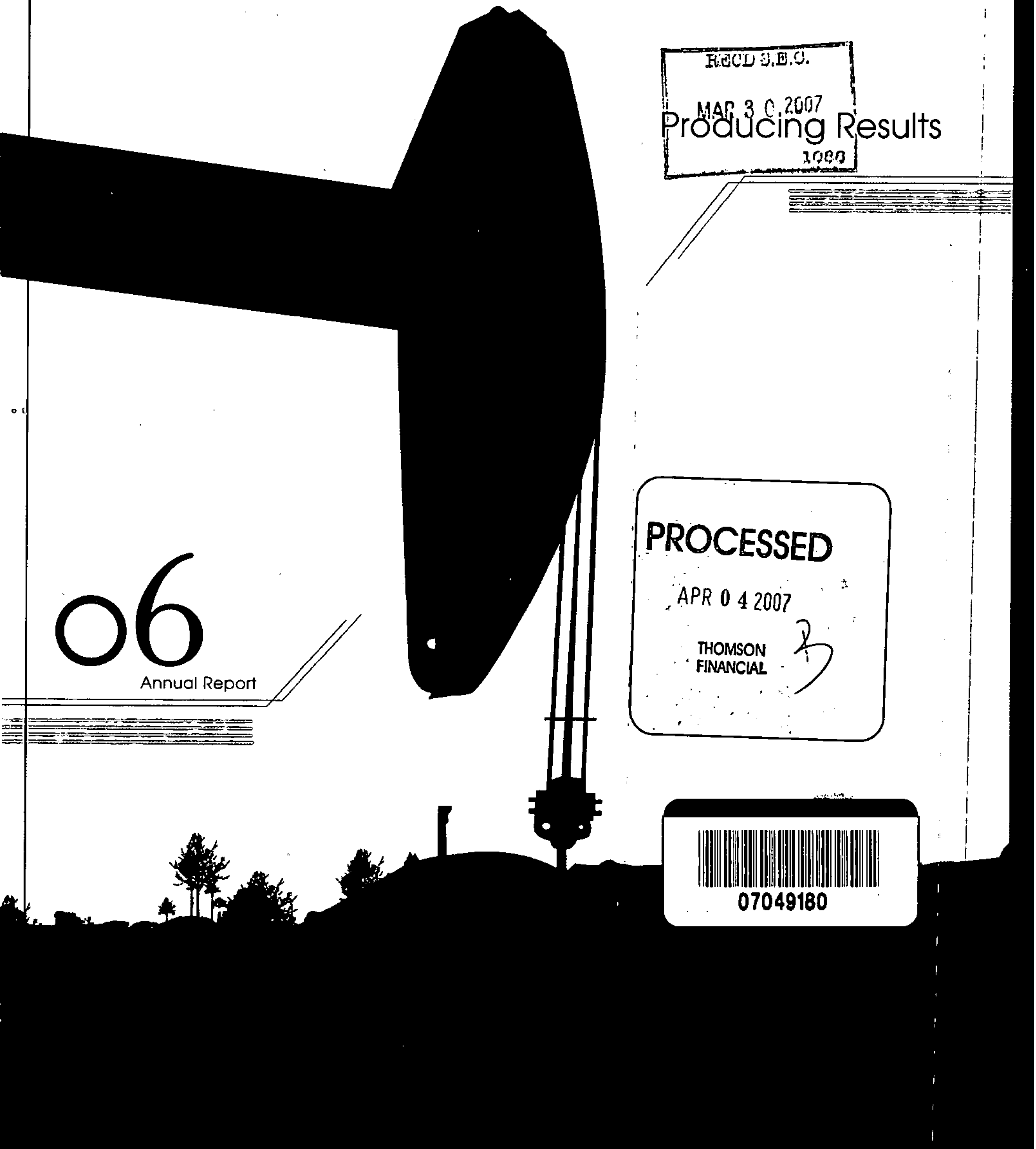
PXP

Plains Exploration & Production Company



Producing Results

06
Annual Report

OUR COMPANY

PXP is an independent oil and gas company primarily engaged in the activities of acquiring, developing, exploiting, exploring and producing oil and gas properties in the United States. We own oil and gas properties with principal operations in the Los Angeles, San Joaquin and Santa Maria Basins onshore and offshore California; and the Gulf Coast Basin onshore and offshore Louisiana, including the Gulf of Mexico. Assets in our principal focus areas include mature properties with long-lived reserves and significant development and exploitation opportunities as well as newer properties with development, exploitation and exploration potential.

FINANCIAL HIGHLIGHTS

(in thousands, except per share & percentage information)	2006	2005	2004 (1)	2003 (2)	2002
RESERVE DATA:					
Total oil reserves (barrels)	333,217	356,333	351,403	227,728	240,161
Total gas reserves (Mcf)	110,922	267,921	407,400	319,177	77,154
Total barrels of oil equivalent (BOE)	351,704	400,987	419,303	280,924	253,020
Percentage proved developed volume	52%	67%	68%	58%	54%
Estimated future net cash flows	$ 5,652,412	$ 6,772,811	$ 4,651,720	$ 3,040,267	$ 2,413,211
Standardized measure	$ 2,510,663	$ 3,082,166	$ 2,236,719	$ 1,256,803	$ 883,507
Percentage proved developed present value	68%	77%	79%	71%	60%
OPERATING DATA:					
Oil production (barrels)	18,975	18,671	16,441	9,267	8,783
Average oil price (per barrel) (3)	$ 55.62	$ 46.76	$ 36.12	$ 26.92	$ 22.04
Gas production (Mcf)	20,629	29,359	38,590	18,195	3,362
Average gas price (per Mcf) (3)	$ 6.73	$ 7.15	$ 5.90	$ 5.01	$ 3.06
BOE production	22,413	23,564	22,872	12,300	9,343
Average BOE price	$ 53.76	$ 45.96	$ 35.92	$ 27.69	$ 21.83
Production expense per BOE	$ 14.49	$ 12.10	$ 9.76	$ 8.52	$ 8.40
SELECTED FINANCIAL DATA:					
Total revenue	$ 1,018,503	$ 944,420	$ 671,706	$ 304,090	$ 188,563
Operating income	$ 1,348,450	$ 343,700	$ 208,599	$ 103,629	$ 64,567
Income (loss) before cumulative effect of accounting change	$ 599,710	$ (214,012)	$ 8,840	$ 47,087	$ 26,237
Cumulative effect of accounting change, net of tax	$ (2,182)	-	-	$ 12,324	-
Net income (loss)	$ 597,528	$ (214,012)	$ 8,840	$ 59,411	$ 26,237
Income (loss) per share					
Before cumulative effect of accounting change	$ 7.67	$ (2.75)	$ 0.14	$ 1.41	$ 1.08
Cumulative effect of accounting change	$ (0.03)	-	-	$ 0.37	-
Net income (loss)	$ 7.64	$ (2.75)	$ 0.14	$ 1.78	$ 1.08
Weighted average shares outstanding					
Basic	77,273	77,726	63,542	33,321	24,193
Diluted	78,234	77,726	64,014	33,469	24,201
Total assets	$ 2,463,228	$ 2,741,942	$ 2,633,245	$ 1,212,268	$ 561,023
Long-term debt	$ 235,500	$ 797,375	$ 635,468	$ 487,906	$ 233,166
Total shareholders' equity	$ 1,130,683	$ 718,337	$ 870,375	$ 354,256	$ 173,820

(1) Reflects the acquisition of Nuevo Energy Company effective May 14, 2004.
(2) Reflects the acquisition of 3TEC Energy Corporation effective June 1, 2003.
(3) Average realized sales price before derivative transactions.

TO OUR SHAREHOLDERS

PXP completed another dynamic and successful year in which our accomplishments resulted in substantially improved operational and financial results. Operationally our exploration program in the Gulf of Mexico yielded three significant discoveries, and we realized $1.6 billion in asset sales. Financially we reported substantially improved net income and net cash flow provided by operating activities, we strengthened our balance sheet and we repurchased 6.6 million common shares.

PXP's 2006 accomplishments were recognized by the market. We ended the year with a closing stock price of $47.53 per share which is the highest year-end stock price in the Company's history. Shareholders realized a 19.6% total return and we outperformed our peer group by over 20% and the S&P MidCap 400 Index by over 9%. Since becoming a public company in 2002, PXP's total return to shareholders has been 422%.

Our long-term value creation strategy to accelerate per-share growth is established and momentum is building. Our strategy is balanced to optimize the value of our long-lived California legacy oil fields and to build on our exploration successes in the Gulf of Mexico while pursuing additional high-impact opportunities. Our talented and dedicated employees are energized; the new management team is aligned and focused.

OPERATIONAL PERFORMANCE

During the year we received numerous operating and safety excellence awards in California and produced 22.4 million barrels of oil equivalent. At year end our production volume was approximately 55.4 thousand barrels of oil equivalent per day, and our proved reserves were 352 million barrels of oil equivalent. While we are pleased with our operational performance overall, 2006 was challenging. During the year, leadership changes were implemented followed by a company reorganization from independent business units to functional reporting throughout the Company. We look for improved performance going forward.

Capital expenditures totaled $648 million for 2006 compared to $581 million in 2005. The increase is primarily attributed to additional exploratory opportunities in the Gulf of Mexico. Approximately $321 million of 2006 spending supported exploration activities including investments in seismic data and Gulf of Mexico lease blocks.

EXPLORATION

During 2006, our exploration investment in Gulf of Mexico lower/middle Miocene trend prospects yielded three discoveries: the Big Foot Prospect, the Caesar Prospect, and the Friesian Prospect. Two of the discoveries, Big Foot and Caesar were sold in November for $706 million. We announced the Friesian discovery in November 2006 and it is awaiting development and further delineation drilling.

The Company's Gulf of Mexico exploration inventory is substantial and now includes up to 30 high-impact prospects in various water depths. Building on the 2006 exploration success in the Gulf of Mexico Miocene trend, PXP intends to continue focusing its exploration expertise by being active in this trend during 2007.

DEVELOPMENT

PXP controls a large California oil resource base characterized by long-lived reserves and a strong development profile. We concentrate on development projects in these legacy oil fields located in the Los Angeles, San Joaquin, and Santa Maria Basins onshore and offshore California because these projects produce solid economic returns, provide repeatable reserve additions, and generate substantial cash flow per share.

During 2006, activity in each of the existing core California asset areas remained high. Offshore California at our Point Arguello Unit and at our Point Pedernales Field, we drilled the remaining development wells at the Rocky Point project and the scheduled in-fill wells at Point Pedernales. Going forward much of the activity on these assets will concentrate on maintaining production through well workovers and recompletions.

Onshore California in the San Joaquin Valley, we focused on steamflood and horizontal-well development. In the Los Angeles Basin we focused on the Inglewood Field, developing both the shallow as well as the deeper productive zones through primary recovery and waterflood activities. Late in the year we began drilling new wells in the Arroyo Grande Field, which is primarily under continuous steam injection. With over 2,500 drill locations identified in the San Joaquin Valley, the Arroyo Grande Field, and the Los Angeles Basin, these asset areas show promise for sustainable multi-year drilling programs providing future reserves and production.

ASSET RATIONALIZATION

Always conscious of market conditions, asset net present values, operating efficiencies and costs, we regularly scrutinize our asset portfolio for opportunities to capture value on assets with limited strategic value. In addition to the $706 million deepwater property sale, we sold 43 million proven barrels of oil equivalent reserves located in California and Texas for $864 million. The proceeds from the two sales totaled $1.6 billion and were used to strengthen the balance sheet and to repurchase PXP common shares. Following the sale PXP's operations are concentrated in California and the Gulf Coast region.

ADDITIONAL HIGH-IMPACT PROJECTS

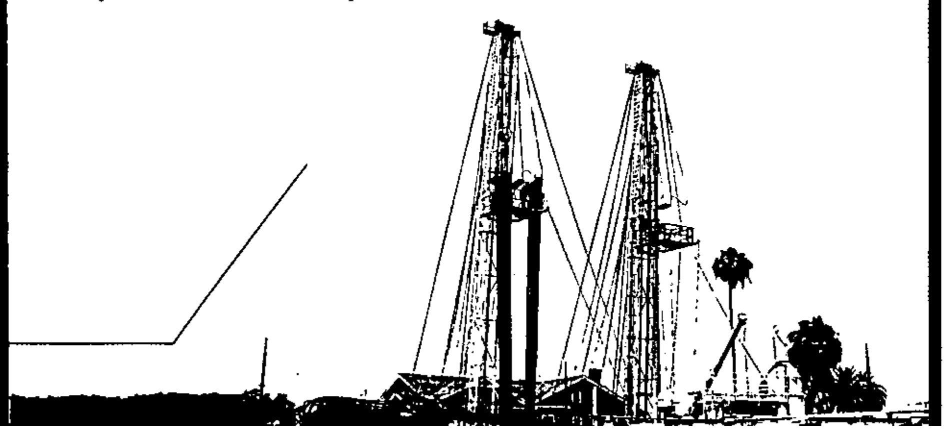
PXP has other potentially high-impact projects that it is actively pursuing. The Eagle Project is a large natural gas prospect in the Green River Basin in Wyoming. This project is currently in the permitting phase and initial drilling is expected in 2008. The second is PXP's California surface real estate monetization opportunity. This is a multi-year project involving surface real estate in the Los Angeles, Santa Barbara, and San Luis Obispo counties of Southern California. The project is currently in the permitting phase with initial results anticipated late 2008.

FINANCIAL PERFORMANCE

The year 2006 will be remembered by continued global uncertainty regarding commodity supply and demand fundamentals resulting in high commodity prices and an active acquisition and divestiture market. These two macro trends presented numerous opportunities, and we were successful in both identifying and leveraging them for the long-term benefit of the Company and shareholders.

PXP's net income for the period was $598 million compared to a net loss of $214 million in 2005. Net income for 2006 benefited from high commodity prices and includes a $983 million pre-tax gain on the sale of oil and gas properties and a $298 million pre-tax loss on mark-to-market derivative contracts.

Net cash provided by operating activities during the year increased 46% to $675 million compared to $463 million provided in 2005. The improvement in cash flow was driven by higher commodity prices and a substantially improved crude oil derivative position.



2006 ACCOMPLISHMENTS SET PACE FOR 2007

« Reported net income of $598 million compared to a $214 million loss

« Increased net cash provided by operating activities by 46%

« Repurchased 6.6 million common shares

« Announced three GOM deepwater Miocene discoveries

« Expanded the exploration prospect portfolio in the GOM Miocene trend

« Generated proceeds of $1.6 billion from two asset sales

« Reduced long-term debt by $562 million and closed out $600 million of hedge liabilities

« Received numerous operating and safety excellence awards in California

« Announced key promotions: **Doss R. Bourgeois** to Executive Vice President — Exploration & Production and **Winston M. Talbert** to Executive Vice President and Chief Financial Officer.

« Retained and hired diverse, talented employees in a highly competitive market

We ended the year with improved capitalization and liquidity. As part of the repositioning and organization of PXP, we executed a strategy to return value created in the deepwater and through previous acquisitions back to PXP shareholders. This value was returned through the repurchase and redemption of all of its outstanding public debt, thereby allowing the Company to repurchase a meaningful amount of its public stock. In addition, PXP also closed out its underwater collar positions which had created substantial mark-to-market losses for the Company throughout 2005 and 2006. The net result, the Company closed out $600 million of hedge liabilities, reduced long-term debt by $562 million and repurchased $300 million of PXP stock or roughly 6.6 million of its common shares outstanding. PXP has approximately $200 million remaining under the original $500 million authorization granted in December 2005.

PXP's strong balance sheet enhances our financial flexibility to seek investment opportunities with long-term benefits for its shareholders and to opportunistically purchase PXP common shares.

POSITIONED FOR ACCELERATED PER SHARE GROWTH

- « Large California oil resource base to develop
- « Up to 30 Gulf of Mexico Miocene trend prospects to explore
- « Strong balance sheet with year-end debt to capitalization of 17%
- « Substantial oil price downside protection

LOOKING AHEAD

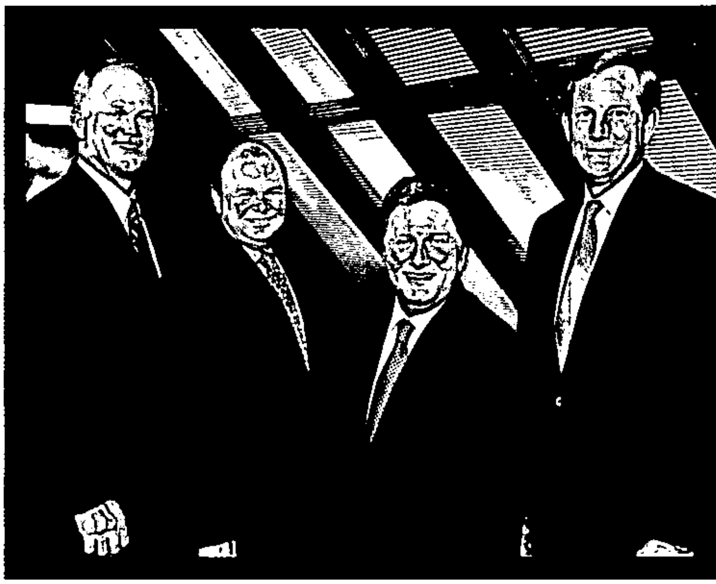
PXP produced value-added progress in 2006, and expects to continue to build momentum as we execute our long-term plan. Our 2007 capital budget is estimated to be $600 million.

As part of our balanced approach to creating shareholder value, approximately 50% of the 2007 capital budget supports continued development of the Company's legacy California oil fields with the remaining dedicated to high impact exploration projects, primarily targeting the Miocene trend in the Gulf of Mexico. We are committed to disciplined execution of our capital program, and because we do not have multi-year financial exploration commitments we have the flexibility to adjust spending as needed to respond to broader market conditions.

Moving into 2007, we enter another exciting chapter in our history. The Company is poised with significant financial flexibility, a large exploration and development project inventory, and a team of talented individuals dedicated to achieving results. I want to thank you for your continued support of PXP, and I look forward to sharing the rewards with you in the coming years.

JAMES C. FLORES
Chairman, President and
Chief Executive Officer

PXP EXECUTIVE MANAGEMENT



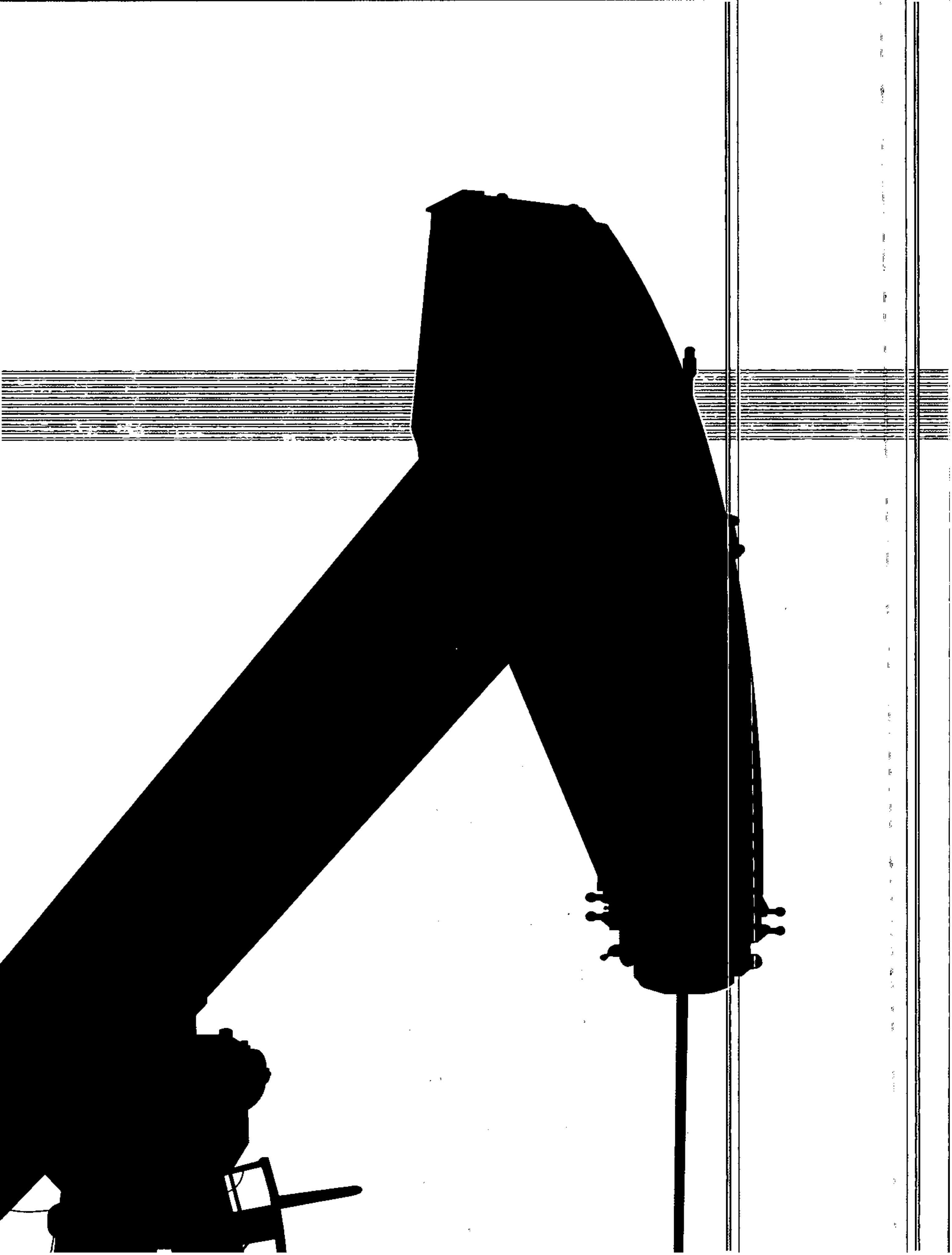
(from left to right)

Doss R. Bourgeois, Executive Vice President — Exploration & Production

Winston M. Talbert, Executive Vice President and Chief Financial Officer

James C. Flores, Chairman, President and Chief Executive Officer

John F. Wombwell, Executive Vice President and General Counsel



PXP FORM 10-K

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2006

OR

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

Commission file number: 001-31470

PLAINS EXPLORATION & PRODUCTION COMPANY

(Exact name of registrant as specified in its charter)

Delaware	**33-0430755**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

700 Milam Street, Suite 3100
Houston, Texas 77002
(Address of principal executive offices)
(Zip Code)

(713) 579-6000
(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 $0.01 per share	**New York Stock Exchange**

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐

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

On January 31, 2007, there were 72.4 million shares of the registrant's Common Stock outstanding. 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 $2.9 billion on June 30, 2006 (based on $40.54 per share, the last sale price of the Common Stock as reported on the New York Stock Exchange on such date).

DOCUMENTS INCORPORATED BY REFERENCE: The information required in Part III of the Annual Report on Form 10-K is incorporated by reference to the registrant's definitive proxy statement to be filed pursuant to Regulation 14A for the registrant's 2007 Annual Meeting of Stockholders.

PLAINS EXPLORATION & PRODUCTION COMPANY
2006 ANNUAL REPORT ON FORM 10-K

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STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K includes forward-looking information regarding Plains Exploration & Production Company that is intended to be covered by the safe harbor for "forward-looking statements" provided by the Private Securities Litigation Reform Act of 1995. 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", and similar expressions, are forward-looking statements. Although we believe that our expectations are based on reasonable assumptions, there are risks, uncertainties and other factors that could cause actual results to be materially different from those in the forward-looking statements. These factors include, among other things:

- 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, including the impact on our reserve volumes and values and our earnings as a result of our derivative positions;
- 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;
- the success of our derivative activities;
- the success of our risk management activities;
- unexpected difficulties in integrating our operations as a result of any significant acquisitions;
- the effects of competition;
- 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 reliance on these statements without also considering the risks and uncertainties associated with these statements and our business that are discussed in this report and our other filings with the SEC. Moreover, 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 for any obligation to disclose material information under the Federal securities laws, we do not intend to update these forward-looking statements and information. See Item 1A – "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 100 F Street, NE, Room 1580 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 website at *www.sec.gov*. No information from the SEC's website is incorporated by reference herein. Our website is *www.plainsxp.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 website. These documents are posted to our website as soon as reasonably practicable after we have filed or furnished these documents with the SEC. We have placed on our website copies of our Corporate Governance Guidelines, charters of our Audit, Organization & Compensation and Nominating & Corporate Governance Committees, and our Policy Concerning Corporate Ethics and Conflicts of Interest. We intend to post amendments to and waivers of our Policy Concerning Corporate Ethics and Conflicts of Interest (to the extent applicable to our principal executive officer, our principal financial officer and our principal accounting officer) at this location on our website. Stockholders may request a printed copy of these governance materials by writing to the Corporate Secretary, Plains Exploration & Production Company, 700 Milam, Suite 3100, Houston, TX 77002. No information from our website is incorporated by reference herein.

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 document:

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 barrels at a ratio of 6 Mcf to 1 Bbl of oil.

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 or gas from an established spot market price to reflect differences in the quality and/or location of oil or gas.

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.

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

MBOE. One thousand BOE.

Mcf. One thousand cubic feet of gas.

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

MMBOE. One million BOE.

MMBtu. One million British thermal units. One British thermal unit is the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

MMcf. One million cubic feet of gas.

Oil. Crude oil, condensate and natural gas liquids.

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

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

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 natural 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 natural gas liquids, that may occur in undrilled prospects; and (iv) oil, gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

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 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 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.

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

Reserve additions. Changes in proved reserves due to revisions of previous estimates, extensions, discoveries, improved recovery and other additions and purchases of reserves in-place.

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 volumes.

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.

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.

The terms "development well", "exploratory well", "proved developed reserves", "proved reserves" and "proved undeveloped reserves" are defined by the SEC. References herein to "Plains Exploration", "PXP", the "Company", "we", "us" and "our" mean Plains Exploration & Production Company.

PART I

Items 1 and 2. *Business and Properties*

General

We are an independent oil and gas company primarily engaged in the activities of acquiring, developing, exploiting, exploring and producing oil and gas properties in the United States. Our core areas of operations are:

- the Los Angeles and San Joaquin Basins onshore California;
- the Santa Maria Basin offshore California; and
- the Gulf Coast Basin onshore and offshore Louisiana, including the Gulf of Mexico.

Assets in our principal focus areas include mature properties with long-lived reserves and significant development and exploitation opportunities as well as newer properties with development, exploitation and exploration potential. We use derivative contracts to manage our exposure to commodity price risk.

Prior to December 18, 2002 we were a wholly owned subsidiary of Plains Resources Inc. ("Plains Resources"). On December 18, 2002 Plains Resources distributed 100% of the issued and outstanding shares of our common stock to the holders of record of Plains Resources' common stock as of December 11, 2002. Each Plains Resources stockholder received one share of our common stock for each share of Plains Resources common stock held.

Oil and Gas Reserves

As of December 31, 2006 we had estimated proved reserves of 351.7 MMBOE, of which 95% was comprised of oil and 52% was proved developed. Approximately 99% of our proved reserves are located onshore and offshore California. We have a total proved reserve life of approximately 17 years and a proved developed reserve life of approximately 9 years. We believe our long-lived, low production decline reserve base combined with our active risk management program should provide us with relatively stable and recurring cash flow. As of December 31, 2006 and based on year-end 2006 spot market prices of $61.05 per Bbl of oil and $6.30 per MMBtu of gas, as adjusted for area and quality differentials, our reserves had a standardized measure of $2.5 billion.

The following table sets forth certain information with respect to our reserves 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 SEC, which requires the application of year-end prices for each year, held constant throughout the projected reserve life.

	As of December 31,		
	2006	2005	2004
	(dollars in thousands)		
Oil and Gas Reserves			
Oil (MBbls)			
Proved developed	171,646	234,638	233,707
Proved undeveloped	161,571	121,695	117,696
	333,217	356,333	351,403
Gas (MMcf)			
Proved developed	62,021	193,904	305,009
Proved undeveloped	48,901	74,017	102,391
	110,922	267,921	407,400
MBOE	351,704	400,987	419,303
Standardized Measure (1)	$2,510,663	$3,082,166	$2,236,719
Average year-end realized prices (2)			
Oil (per Bbl)	$ 50.81	$ 51.40	$ 30.91
Gas (per Mcf)	$ 6.14	$ 8.02	$ 5.93
Year-end NYMEX prices			
Oil (per Bbl)	$ 61.05	$ 61.04	$ 43.45
Gas (per Mcf)	$ 6.30	$ 11.23	$ 6.15
Reserve life (years) (3)	17.3	17.3	16.3

(1) Our year-end 2006 standardized measure includes future development costs related to proved undeveloped reserves of $163 million in 2007, $194 million in 2008 and $137 million in 2009.

(2) Based on prices in effect at year-end with adjustments based on location and quality. The market price for California crude oil differs from the established market indices due primarily to the higher transportation and refining costs associated with heavy oil.

(3) 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 volumes. Production volumes are based on annualized fourth quarter production and are adjusted, if necessary, to reflect property acquisitions and dispositions.

During the three-year period ended December 31, 2006 we participated in 60 exploratory wells, of which 36 were successful, and 563 development wells, 555 of which were successful. During this period, we incurred aggregate oil and gas acquisition, exploitation, development and exploration costs of $2.8 billion, approximately 84% of which was for acquisition, exploitation and development activities. During this period proved reserve additions totaled 271 MMBOE. Reserve additions and the number of wells drilled do not include any amounts attributable to the two deepwater Gulf of Mexico discoveries that were sold to Statoil Gulf of Mexico LLC ("Statoil") in November 2006 prior to the wells being completed and any reserve additions being recognized. Costs include expenditures related to these discoveries. See—Divestments. Approximately 52% of our reserves at December 31, 2006 are classified as proved developed compared to 67% at December 31, 2005. The proved developed ratio was primarily impacted by our 2006 producing property sales and a reclassification at certain California properties.

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. Many of the factors that impact these estimates are beyond our control. Reservoir engineering is a subjective process of estimating the recovery from underground accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. Because all reserve estimates are to some degree speculative, the quantities of oil and gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures, and future oil and gas sales prices may all differ from those assumed in these estimates. In addition, different reserve engineers may make different estimates of reserve quantities and cash flows based upon the same available data. Therefore, the standardized measure shown above represents estimates only and should not be construed as the current market value of the estimated oil and gas reserves attributable to our properties.

In accordance with SEC guidelines, the reserve engineers' estimates of future net revenues from our properties, and the present value of the properties, are made using oil and gas sales prices in effect as of the dates of such estimates and are held constant throughout the life of the properties, except where the guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations but excluding the effect of any derivatives we have in place. Historically, the prices for oil and gas have been volatile and are likely to continue to be volatile in the future.

Since December 31, 2005 we have not filed any estimates of total net proved oil or gas reserves with any federal authority or agency other than the SEC.

Acquisitions

We intend to be opportunistic in pursuing selective acquisitions of oil or gas properties or exploration projects. We will consider opportunities located in our current core areas of operation as well as projects in other areas that meet our investment criteria.

In April 2005 we acquired certain California producing oil and gas properties, primarily located in the Los Angeles Basin of onshore California with some smaller properties located in adjacent Ventura County, from a private company for $117 million. In September 2005 we acquired an additional 16.7% interest in the Point Arguello Unit, Rocky Point development project and related facilities, offshore California, from subsidiaries of Chevron U.S.A. Inc. This acquisition increased our working interest in that operation to 69.3%.

In May 2004 we acquired Nuevo Energy Company ("Nuevo") in a stock-for-stock transaction. In the acquisition, each outstanding share of Nuevo common stock was converted into 1.765 shares of PXP common stock and Nuevo became our wholly owned subsidiary. At the closing of this transaction we issued 36.5 million additional PXP common shares and assumed $303 million in debt and $115 million of $2.875 Term Convertible Securities, Series A, or TECONS. Prior to the acquisition, Nuevo was engaged in the upstream activities of acquiring, exploiting, developing and producing oil and gas primarily onshore and offshore California and in west Texas. We accounted for the transaction as a purchase under purchase accounting rules effective May 14, 2004.

In June 2003, we acquired 3TEC Energy Corporation ("3TEC") for approximately $312.9 million in cash and common stock plus $90.0 million to retire 3TEC's outstanding debt. Prior to the acquisition, 3TEC was engaged in the upstream activities of acquiring, exploiting, developing and producing oil and gas in east Texas and the Gulf Coast region, both onshore and in the shallow waters of the Gulf of Mexico. We accounted for the transaction as a purchase under purchase accounting rules effective June 1, 2003.

Divestments

On November 1, 2006 we closed the sale of non-producing oil and gas properties to Statoil. We sold Statoil our working interests in two deepwater Gulf of Mexico discoveries, Big Foot and Caesar, and one deepwater exploration prospect, Big Foot North, comprising a total of four deepwater lease blocks, Green Canyon blocks 683 and 952 and Walker Ridge blocks 28 and 29. In addition, we granted Statoil certain negotiation rights with respect to future sales of certain other PXP deepwater Gulf of Mexico exploration assets. We received approximately $706 million in cash proceeds and recognized a pre-tax gain of $638 million.

On September 29, 2006 we closed the sale of non-strategic oil and gas properties located primarily in California and Texas to subsidiaries of Occidental Petroleum Corporation ("Occidental"). The properties included our interests in the Asphalto, Buena Vista and Mt. Poso fields in the San Joaquin Valley, the Sansinena field in the Los Angeles Basin, the Pakenham field in West Texas and various other minor properties. This transaction had an effective date of October 1, 2006. We received approximately $864 million in cash proceeds and recognized a $345 million pre-tax gain. As of December 31, 2005, our independent reserve engineers estimated these properties had proven reserves of approximately 45 million equivalent barrels of oil. On a barrel of oil equivalent basis, these properties represented approximately 12% of our sales volumes for the third quarter of 2006.

Proceeds from the 2006 transactions were used to retire debt and settle the liability associated with the elimination of our 2007 and 2008 crude oil collars. See Item 7—"Managements Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources".

In May 2005 we closed the sale to XTO Energy, Inc. of interests in producing properties located in East Texas and Oklahoma for net proceeds of approximately $341 million. The proceeds were primarily used to fund the transactions to eliminate all of our 2006 oil price swaps and collars.

In December 2004, we completed the sale of certain properties located offshore California and onshore South Texas, New Mexico, and South Louisiana. These unrelated transactions included the divestment of 11 platforms in federal and state waters off the coast of California and three related onshore facilities and essentially all our remaining assets in South Texas and New Mexico. These divestments were conducted via negotiated and auction transactions. In aggregate, we received net proceeds of approximately $152 million from these transactions. We retained certain abandonment obligations in connection with the offshore California properties. During 2004 we also sold our interests in certain other non-core producing properties for aggregate net proceeds of approximately $28 million.

Exploitation, Development and Exploration

We expect to continue our reserve and production growth through the exploitation and development of our existing inventory of projects in each of our primary operating areas. To complement the exploitation and development activities, we expect to continue to expand on our success in exploratory drilling by taking advantage of our exploratory projects in the Gulf of Mexico, south Louisiana, Wyoming and Nevada. To implement the plans, we will focus on:

- allocating investment capital prudently after rigorous evaluation;
- optimizing production practices;
- realigning and expanding injection processes;
- performing stimulations, recompletions, artificial lift upgrades and other operating margin and reserve enhancements;
- focusing geophysical and geological talent;

- employing modern seismic applications;
- establishing land and prospect inventory practices to reduce costs; and
- using new technology applications in drilling and completion practices.

By implementing our exploitation, development and exploration plan, we seek to increase cash flows and enhance the value of our asset base. In doing so, we add to and enhance our proved reserves. During the three-year period ended December 31, 2006 our additions to proved reserves, excluding reserves added as a result of acquisition activities, totaled 63 MMBOE. During this period we incurred aggregate oil and gas exploitation, development and exploration costs of $1.2 billion.

The Board of Directors has approved a $600 million 2007 capital budget with approximately 50% to be utilized for continued development of the Company's California oil fields and the balance for high impact exploration projects, primarily targeting the Miocene trend in the Gulf of Mexico. The capital budget includes estimated capitalized general and administrative and interest expense of approximately $35 million.

In 2007 we plan to drill approximately 200 development wells in our oil fields located in the Los Angeles, San Joaquin, and Santa Maria Basins onshore and offshore California. We will continue to develop the large Inglewood Field complex, including Las Cienegas, in the Los Angeles Basin with waterflood development drilling. The San Joaquin Valley fields, Cymric, Midway Sunset, South Belridge, and Arroyo Grande area drilling includes expansion of existing tertiary recovery steamfloods, as well as development of new steam projects.

Continuing with the exploration success we have had in the Gulf of Mexico Miocene trend, our current inventory now includes approximately 30 to 35 prospects. We intend to continue focusing our exploration expertise in the Miocene trend by participating in ten of these prospects during 2007. These consist of Gulf of Mexico deepwater prospects and prospects located near existing infrastructure. The Miocene prospects located near existing infrastructure are part of a recent agreement with McMoRan Exploration Co. ("McMoRan") whereby we plan to participate in up to nine exploratory tests in 2007.

Description of Properties

Onshore and Offshore California

LA Basin

We essentially hold a 100% working interest in most of our LA Basin properties, including interests in the Montebello, Inglewood, Inglewood satellite, Las Cienegas and other smaller LA Basin fields. Our LA Basin fields have 696 producing and 359 waterflood injection wells. The LA Basin properties are characterized by lighter crude (23 to 29 degree API), wells from 2,000 feet to over 10,000 feet (at our Deep Inglewood project) and include both primary production and waterfloods.

In 2006 we spent $121 million on capital projects in the LA Basin. Drilling activity this year has been concentrated in the Inglewood Field on the Vickers Rindge waterflood zone with 35 wells drilled and expanding the development in the Moynier and Rubel formations with six wells drilled. In addition, we drilled two wells in the Las Cienegas Field. The Inglewood field accounted for $97 million or 81% of the capital associated with LA Basin projects. Our net average daily sales from our LA Basin properties in the fourth quarter of 2006 was 14.1 MBOE per day.

In 2007 we will continue to develop and optimize our Vickers Rindge waterflood project at Inglewood by drilling 30 wells accompanied by additional well work including recompletions and improvement to the water injection patterns. We will continue expansion with the Rubel Moynier waterflood at Deep Inglewood by drilling 10 wells. Additional work scheduled in the LA Basin area includes 10 wells at Montebello and 6 wells at Las Cienegas.

San Joaquin Basin

We hold interests in the Cymric, Midway Sunset, South Belridge and various other fields in the San Joaquin Basin. Our San Joaquin properties are generally characterized by heavier oil (12 to 16 degree API), and shallow wells (generally less than 2,000 feet) that require cyclic or continuous thermal stimulation. These properties also produce lesser amounts of lighter oil and natural gas under primary recovery.

In 2006, we spent $116 million on capital projects in the San Joaquin Basin and drilled 141 wells. Drilling was concentrated in the Midway Sunset Field where we spent $52 million and drilled 64 wells and in the Cymric Field, where we spent $47 million and drilled 59 wells. Our net average daily sales from our San Joaquin Basin properties in the fourth quarter of 2006 was 21.6 MBOE per day.

At Midway Sunset field our development and expansion program in 2007 includes 59 Diatomite, 30 Marvic Spellacy and 6 Potter wells and accompanying facility expansion. We will also continue Cymric field development with 22 Diatomite and 12 Tulare wells.

Other Onshore California

We hold a 100% working interest (94% net revenue interest) in the Arroyo Grande field located in San Luis Obispo County, California. The field is primarily under continuous steam injection. We have drilled wells to downsize the injection patterns in the currently developed area from five acres to one and a quarter acres to accelerate recoveries, and realigned steam injection within these areas to increase the efficiency of the recovery process. In 2006, we spent $6 million on capital projects in this field and drilled seven wells. Our net average daily sales from the Arroyo Grande field in the fourth quarter of 2006 was 1.5 MBOE per day.

Santa Maria Basin Offshore California

Point Arguello Unit/P-0451 E/2. We are the operator and hold 69.3% working interests in the Point Arguello Unit and the various partnerships owning the related transportation, processing and marketing infrastructure. We are also the operator of federal offshore lease P-0451 and have agreements in place between the P-0451 owners and the Point Arguello Unit owners that will allow us to participate with at least a 69.3% working interest in the development of the east half of the P-0451 lease.

The companies from which we purchased our interests in the Point Arguello Unit retained responsibility for the majority of the abandonment costs, including: (1) removing, dismantling and disposing of the existing offshore platforms; (2) removing and disposing of all existing pipelines; and (3) removing, dismantling, disposing and remediating all existing onshore facilities. We are responsible for our 69.3% share of other abandonment costs which primarily consist of well-bore abandonments and conductor removals.

In 2006, we spent $23 million on Point Arguello Unit/P-0451 E/2 capital projects, including the drilling of one well, and our net average daily oil sales in the fourth quarter of 2006 was 5.0 MBOE per day.

Point Pedernales. We hold a 100% working interest in the offshore Pt. Pedernales field which includes one platform and support facilities which lie within the onshore Lompoc field. The offshore Pt. Pedernales field utilizes one platform to exploit the Federal OCS Monterey Reservoir utilizing extended reach directional wells. In 2006 we spent $37 million on capital projects in this field and drilled four wells. Our combined net average daily sales from our Pt. Pedernales field and Lompoc field in the fourth quarter of 2006 was 8.5 MBOE per day.

Gulf Coast Basin—Onshore and Offshore Louisiana

In 2006, we spent $267 million on exploration and development projects in the Gulf Coast Basin. We participated in a total of 17 wells, 7 of which were successful and 4 of which were in progress at year end. Our net average sales for this area was 3.2 MBOE per day in the fourth quarter of 2006.

In the deepwater Middle/Lower Miocene trend area of the Gulf of Mexico, on Walker Ridge Blocks 28 and 29 we had a 12.5% interest in the Big Foot discovery well that was announced in January 2006 and the successful side track well. On Green Canyon Blocks 683 and 952 we had a 17.5% interest in the Caesar discovery well and the successful offset well. In the fourth quarter of 2006 our interest in these blocks and one deepwater exploration prospect, Big Foot North, were sold to Statoil for $706 million. See—Divestments.

On Green Canyon Block 599 we have a 50% interest in the Friesian discovery well. The discovery was prepared for completion and temporarily abandoned. Additional drilling and/or development plans are subject to further analysis.

In November 2006 we entered into an exploration agreement with McMoRan under the terms of which we will participate in up to nine of McMoRan's Miocene exploratory prospects for approximately 60% of McMoRan's interest. Under the agreement, we paid McMoRan $20 million for leasehold interests and associated prospects. To date one well has been drilled, an unsuccessful exploratory well, and two wells are in progress.

In 2007 we will continue to drill select deepwater Gulf of Mexico exploration prospects.

Other Areas

In Wyoming, we anticipate securing the required permits to allow drilling in 2008, dependent on when permits are issued and seasonal limitations, on a gas prospect in the Green River Basin that was acquired during 2005. In Nevada, we anticipate drilling two exploratory wells in the eastern part of the state in 2007.

Acquisition, Exploration, Exploitation and Development Expenditures

The following table summarizes the costs incurred during the last three years for our exploitation and development, exploration and acquisition activities.

	Year Ended December 31,		
	2006	2005	2004
	(In thousands of dollars)		
Property acquisitions costs:			
Unproved properties	$ 48,315	$ 16,682	$ 144,894
Proved properties	7,175	134,696	1,210,758
Exploration costs	272,352	129,066	57,530
Exploitation and development costs	319,730	300,439	141,198
	$647,572	$580,883	$1,554,380

Exploitation and development costs include expenditures of $128 million in 2006, $114 million in 2005 and $31 million in 2004 related to the development of proved undeveloped reserves included in our proved oil and gas reserves at the beginning of each year. Exploitation and development costs include capital costs required to maintain our proved developed producing reserves.

Production and Sales

The following table presents information with respect to oil and gas production attributable to our properties, the revenues we derived from the sale of this production, average sales prices we realized and our average production expenses during the years ended December 31, 2006, 2005 and 2004.

	Year Ended December 31,		
	2006	2005	2004
Daily Average Volumes			
Oil and liquids sales (Bbls)	51,985	51,154	44,920
Gas (Mcf)			
Production	56,519	80,435	105,436
Used in steam operations	13,214	14,358	11,264
Sales	43,305	66,077	94,172
BOE			
Production	61,405	64,560	62,493
Sales	59,202	62,166	60,615
Unit Economics (in dollars)			
Average NYMEX Prices			
Oil	$ 66.23	$ 56.61	$ 41.43
Gas	7.21	8.62	6.14
Average Realized Sales Price Before Derivative Transactions			
Oil (per Bbl)	$ 55.62	$ 46.76	$ 36.12
Gas (per Mcf)	6.73	7.15	5.90
Per BOE	53.76	45.96	35.92
Costs and Expenses per BOE			
Production costs			
Lease operating expenses	$ 8.32	$ 5.97	$ 5.36
Steam gas costs	2.95	3.32	1.77
Electricity	1.76	1.35	1.32
Production and ad valorem taxes	1.15	1.03	0.98
Gathering and transportation	0.31	0.43	0.33
DD&A (oil and gas properties)	8.96	7.39	5.93

See Item 7—"Managements Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations" for cash payments related to our derivatives.

Product Markets and Major Customers

Our revenues are highly dependent upon the prices of, and demand for, oil and gas. Historically, the markets for oil and gas have been volatile and are likely to continue to be volatile in the future. The prices we receive for our oil and gas production are subject to wide fluctuations and depend on numerous factors beyond our control, including location and quality differentials, seasonality, economic conditions, foreign imports, political conditions in other oil-producing and gas-producing countries, the actions of OPEC, and domestic government regulation, legislation and policies. Decreases in oil and gas prices have had, and could have in the future, an adverse effect on the carrying value and volumes of our proved reserves and our revenues, profitability and cash flow.

We use various derivative instruments to manage our exposure to commodity price risks. Derivatives provide us protection on the volumes if prices decline below the prices at which the derivatives are set. However, ceiling prices in derivatives may result in receiving less revenue on the volumes than would be received in the absence of the derivatives. Our derivative instruments currently consist of crude oil put option contracts entered into with financial institutions.

A substantial portion of our oil and gas reserves are located in California and approximately 63% of our production is attributable to heavy crude (generally 21 degree API gravity crude oil or lower). The market price for California crude oil differs from the established market indices in the U.S., due principally to the higher transportation and refining costs associated with heavy oil.

Our heavy crude is primarily sold to ConocoPhillips under a 15-year contract which expires on December 31, 2014. This contract provides for pricing based on a percentage of the NYMEX crude oil price for each type of crude oil that we produce and deliver to ConocoPhillips in California. This percentage may be renegotiated every two years, with the current percentage rates eligible for renegotiation effective at the end of 2007. We are currently receiving approximately 83% of the NYMEX index price for crude oil sold under the ConocoPhillips contract, representing approximately 56% of our total crude oil production.

Approximately 35% of our crude oil production is sold through Plains Marketing, L.P. ("PMLP") with 46% sold under contracts that provide for NYMEX less a fixed price differential (currently averaging NYMEX less $5.50) and the remainder sold under contracts that provide for monthly field posted prices. These contracts expire at various times through 2008. The marketing agreement with PMLP provides that PMLP will purchase for resale at market prices certain of our oil production for which PMLP charges a marketing fee of either $0.20 or $0.15 per barrel based upon the contract the barrels are resold under.

Prices received for our gas are subject to seasonal variations and other fluctuations. Approximately 80% of our gas production is sold monthly based on industry recognized, published index pricing. The remainder is priced daily on the spot market. Fluctuations between the two pricing mechanisms can significantly impact the overall differential to the Henry Hub.

During 2006, 2005 and 2004 sales to ConocoPhillips accounted for 54%, 44% and 33%, respectively, of our total revenues and sales to PMLP accounted for 41%, 38% and 33%, respectively, of our total revenues. During such periods no other purchaser accounted for more than 10% of our total revenues. The loss of any single significant customer or contract could have a material adverse short-term effect, however, we do not believe that the loss of any single significant customer or contract would materially affect our business in the long-term. We believe such purchasers could be replaced by other purchasers under contracts with similar terms and conditions. However, their role as the purchaser of a significant portion of our oil production does have the potential to impact our overall exposure to credit risk, either positively or negatively, in that they may be affected by changes in economic, industry or other conditions.

Substantially all of our oil and gas production is transported by pipelines 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 decreases in a significant portion of our oil and gas production.

Productive Wells and Acreage

As of December 31, 2006 we had working interests in 2,394 gross (2,356 net) active producing oil wells and 21 gross (12 net) active producing gas wells. The following table sets forth information with respect to our developed and undeveloped acreage as of December 31, 2006:

	Developed Acres		Undeveloped Acres (1)	
	Gross	Net	Gross	Net
California				
Onshore	91,125	65,013	103,705	72,101
Offshore	41,588	34,328	125,330	21,503
Kansas	—	—	40,191	31,471
Louisiana				
Onshore	7,052	2,943	34,189	30,608
Offshore	9,213	4,870	165,662	42,942
Nevada	—	—	56,466	45,173
Wyoming	—	—	61,902	51,985
Total	148,978	107,154	587,445	295,783

(1) Less than 10% of total net undeveloped acres are covered by leases that expire from 2007 through 2009.

Drilling Activities

Information with regard to our drilling activities during the years ended December 31, 2006, 2005 and 2004 is set forth below:

	Year Ended December 31,					
	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Oil	1.0	1.0	5.0	5.0	13.0	13.0
Gas	6.0	4.7	6.0	2.7	5.0	2.0
Dry	8.0	6.0	6.0	3.1	10.0	5.3
	15.0	11.7	17.0	10.8	28.0	20.3
Development Wells						
Oil	186.0	185.8	217.0	216.4	65.0	64.2
Gas	5.0	4.4	30.0	12.0	52.0	22.4
Dry	4.0	4.0	3.0	3.0	1.0	1.0
	195.0	194.2	250.0	231.4	118.0	87.6
	210.0	205.9	267.0	242.2	146.0	107.9

At December 31, 2006 there were four gross exploratory wells (1.0 net) in progress.

Real Estate

We are in the process of pursuing surface development of portions of the following tracts of real property, some of which are used in our oil and gas operations:

Property	Location	Approximate Acreage (Net to Our Interest)
Montebello	Los Angeles County, California	497
Arroyo Grande	San Luis Obispo County, California	1,080
Lompoc	Santa Barbara County, California	3,727

In January 2006 we entered into real estate consulting agreements with Cook Hill Properties, LLC. Under the terms of the agreements Cook Hill Properties will be responsible for creating a development plan and obtaining all necessary permits for real estate development in an environmentally responsible manner on the surface estates of our properties listed above. Cook Hill Properties is a 15% participant in the venture and can earn an additional incentive on each property.

Our objective relative to the Montebello project is to take advantage of the positioning of this site as a potential significant residential development project in the San Gabriel Valley region of Greater Los Angeles. The project is located in southeastern Los Angeles County 10 miles east of downtown Los Angeles. Our objective in Lompoc and Arroyo Grande is to provide similar sustainable development inventory to California's Central Coast. Our Lompoc property is located midway between Santa Barbara and San Luis Obispo a few miles inland from the Pacific Ocean; our Arroyo Grande property is located in the geographically desirable region near Pismo Beach and the Edna Valley.

We are actively pursuing the entitlement process for our Montebello and Lompoc properties and are engaged in pre-entitlement activities in Arroyo Grande. Our current development plans include master planned communities with a range of housing from entry level to executive and estate homes, parks and recreational land uses.

In the course of our business, certain of our properties may be subject to easements or other incidental property rights and legal requirements that may affect the use and enjoyment of our property. In 2006 we spent approximately $5 million on our real estate projects.

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 interfere with our use of the properties in the operation of our business.

We believe that we have generally satisfactory title to or rights in all of our producing properties. As is customary in the oil and gas industry, we make minimal investigation of title at the time we acquire undeveloped properties. We make title investigations and receive title opinions of local counsel only before we commence drilling operations. We believe that we have satisfactory title to all of our other assets. Although title to our properties is subject to encumbrances in certain cases, we believe that none of these burdens will materially detract from the value of our properties or from our interest therein or will materially interfere with our use in the operation of our business.

Competition

Our competitors include major integrated oil and gas companies and numerous independent oil and gas companies, individuals and drilling and income programs. Many of our larger competitors possess and employ financial and personnel resources substantially greater than ours. These competitors 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 prospects and resources in the oil and gas industry.

Regulation

Our operations are subject to extensive governmental regulation. Many federal, state and local legislative and regulatory bodies agencies are authorized to issue, and have issued, laws and regulations binding on the oil and gas industry and its individual participants. The failure to comply with these laws and regulations can result in substantial penalties. The regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability. However, we do not believe that we are affected in a significantly different manner by these laws and regulations than are our competitors. Due to the myriad of complex federal, state and local laws and 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, or OSHA, and comparable state and local statutes and rules that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard, the United States Environmental Protection Agency community-right-to know regulations, and similar state and local statutes and rules require that we maintain certain information about hazardous conditions or materials used or produced in our operations and that we provide this information to our employees, 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 conditions or substances.

MMS. The United States Minerals Management Service, or MMS, has broad authority to regulate our oil and gas operations on offshore leases in federal waters. It must approve and grant permits in connection with our exploration, drilling, development and production plans in federal waters. Additionally, the MMS has promulgated regulations requiring offshore production facilities to meet stringent engineering, construction, and environmental specifications, including regulations restricting the flaring or venting of gas, governing the plugging and abandonment of wells and controlling the removal of production facilities. Under certain circumstances, the MMS may suspend or terminate any of our operations on federal leases, as discussed in "Risk Factors—Governmental agencies and other bodies, including those in California, might impose regulations that increase our costs and may terminate or suspend our operations". The MMS has adopted regulations providing for enforcement actions, including civil penalties, and lease forfeiture or cancellation for failure to comply with approved plans for offshore operations. The MMS has also established rules governing the calculation of royalties and the valuation of oil produced from federal offshore leases and regulations regarding costs for gas transportation. Delays in the approval of plans and issuance of permits by the MMS because of staffing, economic, environmental or other reasons (or other actions taken by the MMS under its regulatory authority) could adversely affect our operations.

The now-dormant Nuevo Energy Company ("Nuevo") was acquired by the Company in May 2004. The United States Attorney's Office has notified Nuevo that it is investigating allegations that during 2000-2002, prior to the acquisition, an unaffiliated contract operator retained by Nuevo may have falsified certain records in violation of federal laws related to equipment testing. We are cooperating with this investigation. Under certain laws, Nuevo may be held responsible for the actions of its agents.

However, we do not believe that such investigation will have a material adverse effect on the Company.

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

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

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

FERC, the United States Congress or state regulatory agencies may consider additional proposals or proceedings that might affect the gas industry. We cannot predict when or if these proposals will become effective or any effect they may have on our operations. We do not believe, however, that any of these proposals will affect us any differently than other gas producers with which we compete.

Environmental. Our operations and properties are subject to extensive and increasingly stringent 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 the discharge of materials into the environment. Such statutes include, but are not limited to, the Comprehensive Environmental Response, Compensation and Liability Act, Resource Conservation and Recovery Act, Clean Air Act, Clean Water Act, and Safe Drinking Water Act. Statutes that specifically provide protection to animal and plant species and which may apply to our operations include, but are not limited to, the Marine Mammal Protection Act, the Marine Protection, the Research and Sanctuaries Act, the Endangered Species 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 promulgated thereunder 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.

As with our 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 that comply with such laws and regulations are similarly affected. Environmental laws and regulations have historically been subject to change, and we are unable to predict the ongoing cost to us of complying with these laws and regulations or the future impact of these laws and regulations on our operations. If a person violates, or is otherwise liable under, 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 incur substantial expense, including remediation costs and other liability under applicable laws and regulations, as well as claims made by neighboring landowners and other third parties for personal injury and property damage.

Permits. Our operations are subject to various federal, state and local laws and regulations that include requiring permits for the drilling of wells, maintaining bonding and insurance requirements to drill, operate, plug and abandon, and restore the surface associated with our wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandonment of wells, the disposal of fluids and solids used in connection with our operations and air emissions associated with our operations. Also, we have permits from numerous jurisdictions, including the city and county of Los Angeles, California, the city of Culver City, California, the City of La Habra Heights, California, the City of Commerce, California, the county of Kern, California, the county of Ventura, California, the city of Montebello, California, the city of Beverly Hills, California and the county of Santa Barbara, California to operate crude oil, natural gas and related pipelines and equipment that run within the boundaries of these governmental jurisdictions. The permits required for various aspects of our operations are subject to revocation, modification and renewal by issuing authorities.

Plugging, Abandonment and Remediation Obligations

Consistent with normal industry practices, substantially all of 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, the purchaser assumes the obligation to plug and abandon wells that are part of such assets. However, in some instances, we receive an indemnity with respect to those costs.

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

We estimate our 2007 cash expenditures related to plugging, abandonment and remediation will be approximately $4 million. Due to the long life of our onshore California reserve base we do not expect our cash outlays for such expenditures for these properties will increase significantly in the next several years. At the Arguello Unit, offshore California, the companies from which we purchased our interests retained responsibility for the majority of the abandonment costs, including: (1) removing, dismantling and disposing of the existing offshore platforms; (2) removing and disposing of all existing pipelines; and (3) removing, dismantling, disposing and remediating all existing onshore facilities. We are responsible for our 69.3% share of other abandonment costs which primarily consist of well-bore abandonments and conductor removals.

In connection with the sale of certain properties offshore California in December 2004 we retained the responsibility for certain abandonment costs, including removing, dismantling and disposing of the existing offshore platforms. The present value of such abandonment costs, $39 million ($78 million undiscounted), are included in our asset retirement obligation as reflected on our consolidated balance sheet. In addition, we agreed to guarantee the performance of the purchaser with respect to the remaining abandonment obligations related to the properties (approximately $46 million). To secure its abandonment obligations the purchaser of the properties is required to periodically deposit funds into an escrow account. At December 31, 2006 the escrow account had a balance of $3 million. The fair value of our guarantee, $0.3 million, is included in Other Long-Term Liabilities in the Consolidated Balance Sheet.

Employees

As of January 31, 2007 we had 610 full-time employees, 281 of whom were field personnel involved in oil and gas producing activities. We believe our relationship with our employees is good. None of our employees is represented by a labor union.

Item 1A. ***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 or debt securities.

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

Our success is largely dependent on oil and gas prices, which are extremely volatile. Any substantial or extended decline in the price of oil and gas below current levels will have a negative impact on our business operations and future revenues. Moreover, oil and gas prices depend on factors we cannot control, such as:

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

With respect to our business, prices of oil and gas will affect:

- our revenues, cash flows, profitability 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 and our oil and gas reserve volumes.

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 and gas 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 and gas prices in effect on the dates 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;
- 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.

If we are unable to replace the reserves that we have produced, our reserves and revenues will decline.

Our future success depends 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.

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.

A substantial portion of our oil and gas reserves are located in California. Because our reserves are not as diversified geographically as many of our competitors, our business is subject to local conditions more 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 California oil production is heavier than premium grade light oil. Due to the processes required to refine this type of oil and the transportation requirements, it is difficult to market California oil production outside California. Additionally, the margin (sales price minus production costs) on heavy oil sales is generally less than that of lighter oil sales due to price differentials, and the effect of material price decreases will more adversely affect the profitability of heavy oil production compared with lighter grades of oil.

We intend to continue to enter into derivative contracts for a portion of our crude oil production, which may result in our making cash payments or prevent us from receiving the full benefit of increases in prices for oil and which may cause volatility in our reported earnings.

We use derivative instruments to manage our commodity price risk. This practice may prevent us from receiving the full advantage of increases in oil prices above the maximum fixed amount specified in the derivative agreement. The level of derivative activity depends on our view of market conditions, available derivative prices and our operating strategy.

For 2007 and 2008, our crude oil derivative position consists exclusively of purchased put option contracts with a strike price of $55.00 on 50,000 barrels per day for 2007 and 42,000 barrels per day for 2008. The only cash settlements we are required to make on these contracts are option premiums and interest, which are expected to total approximately $111 million in 2007 and $58 million in 2008. In return, to the extent the daily average NYMEX price for West Texas Intermediate crude oil is less than $55.00, we will receive the difference between $55.00 and the daily average NYMEX price for West Texas Intermediate crude oil.

See Item 7A—"Qualitative and Quantitative Disclosures About Market Risk" for a summary of our current derivative positions. Since our remaining derivative position consists entirely of crude oil put options, there will continue to be volatility in derivative gains or losses on our income statement, however, our ultimate potential loss will be limited to the cost of the options.

Our offshore operations are subject to substantial regulations and risks, which could adversely affect our ability to operate and our financial results.

We conduct operations offshore California and Louisiana. Our offshore activities are subject to more extensive governmental regulation than our other oil and gas activities. In addition, we are vulnerable to the risks associated with operating offshore, including risks relating to:

- hurricanes and other adverse weather conditions;
- oil field service costs and availability;
- compliance with environmental and other laws and regulations;
- remediation and other costs resulting from oil spill releases of hazardous materials and other environmental damages; and
- failure of equipment or facilities.

The majority of our oil production in California is dedicated to two customers and as a result, our credit exposure to those customers is significant.

We have entered into oil marketing arrangements with PMLP and with ConocoPhillips under which PMLP or ConocoPhillips purchase the majority of our net oil production in California. We generally do not require letters of credit or other collateral from PMLP or ConocoPhillips to support these trade receivables. Accordingly, a material adverse change in PMLP's or ConocoPhillips's financial condition could adversely impact our ability to collect the applicable receivables, and thereby affect our financial condition.

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.

In addition, our operations in California are susceptible to damage from natural disasters, such as earthquakes, mudslides and fires, and our Gulf of Mexico operations are susceptible to hurricanes. Any of these operating hazards could cause serious injuries, fatalities, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages, or property damage, all of 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. The insurance market in general and the energy insurance market in particular have been difficult markets over the past several years. As a result, we do not believe that insurance coverage for the full potential liability, especially environmental liability, is currently available at reasonable cost. 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.

We may not be successful in acquiring, exploiting, developing or exploring for oil and gas properties.

The successful acquisition, exploitation or development of, or exploration for, oil and gas properties requires an assessment of recoverable reserves, future oil and gas prices and operating costs, potential environmental and other liabilities, and other factors. These assessments are necessarily inexact. As a result, we may not recover the purchase price of a property from the sale of production from the property, or may not recognize an acceptable return from properties we do acquire. In addition, our exploitation and development and exploration operations may not result in any increases in reserves. Our operations may be curtailed, delayed or canceled as a result of:

- inadequate capital or other factors, such as title problems;
- weather;
- compliance with governmental regulations or price controls;
- mechanical difficulties; or
- shortages or delays in the delivery of equipment.

In addition, exploitation and development costs may greatly exceed initial estimates. In that case, we would be required to make unanticipated expenditures of additional funds to develop these projects, which could materially and adversely affect our business, financial condition and results of operations.

Furthermore, exploration for oil and gas, particularly offshore, has inherent and historically higher risk than exploitation and development activities. Future reserve increases and production may be dependent on our success in our exploration efforts, which may be unsuccessful.

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

Our success is materially dependent upon the demand for oil and gas. The availability of a ready market for our oil and gas 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 and gas diminishes, our financial results would be negatively impacted.

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

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. We do not have key man insurance.

Governmental agencies and other bodies, including those in California, 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 California, vested with broad 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, or their interpretations, could be changed, and any changes could increase costs of compliance and costs of operating drilling equipment or significantly limit drilling activity.

Under certain circumstances, the MMS may require that our operations on federal leases be suspended or terminated. These circumstances include our failure to pay royalties or our failure to comply with safety and environmental regulations. The requirements imposed by these laws and regulations are frequently changed and subject to new interpretations.

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. 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;
- financial assurance under the Oil Pollution Act of 1990; 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.

Some of our onshore California fields have been in operation for more than 90 years, and current or future local, state and federal environmental and other laws and regulations may require substantial expenditures to remediate the properties or to otherwise comply with these laws and regulations. In addition, approximately 183 acres of our 480 acres in the Montebello field have been designated as California Coastal Sage Scrub, a known habitat for the coastal California gnatcatcher, which is a type of bird designated as threatened under the Federal Endangered Species Act. A variety of existing laws, rules and guidelines govern activities that can be conducted on properties that contain coastal sage scrub and gnatcatchers and generally limit the scope of operations that we can conduct on this property. The presence of coastal sage scrub and gnatcatchers in the Montebello field and other existing or future laws, rules and guidelines could prohibit or limit our operations and our planned activities for this property.

Our acquisition strategy could fail or present unanticipated problems for our business in the future, which could adversely affect our ability to make acquisitions or realize anticipated benefits of those acquisitions.

Our growth strategy may include acquiring oil and gas 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;
- difficulty in assuming recoverable reserves, future production rates, operating costs, infrastructure requirements, environmental and other liabilities, and other factors beyond our control;
- 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 net income could be negatively affected by stock based compensation charges.

We adopted Statement of Financial Accounting Standards ("SFAS") No. 123R, "Share-Based Payment" ("SFAS 123R") effective January 1, 2006. SFAS 123R requires that the compensation cost relating to share-based payment transactions be recognized in financial statements based on the fair value of the equity or liability instruments issued. Under SFAS 123R our SARs and certain of our restricted stock units are considered liability awards and are remeasured to fair value each reporting period with changes in fair value reported in earnings. As a result, we expect volatility in our earnings as our stock price changes.

We recognized $55 million, $78 million and $44 million of stock based compensation expense for the years ended December 31, 2006, 2005 and 2004, respectively.

Our results of operations could be adversely affected as a result of goodwill impairments.

In a purchase transaction, goodwill represents the excess of the purchase price plus the liabilities assumed, including deferred income taxes recorded in connection with the transaction, over the fair value of the net assets acquired. At December 31, 2006 goodwill totaled $159 million and represented 6% of our total assets.

Goodwill is not amortized, but instead must be tested at least annually for impairment by applying a fair-value based test. Goodwill is deemed impaired to the extent of any excess of its carrying amount over the residual fair value of the reporting unit. Such impairment could significantly reduce earnings during the period in which the impairment occurs and would result in a corresponding reduction to goodwill and stockholders' equity. The most significant factors that could result in the impairment of our goodwill would be significant declines in oil and gas prices and/or reserve volumes which would result in a decline in the fair value of our oil and gas properties.

If oil and gas prices decrease, we may be required to take writedowns.

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 and gas production at the oil and gas prices in effect at the end of each fiscal quarter and require a write-down if our capitalized costs exceed this "ceiling," even if prices declined for only a short period of time. We have had no write-downs due to these ceiling test limitations since 1998. Given the volatility of oil and gas prices, it is likely that our estimate of discounted future net revenues from proved oil and gas reserves will change in the near term. If oil and gas prices decline significantly 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.

Terrorist activities and the potential for military and other actions could adversely affect our business.

The threat of terrorism and the impact of military and other actions have caused instability in world financial markets and could lead to increased volatility in prices for natural gas and oil, all of which could adversely affect the markets for our operations. Future acts of terrorism could be directed against companies operating in the United States. The U.S. government has issued public warnings that indicate that energy assets may be specific targets of terrorist organizations. These developments have subjected our operation to increased risk and, depending on their ultimate magnitude, could have a material adverse effect on our business.

We face strong competition.

We face strong competition in all aspects of our business. Competition is particularly intense for prospective undeveloped leases and purchases of proved oil and gas reserves. There is also competition for the rigs and related equipment and services that are necessary for us to develop and operate our natural gas and oil properties. Our competitive position is also highly dependent on our ability to recruit and retain geological, geophysical and engineering expertise. We compete for prospects, proved reserves, field services and qualified oil and gas professionals with major and diversified energy companies. Some companies may be able to more successfully define, evaluate, bid for and purchase properties and prospects than us.

Our real estate entitlement efforts are subject to an intensive regulatory approval process.

Before being in a position to develop a property or to sell entitled land to a developer, we must obtain a variety of approvals from local, state and federal permitting authorities with respect to a number of matters including, without limitation:

- land use issues including zoning, subdivision, density, traffic, grading and site planning; and
- environmental issues including air and water quality and protection of endangered species and their habitats.

A portion of our surface acreage in Montebello has been designated as California Coastal Sage Scrub, a known habitat for the California Gnatcatcher, which is a species of bird designated as threatened under the Federal Endangered Species Act. We are consulting with the U.S. Fish and Wildlife Service and other regulatory agencies regarding proposed development footprints and habitat mitigation and protection strategies but the results of these consultations cannot be predicted.

Some of the regulatory approvals we are seeking are discretionary by nature. The entitlement approval process is often a lengthy and complex procedure requiring, among other things, the submission of development plans and reports and presentations at public hearings. Because of the provisional nature of these approvals and the concerns of various environmental and public interest groups, our ability to entitle and realize future income from our surface properties could be delayed, reduced, prevented or made more expensive.

Our real estate surface development efforts are greatly affected by the performance of the real estate market.

Our real estate activities are subject to numerous factors beyond our control, including: local real estate market conditions (both where our properties are located and in areas where our potential customers reside); substantial existing and potential competition; general national, regional and local economic conditions; fluctuations in interest rates and mortgage availability; and changes in demographic conditions. Real estate markets have historically been subject to strong periodic cycles driven by numerous factors beyond the control of market participants. Real estate investments often cannot easily be converted into cash and market values may be adversely affected by these economic circumstances, market fundamentals, competition and demographic conditions. Because of the effect these factors have on real estate values, it is difficult to predict with certainty the level of future sales or sales prices that will be realized for individual assets.

Our real estate surface development activities lack geographic diversification.

Our surface entitlement and development activities are limited to the following California counties: Los Angeles, Santa Barbara and San Luis Obispo. Economic and other events that adversely impact this comparatively narrow geographic region will have a direct negative impact on our real estate efforts.

Item 1B. *Unresolved Staff Comments*

Not applicable.

Item 3. *Legal Proceedings*

On November 15, 2005, the United States Court of Federal Claims issued a ruling granting the plaintiffs' motion for summary judgment as to liability and partial summary judgment as to damages in the breach of contract lawsuit Amber Resources Company et al. v. United States, Case No. 02-30c.

The Court's ruling also denied the United States' motion to dismiss and motion for summary judgment. The United States Court of Federal Claims ruled that the federal government's imposition of new and onerous requirements that stood as a significant obstacle to oil and gas development breached agreements that it made when it sold 36 federal leases offshore California. The Court further ruled that the Government must give back to the current lessees the more than $1.1 billion in lease bonuses it had received at the time of sale. On October 31, 2006, the Court issued an unfavorable decision on the plaintiff's motion for partial summary judgment concerning plaintiffs' additional claims regarding the hundreds of millions of dollars that have been spent in the successful efforts to find oil and gas in the disputed lease area, and other matters. Plaintiff's filed a motion for final judgment on November 29, 2006 and the court granted such motion on January 11, 2007. Judgment on the $1.1 billion was filed January 12, 2007. The United States has filed its notice of appeal and Plaintiffs intend to file a cross-appeal concerning the Court's October 31, 2006 decision. No payments will be made until all appeals have either been waived or exhausted. We are among the current lessees of the 36 leases. Our share of the $1.1 billion award is in excess of $80 million.

We are a defendant in various other lawsuits arising in the ordinary course of our business. While the outcome of these lawsuits cannot be predicted with certainty and could have a material adverse effect on our financial position, we do not believe that the outcome of these 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.

PART II

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

Price Range of Common stock

Our common stock is listed on the New York Stock Exchange under the symbol "PXP". The following table sets forth the range of high and low sales prices for our common stock as reported on the New York Stock Exchange Composite Tape for the periods indicated below:

	High	Low
2006		
1st Quarter	$46.90	$36.58
2nd Quarter	42.54	31.45
3rd Quarter	47.00	39.72
4th Quarter	49.37	40.20
2005		
1st Quarter	$39.25	$24.00
2nd Quarter	37.66	28.02
3rd Quarter	44.60	34.47
4th Quarter	46.66	35.20

At January 31, 2007 we had approximately 1,509 shareholders of record.

Dividend Policy

We have not paid any cash dividends and do not anticipate declaring or paying any cash dividends in the future. We intend to retain our earnings to finance the expansion of our business, repurchase shares of our common stock and for general corporate purposes. Our Board of Directors will have the authority to declare and pay dividends on our common stock in its discretion, as long as we have funds legally available to do so. As discussed in Item 7—Managements Discussion and Analysis of Financial Condition and Results of Operations—Financing Activities and Note 6 to the Consolidated Financial Statements, our credit facility restricts our ability to pay cash dividends.

Issuer Purchases of Equity Securities

Our Board of Directors has authorized the repurchase of up to $500 million of PXP common stock. The shares will be repurchased from time to time in open market transactions or privately negotiated transactions at our discretion, subject to market conditions and other factors.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 to October 31, 2006	15,750	$41.33	—	$399,240,000
November 1 to November 30, 2006	1,529,100	$43.40	1,529,100	$332,885,000
December 1 to December 31, 2006	2,723,550	$47.94	2,650,400	$205,817,000

The 15,750 shares in October 2006 and 73,150 of the shares in December 2006 were withheld from vested equity awards for employees in order to satisfy required withholding taxes.

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. You should read this information in conjunction with Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and notes thereto. This information is not necessarily indicative of our future results.

	Year Ended December 31,				
	2006	2005	2004 (1)	2003 (2)	2002
	(In thousands, except per share amounts)				
Revenues	$1,018,503	$ 944,420	$ 671,706	$304,090	$188,563
Costs and Expenses					
Production costs	313,125	285,292	223,080	104,819	78,451
General and administrative	123,134	127,513	92,042	43,158	15,186
Depreciation, depletion, amortization and accretion	216,782	187,915	147,985	52,484	30,359
Gain on sale of oil and gas properties	(982,988)	—	—	—	—
	(329,947)	600,720	463,107	200,461	123,996
Income from Operations	1,348,450	343,700	208,599	103,629	64,567
Other Income (Expense)					
Interest expense	(64,675)	(55,421)	(37,294)	(23,778)	(19,377)
Debt extinguishment costs	(45,063)	—	(19,691)	—	—
Gain (loss) on mark-to-market derivative contracts (3)	(297,503)	(636,473)	(150,314)	847	—
Gain on termination of merger agreement	37,902	—	—	—	—
Interest and other income (expense)	5,496	3,324	723	(159)	(2,221)
Income (Loss) Before Income Taxes and Cumulative Effect of Accounting Change	984,607	(344,870)	2,023	80,539	42,969
Income tax (expense) benefit					
Current	(142,378)	229	(375)	(1,224)	(6,353)
Deferred	(242,519)	130,629	7,192	(32,228)	(10,379)
Income (Loss) Before Cumulative Effect of Accounting Change	599,710	(214,012)	8,840	47,087	26,237
Cumulative effect of accounting change, net of tax (expense)/benefit (4)	(2,182)	—	—	12,324	—
Net Income (Loss)	$ 597,528	$(214,012)	$ 8,840	$ 59,411	$ 26,237
Earnings (Loss) Per Share					
Basic					
Income (loss) before cumulative effect of accounting change	$ 7.76	$ (2.75)	$ 0.14	$ 1.41	$ 1.08
Cumulative effect of accounting change	(0.03)	—	—	0.37	—
Net income (loss)	$ 7.73	$ (2.75)	$ 0.14	$ 1.78	$ 1.08
Diluted					
Income (loss) before cumulative effect of accounting change	$ 7.67	$ (2.75)	$ 0.14	$ 1.41	$ 1.08
Cumulative effect of accounting change	(0.03)	—	—	0.37	—
Net income (loss)	$ 7.64	$ (2.75)	$ 0.14	$ 1.78	$ 1.08
Weighted Average Common Shares Outstanding					
Basic	77,273	77,726	63,542	33,321	24,193
Diluted	78,234	77,726	64,014	33,469	24,201

(1) Reflects acquisition of Nuevo effective May 14, 2004.
(2) Reflects acquisition of 3TEC effective June 1, 2003.
(3) We do not use hedge accounting for certain of our derivative instruments, because the derivatives do not qualify or we have elected not to use hedge accounting. Consequently, these derivative contracts are marked-to-market each quarter with fair value gains and losses, both realized and unrealized, recognized currently as a gain or loss on mark-to-market derivative contracts on the income statement. Cash flow is only impacted to the extent the actual settlements under the contracts result in making or receiving a payment from the counterparty.
(4) Cumulative effect of adopting SFAS 123R in 2006 and SFAS No. 143—"Accounting for Asset Retirement Obligations" in 2003.

Table continued on following page

	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(In thousands of dollars)				
Cash Flow Data					
Net cash provided by operating activities	$ 674,981	$ 463,334	$ 363,219	$ 118,278	$ 78,826
Net cash provided by (used in) investing activities	811,999	(168,420)	5,414	(368,710)	(64,158)
Net cash (used in) provided by financing activities	(1,487,633)	(294,907)	(368,465)	250,781	(13,653)

	As of December 31,				
	2006	2005	2004	2003	2002
	(In thousands of dollars)				
Balance Sheet Data					
Assets					
Cash and cash equivalents	$ 899	$ 1,552	$ 1,545	$ 1,377	$ 1,028
Other current assets	183,897	291,780	256,622	87,104	47,854
Property and equipment, net	2,107,524	2,251,887	2,184,962	965,748	502,065
Goodwill	158,515	173,858	170,467	147,251	—
Other assets	12,393	22,865	19,649	10,788	10,076
	$ 2,463,228	$2,741,942	$2,633,245	$1,212,268	$561,023
Liabilities and Stockholders' Equity					
Current liabilities	$ 460,192	$ 363,998	$ 426,395	$ 155,086	$ 86,175
Long-term debt	235,500	797,375	635,468	487,906	233,166
Other long-term liabilities	170,574	603,422	381,524	65,429	6,303
Deferred income taxes	466,279	258,810	319,483	149,591	61,559
Stockholders' equity	1,130,683	718,337	870,375	354,256	173,820
	$ 2,463,228	$2,741,942	$2,633,245	$1,212,268	$561,023

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.

Company Overview

We are an independent oil and gas company primarily engaged in the activities of acquiring, developing, exploiting, exploring and producing oil and gas properties in the United States. Our core areas of operations are:

- the Los Angeles and San Joaquin Basins onshore California;
- the Santa Maria Basin offshore California; and
- the Gulf Coast Basin onshore and offshore Louisiana, including the Gulf of Mexico.

Assets in our principal focus areas include mature properties with long-lived reserves and significant development and exploitation opportunities as well as newer properties with development, exploitation and exploration potential. Our primary sources of liquidity are cash generated from our operations and our senior revolving credit facility. At December 31, 2006 we had approximately $504 million of availability under our senior revolving credit facility. We believe that we have sufficient liquidity through our cash from operations and borrowing capacity under our senior revolving credit facility to meet our short-term and long-term normal recurring operating needs, derivative obligations, debt service obligations, contingencies, anticipated capital expenditures and expenditures under our stock repurchase program. In addition, the majority of our capital expenditures and expenditures under our stock repurchase program are discretionary and could be curtailed if our cash flows declined from expected levels.

Our cash flows depend on many factors, including the price of oil and gas, the success of our acquisition and drilling activities and the operational performance of our producing properties. We use derivative instruments to manage our commodity price risk. This practice may prevent us from receiving the full advantage of increases in oil or gas prices above the maximum fixed amount specified in the derivative agreement. The level of derivative activity depends on our view of market conditions, available derivative prices and our operating strategy (see "—Derivative Instruments and Hedging").

In September 2006 and November 2006 we completed property sales that generated approximately $1.6 billion of cash proceeds. We used the proceeds to repay the then outstanding balance on our senior revolving credit facility and short-term credit facility, redeem all $250 million outstanding principal of our 7.125% Senior Notes, purchase $274.9 million of the $275 million outstanding principal of our 8.75% Senior Subordinated Notes, and settle the $605 million liability associated with the elimination of our 2007 and 2008 crude oil collars (see "Liquidity and Capital Resources" and "Financing Activities").

Divestitures

On November 1, 2006 we closed the sale of certain non-producing oil and gas properties to Statoil. This transaction had an effective date of September 1, 2006. The Company received approximately $706 million in cash proceeds and recognized a $638 million pre-tax gain. Statoil has also been granted certain negotiation rights with respect to future sales of certain other PXP deepwater Gulf of Mexico exploration assets.

On September 29, 2006 we closed the sale of oil and gas properties to subsidiaries of Occidental. This transaction had an effective date of October 1, 2006. We received approximately $864 million in cash proceeds and recognized a $345 million pre-tax gain. As of December 31, 2005, our independent reserve engineers estimated these properties had proven reserves of approximately 45 million equivalent barrels of oil. On a barrel of oil equivalent basis, these properties represented approximately 12% of our sales volumes for the third quarter of 2006.

We follow the full cost method of accounting under which proceeds from the sale of oil and gas properties are accounted for as reductions to capitalized costs unless such sales involve a significant change in the relationship between capitalized costs and the estimated value of proved reserves, in which case a gain or loss is recognized. When a gain or loss is recognized, total capitalized costs within the cost center are allocated between the reserves sold and the reserves retained on the same basis used to compute amortization unless there are substantial economic differences between the properties sold and those retained, in which case capitalized costs are allocated on the basis of the relative fair values of the properties. With respect to the sale of properties to Occidental, capitalized costs were allocated on the basis of the relative fair values of the properties. With respect to the sale of properties to Statoil, capitalized costs consist of the costs of the prospects that were classified as costs not subject to amortization and were not part of the full cost center.

In May 2005 we closed the sale to XTO Energy, Inc. of interests in producing properties located in East Texas and Oklahoma for net proceeds of approximately $341 million. In December 2004, we completed the sale of certain properties located offshore California and onshore South Texas, New Mexico, and South Louisiana. These unrelated transactions included the divestment of 11 platforms in federal and state waters off the coast of California and three related onshore facilities and essentially all our remaining assets in South Texas and New Mexico. These divestments were conducted via negotiated and auction transactions. In aggregate, we received net proceeds of approximately $152 million from these transactions. We retained certain abandonment obligations in connection with the offshore California properties. During 2004 we also sold our interests in certain other non-core producing properties for aggregate net proceeds of approximately $28 million.

Acquisitions

In April 2005 we acquired certain California producing oil and gas properties, primarily located in the Los Angeles Basin of onshore California with some smaller properties located in adjacent Ventura County, from a private company for $117 million. In September 2005 we acquired an additional 16.7% interest in the Point Arguello Unit, Rocky Point development project and related facilities, offshore California, from subsidiaries of Chevron U.S.A. Inc. This acquisition increased our working interest in that operation to 69.3%.

In May 2004 we acquired Nuevo in a stock-for-stock transaction. In the acquisition, each outstanding share of Nuevo common stock was converted into 1.765 shares of PXP common stock and Nuevo became our wholly owned subsidiary. At the closing of this transaction we issued 36.5 million additional PXP common shares and assumed $303 million in debt and $115 million of $2.875 Term Convertible Securities, Series A, or TECONS. Prior to the acquisition, Nuevo was engaged in the upstream activities of acquiring, exploiting, developing and producing oil and gas primarily onshore and offshore California and in west Texas. We accounted for the transaction as a purchase under purchase accounting rules effective May 14, 2004.

Derivative Instruments and Hedging

During 2006, we eliminated all of our 2007 and 2008 crude oil collars and acquired downside crude oil price protection for a substantial amount of our estimated 2007 and 2008 production with $55 put option contracts. We paid $593 million to eliminate the collars which were for 22,000 barrels of oil per day for all of 2007 and 2008 with a floor price of $25.00 and an average ceiling price of $34.76. Approximately $170 million of mark-to-market losses related to the collars was recognized in our income statement in 2006 and $423 million in prior periods. We also recognized $12 million of interest expense in 2006 related to the elimination of the collars.

For 2007 and 2008 our derivative position consists exclusively of purchased put option contracts with a strike price of $55.00 on 50,000 barrels per day for 2007 and 42,000 barrels per day for 2008. The only cash settlements we are required to make on these contracts are option premiums and interest, which are expected to total approximately $111 million in 2007 and $58 million in 2008. In return, to the extent the daily average NYMEX price for West Texas Intermediate crude oil is less than $55.00, we will receive the difference between $55.00 and the daily average NYMEX price for West Texas Intermediate crude oil.

Since our remaining derivative position consists entirely of crude oil put options, there will continue to be volatility in derivative gains or losses on our income statement, however, our ultimate potential loss will be limited to the cost of the options.

General

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, gas and natural gas liquids. 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 and gas. Historically, the markets for oil and gas have been volatile and are likely to continue to be volatile in the future. The prices we receive for our oil and gas 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 and gas 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 and gas prices decline significantly 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 estimated proved reserves, our reserve volumes and our revenues, profitability and cash flow.

Our oil and gas production expenses include salaries and benefits of personnel involved in production activities, steam gas costs, 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 estimated proved reserves. For the purposes of computing depletion, estimated proved reserves are redetermined as of the end of each year and on an interim basis when deemed necessary.

General and administrative expenses ("G&A") consist primarily of salaries and related benefits of administrative personnel (including stock based compensation), office rent, systems costs and other administrative costs.

Results Overview

Our earnings are subject to volatility due to: (i) gains and losses on derivative contracts subject to mark-to-market accounting as changes occur in the NYMEX price indexes; and (ii) stock appreciation rights ("SARs") and certain of our restricted stock units, which are accounted for as liability awards under SFAS 123R and are remeasured to fair value each reporting period. The fair value of SARs and restricted stock units is related to the market price of our common stock and will fluctuate with movements in our stock price. Our results reflect the acquisition of Nuevo effective May 14, 2004.

In 2006 we reported net income of $597.5 million, or $7.64 per diluted share. Net income for the period includes a $983 million pre-tax gain on sales of oil and gas properties, a $298 million pre-tax derivative mark-to-market loss, debt extinguishment costs of $45.1 million and a $38 million gain on the termination of a merger agreement. Cash payments related to mark-to-market derivative contracts that settled during the period totaled $101 million for 2006. Our net income in 2006 includes a non-cash, after-tax expense related to the adoption of SFAS 123R of $2.2 million, or $0.03 per share.

In 2005, primarily as a result of a $636 million derivative mark-to-market loss, we reported a net loss of $214 million, or $2.75 per share compared to net income of $8.8 million, or $0.14 per diluted share for 2004. Cash payments related to mark-to-market derivative contracts that settled during the period totaled $280 million for 2005.

In 2004, primarily as a result of a $150 million derivative mark-to-market loss, we reported net income of $8.8 million, or $0.14 per diluted share. Cash payments related to mark-to-market derivative contracts that settled during the period totaled $32 million for 2004.

Results of Operations

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

	Year Ended December 31,		
	2006	2005	2004
Sales Volumes			
Oil and liquids sales (MBbls)	18,975	18,671	16,441
Gas (MMcf)			
Production	20,629	29,359	38,590
Used in steam operations	4,823	5,241	4,123
Sales (1)	15,806	24,118	34,467
MBOE			
Production	22,413	23,564	22,872
Sales (1)	21,609	22,691	22,185
Daily Average Volumes			
Oil and liquids sales (Bbls)	51,985	51,154	44,920
Gas (Mcf)			
Production	56,519	80,435	105,436
Used in steam operations	13,214	14,358	11,264
Sales (1)	43,305	66,077	94,172
BOE			
Production	61,405	64,560	62,493
Sales (1)	59,202	62,166	60,615
Unit Economics (in dollars) (2)			
Average NYMEX Prices			
Oil	$ 66.23	$ 56.61	$ 41.43
Gas	7.21	8.62	6.14
Average Realized Sales Price Before Derivative Transactions			
Oil (per Bbl)	$ 55.62	$ 46.76	$ 36.12
Gas (per Mcf)	6.73	7.15	5.90
Per BOE	53.76	45.96	35.92
Costs and Expenses per BOE			
Production costs			
Lease operating expenses	$ 8.32	$ 5.97	$ 5.36
Steam gas costs	2.95	3.32	1.77
Electricity	1.76	1.35	1.32
Production and ad valorem taxes	1.15	1.03	0.98
Gathering and transportation	0.31	0.43	0.33
DD&A (oil and gas properties)	8.96	7.39	5.93

(1) 2005 and 2004 amounts represent volumes presented on a basis consistent with 2006. See Note 2.

(2) Prior to 2006 gas revenues included amounts attributable to buy-sell contracts related to our thermal recovery operations in California and associated costs were included in steam gas costs. As a result of our adoption of EITF 04-13 effective January 1, 2006, in 2006 certain costs associated with such contracts are reflected as a reduction in gas revenues and the associated volumes are not included in sales volumes. Amounts per BOE reflected in the foregoing table are based on production volumes for 2005 and 2004 and sales volumes for 2006.

The following table reflects cash receipts (payments) made with respect to derivative contracts during the periods presented (in thousands):

	Year Ended December 31,		
	2006	2005	2004
Contracts accounted for using hedge accounting			
Oil sales	$ —	$ (53,044)	$(207,414)
Gas sales	—	(6,255)	(17,504)
Gas purchases	—	10,293	3,649
Elimination of crude oil swaps	—	(147,280)	—
Mark-to-market contracts			
Oil sales	(89,596)	(279,982)	(25,267)
Gas sales	—	—	(6,920)
Gas purchases	(11,425)	—	—
Elimination of crude oil collars (1)	(593,283)	(145,383)	—

(1) 2006 does not include interest paid of $12 million.

Comparison of Year Ended December 31, 2006 to Year Ended December 31, 2005

Oil and gas revenues. Oil and gas revenues increased $75.2 million, to $1,016.0 million for 2006 from $940.8 million for 2005 primarily due to higher realized prices.

Oil revenues excluding the effects of hedging, increased $182.4 million to $1.1 billion for 2006 from $873.1 million for 2005 reflecting higher realized prices ($165.5 million) and higher sales volumes ($16.9 million). Our average realized price for oil increased $8.86 to $55.62 per Bbl for 2006 from $46.76 per Bbl for 2005. The increase is primarily attributable to an improvement in the NYMEX oil price, which averaged $66.23 per Bbl in 2006 versus $56.61 per Bbl in 2005. Oil sales volumes increased 0.8 MBbls per day to 52.0 MBbls per day in 2006 from 51.2 MBbls per day in 2005 as higher sales volumes from our California properties was partially offset by lower volumes due to the property divestitures in 2006.

Hedging had the effect of decreasing our oil revenues by $145.8 million, or $7.68 per Bbl in 2006 compared to $139.1 million or $7.45 per Bbl in 2005. The 2006 amount represents the deferred losses related to our 2006 swaps that were terminated in 2005. The 2005 amount includes $106.2 million of deferred losses related to our 2005 swaps that were terminated in 2004. These losses were deferred in Accumulated Other Comprehensive Income ("OCI") and recognized as a reduction to oil revenues as the hedged production was sold.

Gas revenues, excluding the effects of hedging, decreased $103.5 million to $106.3 million in 2006 from $209.8 million in 2005 due to decreased sales volumes ($55.9 million), a decrease in revenues due to a change in the presentation of certain costs related to buy-sell contracts ($36.9 million) and lower realized prices ($10.7 million). Gas revenues for 2005 include $36.9 million attributable to buy-sell contracts related to our thermal recovery operations in California. As a result of our adoption of EITF 04-13 effective January 1, 2006 (see Note 1 to the consolidated financial statements), in 2006 certain costs associated with such contracts are reflected as a reduction in gas revenues. Our average realized price for gas was $6.73 per Mcf in 2006 compared to $7.15 per Mcf in 2005. Hedging had the effect of decreasing our 2005 gas revenues by $3.1 million or $0.10 per Mcf.

Gas sales volumes decreased from 66.1 MMcf per day in 2005 to 43.3 MMcf per day in 2006 primarily reflecting the effect of property divestitures in the second quarter of 2005 and the fourth quarter of 2006.

Lease operating expenses. Lease operating expenses increased $39.1 million, to $179.7 million in 2006 from $140.6 million in 2005. The increase is primarily attributable to higher expenditures for well workovers and repairs and maintenance, increased labor costs and general cost increases from service providers. On a per unit basis, lease operating expenses increased to $8.32 per BOE in 2006 versus $5.97 per BOE in 2005 due to increased costs and lower volumes.

Steam gas costs. Steam gas costs decreased $14.5 million, to $63.8 million in 2006 from $78.3 million in 2005. Steam gas costs for 2005 include certain costs ($36.9 million) attributable to buy-sell contracts that after the adoption of EITF 04-13 are included in gas revenues. On a basis comparable to 2006, 2005 steam gas costs would have been $41.3 million, or $1.75 per BOE, compared to $63.8 million, or $2.95 per BOE, in 2006, primarily reflecting higher steam volumes partially offset by a decrease in the cost of natural gas used in the process.

Electricity. Electricity increased $6.2 million, to $38.0 million in 2006 from $31.8 million in 2005, primarily reflecting higher cost for purchased electricity and an increase in usage. On a per unit basis, electricity increased to $1.76 per BOE in 2006 versus $1.35 per BOE in 2005.

Production and ad valorem taxes. Production and ad valorem taxes increased $0.3 million, to $24.8 million in 2006 from $24.5 million in 2005 primarily reflecting the effect of increased oil and gas prices partially offset by the effect of the property divestitures in 2005 and 2006.

Gathering and transportation expenses. Gathering and transportation expenses decreased $3.3 million, to $6.8 million in 2006 from $10.1 million in 2005 primarily reflecting the effect of the property divestitures in 2005 and 2006.

General and administrative expense. G&A expense decreased $4.4 million, to $123.1 million in 2006 from $127.5 million in 2005 due to lower stock based compensation expense ($52.2 million in 2006 versus $77.2 million in 2005) partially offset by increases in other G&A expenses ($70.9 million in 2006 versus $50.3 million in 2005). The decrease in stock based compensation in 2006 primarily reflects lower expense for SARs which fluctuates with changes in our stock price and other factors that impact fair value and approximately $19 million of expense in 2005 related to restricted stock units that vested based on the performance of our common stock. The increase in other G&A expenses is primarily due to increased compensation costs reflecting higher costs to attract and retain a highly qualified workforce, aircraft costs and contributions. G&A expense for 2006 includes $9.6 million in stock based compensation expense and $2.9 million in cash payments related to officer resignations and organizational changes.

G&A expense does not include amounts capitalized as part of our acquisition, exploration and development activities. Capitalized costs increased to $34.8 million in 2006 compared to $24.5 million in 2005, primarily reflecting increased costs.

Depreciation, depletion and amortization, or DD&A. DD&A expense increased $26.9 million, to $207.2 million in 2006 from $180.3 million in 2005. Approximately $25.5 million of the increase was attributable to our oil and gas DD&A, primarily due to a higher per unit rate. Our oil and gas unit of production rate increased to $8.96 per BOE in 2006 compared to $7.39 per BOE in 2005. The increase primarily reflects the effect of increased future development costs, higher cost reserve additions and exploration costs.

Accretion expense. Accretion expense increased $2.0 million, to $9.6 million in 2006 from $7.6 million in 2005, primarily reflecting higher estimated future costs of our abandonment obligations.

Gain on sale of oil and gas properties. On September 29 and November 1, 2006 we closed on sales of oil and gas properties and recognized pre-tax gains totaling $983.0 million (see "Company Overview—Property Divestitures").

Interest expense. Interest expense increased $9.3 million, to $64.7 million in 2006 from $55.4 million in 2005 primarily due to higher interest costs related to certain of our derivative transactions. Interest expense does not include interest capitalized on oil and gas properties not subject to amortization. We capitalized $7.9 million and $3.5 million of interest in 2006 and 2005, respectively.

Debt extinguishment costs. In connection with the retirement of our 7.125% Senior Notes and 8.75% Senior Subordinated Notes, in 2006 we recorded $45.1 million of debt extinguishment costs.

Gain (loss) on mark-to-market derivative contracts. We do not use hedge accounting for certain of our derivative instruments, because the derivatives do not qualify or we have elected not to use hedge accounting. Consequently, these derivative contracts are marked-to-market each quarter with fair value gains and losses, both realized and unrealized, recognized currently as a gain or loss on mark-to-market derivative contracts on the income statement. Cash flow is only impacted to the extent the actual settlements under the contracts result in making or receiving a payment from the counterparty.

As a result of the significant increase in oil prices, we recognized losses related to mark-to-market derivative contracts of $297.5 million and $636.5 million in 2006 and 2005, respectively. Cash payments related to these contracts that settled totaled $101.0 million and $280.0 million in 2006 and 2005, respectively. In addition, in 2005 we paid $145.4 million in connection with the elimination of our 2006 collars and in 2006 we paid $593.3 million in connection with the elimination of our 2007 and 2008 collars.

Gain on termination of merger agreement. On April 24, 2006 we announced that we had entered into a definitive agreement to acquire Stone Energy Corporation ("Stone") in a stock-for-stock transaction. On June 22, 2006 the agreement was terminated by Stone in order for Stone to enter into a merger agreement with another company. In connection with the termination of the merger agreement we received a termination fee of $43.5 million and recognized a gain, net of merger related costs, of $37.9 million.

Interest and other income. Interest and other income increased $2.2 million to $5.5 million in 2006 compared to $3.3 million in 2005.

Income tax expense. Our 2006 income tax expense was $384.9 million, reflecting an annual effective tax rate of 39%. Variances in our annual effective tax rate from the 35% federal statutory rate are caused by the effect of state income taxes and permanent differences primarily related to expenses that are not deductible because of Internal Revenue Service ("IRS") limitations. Our current tax expense primarily reflects the effect of the taxable gains on the sales of oil and gas properties during 2006 and the related effect of the utilization of net operating loss carryforwards and enhanced oil recovery ("EOR") credits.

EOR credits are credits against federal and state income taxes for certain costs related to extracting high-cost oil, utilizing certain prescribed "enhanced" (tertiary) recovery methods. EOR credits are subject to a phase out according to the level of average domestic crude oil prices. As a result of the increase in oil prices in 2005, companies did not earn EOR credits in 2006.

In 2007 we expect our overall effective tax rate to be in excess of 40% primarily reflecting the effect of state income taxes and permanent differences primarily related to expenses that are not deductible because of IRS limitations. In 2007 we expect our current tax expense to be significantly lower due to the absence of the previously discussed gains and increased capital spending.

Our 2005 income tax expense was a benefit of $130.9 million, reflecting an annual effective tax rate of 38%. Variances in the annual effective tax rate from the 35% federal statutory rate are caused by state income taxes, EOR credits and permanent differences primarily reflecting expenses that are not deductible because of IRS limitations.

Comparison of Year Ended December 31, 2005 to Year Ended December 31, 2004

Oil and gas revenues. Oil and gas revenues increased $271.4 million, to $940.8 million for 2005 from $669.4 million for 2004. The increase is primarily due to increased production volumes attributable to the properties acquired in the Nuevo acquisition and higher realized prices.

Oil revenues excluding the effects of hedging, increased $279.3 million to $873.1 million for 2005 from $593.8 million for 2004 reflecting higher realized prices ($175.0 million) and higher production ($104.3 million). Our average realized price for oil increased $10.64 to $46.76 per Bbl for 2005 from $36.12 per Bbl for 2004. The increase is primarily attributable to an improvement in the NYMEX oil price, which averaged $56.61 per Bbl in 2005 versus $41.43 per Bbl in 2004. Oil production increased to 51.2 MBbls per day in 2005 from 44.9 MBbls per day in 2004, primarily due to production attributable to the properties acquired in the Nuevo acquisition that were in our results for the full year 2005.

Hedging had the effect of decreasing our oil revenues by $139.1 million, or $7.45 per Bbl in 2005 compared to $145.8 million or $8.87 per Bbl in 2004. The 2005 amount includes $106.2 million of deferred losses related to 2005 swaps that were terminated in 2004. These losses were deferred in OCI until the production that was originally hedged was produced and delivered during 2005.

Gas revenues excluding the effects of hedging, decreased $17.7 million to $209.8 million in 2005 from $227.5 million in 2004 due to decreased production volumes ($66.0 million) partially offset by higher realized prices ($48.3 million). Our average realized price for gas was $7.15 per Mcf for 2005 compared to $5.90 per Mcf for 2004. Gas production decreased from 105.4 MMcf in per day 2004 to 80.4 MMcf per day in 2005 primarily due to the sale of our properties in East Texas and Oklahoma in the second quarter of 2005 and shut-in production due to hurricanes Katrina and Rita.

Hedging had the effect of decreasing our 2005 gas revenues by $3.1 million, or $0.10 per Mcf, and decreased our 2004 gas revenues by $6.1 million, or $0.16 per Mcf.

Lease operating expenses. Lease operating expenses increased $18.1 million, to $140.6 million in 2005 from $122.5 million in 2004. The increase is primarily attributable to costs attributable to properties acquired in the Nuevo acquisition and higher expenditures for well workovers. On a per unit basis, lease operating expenses increased to $5.97 per BOE in 2005 versus $5.36 per BOE in 2004 due to increased costs and lower production volumes.

Steam gas costs. Steam gas costs increased $37.8 million, to $78.3 million in 2005 from $40.5 million in 2004 primarily reflecting the steam costs attributable to properties acquired in the Nuevo acquisition.

Electricity. Electricity increased $1.7 million, to $31.8 million in 2005 from $30.1 million in 2004, primarily reflecting higher costs for purchased electricity. On a per unit basis, electricity increased to $1.35 per BOE in 2005 versus $1.32 per BOE in 2004.

Production and ad valorem taxes. Production and ad valorem taxes increased $2.2 million, to $24.5 million for 2005 from $22.3 million for 2004 primarily due to the properties acquired in the Nuevo acquisition and increased oil and gas prices.

Gathering and transportation expenses. Gathering and transportation expenses increased $2.5 million, to $10.1 million for 2005 from $7.6 million for 2004 primarily due to the properties acquired in the Nuevo acquisition.

General and administrative expense. G&A expense increased $35.5 million, to $127.5 million in 2005 from $92.0 million in 2004 due to higher stock based compensation expense ($77.2 million in 2005 versus $43.6 million in 2004) and increases in other G&A expenses ($50.3 million in 2005 versus $48.4 million in 2004). The increase in stock based compensation is primarily due to $19 million of expense in 2005 related to restricted stock units that vested based on the performance of our common stock and increased expense for restricted stock units and SARs. The increase in other G&A expenses is primarily due to increased costs resulting from the Nuevo acquisition and higher employee headcount and related compensation costs. G&A expense for 2004 includes $6.2 million of merger related costs associated with the Nuevo acquisition and a $6.8 million provision with respect to legal and regulatory matters, primarily related to leasehold ownership and operations and permit compliance matters.

G&A expense does not include amounts capitalized as part of our acquisition, exploration and development activities. We capitalized $24.5 million and $16.2 million of G&A expense in 2005 and 2004, respectively.

Depreciation, depletion and amortization, or DD&A. DD&A expense increased $40.9 million, to $180.3 million in 2005 from $139.4 million in 2004. Approximately $38.4 million of the increase was attributable to our oil and gas DD&A due to a higher per unit rate and higher production. Our oil and gas unit of production rate increased to $7.39 per BOE in 2005 compared to $5.93 per BOE in 2004. The increase primarily reflects the effect of property acquisitions, higher future development costs and 2005 capital costs for which there were no immediate reserve additions.

Interest expense. Interest expense increased $18.1 million, to $55.4 million for 2005 from $37.3 million for 2004 primarily due to higher outstanding debt as a result of the Nuevo acquisition and 2005 property acquisitions. Interest expense does not include interest capitalized on oil and gas properties not subject to amortization. We capitalized $3.5 million and $7.0 million of interest in 2005 and 2004, respectively.

Gain (loss) on mark-to-market derivative contracts. We do not use hedge accounting for certain of our derivative instruments, because the derivatives do not qualify or we have elected not to use hedge accounting. Consequently, these derivative contracts are marked-to-market each quarter with fair value gains and losses, both realized and unrealized, recognized currently as a gain or loss on mark-to-market derivative contracts on the income statement. Cash flow is only impacted to the extent the actual settlements under the contracts result in making or receiving a payment from the counterparty.

As a result of the significant increase in oil prices, we recognized a $636.5 million loss related to mark-to-market derivative contracts in 2005. Cash payments related to these contracts that settled in 2005 totaled $280.0 million. In addition, in 2005 we paid $145.4 million in connection with the elimination of our 2006 oil collars. In 2004 we recognized a loss on mark-to-market derivative contracts of $150.3 million. Cash payments related to these contracts that settled in 2004 totaled $32.2 million.

Debt extinguishment costs. In connection with the retirement of the debt assumed in the acquisition of Nuevo, in 2004 we recorded $19.7 million of debt extinguishment costs.

Income tax expense. Our 2005 income tax expense was a benefit of $130.9 million, reflecting an annual effective tax rate of 38%. Variances in our annual effective tax rate from the 35% federal statutory rate are caused by state income taxes, Enhanced Oil Recovery (EOR) credits and permanent differences primarily reflecting expenses that are not deductible because of IRS limitations. Our 2005 income tax expense includes a charge of $3.3 million to deferred income tax expense to reflect an increase in the estimated California apportionment factor as a result of the sale of the Company's properties in East Texas and Oklahoma and the purchase of California.

In 2004 our income tax expense was a benefit of $6.8 million that included a $9.5 million deferred benefit related to EOR credits and a $2.8 million deferred benefit related to state income taxes as a result of the restructuring of certain subsidiaries. These benefits were partially offset by approximately $4.0 million of expenses that are not deductible because of IRS limitations. Our 2004 income tax expense included $0.7 million of state income taxes (net of federal benefit).

Liquidity and Capital Resources

In September 2006 and November 2006 we completed property sales that generated approximately $1.6 billion of cash proceeds. We used the proceeds to repay the then outstanding balance on our senior revolving credit facility and short-term credit facility, redeem all $250 million outstanding principal of our 7.125% Senior Notes, purchase $274.9 million of the $275 million outstanding principal of our 8.75% Senior Subordinated Notes, and settle the $605 million liability associated with our 2007 and 2008 crude oil collars. See Company Overview for a more complete discussion of the sales transactions

Our primary sources of liquidity are cash generated from our operations and our revolving credit facility. At December 31, 2006 we had approximately $504 million of availability under our revolving credit facility. We have made and will continue to make substantial capital expenditures for the acquisition, exploitation, development, exploration and production of oil and gas. We have a 2007 capital budget of approximately $600 million and approximately $206 million remaining authorization under our stock repurchase program. We believe that we have sufficient liquidity through our cash from operations and borrowing capacity under our revolving credit facility to meet our short-term and long-term normal recurring operating needs, derivative obligations, current income tax obligations, debt service obligations, expenditures under our stock repurchase program, contingencies and anticipated capital expenditures.

Our cash flows depend on many factors, including the price of oil and gas, the success of our acquisition and drilling activities and the operational performance of our producing properties. We use derivative instruments to manage our commodity price risk. This practice may prevent us from receiving the full advantage of increases in oil or gas prices above the maximum fixed amount specified in the derivative agreement. The level of derivative activity depends on our view of market conditions, available derivative prices and our operating strategy. In addition, the majority of our capital expenditures and expenditures under our stock repurchase program are discretionary and could be curtailed if our cash flows declined from expected levels.

Working Capital

At December 31, 2006 we had a working capital deficit of approximately $275 million. Our working capital deficit is affected by fluctuations in the fair value of our commodity derivative instruments and stock appreciation rights. As of December 31, 2006, we had net short-term liabilities of $64 million and $35 million for derivatives and stock appreciation rights, respectively. In addition, we had $94 million of current income taxes payable as of December 31, 2006 primarily as a result of the oil and gas property sales that we completed during 2006 (see "Company Overview—Property Divestitures"). Excluding such items our working capital deficit was approximately $82 million. We generally have a working capital deficit because we use excess cash to pay down borrowings under our senior revolving credit facility.

Financing Activities

Senior Revolving Credit Facility. On May 16, 2005, we entered into an Amended and Restated Credit Agreement (the "Amended Credit Agreement") which established the facility size at $750 million. The borrowing base is redetermined on a semi-annual basis, with PXP and the lenders each having the right to one annual interim unscheduled redetermination, and may be adjusted based on PXP's oil and gas properties, reserves, other indebtedness and other relevant factors. Our borrowing base was redetermined in November 2006 and is currently $1.25 billion. At this time we have not elected to seek an increase in the size of our credit facility. Additionally, the Amended Credit Agreement contains a $75 million sub-limit for letters of credit. The Amended Credit Agreement matures on May 16, 2010. Collateral consists of 100% of the shares of stock of substantially all our domestic subsidiaries and mortgages covering at least 80% of the total present value of our domestic oil and gas properties.

The Amended Credit Agreement contains negative covenants that limit our ability, as well as the ability of our restricted subsidiaries, among other things, to incur additional debt, pay dividends on stock, make distributions of cash or property, change the nature of our business or operations, redeem stock or redeem subordinated debt, make investments, create liens, enter into leases, sell assets, sell capital stock of subsidiaries, guarantee other indebtedness, enter into agreements that restrict dividends from subsidiaries, enter into certain types of swap agreements, enter into gas imbalance or take-or-pay arrangements, merge or consolidate and enter into transactions with affiliates. In addition, we are required to maintain a current ratio, which includes availability under the Amended Credit Agreement, of at least 1.0 to 1.0 and a ratio of debt to EBITDAX (as defined) of no greater than 4.25 to 1.00.

The effective interest rate on our borrowings under the Amended Credit Agreement was 6.4% at December 31, 2006. At that date we were in compliance with the covenants contained in the Amended Credit Agreement and could have borrowed the full amount available under the Amended Credit Agreement.

7.125% Senior Notes and 8.75% Senior Subordinated Notes. On November 3, 2006 we made payments totaling $268.6 million to retire all $250 million outstanding principal amount of our 7.125% Senior Notes due 2014 (the "Senior Notes"). The redemption price of $1.074.50 per $1,000 principal amount is based on a "make-whole" calculation tied to a comparable United States Treasury security.

On November 3, 2006 we made payments totaling $291.9 million to retire $274.9 million of the $275 million outstanding principal amount of our 8.75% Senior Subordinated Notes due 2012 (the "Senior Subordinated Notes"). The purchase price of $1,042.07 per $1,000 principal amount was based on a 50 basis point spread over a reference U.S. Treasury security, as determined on October 19, 2006. The payment to holders who provided consents to eliminate substantially all the restrictive covenants and certain events of default from the indenture governing the Senior Subordinated Notes included a consent payment of $20.00 per $1,000 principal amount of notes tendered (a total of $5.5 million).

In the fourth quarter of 2006 we recorded a charge to earnings in connection with the debt retirement transactions of $45.1 million.

Short-term Credit Facility. We have a short-term credit facility under the terms of which we may make borrowings from time to time until May 1, 2007, not to exceed at any time the maximum principal amount of $25.0 million. No advance under the short-term facility may have a term exceeding fourteen days and all amounts outstanding are due and payable no later than May 1, 2007. Each advance under the short-term facility shall bear interest at a rate per annum mutually agreed on by the bank and the Company. No amounts were outstanding under the short-term credit facility at December 31, 2006.

Shelf Registration. We have filed with the Securities and Exchange Commission a universal shelf registration statement, which became effective May 2, 2005, that allows us to issue up to $500 million of debt and/or equity securities. The prices and terms of the debt and/or equity securities will be determined at the time of the sale.

Cash Flows

	Year Ended December 31,		
	2006	2005	2004
		(in millions)	
Cash provided by (used in):			
Operating activities	$ 675.0	$ 463.3	$ 363.2
Investing activities	812.0	(168.4)	5.4
Financing activities	(1,487.6)	(294.9)	(368.4)

Net cash provided by operating activities was $675.0 million in 2006, $463.3 million in 2005 and $363.2 million in 2004. The 2005 amount was reduced by the $147.3 million payment to eliminate all of our 2006 oil price swaps. The increases in net cash provided by operating activities in 2006 and 2005 are primarily a result of increased oil and gas prices. As discussed below, certain of our derivative cash payments are classified as a financing or investing activity.

Net cash provided by investing activities was $812.0 million in 2006, reflecting property sales proceeds of $1.6 billion, net of additions to oil and gas properties of $634.3 million and derivative settlements of $93.4 million. Net cash used in investing activities was $168.4 million in 2005 primarily reflecting additions to oil and gas properties of $509.1 million partially offset by property sales proceeds of $346.5 million. Net cash provided by investing activities was $5.4 million in 2004, primarily a result of property sales proceeds of $239.0 million, net of additions to oil and gas properties of $211.4 million.

Under SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities", certain of our derivatives are deemed to contain a significant financing element and cash settlements with respect to such derivatives are required to be reflected as financing activities. Net cash used in financing activities in 2006 was $1.5 billion, primarily reflecting payments totaling $524.9 million to retire the Senior Notes and the Senior Subordinated Notes, $298.4 million to repurchase stock, $621.9 million in financing derivative settlements and $36.5 million in net repayments under our revolving credit facilities. Net cash used in financing activities in 2005 was $294.9 million, primarily reflecting $162.0 million in net borrowings under our credit facility and the payment of $459.5 million in financing derivative settlements. Net cash used in financing activities in 2004 was $368.4 million. During 2004 borrowings under our credit facility decreased $101.0 million and we received $248.7 million in proceeds from the issuance of our 7.125% Senior Notes. These proceeds and funds generated by our operations were used to retire $405.0 million in debt assumed in the Nuevo acquisition and to pay $9.3 million in debt financing costs and $103.5 million in derivative settlements.

Capital Requirements

We have made and will continue to make substantial capital expenditures for the acquisition, exploitation, development, exploration and production of oil and gas. We have a capital budget for 2007, excluding acquisitions, of approximately $600 million. We believe that we have sufficient liquidity through our cash from operations and borrowing capacity under our revolving credit facility to meet our short-term and long-term normal recurring operating needs, derivative obligations, debt service obligations, expenditures under our stock repurchase program, contingencies and anticipated capital expenditures. In addition, the majority of our capital expenditures and expenditures under our stock repurchase program are discretionary and could be curtailed if our cash flows declined from expected levels.

Stock Repurchase Program

Our Board of Directors has authorized the repurchase of up to $500 million of our common stock. The shares will be repurchased from time to time in open market transactions or privately negotiated transactions at our discretion, subject to market conditions and other factors. As of January 31, 2007 we had made purchases totaling $295 million under this program.

Commitments and Contingencies

Contractual obligations. At December 31, 2006, the aggregate amounts of contractually obligated payment commitments for the next five years are as follows (in thousands):

	2007	2008 and 2009	2010 and 2011	Thereafter
Operating leases	$ 7,081	$ 13,168	$ 10,307	$16,653
Commodity derivative contracts	110,987	58,212	—	—
Long-term debt	—	—	236,000	—
Interest on debt	16,375	32,755	6,177	—
Other	300	4,902	1,240	12,598
	$134,743	$109,037	$253,724	$29,251

Operating leases relate primarily to obligations associated with aircraft, our office facilities and certain cogeneration operations in California. The obligation for commodity derivative contracts represents the cost to purchase crude oil put options that will be paid when such options are settled.

The long-term debt and interest payments amounts consist of amounts due under our credit facility and interest payments to maturity. The principal amount under our credit facility varies based on our cash inflows and outflows and the amounts reflected in this table assume the principal amount outstanding at December 31, 2006 remains outstanding to maturity with interest and commitment fees calculated at the rates in effect at that date.

Our liabilities also include:

- Asset retirement obligations ($3.9 million current and $133.4 million long-term) that represent the estimated fair value at December 31, 2006 of our obligations with respect to the retirement/abandonment of our oil and gas properties. Each reporting period the liability is accreted to its then present value. The ultimate settlement amount and the timing of the settlement of such obligations is unknown because they are subject to, among other things, federal, state and local regulation and economic factors. See Note 5 to the Consolidated Financial Statements.
- Stock appreciation rights ($57.4 million current and $3.9 million long-term) that represent the net liability for the deemed vested portion of SARs. The liability at December 31, 2006 is calculated based on our closing stock price at that date. The ultimate settlement amount of such liability is unknown because settlements are based on the market price of our common stock at the time the SARs are exercised. At December 31, 2006 we had approximately 2.2 million SARs outstanding of which 1.4 million were vested. If all of the vested SARs were

exercised, based on $47.53, the price of our common stock as of December 31, 2006, we would pay $52.3 million to holders of the SARs. In 2006 we made cash payments of $17.7 million for SARs that were exercised during that period. See "Critical Accounting Policies and Factors that May Affect Future Results – Stock based compensation".

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. However, in some instances, we have received an indemnity in connection with such purchase. There can be no assurance that we will be able to collect on these indemnities. Often these regulations are more burdensome on older properties that were operated before the regulations came into effect such as some of our properties in California that have operated for over 90 years. We have established policies for continuing compliance with environmental laws and regulations. We also 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.

Plugging, Abandonment and Remediation Obligations. Consistent with normal industry practices, substantially all of 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 the purchaser assumes the obligation to plug and abandon wells that are part of such assets. However, in some instances, we received an indemnity with respect to those costs. We cannot assure you that we will be able to collect on these indemnities.

We estimate our 2007 cash expenditures related to plugging, abandonment and remediation will be approximately $4 million. Due to the long life of our onshore California reserve base we do not expect our cash outlays for such expenditures for these properties will increase significantly in the next several years. At the Arguello Unit, offshore California, the companies from which we purchased our interests retained responsibility for the majority of the abandonment costs, including: (1) removing, dismantling and disposing of the existing offshore platforms; (2) removing and disposing of all existing pipelines; and (3) removing, dismantling, disposing and remediating all existing onshore facilities. We are responsible for our 69.3% share of other abandonment costs which primarily consist of well-bore abandonments and conductor removals.

In connection with the sale of certain properties offshore California in December 2004 we retained the responsibility for certain abandonment costs, including removing, dismantling and disposing of the existing offshore platforms. The present value of such abandonment costs, $39 million ($78 million undiscounted), are included in our asset retirement obligation as reflected on our consolidated balance sheet. In addition, we agreed to guarantee the performance of the purchaser with respect to the remaining abandonment obligations related to the properties (approximately $46 million). To secure its abandonment obligations the purchaser of the properties is required to periodically deposit funds into an escrow account. At December 31, 2006 the escrow account had a balance of $3 million. The fair value of our guarantee, $0.3 million, is included in Other Long-Term Liabilities in the Consolidated Balance Sheet.

For a further discussion of our obligations to incur plugging, abandonment and remediation costs, see Items 1 and 2—. "Business and Properties—Plugging, Abandonment and Remediation Obligations".

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 crude oil and natural gas properties and the marketing, transportation and storage of crude oil. It is management's belief that such commitments will be met without a material adverse effect on our financial position, results of operations or cash flows.

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, oil spills, releases of 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. Our operations in California, including transportation of oil by pipelines within the city and county of Los Angeles, are especially susceptible to damage from earthquakes and involve increased risks of personal injury, property damage and marketing interruptions because of the population density of southern California. 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. We maintain coverage for earthquake damages in California but this coverage may not provide for the full effect of damages that could occur and we may be subject to additional liabilities. 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.

Sale of Nuevo's Congo operations. Upon our acquisition of Nuevo, we became a party to an existing agreement between Nuevo, CMS NOMECO Oil & Gas Co. (CMS) and a third party. Under the agreement, Nuevo and CMS may be liable to the third party for the recapture of dual consolidated losses (DCLs) in connection with each company's 1995 acquisition of Congolese properties. Nuevo and CMS agreed to indemnify each other for any act that would cause the third party to experience a liability from the recapture of DCLs as a result of a triggering event.

CMS sold its interest in the Congolese properties to a subsidiary of Perenco, S.A. (Perenco) in 2002. In 2004 Nuevo sold its interest in the Congolese properties to Perenco. Both CMS and Perenco, have received from the Internal Revenue Service (IRS), in accordance with the U.S. consolidated return regulations, a closing agreement confirming that the transaction will not trigger recapture. We and Perenco have finalized closing agreements with the IRS confirming that neither our merger with Nuevo, nor the sale of our interest in the Congolese properties to Perenco will trigger recapture. There is no remaining contingent liability relative to Nuevo's former interest. The estimated remaining contingent liability relative to CMS' former interest is $19.5 million, for which we would be jointly liable. We believe the occurrence of a triggering event in the future is remote and we do not believe the agreements will have a material adverse affect upon us.

Industry Concentration

Financial instruments which potentially subject us to concentrations of credit risk consist principally of accounts receivable with respect to our oil and gas operations and derivative instruments related to our hedging activities. During 2006, 2005 and 2004 sales to ConocoPhillips accounted for 54%, 44% and 33%, respectively, of our total revenues and sales to PMLP accounted for 41%, 38% and 33%, respectively, of our total revenues. During such periods no other purchaser accounted for more than 10% of our total revenues. The loss of any single significant customer or contract could have a material adverse short-term effect, however, we do not believe that the loss of any single significant customer or contract would materially affect our business in the long-term. We believe such purchasers could be replaced by other purchasers under contracts with similar terms and conditions. However, their role as the purchaser of a significant portion of our oil production does have the potential to impact our overall exposure to credit risk, either positively or negatively, in that they may be affected by changes in economic, industry or other conditions.

The five financial institutions that are contract counterparties for our derivative commodity contracts all have Standard & Poor's ratings of A or better and all such financial institutions are participating lenders in our revolving credit facility. At December 31, 2006 we were in a net liability position with all such counterparties.

There are a limited number of alternative methods of transportation for our production. Substantially all of our oil and gas production is transported by pipelines 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 and gas production which could have a negative impact on future results of operations or cash flows.

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 and gas have historically been volatile. Decreases in oil and gas prices from current levels will adversely affect our revenues, results of operations, cash flows and proved reserve volumes and value. 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 derivative arrangements relating to a portion of our oil and gas production to achieve a more predictable cash flow, as well as to reduce our exposure to adverse price fluctuations. Derivative instruments used are typically fixed price swaps and collars and purchased puts and calls. While the use of these types of 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 and cash flows is limited when commodity prices increase.

We do not use hedge accounting for our derivative instruments, because the derivatives do not qualify or we have elected not to use hedge accounting. These derivative contracts are marked-to-market each quarter with fair value gains and losses, both realized and unrealized, recognized currently as a gain or loss on mark-to-market derivative contracts on the income statement. Consequently, we expect continued volatility in our reported earnings as changes occur in the NYMEX indexes. Since our remaining derivative position consists entirely of crude oil put options, there will continue to be volatility in derivative gains or losses on our income statement, however, our ultimate potential loss will be limited to the cost of the options. Cash flow is only impacted to the extent the actual settlements under the contracts result in making or receiving a payment from the counterparty.

The estimation of fair values of derivative instruments requires substantial judgment. We estimate the fair values of our derivatives using an option-pricing model. The option-pricing model utilizes various factors including NYMEX and over-the-counter price quotations, volatility and the time value of options. The estimated future prices are compared to the prices fixed by the agreements and the resulting estimated future cash inflows (outflows) over the lives of the derivative instruments are discounted using rates under our revolving credit facility. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts, regional price differentials and interest rates.

For a further discussion concerning our risks related to oil and gas prices and our hedging programs, see Item 7A—"Quantitative and Qualitative Disclosures about Market Risks".

Write-downs under full cost ceiling test rules. Under the SEC's full cost accounting rules we review the carrying value of our proved oil and gas properties each quarter. Under these rules, capitalized costs of proved oil and gas properties (net of accumulated depreciation, depletion and amortization, and deferred income taxes) may not exceed a "ceiling" equal to:

- the 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 and gas production at the oil and gas prices in effect at the end of each fiscal quarter and require a write-down if our capitalized costs exceed this "ceiling," even if prices declined for only a short period of time. We have had no write-downs due to these ceiling test limitations since 1998. Given the volatility of oil and gas prices, it is likely that our estimate of discounted future net revenues from proved oil and gas reserves will change in the near term. If oil and gas prices decline significantly 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. At December 31, 2006, the ceiling with respect to our oil and gas properties exceeded the net capitalized costs of those properties by approximately $1.4 billion.

Oil and gas reserves. Our proved reserve information is 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 standardized measure reflects the current market 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.

A large portion of our reserve base (approximately 95% at December 31, 2006) 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.

Future development and abandonment costs. Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment.

Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, water depth, reservoir depth and characteristics, currently available procedures and consultations with engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis. Changes in estimated future abandonment costs would affect our liability for asset retirement obligations, future accretion expense and DD&A.

DD&A. Our rate for 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.

Based on our estimated proved reserves and our net oil and gas properties subject to amortization at December 31, 2006: (i) a 5% increase in our costs subject to amortization would increase our DD&A rate by approximately $0.53 per BOE and (ii) a five percent positive or negative revision to proved reserves would decrease or increase our DD&A rate by approximately $0.50 per BOE.

Stock based compensation. Under SFAS 123R SARs certain of our restricted stock units are considered liability awards and are remeasured to fair value each reporting period with changes in fair value reported in earnings. As a result, we expect volatility in our earnings as our stock price changes.

We utilize the Black-Scholes option pricing model to measure the fair value of our SARs and in the case of restricted stock unit grants that include common stock price based performance targets we utilize a Monte-Carlo simulation model to estimate the fair value and the number of restricted stock units expected to be issued in the future. Expected volatility is based on the historical volatility of our common stock and other factors. We use historical experience with exercise and post exercise behavior to determine expected life. The use of such models requires substantial judgement with respect to expected life, volatility, expected returns and other factors.

We recognized $55 million, $78 million and $44 million of stock based compensation expense for the years ended December 31, 2006, 2005 and 2004, respectively.

Goodwill. In a purchase transaction, goodwill represents the excess of the purchase price plus the liabilities assumed, including deferred income taxes recorded in connection with the merger, over the fair value of the net assets acquired. At December 31, 2006 goodwill totaled $159 million and represented approximately 6% of our total assets.

We account for goodwill in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" ("SFAS 142'). Goodwill is not amortized, it is tested at least annually for impairment at a level of reporting referred to as a reporting unit. Impairment is the condition that exists when the carrying amount of goodwill exceeds its implied fair value. A two-step impairment test is used to identify potential goodwill impairment and measure the amount of a goodwill impairment loss to be recognized (if any). The first step of the goodwill impairment test, used to identify potential impairment, compares the fair value of a reporting unit with its carrying amount, including goodwill. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not impaired, thus the second step of the impairment test is unnecessary.

The second step of the goodwill impairment test, used to measure the amount of impairment loss, compares the implied fair value of reporting unit goodwill with the carrying amount of that goodwill. If the carrying amount of reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to that excess. The loss recognized cannot exceed the carrying amount of goodwill.

We follow the full cost method of accounting and all of our operations are located in the United States. We have determined that for the purpose of performing an impairment test in accordance with SFAS 142, we have one reporting unit. SFAS 142 states that quoted market prices in active markets are the best evidence of fair value and shall be used as the basis for the measurement, if available. Accordingly, we use the quoted market price of our common stock to determine the fair value of our reporting unit.

An impairment of goodwill could significantly reduce earnings during the period in which the impairment occurs and would result in a corresponding reduction to goodwill and stockholders' equity. The most significant factors that could result in the impairment of our goodwill would be significant declines in oil and gas prices and/or estimated reserve volumes which would result in a decline in the fair value of our reporting unit.

Recent Accounting Pronouncements

In February 2006, the FASB issued SFAS No. 155 "Accounting for Certain Hybrid Financial Instruments and Amendment to FASB Statements No. 133 and 140" ("SFAS 155") which eliminates the exemption from applying SFAS No. 133 to interests in securitized financial assets so that similar instruments are accounted for similarly regardless of the form of the instruments. SFAS 155 also allows the election of fair value measurement at acquisition, at issuance, or when a previously recognized financial instrument is subject to a remeasurement event. Adoption is effective for all financial instruments acquired or issued after the beginning of the first fiscal year that begins after September 15, 2006. Early adoption is permitted. The adoption of SFAS 155 is not expected to have a material effect on our consolidated financial position, results of operations or cash flows.

In March 2006, the FASB issued SFAS No. 156 "Accounting for Servicing of Financial Assets an Amendment of FASB Statement No. 140" ("SFAS 156") which requires all separately recognized servicing assets and servicing liabilities be initially measured at fair value. SFAS 156 permits, but does not require, the subsequent measurement of servicing assets and servicing liabilities at fair value. Adoption is required as of the beginning of the first fiscal year that begins after September 15, 2006. Early adoption is permitted. The adoption of SFAS 156 is not expected to have a material effect on our consolidated financial position, results of operations or cash flows.

In June 2006, the FASB issued FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes (an interpretation of FASB Statement No. 109)" ("FIN 48"). This interpretation was issued to clarify the accounting for uncertainty in income taxes recognized in the financial statements by prescribing a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The provisions of FIN 48 are effective beginning January 1, 2007 with the cumulative effect of the change in accounting principle recorded as an adjustment to the opening balance of retained earnings, goodwill, deferred income taxes and income taxes payable in the consolidated balance sheet. While we are still evaluating our tax positions, we do not anticipate that FIN 48 will have a material impact on our consolidated financial statements.

In September 2006, the FASB issued SFAS 157, "Fair Value Measurements" which is effective for fiscal years beginning after November 15, 2007 and for interim periods within those years. This statement defines fair value, establishes a framework for measuring fair value and expands the related disclosure requirements. We are currently evaluating the potential impact of this statement.

In September 2006, the FASB issued FASB Staff Position AUG AIR-1, "Accounting for Planned Major Maintenance Activities" which is effective for fiscal years beginning after December 15, 2006. This position statement eliminates the accrue-in-advance method of accounting for planned major maintenance activities. We do not expect this pronouncement to have a significant impact on our consolidated financial position, results of operations or cash flows.

In September 2006, the SEC Staff issued Staff Accounting Bulletin No. 108 "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" ("SAB 108"), in an effort to address diversity in the accounting practice of quantifying misstatements and the potential for improper amounts on the balance sheet. Prior to the issuance of SAB 108, the two methods used for quantifying the effects of financial statement errors were the "roll-over" and "iron curtain" methods. Under the "roll-over" method, the primary focus is the income statement, including the reversing effect of prior year misstatements. The criticism of this method is that misstatements can accumulate on the balance sheet. The "iron curtain" method focuses on the effect of correcting the ending balance sheet, with less importance on the reversing effects of prior year errors in the income statement. SAB 108 establishes a "dual approach" which requires the quantification of the effect of financial statement errors on each financial statement, as well as related disclosures. Public companies are required to record the cumulative effect of initially adopting the "dual approach" method in the first year ending after November 16, 2006 by recording any necessary corrections to asset and liability balances with an offsetting adjustment to the opening balance of retained earnings. The use of this cumulative effect transition method also requires detailed disclosures of the nature and amount of each error being corrected and how and when they arose. The adoption of SAB 108 had no impact on our consolidated financial position, results of operations or cash flows.

Item 7A. *Qualitative And Quantitative Disclosures About Market Risk*

Commodity Price Risk

Our primary market risk is oil and gas commodity prices. Historically the markets for oil and gas have been volatile and are likely to continue to be volatile in the future. We use various derivative instruments to manage our exposure to commodity price risk on sales of oil and gas. All derivative instruments are recorded on the balance sheet at fair value. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in fair value, both realized and unrealized, are recognized currently in our income statement as a gain or (loss) on mark-to-market derivative contracts. Cash flows are only impacted to the extent the actual settlements under the contracts result in making a payment to or receiving a payment from the counterparty. If a derivative is designated as a cash flow hedge and qualifies for hedge accounting, any unrealized gain or loss is deferred in OCI, a component of Stockholders' Equity, until the hedged oil and gas production is sold. Realized gains and losses on derivative instruments that are designated as a hedge and qualify for hedge accounting are generally included in oil and gas revenues in the period the hedged volumes are sold. Gains and losses deferred in OCI related to cash flow hedges for which hedge accounting has been discontinued remain in OCI until the related product has been delivered.

See Note 4 to the Consolidated Financial Statements—"Derivative Instruments and Hedging Activities" for a discussion of our derivative activities.

During 2006, we eliminated all of our 2007 and 2008 crude oil collars and acquired downside crude oil price protection for a substantial amount of our estimated 2007 and 2008 production with $55 put option contracts. We paid $593 million to eliminate the collars which were for 22,000 barrels of oil per day for all of 2007 and 2008 with a floor price of $25.00 and an average ceiling price of $34.76. Approximately $170 million of mark-to-market losses related to the collars was recognized in our income statement in 2006 and $423 million in prior periods. We also recognized $12 million of interest expense in 2006 related to the elimination of the collars.

At December 31, 2006 we had the following open commodity derivative positions, none of which were designated as hedging instruments:

Period	Instrument Type	Daily Volumes	Average Price	Index
Sales of Crude Oil Production				
2007				
Jan-Dec	Put options	50,000 Bbls	$55.00 Strike price	WTI
2008				
Jan-Dec	Put options	42,000 Bbls	$55.00 Strike price	WTI

The only cash settlements we are required to make on these put contracts are option premiums and interest, which are expected to total approximately $111 million in 2007 and $58 million in 2008. Such amounts are not included in the fair value of derivatives not designated as hedging instruments in the following table.

The fair value of outstanding crude oil commodity derivative instruments at December 31, 2006 and the change in fair value that would be expected from a 10% price increase is (in millions):

	Fair Value	Effect of 10% Price Increase
Derivatives not designated as hedging instruments	$56.8	$(26.9)

The fair value of the commodity derivative contracts are estimated based on quoted prices from independent reporting services compared to the contract price of the agreement, and approximate the gain or loss that would have been realized if the contracts had been closed out at period end. All 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% increase 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% change in prompt month 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.

The five financial institutions that are contract counterparties for our derivative commodity contracts all have Standard & Poor's ratings of A or better and all such financial institutions are participating lenders in our revolving credit facility. At December 31, 2006 we were in a net liability position with all such counterparties.

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

Price differentials. Our realized wellhead oil and gas prices are lower than the NYMEX index level as a result of area and quality differentials. See Items 1 and 2. Business and Properties—Product Markets and Major Customers.

Approximately 80% of our gas production is sold monthly off of industry recognized, published index pricing and the remainder is priced daily on the spot market. Fluctuations between the two pricing mechanisms can significantly impact the overall differential to the Henry Hub.

Interest Rate Risk

We are exposed to market risk due to the floating interest rates on our senior revolving credit facility and our short-term credit facility. At December 31, 2006, $236 million was outstanding under our senior revolving credit facility at an effective interest rate of 6.4%. No amounts were outstanding under our short-term credit facility at December 31, 2006. The carrying value of our senior revolving credit facility approximates its fair value, as interest rates are variable, based on prevailing market rates. Based on the $236 million outstanding under our senior revolving credit facility at December 31, 2006, on an annualized basis a 1% change in the effective interest rate would result in a $2.3 million change in our interest costs.

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

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

Item 9. ***Changes In And Disagreements With Accountants On Accounting And Financial Disclosure***

Not Applicable.

Item 9A. ***Controls And Procedures***

Conclusion Regarding the Effectiveness of Disclosure 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) and 15d-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 believe that the disclosure controls and procedures as of December 31, 2006 were 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.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, the Company's principal executive and principal financial officers and implemented by the Company's Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that: (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2006.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Controls

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2006 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information***

Not Applicable

PART III

Item 10. *Directors, Executive Officers And Corporate Governance*

Information regarding our directors and executive officers will be included in an amendment to this Form 10-K or in the proxy statement for the 2007 annual meeting of stockholders, in either case, to be filed within 120 days after December 31, 2006, and is incorporated by reference to this report.

Directors and Executive Officers of Plains Exploration & Production Company

Listed below are our directors and executive officers, their age as of January 31, 2007 and their business experience for the last five years.

Directors

James C. Flores, age 47, Chairman of the Board, Chief Executive Officer and a Director since September 2002 and President since March 2004. He has been Chairman of the Board and Chief Executive Officer of Plains since December 2002, and President since March 2004. He was also Chairman of the Board of Plains Resources, Inc. ("Plains Resources," now known as Vulcan Energy Corporation) from May 2001 to June 2004 and is currently a director of Vulcan Energy. He was Chief Executive Officer of Plains Resources from May 2001 to December 2002. He was Co-founder as well as Chairman, Vice Chairman and Chief Executive Officer at various times from 1992 until January 2001 of Ocean Energy, Inc., an oil and gas company.

Isaac Arnold, Jr., age 71, Director since May 2004. He also was a director of Nuevo Energy Company from 1990 to May 2004. Mr. Arnold currently serves as Chairman of the Board of Quintana Petroleum Corporation. He has been a director of Legacy Holding Company since 1989 and Legacy Trust Company since 1997 and is currently Director Emeritus of both. He has been a director of Cullen Center Bank & Trust since its inception in 1969 and has been a director of Cullen/Frost Bankers, Inc. and is currently Director Emeritus of both. Mr. Arnold is a trustee of the Museum of Fine Arts Houston and The Texas Heart Institute. Mr. Arnold received his B.B.A. from the University of Houston in 1959.

Alan R. Buckwalter, III, age 59, Director since March 2003. He retired in January 2003 as Chairman of JPMorgan Chase Bank, South Region, a position he had held since 1998. From 1990 to 1998 he was President of Texas Commerce Bank—Houston, the predecessor entity of JPMorgan Chase Bank. Prior to 1990 Mr. Buckwalter held various executive management positions within the organization. Mr. Buckwalter currently serves on the boards of Service Corporation International, the Texas Medical Center, Greater Houston Area Red Cross, University of St. Thomas and St. Luke's Hospital System. He sits on the Audit Committee and is Chairman of the Compensation Committee for Service Corporation International.

Jerry L. Dees, age 66, Director since September 2002. He also was a director of Plains Resources from 1997 to December 2002. Mr. Dees has been a director of Geotrace Technologies, Inc. since 2005. He retired in 1996 as Senior Vice President, Exploration and Land, for Vastar Resources, Inc. (previously ARCO Oil and Gas Company), a position he had held since 1991.

Tom H. Delimitros, age 66, Director since September 2002.. He also was a director of Plains Resources from 1988 to December 2002. He has been a General Partner of AMT Venture Funds, a venture capital firm, since 1989. He is also a director of Tetra Technologies, Inc., a publicly traded energy services company. He currently serves as Chairman for three privately owned companies. Previously, he has served as President and CEO for Magna Corporation, (now Baker Petrolite, a unit of Baker Hughes). From 1983 to 1988, Mr. Delimitros was a General Partner of Sunwestern Investment Funds and Senior Vice President of Sunwestern Management, Inc.

Robert L. Gerry III, age 69, Director since May 2004. He was also a director of Nuevo from 1990 to May 2004. He has been chairman and chief executive officer of Vaalco Energy, Inc., a publicly traded independent oil and gas company which does not compete with Plains, since 1997. From 1994 to 1997, Mr. Gerry was vice chairman of Nuevo. Prior to that, he was president and chief operating officer of Nuevo since its formation in 1990. Mr. Gerry also currently serves as a trustee of Texas Children's Hospital.

John H. Lollar, age 68, Director since September 2002. He also was a director of Plains Resources from 1995 to December 2002. He has been the Managing Partner of Newgulf Exploration L.P. since December 1996. He is also a director of Lufkin Industries, Inc., a manufacturing firm, where he is a member of the Compensation Committee and Chairman of the Audit Committee. Mr. Lollar was Chairman of the Board, President and Chief Executive Officer of Cabot Oil & Gas Corporation from 1992 to 1995, and President and Chief Operating Officer of Transco Exploration Company from 1982 to 1992.

Executive Officers

James C. Flores, age 47, Chairman of the Board, Chief Executive Officer and a Director since September 2002 and President since March 2004. He has been Chairman of the Board and Chief Executive Officer of Plains since December 2002, and President since March 2004. He was also Chairman of the Board of Plains Resources, Inc. ("Plains Resources," now known as Vulcan Energy Corporation) from May 2001 to June 2004 and is currently a director of Vulcan Energy. He was Chief Executive Officer of Plains Resources from May 2001 to December 2002. He was Co-founder as well as Chairman, Vice Chairman and Chief Executive Officer at various times from 1992 until January 2001 of Ocean Energy, Inc., an oil and gas company.

Doss R. Bourgeois, age 49. Executive Vice President—Exploration and Production since June 2006. He was Plains' Vice President of Development from April 2006 to June 2006. He was also Plains' Vice President Eastern Development Unit from May 2003 to April 2006. Prior to that time, Mr. Bourgeois was Vice President from August 1993 to May 2003 at Ocean Energy, Inc.

Winston M. Talbert, age 44, Executive Vice President and Chief Financial Officer since June 2006. He joined Plains in May 2003 as Vice President Finance & Investor Relations and in May 2004, Mr. Talbert became Vice President Finance & Treasurer. Prior to joining Plains, Mr. Talbert was Vice President and Treasurer at Ocean Energy, Inc. from August 2001 to May 2003 and Assistant Treasurer from October 1999 to August 2001.

John F. Wombwell, age 45, Executive Vice President, General Counsel and Secretary since September 2003. He was also Plains Resources' Executive Vice President, General Counsel, and Secretary from September 2003 to June 2004. He was previously a Senior Executive Officer with two New York Stock Exchange traded companies, serving as General Counsel of ExpressJet Holdings, Inc. from April 2002 until September 2003 and prior to joining ExpressJet, Mr. Wombwell was General Counsel of Integrated Electrical Services, Inc. from January 1998 to April 2002. Prior to that time, Mr. Wombwell was a partner at the national law firm of Andrews Kurth LLP with a practice focused on representing public companies with respect to corporate and securities matters.

Item 11. *Executive Compensation*

Information regarding executive compensation will be included in an amendment to this Form 10-K or in the proxy statement for the 2007 annual meeting of stockholders and is incorporated by reference to this report.

Item 12. *Security Ownership Of Certain Beneficial Owners And Management And Related Stockholder Matters*

Information regarding beneficial ownership will be included in an amendment to this Form 10-K or in the proxy statement for the 2007 annual meeting of stockholders and is incorporated by reference to this report.

Item 13. *Certain Relationships And Related Transactions, And Director Independence*

Information regarding certain relationships and related transactions will be included in an amendment to this Form 10-K or in the proxy statement for the 2007 annual meeting of stockholders and is incorporated by reference to this report.

Item 14. *Principal Accounting Fees And Services*

Information regarding principal accounting fees and services will be included in an amendment to this Form 10-K or in the proxy statement for the 2007 annual meeting of stockholders and is incorporated by reference to this report.

PART IV

Item 15. *Exhibits, Financial Statement Schedules*

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

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

(a) (3) Exhibits

Exhibit Number	Description
3.1	Certificate of Incorporation of Plains Exploration & Production Company (incorporated by reference to Exhibit 3.1 to the Company's Amendment No. 2 to Registration Statement on Form S-1 (file no. 333-90974) filed on October 3, 2002 (the "Amendment No. 2 to Form S-1")).
3.2	Certificate of Amendment to the Certificate of Incorporation of Plains Exploration & Production Company dated May 14, 2004 (incorporated by reference to Exhibit 3.1 to the Company's Form 10-Q for the period ending June 30, 2004 (the "June 30, 2004 10-Q")).
3.3	Bylaws of Plains Exploration & Production Company (incorporated by reference to Exhibit 3.2 to the Amendment No. 2 to Form S-1).
4.1	Amended and Restated Indenture, dated as of June 18, 2004, among Plains Exploration & Production Company, Plains E&P Company, the Subsidiary Guarantors parties thereto, and JPMorgan Chase Bank, as Trustee (including form of 8¾% Senior Subordinated Note) (incorporated by reference to Exhibit 4.1 to the June 30, 2004 10-Q).
4.2	First Amendment dated December 1, 2005, to Amended and Restated Indenture dated as of June 18, 2004, among Plains Exploration & Production Company, the Subsidiary Guarantors parties thereto, and JPMorgan Chase Bank, National Association as Trustee (incorporated by reference to Exhibit 4.01 to the Company's Current Report on Form 8-K filed December 6, 2005).
4.3	Second Supplemental Indenture dated as of June 30, 2004, to Amended and Restated Indenture dated as of June 18, 2004, among Plains Exploration & Production Company, Plains E&P Company, the Subsidiary Guarantors parties thereto, and JPMorgan Chase Bank, as Trustee (incorporated by reference to Exhibit 4.2 to the June 30, 2004 10-Q).
4.4	Third Supplemental Indenture dated as of December 30, 2004, to Amended and Restated Indenture dated as of June 18, 2004, among Plains Exploration & Production Company, the Subsidiary Guarantors parties thereto, Plains Louisiana Inc., PXP Louisiana L.L.C. and JPMorgan Chase Bank, as Trustee (incorporated by reference to Exhibit 4.3 to the Company's Form 10-K for the year ended December 31, 2004 (the "2004 10-K")).
4.5	Fourth Supplemental Indenture dated as of June 28, 2005, to Amended and Restated Indenture dated as of June 18, 2004, among Plains Exploration & Production Company, Brown PXP Properties, LLC, the Subsidiary Guarantors parties thereto and JPMorgan Chase Bank, as Trustee (incorporated by reference to Exhibit 4.1 to the Company's Form 10-Q for the period ending June 30, 2005 (the "June 30, 2005 10-Q").
4.6	Amended and Restated Credit Agreement dated effective as of May 16, 2005, among Plains Exploration & Production Company, as borrower, each of the lenders that is a signatory thereto, and JPMorgan Chase Bank as administrative agent (incorporated by reference to Exhibit 10.1 to the June 30, 2005 10-Q).

Exhibit Number	Description
4.7	First Amendment, dated as of November 1, 2005, to Amended and Restated Credit Agreement, dated as of N May 16, 2005, among Plains Exploration & Production Company, the Guarantors, JPMorgan Chase Bank, N.A. as administrative agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed November 15, 2005).
4.8	Fifth Supplemental Indenture, dated as of August 21, 2006, to Amended and Restated Indenture dated as of June 18, 2004, among Cane River Development LLC, PXP Deepwater L.L.C., Plains Exploration & Production Company, the Subsidiary Guarantors parties thereto and JPMorgan Chase Bank, National Association (incorporated by reference to Exhibit 4.1 to the Company's Form 10-Q for the period ending September 30, 2006 (the "September 30, 2006 10-Q").
4.9	Second Amendment and Waiver, dated as of September 28, 2006, to Amended and Restated Credit Agreement dated as of May 16, 2005, among Plains Exploration & Production Company, the lenders party thereto, and JPMorgan Chase Bank, N.A., as administrative agent for the lenders (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed October 4, 2006 (the "October 4, 2006 Form 8-K")).
4.10	Sixth Supplemental Indenture dated as of October 20, 2006, to Amended and Restated Indenture dated as of June 18, 2004, among Plains Exploration & Production Company, the Subsidiary Guarantors parties thereto and The Bank of New York Trust Company, National Association, as trustee. (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed October 24, 2006).
10.1	Purchase and Sale Agreement made and entered into on March 31, 2005, by and among PXP Texas Limited Partnership, PXP Gulf Coast Inc., and PXP Louisiana LLC, and XTO Energy Inc., (incorporated by reference to Exhibit 10.1 to the Company's Form 10-Q for the period ending March 31, 2005 (the "March 31, 2005 10-Q").
10.2	Purchase and Sale Agreement dated as of March 11, 2005, by and between Bentley-Simonson, Inc., and Plains Exploration & Production Company (incorporated by reference to Exhibit 10.2 to the March 31, 2005 10-Q).
10.3	Consulting Agreement, dated as of January 19, 2006, between Montebello Land Company LLC and Cook Hill Properties LLC (incorporated by reference to Exhibit 10.3 to the Company's Form 10-K for the year ended December 31, 2005 (the "2005 10-K")
10.4	Consulting Agreement, dated as of January 19, 2006, between Lompoc Land Company LLC and Cook Hill Properties LLC (incorporated by reference to Exhibit 10.4 to the 2005 10-K)
10.5	Consulting Agreement, dated as of January 19, 2006, between Arroyo Grande Land Company LLC and Cook Hill Properties LLC (incorporated by reference to Exhibit 10.5 to the 2005 10-K)
10.6	Crude Oil Marketing Agreement, dated July 15, 2004, by and among Plains Exploration & Production Company, Arguello, Inc., PXP Gulf Coast Inc., and Plains Marketing, L.P. (incorporated by reference to Exhibit 10.7 to the 2004 10-K).
10.7	First Amendment to Crude Oil Marketing Agreement, dated as of October 19, 2004, among Plains Exploration & Production Company, Arguello, Inc., PXP Gulf Coast Inc., and Plains Marketing, L.P (incorporated by reference to Exhibit 10.2 to the September 30, 2004 10-Q).

Exhibit Number	Description
10.8	Crude Oil Purchase Agreement dated January 1,, 2000 between Plains Exploration & Production Company (as successor to Nuevo Energy Company) and ConocoPhillips (as successor to Tosco Corporation) (incorporated by reference to Exhibit 10.1 to Nuevo Energy Company's Current Report on Form 8-K filed February 23, 2000 (file no. 0-10537)).
10.9	Plains Exploration & Production Company 2002 Stock Incentive Plan (incorporated by reference to Exhibit 10.21 to the Amendment No. 1 to Form 10).
10.10	Form of Plains Restricted Stock Award Agreement under the 2002 Incentive Plan (incorporated by reference to Exhibit 10.19 to the Company's Form 10-K for the year ended December 31, 2002).
10.11	First Amendment to the Plains Exploration & Production Company 2002 Stock Incentive Plan (incorporated by reference to Exhibit 10.32 to the Company's Amendment No. 1 to Form S-4 (file no. 333-103149) filed on March 27, 2003).
10.12	Plains Exploration & Production Company 2004 Stock Incentive Plan (incorporated by reference to Annex D to the Company's Amendment No. 1 to Form S-4 (file no. 333-113536) filed on April 12, 2004).
10.13	Amended and Restated Plains Exploration & Production Company Executives' Long-Term Retention and Deferred Compensation Agreement effective as of February 10, 2006 (incorporated by reference to Exhibit 10.16 to the 2005 10-K)
10.14	Long-Term Retention and Deferral Agreement for James C. Flores (incorporated by reference to Exhibit 10.3 to the June 30, 2005 10-Q).
10.16	First Amendment to the Plains Exploration & Production Company Long-Term Retention Agreement for James C. Flores (incorporated by reference to Exhibit 10.19 to the 2005 10-K).
10.17	First Amendment to the Plains Exploration & Production Company Long-Term Retention Agreement for Executive Vice Presidents (incorporated by reference to Exhibit 10.20 to the 2005 10-K).
10.18	Employment Agreement, effective as of June 9, 2004, between Plains Exploration & Production Company and James C. Flores (incorporated by reference to Exhibit 10.20 to the 2004 10-K).
10.19	Employment Agreement, effective as of June 9, 2004, between Plains Exploration & Production Company and John F. Wombwell (incorporated by reference to Exhibit 10.22 to the 2004 10-K).
10.20	First Amendment to Employment Agreement, effective as of June 4, 2004, and dated as of February 10, 2006, between Plains Exploration & Production Company and James C. Flores (incorporated by reference to Exhibit 10.25 to the 2005 10-K).
10.21	First Amendment to Employment Agreement, effective as of June 4, 2004, and dated as of February 10, 2006, between Plains Exploration & Production Company and John F. Wombwell (incorporated by reference to Exhibit 10.27 to the 2005 10-K).
10.22	Form of Election for Director Deferral of Restricted Stock Awards (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed January 4, 2005).

Exhibit Number	Description
10.23	Summary of Executive Officer Salary Increases (incorporated by reference to Exhibit 10.4 to the Company's Form 10-Q for the period ending March 31, 2006 (the "March 31, 2006 10-Q").
10.24	Summary of Director Compensation Program (incorporated by reference to Exhibit 10.5 to the March 31, 2006 10-Q).
10.25	First Amendment to the Plains Exploration & Production Company 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the September 30, 2006 10-Q).
10.26	First Amendment to the Plains Exploration & Production Company 2002 Rollover Stock Incentive Plan (incorporated by reference to Exhibit 10.2 to the September 30, 2006 10-Q).
10.27	Second Amendment to the Plains Exploration & Production Company 2002 Stock Incentive Plan (incorporated by reference to Exhibit 10.3 to the September 30, 2006 10-Q).
10.28	Purchase and Sale Agreement dated as of August 6, 2006, and effective as of October 1, 2006, by and among Plains Exploration & Production Company, PXP Gulf Coast Inc., PXP Texas Limited Partnership, and Brown PXP Properties, LLC, and Vintage Production California LLC, Occidental of Elk Hills, Inc., Occidental Permian Ltd., Oxy USA Inc., and Occidental International Oil & Gas Ltd. (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K filed August 8, 2006).
10.29	Amendment to Purchase and Sale Agreement dated as of September 29, 2006, by and among Plains Exploration & Production Company, PXP Gulf Coast Inc., PXP Texas Limited Partnership, Brown PXP Properties, LLC, PXP Louisiana L.L.C., and PXP Texas, Inc. and Vintage Production California LLC, Occidental of Elk Hills, Inc., Occidental Permian Ltd., Oxy USA Inc. and Occidental International Oil & Gas Ltd. (incorporated by reference to Exhibit 10.1 to the October 4, 2006 Form 8-K).
10.30	Purchase and Sale Agreement dated as of September 15, 2006, and effective as of September 1, 2006, between Plains Exploration & Production Company and Statoil Gulf of Mexico LLC (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K filed September 18, 2006).
10.31	Form of Long-Term Retention and Deferral Agreement for John F. Wombwell (incorporated by reference to Exhibit 10.7 to the September 30, 2006 10-Q).
10.32	Form of Restricted Stock Unit Agreement under the 2004 Incentive Plan (incorporated by reference to Exhibit 10.8 to the September 30, 2006 10-Q).
10.33	Form of Plains Stock Appreciation Rights Agreement under the 2004 Incentive Plan (incorporated by reference to Exhibit 10.9 to the September 30, 2006 10-Q).
10.34	Form of Restricted Stock Unit Agreement under the 2002 Incentive Plan (incorporated by reference to Exhibit 10.10 to the September 30, 2006 10-Q).
10.35	Form of Plains Stock Appreciation Rights Agreement under the 2002 Incentive Plan (incorporated by reference to Exhibit 10.11 to the September 30, 2006 10-Q).
10.36*	Form of Plains Restricted Stock Award Agreement under the 2004 Incentive Plan.
10.37	Employment Agreement, dated as of November 8, 2006, between Plains Exploration & Production Company and Winston M. Talbert (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed November 13, 2006 (the "November 13, 2006 Form 8-K")).

Exhibit Number	Description
10.38	Employment Agreement, dated as of November 8, 2006, between Plains Exploration & Production Company and Doss R Bourgeois (incorporated by reference to Exhibit 10.2 to the November 8, 2006 Form 8-K).
21.1*	List of Subsidiaries of Plains Exploration & Production Company.
23.1*	Consent of PricewaterhouseCoopers LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Rule 13(a)-14(a)/15d-14(a) Certificate of the Chief Executive Officer.
31.2*	Rule 13(a)-14(a)/15d-14(a) Certificate of the Chief Financial Officer.
32.1**	Section 1350 Certificate of the Chief Executive Officer.
32.2**	Section 1350 Certificate of the Chief Financial Officer.

* Filed herewith.
** Furnished herewith.

SIGNATURES

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

PLAINS EXPLORATION & PRODUCTION COMPANY

Date: February 27, 2007	/s/ JAMES C. FLORES James C. Flores, Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)

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

Date: February 27, 2007	/s/ JAMES C. FLORES James C. Flores, Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)
Date: February 27, 2007	/s/ ISAAC ARNOLD, JR. Isaac Arnold, Jr., Director
Date: February 27, 2007	/s/ ALAN R. BUCKWALTER, III Alan R. Buckwalter, III, Director
Date: February 27, 2007	/s/ JERRY L. DEES Jerry L. Dees, Director
Date: February 27, 2007	/s/ TOM H. DELIMITROS Tom H. Delimitros, Director
Date: February 27, 2007	/s/ ROBERT L. GERRY, III Robert L. Gerry, III, Director
Date: February 27, 2007	/s/ JOHN H. LOLLAR John H. Lollar, Director
Date: February 27, 2007	/s/ WINSTON M. TALBERT Winston M. Talbert, Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: February 27, 2007	/s/ CYNTHIA A. FEEBACK Cynthia A. Feeback, Vice President / Controller and Chief Accounting Officer (Principal Accounting Officer)

PLAINS EXPLORATION & PRODUCTION COMPANY

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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

Report of Independent Registered Public Accounting Firm

To The Board of Directors and Shareholders
of Plains Exploration & Production Company:

We have completed integrated audits of Plains Exploration & Production Company's consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Plains Exploration & Production Company and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Notes 1 and 8 to the consolidated financial statements, on January 1, 2006, the Company changed its method of accounting for its stock-based compensation in connection with its adoption of Statement of Financial Accounting Standards No. 123(R), "Share-based Payment."

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Annual Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 27, 2007

PLAINS EXPLORATION & PRODUCTION COMPANY

CONSOLIDATED BALANCE SHEETS
(in thousands of dollars)

	December 31, 2006	December 31, 2005
ASSETS		
Current Assets		
Cash and cash equivalents	$ 899	$ 1,552
Accounts receivable	113,193	148,691
Inventories	12,394	10,325
Deferred income taxes	51,084	128,816
Other current assets	7,226	3,948
	184,796	293,332
Property and Equipment, at cost		
Oil and natural gas properties—full cost method		
Subject to amortization	2,624,277	2,604,892
Not subject to amortization	142,096	112,204
Other property and equipment	41,392	32,866
	2,807,765	2,749,962
Less allowance for depreciation, depletion and amortization	(700,241)	(498,075)
	2,107,524	2,251,887
Goodwill	158,515	173,858
Other Assets	12,393	22,865
	$2,463,228	$2,741,942
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 131,639	$ 122,996
Commodity derivative contracts	95,162	85,596
Royalties and revenues payable	38,159	43,279
Stock appreciation rights	57,429	55,170
Income taxes payable	94,272	—
Other current liabilities	43,531	56,957
	460,192	363,998
Long-Term Debt		
Revolving credit facility	235,500	272,000
8.75% Senior Subordinated Notes	—	276,538
7.125% Senior Notes	—	248,837
	235,500	797,375
Other Long-Term Liabilities		
Asset retirement obligation	133,420	155,865
Commodity derivative contracts	18,114	440,543
Other	19,040	7,014
	170,574	603,422
Deferred Income Taxes	466,279	258,810
Commitments and Contingencies (Note 10)		
Stockholders' Equity		
Common stock, $0.01 par value, 150.0 million shares authorized, 79.2 million and 78.4 million shares issued at December 31, 2006 and 2005, respectively	792	784
Additional paid-in capital	964,472	940,988
Retained earnings (deficit)	463,864	(133,664)
Accumulated other comprehensive income	—	(89,566)
Treasury stock, at cost, 6.7 million and 5,467 shares at December 31, 2006 and 2005, respectively	(298,445)	(205)
	1,130,683	718,337
	$2,463,228	$2,741,942

See notes to consolidated financial statements.

PLAINS EXPLORATION & PRODUCTION COMPANY

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

	Year Ended December 31, 2006	2005	2004
Revenues			
Oil sales	$1,055,482	$ 873,121	$ 593,809
Oil hedging	(145,755)	(139,089)	(145,753)
Gas sales			
Sales related to buy/sell contracts	—	36,940	23,245
Other	106,319	172,853	204,223
Gas hedging	—	(3,057)	(6,108)
Other operating revenues	2,457	3,652	2,290
	1,018,503	944,420	671,706
Costs and Expenses			
Production costs			
Lease operating expenses	179,741	140,595	122,540
Steam gas costs			
Costs related to buy/sell contracts	—	38,975	23,453
Other	63,811	39,302	17,068
Electricity	38,011	31,817	30,137
Production and ad valorem taxes	24,777	24,478	22,332
Gathering and transportation expenses	6,785	10,125	7,550
General and administrative	123,134	127,513	92,042
Depreciation, depletion and amortization	207,173	180,337	139,422
Accretion	9,609	7,578	8,563
Gain on sale of oil and gas properties	(982,988)	—	—
	(329,947)	600,720	463,107
Income from Operations	1,348,450	343,700	208,599
Other Income (Expense)			
Interest expense	(64,675)	(55,421)	(37,294)
Debt extinguishment costs	(45,063)	—	(19,691)
Loss on mark-to-market derivative contracts	(297,503)	(636,473)	(150,314)
Gain on termination of merger agreement	37,902	—	—
Interest and other income	5,496	3,324	723
Income (Loss) Before Income Taxes and Cumulative Effect of Accounting Change	984,607	(344,870)	2,023
Income tax (expense) benefit			
Current	(142,378)	229	(375)
Deferred	(242,519)	130,629	7,192
Income (Loss) Before Cumulative Effect of Accounting Change	599,710	(214,012)	8,840
Cumulative effect of accounting change (net of income tax benefit of $1,363)	(2,182)	—	—
Net Income (Loss)	$ 597,528	$(214,012)	$ 8,840
Earnings (loss) per share			
Basic			
Income (loss) before cumulative effect of accounting change	$ 7.76	$ (2.75)	$ 0.14
Cumulative effect of accounting change	(0.03)	—	—
Net income (loss)	$ 7.73	$ (2.75)	$ 0.14
Diluted			
Income (loss) before cumulative effect of accounting change	$ 7.67	$ (2.75)	$ 0.14
Cumulative effect of accounting change	(0.03)	—	—
Net income (loss)	$ 7.64	$ (2.75)	$ 0.14
Weighted Average Shares Outstanding			
Basic	77,273	77,726	63,542
Diluted	78,234	77,726	64,014

See notes to consolidated financial statements.

PLAINS EXPLORATION & PRODUCTION COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands of dollars)

	Year Ended December 31,		
	2006	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$ 597,528	$ (214,012)	$ 8,840
Items not affecting cash flows from operating activities			
Gain on sale of oil and gas properties	(982,988)	—	—
Depreciation, depletion, amortization and accretion	216,782	187,915	147,985
Deferred income taxes	242,519	(130,629)	(7,192)
Noncash portion of debt extinguishment costs	9,289	—	(4,453)
Cumulative effect of adoption of accounting change	2,182	—	—
Commodity derivative contracts	443,258	620,564	173,030
Noncash compensation	37,766	55,271	28,360
Other noncash items	(268)	(93)	(144)
Change in assets and liabilities from operating activities, net of effect of acquisitions			
Accounts receivable and other assets	29,739	(29,651)	(15,982)
Inventories	(1,277)	(1,762)	(1,947)
Accounts payable and other liabilities	(13,821)	(24,269)	33,652
Income taxes payable	94,272	—	1,070
Net cash provided by operating activities	674,981	463,334	363,219
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to oil and gas properties	(634,330)	(509,127)	(211,387)
Acquisition of Nuevo Energy Company, net of cash acquired	—	—	(14,156)
Proceeds from sales of oil and gas properties, net of costs and expenses	1,550,663	346,450	238,989
Derivative settlements	(93,411)	—	—
Other	(10,923)	(5,743)	(8,032)
Net cash (used in) provided by investing activities	811,999	(168,420)	5,414
CASH FLOWS FROM FINANCING ACTIVITIES			
Revolving credit facilities			
Borrowings	1,618,900	1,504,200	1,044,850
Repayments	(1,655,400)	(1,342,200)	(1,145,850)
Proceeds from issuance of 7.125% Senior Notes	—	—	248,695
Redemption of long-term debt	(524,863)	—	—
Retirement of debt assumed in acquisition of Nuevo Energy Company	—	—	(405,000)
Costs incurred in connection with financing arrangements	—	(1,600)	(9,325)
Derivative settlements	(621,862)	(459,450)	(103,521)
Treasury stock purchases	(298,445)	—	—
Excess tax benefit from stock-based compensation	2,899	—	—
Other	(8,862)	4,143	1,686
Net cash used in financing activities	(1,487,633)	(294,907)	(368,465)
Net increase (decrease) in cash and cash equivalents	(653)	7	168
Cash and cash equivalents, beginning of period	1,552	1,545	1,377
Cash and cash equivalents, end of period	$ 899	$ 1,552	$ 1,545

See notes to consolidated financial statements.

PLAINS EXPLORATION & PRODUCTION COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands of dollars)

	Year Ended December 31,		
	2006	2005	2004
Net Income (Loss)	$597,528	$(214,012)	$ 8,840
Other Comprehensive Income (Loss)			
Commodity hedging contracts			
Change in fair value	—	(82,942)	(287,186)
Reclassification adjustment for settled contracts	—	31,884	152,983
Reclassification adjustment for terminated contracts	145,755	106,165	—
Related tax benefit (expense)	(56,189)	(20,799)	50,617
Other	—	—	151
	89,566	34,308	(83,435)
Comprehensive Income (Loss)	$687,094	$(179,704)	$ (74,595)

See notes to consolidated financial statements.

PLAINS EXPLORATION AND PRODUCTION COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(share and dollar amounts in thousands)

	Common Stock		Additional Paid-in Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income	Treasury Stock		Total
	Shares	Amount				Shares	Amount	
Balance at December 31, 2003	40,316	$403	$322,856	$ 71,566	$ (40,439)	(17)	$ (130)	$ 354,256
Net income	—	—	—	8,840	—	—	—	8,840
Acquisition of Nuevo Energy Company								
Issuance of stock	36,486	365	574,658	—	—	—	—	575,023
Other	—	—	4,389	—	—	—	—	4,389
Restricted stock awards	235	3	8,082	—	—	—	—	8,085
Treasury stock transactions	—	—	—	—	—	(15)	(265)	(265)
Other comprehensive income	—	—	—	—	(83,435)	—	—	(83,435)
Exercise of stock options and other	142	1	3,481	—	—	—	—	3,482
Balance at December 31, 2004	77,179	772	913,466	80,406	(123,874)	(32)	(395)	870,375
Net loss	—	—	—	(214,012)	—	—	—	(214,012)
Restricted stock awards	1,010	10	21,882	—	—	—	—	21,892
Treasury stock transactions	—	—	(337)	(58)	—	27	190	(205)
Other comprehensive income	—	—	—	—	34,308	—	—	34,308
Exercise of stock options and other	227	2	5,977	—	—	—	—	5,979
Balance at December 31, 2005	78,416	784	940,988	(133,664)	(89,566)	(5)	(205)	718,337
Net income	—	—	—	597,528	—	—	—	597,528
Restricted stock awards	696	7	22,551					22,558
Treasury stock transactions	—	—	—	—	—	(6,725)	(298,240)	(298,240)
Other comprehensive income	—	—	—	—	89,566	—	—	89,566
Exercise of stock options and other	60	1	933	—	—	—	—	934
Balance at December 31, 2006	79,172	$792	$964,472	$ 463,864	$ —	(6,730)	$(298,445)	$1,130,683

See notes to consolidated financial statements.

Note 1—Organization and Significant Accounting Policies

Organization

The consolidated financial statements of Plains Exploration & Production Company, a Delaware corporation, ("PXP", "us", "our", or "we") include the accounts of all its wholly owned subsidiaries. All significant intercompany transactions have been eliminated. Certain reclassifications have been made to prior year statements to conform to the current year presentation.

We are an independent energy company that is engaged in the "upstream" oil and gas business. The upstream business acquires, exploits, develops, explores for and produces oil and gas. Our upstream activities are all located in the United States.

Significant Accounting Policies

Oil and Gas Properties. We follow the full cost method of accounting whereby all costs associated with property acquisition, exploration, exploitation and development activities are capitalized. Such costs include internal general and administrative costs such as payroll and related benefits and costs directly attributable to employees engaged in acquisition, exploration, exploitation and development activities. General and administrative costs associated with production, operations, marketing and general corporate activities are expensed as incurred. These capitalized costs along with our estimated asset retirement obligations recorded in accordance with Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"), are amortized to expense by the unit-of-production method using engineers' estimates of proved oil and natural gas reserves. The costs of unproved properties are excluded from amortization until the properties are evaluated. Interest is capitalized on oil and natural gas properties not subject to amortization and in the process of development. Proceeds from the sale of oil and natural gas properties are accounted for as reductions to capitalized costs unless such sales involve a significant change in the relationship between costs and the estimated value of proved reserves, in which case a gain or loss is recognized. Unamortized costs of proved properties are subject to a ceiling which limits such costs to the present value of estimated future cash flows from proved oil and natural gas reserves of such properties (including the effect of any related hedging activities) reduced by future operating expenses, development expenditures and abandonment costs (net of salvage values) to the extent not included in oil and gas properties pursuant to SFAS 143 and estimated future income taxes thereon.

Asset Retirement Obligations. We account for our asset retirement obligations in accordance with SFAS 143 which requires entities to record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred. A legal obligation is a liability that a party is required to settle as a result of an existing or enacted law, statute, ordinance or contract. When the liability is initially recorded, the entity is required to capitalize the retirement cost of the related long-lived asset. Each period the liability is accreted to its then present value, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, the difference is recognized in Oil and Gas Properties.

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

Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates made by management include (1) oil and natural gas reserves; (2) depreciation, depletion and amortization, including future abandonment costs; (3) assigning fair value and allocating purchase price in connection with business combinations, including goodwill; (4) income taxes; (5) accrued liabilities; (6) stock based compensation; and (7) valuation of derivative instruments. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Cash and Cash Equivalents. Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less. At December 31, 2006 and 2005, the majority of cash and cash equivalents was concentrated in one institution and at times may exceed federally insured limits. We periodically assess the financial condition of the institution and believe that any possible credit risk is minimal. Accounts payable at December 31, 2006 and 2005 includes $5.3 million and $15.0 million, respectively, representing outstanding checks that had not been presented for payment.

Inventory. Oil inventories are carried at the lower of the cost to produce or market value and materials and supplies inventories are stated at the lower of cost or market with cost determined on an average cost method. Inventory consists of the following (in thousands):

	December 31, 2006	December 31, 2005
Oil	$ 4,954	$ 2,099
Materials and supplies	7,440	8,226
	$12,394	$10,325

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

Revenue Recognition. Oil and gas revenue from our interests in producing wells is recognized when the production is delivered and the title transfers.

Derivative Financial Instruments. We use various derivative instruments to manage our exposure to commodity price risk on sales of oil and gas production. At December 31, 2006 our derivative instruments consisted of crude oil put option contracts entered into with financial institutions. We do not enter into derivative instruments for speculative trading purposes. Derivative instruments are accounted for in accordance with SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities", as amended ("SFAS 133"). See Note 4.

Earnings Per Share. Weighted average shares outstanding for computing basic and diluted earnings for the years ended December 31, 2006, 2005 and 2004 were (in thousands):

	Year Ended December 31,		
	2006	2005	2004
Common shares outstanding—basic	77,273	77,726	63,542
Unvested restricted stock, restricted stock units and stock options	961	—	472
Common shares outstanding—diluted	78,234	77,726	64,014

In 2006 we repurchased 6.7 million common shares under our stock repurchase program. Because the shares were repurchased primarily in the fourth quarter of 2006, the effect of such repurchases was to reduce our weighted shares outstanding by approximately 1.6 million shares.

Due to our net loss in 2005 our unvested restricted stock, restricted stock units and stock options (796,000 equivalent shares) were not included in computing earnings per share because the effect was antidilutive. In computing earnings per share, no adjustments were made to reported net income.

Goodwill. In a purchase transaction, goodwill represents the excess of the purchase price plus the liabilities assumed, including deferred income taxes recorded in connection with the transaction, over the fair value of the net assets acquired. Goodwill is not amortized, but instead must be tested at least annually for impairment by applying a fair-value based test. Goodwill is deemed impaired to the extent of any excess of its carrying amount over the residual fair value of the reporting unit. Such impairment could significantly reduce earnings during the period in which the impairment occurs and would result in a corresponding reduction to goodwill and stockholders' equity. The most significant factors that could result in the impairment of our goodwill would be significant declines in oil and gas prices and/or estimated reserve volumes which would result in a decline in the fair value of our oil and gas properties. We follow the full cost method of accounting and all of our operations are located in the United States. We have determined that for the purpose of performing an impairment test, we have one reporting unit. We perform our goodwill impairment test annually on December 31 and have recorded no impairments to goodwill based on such tests.

In 2006 goodwill decreased by $15.3 million as a result of a change in the tax basis related to our 2004 acquisition of Nuevo Energy Company ("Nuevo", see Note 3). In 2005 we completed our evaluation of the assets acquired and liabilities assumed at the time of our Nuevo and goodwill related to the acquisition was increased by $1.0 million.

Business Segment Information. SFAS 131, "Disclosures about Segments of an Enterprise and Related Information" ("SFAS 131") establishes standards for reporting information about operating segments. We acquire, exploit, develop, explore for and produce oil and gas and all of our operations are located in the United States. Our corporate management team administers all properties as a whole rather than as discrete operating segments. We track basic operational data by area, however, we measure financial performance as a single enterprise and not on an area-by-area basis. We allocate capital resources on a project-by-project basis across our entire asset base to maximize profitability without regard to individual areas or segments. Accordingly, we have one operating segment, our oil and gas operations in the United States.

Stock Based Compensation. Effective January 1, 2006, we adopted Statement of Financial Accounting Standards No.123R "Share-Based Payment" ("SFAS 123R") that requires that the compensation cost relating to share-based payment transactions be recognized in the financial statements. We used the "modified prospective approach" as allowed under SFAS 123R. See Note 8.

In prior periods we accounted for stock based compensation using the intrinsic value method pursuant to Accounting Principles Bulletin No. 25 "Accounting for Stock Issued to Employees". No adjustments to our net income or earnings per share would have been required under SFAS No. 123 "Accounting for Stock Based Compensation" ("SFAS 123") because we recognized the same amount of compensation expense for our stock appreciation rights and restricted stock units under APB 25 and we did not issue stock options.

Buy/Sell Contracts. Steam generators utilized in our thermal recovery operations in California are fueled by natural gas. In certain instances we have entered into buy/sell contracts that allow us to exchange gas we produce elsewhere for gas delivered to and used in thermal recovery operations. Effective January 1, 2006 we adopted Emerging Issues Task Force Issue No. 04-13 ("EITF 04-13"), "Accounting for Purchases and Sales of Inventory with the Same Counterparty." EITF 04-13 requires that two or more inventory transactions with the same counterparty be viewed as a single non-monetary transaction if the transactions were entered into in contemplation of one another (as determined in accordance with EITF 04-13). We have determined that transactions under certain of our buy/sell contracts should be presented net in accordance with EITF 04-13. Accordingly, certain costs previously recorded gross in revenues and operating costs in prior periods will be recorded net in 2006 and subsequent periods.

Recent Accounting Pronouncements. In February 2006, the Financial Accounting Standards Board ("FASB") issued SFAS No. 155, "Accounting for Certain Hybrid Financial Instruments" ("SFAS 155"), which eliminates the exemption from applying SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities", to interests in securitized financial assets so that similar instruments are accounted for similarly regardless of the form of the instruments. SFAS 155 also allows the election of fair value measurement at acquisition, at issuance, or when a previously recognized financial instrument is subject to a remeasurement event. Adoption is effective for all financial instruments acquired or issued after the beginning of the first fiscal year that begins after September 15, 2006. Early adoption is permitted. We do not expect the adoption of SFAS 155 to have a material effect on our consolidated financial position, results of operations or cash flows.

In March 2006, the FASB issued SFAS No. 156, "Accounting for Servicing of Financial Assets" ("SFAS 156"), which requires all separately recognized servicing assets and servicing liabilities be initially measured at fair value. SFAS 156 permits, but does not require, the subsequent measurement of servicing assets and servicing liabilities at fair value. Adoption is required as of the beginning of the first fiscal year that begins after September 15, 2006. Early adoption is permitted. We do not expect the adoption of SFAS 156 to have a material effect on our consolidated financial position, results of operations or cash flows.

In June 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes (an interpretation of FASB Statement No. 109)" ("FIN 48"). This interpretation was issued to clarify the accounting for uncertainty in income taxes recognized in the financial statements by prescribing a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The provisions of FIN 48 are effective beginning January 1, 2007 with the cumulative effect of the change in accounting principle recorded as an adjustment to the opening balance of retained earnings, goodwill, deferred income taxes and income taxes payable in the consolidated balance sheet. While we are still evaluating our tax positions, we do not anticipate that FIN 48 will have a material impact on our consolidated financial statements.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" which is effective for fiscal years beginning after November 15, 2007 and for interim periods within those years. This statement defines fair value, establishes a framework for measuring fair value and expands the related disclosure requirements. We are currently evaluating the potential impact of this statement.

In September 2006, the FASB issued FASB Staff Position AUG AIR-1, "Accounting for Planned Major Maintenance Activities" which is effective for fiscal years beginning after December 15, 2006. This position statement eliminates the accrue-in-advance method of accounting for planned major maintenance activities. We do not expect this pronouncement to have a significant impact on our consolidated financial position, results of operations or cash flows.

In September 2006, the SEC Staff issued Staff Accounting Bulletin No. 108 ("SAB No. 108"), "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements," in an effort to address diversity in the accounting practice of quantifying misstatements and the potential for improper amounts on the balance sheet. Prior to the issuance of SAB No. 108, the two methods used for quantifying the effects of financial statement errors were the "roll-over" and "iron curtain" methods. Under the "roll-over" method, the primary focus is the income statement, including the reversing effect of prior year misstatements. The criticism of this method is that misstatements can accumulate on the balance sheet. The "iron curtain" method focuses on the effect of correcting the ending balance sheet, with less importance on the reversing effects of prior year errors in the income statement. SAB No. 108 establishes a "dual approach" which requires the quantification of the effect of financial statement errors on each financial statement, as well as related disclosures. Public companies are required to record the cumulative effect of initially adopting the "dual approach" method in the first year ending after November 16, 2006 by recording any necessary corrections to asset and liability balances with an offsetting adjustment to the opening balance of retained earnings. The use of this cumulative effect transition method also requires detailed disclosures of the nature and amount of each error being corrected and how and when they arose. SAB No. 108 had no effect on our consolidated financial position, results of operations or cash flows.

Note 2—Property Divestitures

On September 29, 2006 we closed on the sale of oil and gas properties to subsidiaries of Occidental Petroleum Corporation ("Occidental"). This transaction had an effective date of October 1, 2006. We received approximately $864 million in cash proceeds and recognized a $345 million pre-tax gain because the sale involved a significant change in the relationship between capitalized costs and proved reserves. As of December 31, 2005, our independent reserve engineers estimated these properties had proven reserves of approximately 45 million equivalent barrels of oil.

We follow the full cost method of accounting under which proceeds from the sale of oil and gas properties are accounted for as reductions to capitalized costs unless such sales involve a significant change in the relationship between capitalized costs and proved reserves, in which case a gain or loss is recognized. When a gain or loss is recognized, total capitalized costs within the cost center are allocated between the reserves sold and the reserves retained on the same basis used to compute amortization unless there are substantial economic differences between the properties sold and those retained, in which case capitalized costs are allocated on the basis of the relative fair values of the properties. With respect to the sale of properties to Occidental, capitalized costs were allocated on the basis of the relative fair values of the properties. A portion of the gain was allocated to certain of our subsidiaries based on the relative reserve volumes sold (see Note 15).

On November 1, 2006 we closed the sale of non-producing oil and gas properties to Statoil Gulf of Mexico LLC ("Statoil"). The Company received approximately $706 million in cash proceeds and recognized a pre-tax gain of $638 million because the sale involved a significant change in the relationship between capitalized costs and proved reserves. With respect to the sale of properties to Statoil, capitalized costs consist of the costs of the prospects that were classified as costs not subject to amortization.

In May 2005 we closed the sale of interests in certain producing properties located in east Texas and Oklahoma for net proceeds of approximately $341 million. In December 2004, we completed the sale of certain properties located offshore California and onshore south Texas, New Mexico, and south Louisiana. These unrelated divestments were conducted via negotiated and auction transactions and we received net proceeds of approximately $152 million. In a series of transactions in the first and second quarters of 2004 we sold our interests in certain non-core producing properties in New Mexico, Texas, Mississippi, Louisiana, and Illinois for proceeds of approximately $28 million. Cash proceeds from these transactions are reflected in the consolidated balance sheet as a reduction in oil and gas properties.

Note 3—Acquisitions

Nuevo Energy Company

On May 14, 2004 we acquired Nuevo in a stock-for-stock transaction (the "Nuevo acquisition"). In the Nuevo acquisition, each outstanding share of Nuevo common stock was converted into 1.765 shares of PXP common stock and Nuevo became our wholly owned subsidiary. The Nuevo acquisition required the issuance of 36.5 million additional PXP common shares, plus the assumption of $303 million in debt and $115 million of $2.875 Term Convertible Securities, Series A, or TECONS. We have accounted for the Nuevo acquisition as a purchase and our results of operations reflect the acquisition effective May 14, 2004.

Pro Forma Information

The following unaudited pro forma information shows the proforma effect of the Nuevo acquisition, the issuance by PXP of $250 million of 7.125% Senior Notes due 2014 and the retirement of Nuevo's 9 3/8% Senior Subordinated Notes and TECONS and the sale of Nuevo's Congo operations. This unaudited pro forma information assumes such transactions occurred on January 1, 2004.

This unaudited pro forma information has been prepared based on our historical consolidated statements of income and the historical consolidated statements of income of Nuevo. We believe the assumptions used provide a reasonable basis for presenting the significant effects directly attributable to the pro forma transactions. This pro forma financial information does not purport to represent what our results of operations would have been if such transactions had occurred on such date.

	Year Ended December 31, 2004
Revenues	$806,637
Income from operations	228,152
Income (loss) from continuing operations	1,053
Net income (loss)	1,053
Basic and diluted earnings per share	
Income (loss) from continuing operations	$ 0.01
Net income (loss)	0.01
Weighted average shares outstanding	
Basic	76,902
Diluted	77,374

Other

In April 2005 we acquired certain California producing oil and gas properties, primarily located in the Los Angeles Basin of onshore California with some smaller properties located in adjacent Ventura County, from a private company for $117 million. In September 2005 we acquired an additional 16.7% interest in the Point Arguello Unit, Rocky Point development project and related facilities, offshore

California, from subsidiaries of Chevron U.S.A. Inc. This acquisition increased our working interest in that operation to 69.3%.

Note 4—Derivative Instruments and Hedging Activities

General

We use various derivative instruments to manage our exposure to commodity price risk on sales of oil and gas production. All derivative instruments are recorded on the balance sheet at fair value. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in fair value, both realized and unrealized, are recognized currently in our income statement as a gain or (loss) on mark-to-market derivative contracts. Cash flows are only impacted to the extent the actual settlements under the contracts result in making a payment to or receiving a payment from the counterparty. If a derivative is designated as a cash flow hedge and qualifies for hedge accounting, any unrealized gain or loss is deferred in Accumulated Other Comprehensive Income ("OCI"), a component of Stockholders' Equity, until the hedged oil and gas production is sold. Realized gains and losses on derivative instruments that are designated as a hedge and qualify for hedge accounting are generally included in oil and gas revenues in the period the hedged volumes are sold. Gains and losses deferred in OCI related to cash flow hedges for which hedge accounting has been discontinued remain in OCI until the related product has been delivered.

Under SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities", certain of our derivatives are deemed to contain a significant financing element because they included off-market terms and cash settlements with respect to such derivatives are required to be reflected as financing activities in the Statement of Cash Flows. Cash settlements with respect to derivatives that are qualified for hedge accounting and do not have a significant financing element are reflected as operating activities in the Statement of Cash Flows. Cash settlements with respect to derivatives that are not qualified for hedge accounting and do not have a significant financing element are reflected as investing activities in the Statement of Cash Flows.

During 2006 and 2005 we eliminated all of our crude oil collars and acquired downside crude oil price protection for a substantial amount of our production with $55 put option contracts. At December 31, 2006 we had the following open commodity derivative positions, none of which were designated as hedging instruments:

Period	Instrument Type	Daily Volumes	Average Price	Index
Sales of Crude Oil Production				
2007				
Jan - Dec	Put options	50,000 Bbls	$55.00 Strike price	WTI
2008				
Jan - Dec	Put options	42,000 Bbls	$55.00 Strike price	WTI

The average strike price for the put options does not reflect the cost to purchase such options. The only cash settlements we are required to make on these contracts are option premiums of $111 million for 2007 and $58 million for 2008, including interest.

Elimination of 2006, 2007 and 2008 Swap and Collar Positions

During 2006 we paid $593.3 million to eliminate all of our 2007 and 2008 crude oil collars for 22,000 barrels of oil per day for all of 2007 and 2008 with a floor price of $25.00 and an average ceiling price of $34.76. Approximately $170 million of mark-to-market losses related to the collars was recognized in our income statement in 2006 and $423 million in prior periods. We also recognized $12 million of interest expense in 2006 related to the elimination of the collars.

During 2005 we completed a series of transactions that eliminated all of our 2006 crude oil price swaps and collars at a pre-tax cost of $292.7 million. Approximately $145.4 million of this amount was attributable to 2006 collars for 22,000 barrels of oil per day with a floor price of $25.00 and an average ceiling price of $34.76. The collars were not accounted for as hedges, therefore, the $145.4 million loss in the fair value of these instruments was recognized in our income statement in 2005 and 2004 and there was no income statement effect in 2006. Approximately $147.3 million of the cost was attributable to 2006 swaps for 15,000 barrels of oil per day at an average price of $25.28. We used hedge accounting through March 2005 for the swaps and as a result the $145.8 million loss in fair value attributable to the swaps was deferred in OCI and recognized as a noncash reduction to oil revenues in 2006 when the hedged production was sold.

Income Statement, Cash Payments and Other Comprehensive Income

During the years ended December 31, 2006, 2005 and 2004 pre-tax amounts recognized in our income statement for derivatives were as follows (in thousands of dollars):

	Year Ended December 31,		
	2006	2005	2004
Loss on mark-to-market derivative contracts	$(297,503)	$(636,473)	$(150,314)
Gain (loss) reclassified from OCI and recognized in:			
Oil revenues (1)	(145,755)	(139,089)	(145,753)
Gas revenues	—	(3,057)	(6,108)
Steam gas costs	—	4,097	(1,124)

(1) Includes $0.1 million in 2005 and $0.3 million in 2004 for hedge ineffectiveness.

During the years ended December 31, 2006, 2005 and 2004 cash payments for derivatives were as follows (in thousands of dollars):

	Year Ended December 31,		
	2006	2005	2004
Contracts accounted for using hedge accounting			
Oil sales	$ —	$ (53,044)	$(207,414)
Gas sales	—	(6,255)	(17,504)
Gas purchases	—	10,293	3,649
Elimination of crude oil swaps	—	(147,280)	—
Mark-to-market contracts			
Oil sales	(89,596)	(279,982)	(25,267)
Gas sales	—	—	(6,920)
Gas purchases	(11,425)	—	—
Elimination of crude oil collars (1)	(593,283)	(145,383)	—

(1) 2006 does not include interest paid of $12 million.

At December 31, 2006 there were no amounts in OCI. At December 31, 2005 OCI consisted of $145.8 million ($89.6 million, net of tax) of deferred losses attributable to the cancelled 2006 swaps that were reclassified to oil and gas revenue in 2006.

Note 5—Asset Retirement Obligations

The following table reflects the changes in our asset retirement obligation during the years ended December 31, 2006, 2005 and 2004 (in thousands):

	Year Ended December 31,		
	2006	2005	2004
Asset retirement obligation—beginning of period	$160,955	$130,469	$ 33,735
Liabilities incurred			
Nuevo acquisition	—	—	128,053
Other acquisitions	—	12,613	—
Property dispositions and other	(30,506)	(2,848)	(38,717)
Settlements	(2,886)	(1,735)	(218)
Change in estimate	(3,134)	11,443	(2,184)
Accretion expense	9,609	7,541	8,563
Asset retirement additions	3,273	3,472	1,237
Asset retirement obligation—end of period (1)	$137,311	$160,955	$130,469

(1) $3.9 million and $5.1 million included in current liabilities at December 31, 2006 and 2005, respectively.

Note 6—Long-Term Debt

At December 31, 2006 and 2005, long-term debt consisted of (in thousands):

	December 31,	
	2006	2005
Senior revolving credit facility	$235,500	$272,000
8.75% senior subordinated notes, including unamortized premium of $1.5 million in 2005	—	276,538
7.125% senior notes, including unamortized discount of $1.2 million in 2005	—	248,837
	$235,500	$797,375

Senior Revolving Credit Facility. On May 16, 2005, we entered into an Amended and Restated Credit Agreement (the "Amended Credit Agreement") which established the facility size at $750 million. The borrowing base is redetermined on a semi-annual basis, with PXP and the lenders each having the right to one annual interim unscheduled redetermination, and may be adjusted based on PXP's oil and gas properties, reserves, other indebtedness and other relevant factors. Our borrowing base was redetermined to be $1.25 billion in November 2006. We have not elected to seek an increase in the size of our credit facility. Additionally, the Amended Credit Agreement contains a $75 million sub-limit for letters of credit. The Amended Credit Agreement matures on May 16, 2010. Collateral consists of 100% of the shares of stock of all our domestic subsidiaries and mortgages covering at least 80% of the total present value of our domestic oil and gas properties.

Amounts borrowed under the Amended Credit Agreement bear an annual interest rate, at our election, equal to either: (i) the Eurodollar rate, which is based on LIBOR, plus an additional variable amount ranging from 1.00% to 1.75%; or (ii) the greatest of (1) the prime rate, as determined by JPMorgan Chase Bank, (2) the certificate of deposit rate, plus 1.0%, or (3) the federal funds rate, plus 0.5%; plus an additional variable amount ranging from 0% to 0.5% for each of (1)-(3). The additional variable amount of interest payable on outstanding borrowings is based on (1) the utilization rate as a percentage of the total amount of funds borrowed under the Amended Credit Agreement to the borrowing base and (2) our long-term debt rating. Commitment fees and letter of credit fees under the Amended Credit Agreement are based on the utilization rate and our long-term debt rating. Commitment fees range from 0.25% to 0.5% of the amount available for borrowing. Letter of credit fees range from 1.00% to 1.75%. The issuer of any letter of credit receives an issuing fee of 0.125% of the undrawn amount. The effective interest rate on our borrowings under the Amended Credit Agreement was 6.4% at December 31, 2006.

The Amended Credit Agreement contains negative covenants that limit our ability, as well as the ability of our restricted subsidiaries, among other things, to incur additional debt, pay dividends on stock, make distributions of cash or property, change the nature of our business or operations, redeem stock or redeem subordinated debt, make investments, create liens, enter into leases, sell assets, sell capital stock of subsidiaries, guarantee other indebtedness, enter into agreements that restrict dividends from subsidiaries, enter into certain types of swap agreements, enter into gas imbalance or take-or-pay arrangements, merge or consolidate and enter into transactions with affiliates. In addition, we are required to maintain a current ratio, which includes availability under the Amended Credit Agreement, of at least 1.0 to 1.0 and a ratio of debt to EBITDAX (as defined) of no greater than 4.25 to 1.00.

At December 31, 2006 we had $10.9 million in letters of credit outstanding under the Amended Credit Agreement. At that date we were in compliance with the covenants contained in the Amended Credit Agreement and could have borrowed the full amount available under the Amended Credit Agreement.

7.125% Senior Notes. On November 3, 2006 we made payments totaling $268.6 million to retire all $250 million outstanding principal amount of our 7.125% Senior Notes due 2014 (the "Senior Notes"). The redemption price of $1.074.50 per $1,000 principal amount was based on a "make-whole" calculation tied to a comparable United States Treasury security.

8.75% Senior Subordinated Notes. On November 3, 2006 we made payments totaling $291.9 million to retire $274.9 million of the $275 million outstanding principal amount of our 8.75% Senior Subordinated Notes due 2012 (the "Senior Subordinated Notes"). The purchase price of $1,042.07 per $1,000 principal amount was based on a 50 basis point spread over a reference U.S. Treasury security, as determined on October 19, 2006. The payment to holders who provided consents to eliminate substantially all the restrictive covenants and certain events of default from the indenture governing the Senior Subordinated Notes included a consent payment of $20.00 per $1,000 principal amount of notes tendered (a total of $5.5 million). The outstanding $0.1 million principal amount, which is redeemable July 1, 2007, is included in Other Current Liabilities in the December 31, 2006 Consolidated Balance Sheet.

Short-term Credit Facility. We may make borrowings from time to time until May 27, 2007, not to exceed at any time the maximum principal amount of $25.0 million. No advance under the short-term facility may have a term exceeding fourteen days and all amounts outstanding are due and payable no later than May 27, 2007. Each advance under the short-term facility shall bear interest at a rate per annum mutually agreed on by the bank and the Company. No amounts were outstanding under the short-term credit facility at December 31, 2006.

Debt Extinguishment Costs. In connection with the retirement of the Senior Notes and the Senior Subordinated Notes, in 2006 we recorded $45.1 million of debt extinguishment costs. In connection with the retirement of the debt assumed in the acquisition of Nuevo in 2004 we recorded $19.7 million of debt extinguishment costs related to the repurchase of all $150 million of Nuevo's outstanding 9 3/8% Senior Subordinated Notes and all $118 million aggregate principal amount of Nuevo's 5.75% Convertible Subordinated Debentures due December 15, 2026.

Note 7—Related Party Transactions

Our Chief Executive Officer is a director of Vulcan Energy Corporation ("Vulcan Energy", formerly known as Plains Resources) and until August 2005 held an interest in the general partner of Plains All American Pipeline, L.P. ("PAA"), a publicly traded master limited partnership. PAA is also an affiliate of Vulcan Energy. Plains Marketing, L.P. ("PMLP"), a subsidiary of PAA, is the marketer/purchaser for a portion of our oil production, including the royalty share of production, under a marketing agreement that provides that PMLP will purchase for resale at market prices certain of our oil production. PMLP charges a marketing fee of either $0.20 or $0.15 per barrel based upon the contract the barrels are resold under. During the years ended December 31, 2005 and 2004 the following amounts were recorded with respect to such transactions (in thousands of dollars):

	Year Ended December 31,	
	2005	2004
Sales of oil to PMLP		
PXP's share	$357,174	$274,447
Royalty owners' share	65,782	54,208
	$422,956	$328,655
Charges for PMLP marketing fees	$ 1,233	$ 1,427

At December 31, 2005 accounts receivable from PAA totaled $36.9 million.

Prior to December 18, 2002 we were a wholly owned subsidiary of Plains Resources Inc. ("Plains Resources"). On December 18, 2002 Plains Resources distributed 100% of the issued and outstanding shares of our common stock to the holders of record of Plains Resources' common stock as of December 11, 2002 (the "spin-off"). In connection with the spin-off we entered into certain agreements with Plains Resources, all of which expired in 2004. For the year ended December 31, 2004 we billed Plains Resources $0.4 million for services provided by us under these agreements and Plains Resources billed us $0.1 million for services they provided to us under these agreements. In addition, for the year ended December 31, 2004 we billed Plains Resources $0.2 million for administrative costs associated with certain special projects performed on their behalf.

In June 2004, based on third party valuations the Company acquired two aircraft from Cypress Aviation LLC ("Cypress"), for $4.5 million. Our Chief Executive Officer is a member of Cypress. Prior to acquiring the aircraft, we chartered private aircraft from Gulf Coast Aviation Inc. ("Gulf Coast"), a corporation that from time-to-time leased aircraft owned by Cypress. In 2004 we paid Gulf Coast $0.5 million in connection with such services. The charter services were arranged with market-based rates.

Note 8—Stock Based and Other Compensation Plans

Prior to January 1, 2006, we accounted for stock based compensation using the intrinsic value method pursuant to Accounting Principles Bulletin No. 25 "Accounting for Stock Issued to Employees" ("APB 25"). No adjustments to our net income or earnings per share would have been required under SFAS No. 123 "Accounting for Stock Based Compensation" ("SFAS 123") because we recognized the same amount of compensation expense for our stock appreciation rights ("SARs") and restricted stock units ("RSUs") under APB 25 and we did not issue stock options. Effective January 1, 2006, we adopted the provisions of SFAS 123R. Under the provisions of SFAS 123R, stock-based compensation is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the requisite employee service period (generally the vesting period of the grant). We adopted SFAS 123R using the modified prospective application method, under which compensation cost is recognized in the financial statements beginning with the adoption date for all share-based payments granted after that date, and for all unvested awards granted prior to the adoption of SFAS 123R. The cumulative adjustment at January 1, 2006 associated with the adoption of SFAS 123R resulted in a $2.2 million charge to earnings (net of a $1.4 million tax benefit). Our paid-in capital was increased by $3.6 million and our deferred tax liability was decreased by $1.4 million.

We have two stock incentive plans, the 2002 Stock Incentive Plan (the "2002 Plan"), which provides for a maximum of 1.5 million shares available for awards, and the 2004 Stock Incentive Plan (the "2004 Plan"), which provides for a maximum of 5.0 million shares available for awards. The 2002 Plan and the 2004 Plan provide for the grant of stock options, and other awards (including performance units, performance shares, share awards, restricted stock, RSUs, and SARs), to our directors, officers, employees, consultants and advisors. Our compensation committee may grant options and SARs on such terms, including vesting and payment forms, as it deems appropriate in its discretion, however, no option or SARs may be exercised more than 10 years after its grant, and the purchase price for incentive stock options and non-qualified stock options may not be less than 100% of the fair market value of our common stock on the date of grant. The compensation committee may grant restricted stock awards, RSUs, share awards, performance units and performance shares on such terms and conditions as it may in its discretion decide.

Upon an event constituting a "change in control" (as defined in the plans) of PXP, all options and SARs will become immediately exercisable in full. In addition, in such an event, unless otherwise determined by our organization and compensation committee, all other awards will vest and all restrictions on such awards will lapse. The Company may, at its discretion, issue new shares or use treasury shares to satisfy vesting requirements.

Stock based compensation costs for the years ended December 31, 2006, 2005 and 2004 was (in thousands):

	Year Ended December 31,		
	2006 (1)	2005 (2)	2004 (2)
Stock-based compensation expense included in:			
General and administrative	$52,196	$77,192	$43,556
Lease operating expenses	3,289	579	336
Oil and natural gas properties under full cost method	8,378	3,082	861
Total stock-based compensation	$63,863	$80,853	$44,753

(1) In accordance with SFAS 123R.
(2) In accordance with APB 25.

Stock based compensation costs charged to earnings for the years ended December 31, 2006, 2005 and 2004 was (in thousands):

	Year Ended December 31,		
	2006 (1)	2005 (2)	2004 (2)
Charged to earnings	$ 55,485	$ 77,771	$ 43,892
Tax benefit	(22,111)	(30,066)	(17,311)
	$ 33,374	$ 47,705	$ 26,581

(1) In accordance with SFAS 123R.
(2) In accordance with APB 25.

There is $164.2 million of total unrecognized compensation cost related to unvested share-based compensation arrangements that is expected to be recognized over a weighted-average period of approximately 5.3 years. The tax benefit realized as a result of the vesting of restricted stock and RSU awards during the year ended December 31, 2006 was $2.9 million. Stock based compensation expense for the year ended December 31, 2006 includes $8.4 million resulting from the accelerated vesting of 0.5 million RSUs. Stock based compensation expense for the year ended December 31, 2005 includes $18.8 million resulting from the accelerated vesting of 1.3 million RSUs because certain stock price targets were met.

Estimates of fair value are not intended to predict actual future events of the value ultimately realized by employees who receive share-based awards, and subsequent events are not indicative of the reasonableness of original estimates of fair value made by the Company under SFAS 123R.

SARs

SARs grants generally vest ratably over three years and expire within five to ten years after the date of grant. These awards are similar to stock options, but are settled in cash rather than in shares of common stock and are classified as liability awards. Under the provisions of SFAS 123R, compensation cost for these awards is determined using a fair-value method and remeasured at each reporting date until the date of settlement. Stock-based compensation expense recognized in the year ended December 31, 2006 is based on SARs ultimately expected to vest and has been reduced for estimated forfeitures.

The following table summarizes the status of our SARs at December 31, 2006 and the changes during the year then ended:

	Outstanding (thousands)	Weighted Average Exercise Price	Aggregate Intrinsic Value ($ thousands)	Weighted Average Remaining Contractual Life (Years)
Outstanding at January 1, 2006	2,615	$16.82		
Granted	310	40.84		
Exercised	(557)	11.77		
Forfeited or expired	(144)	35.64		
Outstanding at December 31, 2006	2,224	20.22	$60,729	3.6
Exercisable at December 31, 2006	1,431	10.97	$52,314	3.6

The total intrinsic value of SARs exercised in the year ended December 31, 2006, 2005 and 2004 was $17.7 million, $22.5 million and $15.2 million, respectively, and the fair value as of December 31, 2006 for SARs granted in the year then ended was $17.03 per share. The weighted average grant date fair value for SARs granted in 2006 was $10.45 per share.

We estimate the fair value of SARs granted using the Black-Scholes valuation model and the fair value of the SARs are remeasured at the end of the period. The following assumptions are as of December 31, 2006:

Expected life (in years)	1-4
Volatility	26.8%-37.3%
Risk-free interest rate	4.7%-5.0%
Dividend yield	0%

Expected volatility is based on the historical volatility of our common stock and other factors. We use historical experience with exercise and post-vesting exercise behavior to determine the SARs expected life. The expected life represents the period of time that SARs granted are expected to be outstanding. The risk-free rate is based on the U.S. Treasury rate with a maturity date corresponding to the SARs' expected life.

Restricted Stock and RSUs

Our stock compensation plans allow grants of restricted stock and RSUs. Restricted stock is issued on the grant date but is restricted as to transferability. RSU awards represent the right to receive common stock when vesting occurs.

Restricted stock and RSU grants generally vest over periods ranging from one to ten years of service. Compensation cost for these awards is based on the closing market price of our common stock on the date of grant. Stock-based compensation expense is based on the awards ultimately expected to vest, and has been reduced for estimated forfeitures. The following table summarizes the status under the provisions of SFAS 123R of our restricted stock and RSUs at December 31, 2006 and the changes during the year then ended:

	Equity Instruments (thousands)	Weighted Average Fair Value	Aggregate Intrinsic Value ($ thousands)	Weighted Average Remaining Contractural Life (Years)
Nonvested at January 1, 2006	4,090	$36.49		
Granted	1,810	41.40		
Vested	(901)	38.64		
Forfeited	(671)	40.07		
Reclassified to liability instruments	(1,275)	40.40		
Nonvested at December 31, 2006	3,053	39.18	$145,109	3.6

	Liability Instruments (thousands)	Weighted Average Fair Value	Aggregate Intrinsic Value ($ thousands)	Average Remaining Contractural Life (Years)
Nonvested at January 1, 2006	—	$ —		
Reclassified from equity instruments	1,275	47.53		
Nonvested at December 31, 2006	1,275	47.53	$ 60,601	8.0

The total intrinsic value of restricted stock and RSUs vested in 2006, 2005 and 2004 was $35.0 million, $57.2 million and $5.9 million, respectively. The intrinsic value is based upon the closing price of Company's common stock on the date restricted stock and RSUs vested. The weighted average grant date fair value of RSUs granted during the years ended December 31, 2005 and 2004 was $38.17 per share and $17.31 per share, respectively.

In 2006 the we granted 300,000 RSUs to certain executives that will vest only upon the event of a change of control (as defined). Because, in the Company's assessment, a change of control is not probable no compensation cost has been recognized for these awards.

The tables above include 2.3 million shares granted under the 2004 Plan in accordance with the provisions of our Long-Term Retention and Deferred Compensation Plan. The plan allows certain executive officers to defer awards of equity compensation and in lieu thereof, an equivalent number of RSUs available under stockholder-approved plans will be credited to an account for the executive. Under the terms of this plan certain executives have been granted the right under the 2004 Plan to receive annual RSU grants beginning in 2005 and continuing until 2014. Each annual credit is subject to continued service by the executive. Under the provisions of SFAS 123R all such future grants are deemed granted in 2005 for the purpose of determining stock-based compensation expense. The weighted average grant date fair value for all these shares is $40.40. The grants have varying vesting dates from 2010 through 2015 but payment of vested RSUs will be generally deferred until September 30, 2015, subject to certain exceptions. At January 1, 2006 these RSUs were classified as equity instruments (as defined in SFAS 123R) and the valuation under SFAS 123R was unchanged from the intrinsic valuation under APB 25. Certain of the awards are classified as liability awards at December 31, 2006 (as defined in SFAS 123R) because we do not have sufficient shares available for issuance under the 2004 Plan for all shares to be granted through 2014 and were revalued to the fair value on that date of $47.53 per share. During 2006, 561,000 shares were forfeited and 99,000 shares vested upon the retirement of one of our executive officers.

In addition, the annual grants may be increased if certain common stock price based performance targets are achieved. No expense was recognized in 2005 under APB 25 for the incremental shares because it was not probable that the target stock price would be met. Upon adoption of SFAS 123R the awards were revalued under the fair value approach in accordance with the provisions of SFAS 123R. We have used a Monte-Carlo simulation model to estimate the value and number of RSUs expected to be granted in the future. This model involves forecasting potential future stock price paths based on the expected return on the common stock and its volatility, then calculating the number of RSUs expected to be granted based on the results of the simulations.

The following assumptions were used at December 31, 2006 with respect to the Monte Carlo simulation model:

Expected annual return	9.50%
Expected daily return	0.04%
Daily standard deviation	2.13%

At December 31, 2006, we estimated that 0.4 million restricted units would be granted as a result of achieving the common stock price based targets. Such units had a weighted average fair value of $46.39 per unit, an aggregate fair value of $19.4 million and a weighted average remaining contractual life of 8 years. The incremental shares are classified as liability instruments based on the shares available for issuance under the 2004 Plan.

Stock Options

As a result of the acquisition of Nuevo in 2004, we converted certain of Nuevo's outstanding stock options to options on our common stock. At December 31, 2006 there were 98,392 options outstanding with an average exercise price of $15.83 per share and an average remaining life of 2.4 years. The intrinsic value of options exercised in the years ended December 31, 2006, 2005 and 2004 was $1.5 million, $4.7 million and $1.0 million, respectively, and the Company received $0.9 million, $4.3 million and $2.0 million, respectively. upon the exercise of such options.

Other

We also have a 401(k) defined contribution plan whereby we have matched 100% of an employee's contribution (subject to certain limitations in the plan). Matching contributions were made

100% in cash. In 2006, 2005 and 2004 we made contributions totaling $4.9 million, $4.4 million and $3.5 million, respectively, to the 401(k) plan.

Subsequent Event

In January 2007 we adopted the 2006 Incentive Plan (the "2006 Incentive Plan"), which provides for a maximum of 1.0 million SARs or RSUs that may be made the subject of awards to employees (other than executive officers). Our compensation committee may grant SARs and RSUs on such terms, including vesting, as it deems appropriate in its discretion, however, no SARs may be exercised more than 10 years after its grant. All payments under the 2006 Incentive Plan must be made in cash. Upon an event constituting a "change in control" (as defined in the 2006 Incentive Plan) of PXP, all SARs will become immediately exercisable in full and all RSUs will vest. In February 2007, 0.7 million SARs were granted under the 2006 Incentive Plan.

Note 9—Income Taxes

For the years ended December 31, 2006, 2005 and 2004 our income tax expense (benefit) consisted of (in thousands):

	Year Ended December 31,		
	2006	2005	2004
Current			
U.S. Federal	$118,659	$ (872)	$(1,215)
State	23,719	643	1,590
	142,378	(229)	375
Deferred			
U.S. Federal	216,117	(119,606)	(3,612)
State	26,402	(11,023)	(3,580)
	242,519	(130,629)	(7,192)
	$384,897	$(130,858)	$(6,817)

Our deferred income tax assets and liabilities at December 31, 2006 and 2005 consist of the tax effect of income tax carryforwards and differences related to the timing of recognition of certain types of costs as follows (in thousands):

	December 31,	
	2006	2005
Deferred tax assets:		
Net operating loss	$ 8,468	$ 73,346
Tax credits	14,556	97,727
Commodity hedging contracts and other	35,232	191,165
	58,256	362,238
Deferred tax liabilities:		
Net oil & gas acquisition, exploration and development costs	(473,451)	(492,232)
Net deferred tax liability	$(415,195)	$(129,994)
Current asset	$ 51,084	$ 128,816
Long-term liability	(466,279)	(258,810)
	$(415,195)	$(129,994)

Tax carryforwards at December 31, 2006, which are available for future utilization on income tax returns, are as follows (in thousands):

FEDERAL	Amount	Expiration
Alternative minimum tax (AMT) credit	$ 894	—
Net operating loss—regular tax	20,425	2018-2024
Net operating loss—AMT tax	20,425	2018-2024
STATE		
Alternative minimum tax (AMT) credit	$ 354	—
Enhanced oil recovery credit	20,665	2014-2020
Net operating loss—regular tax	3,922	2010-2014
Net operating loss—AMT tax	3,922	2010-2014

The tax attributes related to the purchase of Nuevo are subject to statutory limitation under Internal Revenue Code Section 382 on the amount that can be used each year. We do not expect the limitation to materially impact our ability to use such attributes.

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

	Year Ended December 31,		
	2006	2005	2004
U.S. federal income tax provision at statutory rate	$344,613	$(120,704)	$ 708
State income taxes, net of federal benefit	33,754	(13,201)	788
EOR credits	—	(19,637)	(9,547)
Non-deductible expenses	7,947	18,981	4,012
Other	(1,417)	3,703	(2,778)
Income tax expense (benefit) on income before income taxes and cumulative effect of accounting change	$384,897	$(130,858)	$(6,817)

A deferred tax benefit related to non-cash employee compensation of approximately $2.9 million, $1.6 million and $1.2 million was credited to paid-in capital in 2006, 2005 and 2004, respectively. As a result of the acquisition of Nuevo in 2004 we converted certain of Nuevo's stock options to on our common stock. A tax benefit related to these options of approximately $0.2 million and $1.1 million was credited to goodwill in 2006 and 2005, respectively.

Under the terms of a tax allocation agreement, we have agreed to indemnify Plains Resources if the spin-off is not tax-free to Plains Resources as a result of various actions taken by us or with respect to our failure to take various actions. We may not be able to control some of the events that could trigger this indemnification obligation.

Under Section 43 of the Internal Revenue Code of 1986 (as amended) and similar California tax rules, taxpayers may claim enhanced oil recovery ("EOR") tax credits based on capital spending and lease operating expense of qualified projects. EOR credits are subject to a phase out according to the level of average domestic crude oil prices. As a result of the increase in oil prices in 2005, companies did not earn EOR credits in 2006.

We have evaluated certain projects that were operated by Nuevo to determine if they qualify for such credits. Based on our evaluation, we have or will amend certain federal and state income tax returns previously filed by Nuevo to claim EOR tax credits not previously claimed by Nuevo. Our purchase price allocation reflects $43.5 million with respect to such credits. Any additional adjustments resulting from these claims will be reflected in Goodwill.

Note 10—Commitments, Contingencies and Industry Concentration

Commitments and Contingencies

Operating leases. Our operating leases relate primarily to obligations associated with aircraft, our office facilities and certain cogeneration operations in California. Future non-cancellable commitments related to these leases are as follows (in thousands):

2007	$ 7,081
2008	6,939
2009	6,229
2010	5,364
2011	4,943
Thereafter	16,653
	$47,209

Total expenses related to such leases were $6.2 million, $3.4 million and $3.7 million in 2006, 2005 and 2004, respectively.

Environmental matters. As an owner or lessee and operator of oil and gas properties, we are subject to various federal, state, and local laws and regulations relating to discharge of materials into, and protection of, the environment. Often these regulations are more burdensome on older properties that were operated before the regulations came into effect such as some of our properties in California that have operated for over 90 years. We have established policies for continuing compliance with environmental laws and regulations. We also 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.

Plugging, Abandonment and Remediation Obligations. Consistent with normal industry practices, substantially all of 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 the purchaser assumes the obligation to plug and abandon wells that are part of such assets. However, in some instances, we receive an indemnity with respect to those costs. We cannot assure you that we will be able to collect on these indemnities.

In connection with the sale of certain properties offshore California in December 2004 we retained the responsibility for certain abandonment costs, including removing, dismantling and disposing of the existing offshore platforms. The present value of such abandonment costs, $39 million ($78 million undiscounted), are included in our asset retirement obligation as reflected on our consolidated balance sheet. In addition, we agreed to guarantee the performance of the purchaser with respect to the remaining abandonment obligations related to the properties (approximately $46 million). To secure its abandonment obligations the purchaser of the properties is required to periodically deposit funds into an escrow account. At December 31, 2006 the escrow account had a balance of $3 million. The fair value of our guarantee, $0.3 million, is included in Other Long-Term Liabilities in the Consolidated Balance Sheet.

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, oil spills, releases of 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. Our operations in California, including transportation of oil by pipelines within the city and county of Los Angeles, are especially susceptible to damage from earthquakes and involve increased risks of personal injury, property damage and marketing interruptions because of the population density of southern California. 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. We maintain coverage for earthquake damages in California but this coverage may not provide for the full effect of damages that could occur and we may be subject to additional liabilities. 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.

Sale of Nuevo's Congo operations. Upon our acquisition of Nuevo, we became a party to an existing agreement between Nuevo, CMS NOMECO Oil & Gas Co. (CMS) and a third party. Under the agreement, Nuevo and CMS may be liable to the third party for the recapture of dual consolidated losses (DCLs) in connection with each company's 1995 acquisition of Congolese properties. Nuevo and CMS agreed to indemnify each other for any act that would cause the third party to experience a liability from the recapture of DCLs as a result of a triggering event.

CMS sold its interest in the Congolese properties to a subsidiary of Perenco, S.A. ("Perenco") in 2002. Both CMS and Perenco, have received from the Internal Revenue Service (IRS), in accordance with the U.S. consolidated return regulations, a closing agreement confirming that the transaction will not trigger recapture. In 2004 Nuevo sold its interest in the Congolese properties to Perenco. We and Perenco have finalized closing agreements with the IRS confirming that neither our merger with Nuevo, nor the sale of our interest in the Congolese properties to Perenco will trigger recapture. There is no remaining contingent liability relative to Nuevo's former interest. The estimated remaining contingent liability relative to CMS' former interest is $19.5 million, for which we would be jointly liable. We believe the occurrence of a triggering event in the future is remote and we do not believe the agreements will have a material adverse affect upon us.

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 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.

On November 15, 2005, the United States Court of Federal Claims issued a ruling granting the plaintiffs' motion for summary judgment as to liability and partial summary judgment as to damages in the breach of contract lawsuit Amber Resources Company et al. v. United States, Case No. 02-30c. The Court's ruling also denied the United States' motion to dismiss and motion for summary judgment. The United States Court of Federal Claims ruled that the federal government's imposition of new and onerous requirements that stood as a significant obstacle to oil and gas development breached agreements that it made when it sold 36 federal leases offshore California. The Court further ruled that the Government must give back to the current lessees the more than $1.1 billion in lease bonuses it had received at the time of sale. On October 31, 2006, the Court issued an unfavorable decision on the plaintiff's motion for partial summary judgment concerning plaintiffs' additional claims regarding the hundreds of millions of dollars that have been spent in the successful efforts to find oil and gas in the disputed lease area, and other matters. Plaintiff's filed a motion for final judgment on November 29, 2006 and the court granted such motion on January 11, 2007. Judgment on the $1.1 billion was filed January 12, 2007. The United States has filed its notice of appeal and Plaintiffs intend to file a cross-appeal concerning the Court's October 31, 2006 decision. No payments will be made until all appeals have either been waived or exhausted. We are among the current lessees of the 36 leases. Our share of the $1.1 billion award is in excess of $80 million.

We are a defendant in various other lawsuits arising in the ordinary course of our business. While the outcome of these lawsuits cannot be predicted with certainty and could have a material adverse effect on our financial position, we do not believe that the outcome of these legal proceedings, individually or in the aggregate, will have a material adverse effect on our financial condition, results of operations or cash flows.

Industry Concentration

Financial instruments which potentially subject us to concentrations of credit risk consist principally of accounts receivable with respect to our oil and gas operations and derivative instruments related to our hedging activities. During 2006, 2005 and 2004 sales to ConocoPhillips accounted for approximately 54%, 44% and 33%, respectively, of our total revenues and sales to PMLP accounted for approximately 41%, 38% and 33%, respectively, of our total revenues. During such periods no other purchaser accounted for more than 10% of our total revenues. The loss of any single significant customer or contract could have a material adverse short-term effect, however, we do not believe that the loss of any single significant customer or contract would materially affect our business in the long-term. We believe such purchasers could be replaced by other purchasers under contracts with similar terms and conditions. However, their role as the purchaser of a significant portion of our oil production does have the potential to impact our overall exposure to credit risk, either positively or negatively, in that they may be affected by changes in economic, industry or other conditions. We generally do not require letters of credit or other collateral from PMLP or from ConocoPhillips to support trade receivables. Accordingly, a material adverse change in PMLP's or ConocoPhillips's financial condition could adversely impact our ability to collect the applicable receivables, and thereby affect our financial condition.

The five financial institutions that are contract counterparties for our derivative commodity contracts all have Standard & Poor's ratings of A or better and all five of the financial institutions are participating lenders in our revolving credit facility. At December 31, 2006 we were in a net liability position with all such counterparties.

There are a limited number of alternative methods of transportation for our production. Substantially all of our oil and gas production is transported by pipelines 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 and gas production which could have a negative impact on future results of operations or cash flows.

Note 11—Financial instruments

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

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

	December 31, 2006		December 31, 2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt				
Amended Credit Agreement	$235,500	$235,500	$272,000	$272,000
Senior Notes	—	—	248,837	258,800
Senior Subordinated Notes	—	—	276,538	296,300

The carrying value of the Amended Credit Agreement approximates its fair value, as interest rates are variable, based on prevailing market rates. The fair value of the Senior Notes and the Senior Subordinated Notes is based on quoted market prices based on trades of such debt.

Note 12—Supplemental Cash Flow Information

Cash payments for interest and income taxes were (in thousands of dollars):

	Year Ended December 31,		
	2006	2005	2004
Cash payments for interest	$79,956	$54,574	$29,515
Cash payments for income taxes	$44,863	$ 2,141	$ 2,305

At December 31, 2006 and 2005 accrued capital expenditures included in Accounts Payable in the Consolidated Balance Sheet were $71 million and $67 million, respectively.

Common stock issued for no cash payment in connection with compensation plans (amounts in thousands):

	Year Ended December 31,		
	2006	2005	2004
Shares	901	969	328
Amount	$25,959	$17,098	$3,855

The 2004 Nuevo acquisition involved non-cash consideration as follows (in thousands of dollars):

Common stock issued	$ 575,023
Stock options assumed	4,389
Senior Subordinated Notes	162,945
Bank Credit Facility	140,000
TECONS	103,815
Current liabilities	255,733
Other noncurrent liabilities	33,583
Deferred income tax liabilities	221,803
Asset retirement obligation	128,053
	$1,625,344

Note 13—Oil and Natural Gas Activities

Costs incurred

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

	Year Ended December 31,		
	2006	2005	2004
Property acquisitions costs			
Unproved properties			
Nuevo acquisition	$ —	$ —	$ 137,457
Other	48,315	16,682	7,437
Proved properties			
Nuevo acquisition			
Asset retirement cost	—	—	128,053
Other	—	—	1,079,967
Other	7,175	134,696	2,738
Exploration costs	272,352	129,066	57,530
Exploitation and development costs	319,730	300,439	141,198
	$647,572	$580,883	$1,554,380

Amounts presented include capitalized general and administrative expense of $34.8 million, $24.5 million and $16.2 million in 2006, 2005 and 2004, respectively, and capitalized interest expense of $7.9 million, $3.5 million and $7.0 million in 2006, 2005 and 2004, respectively.

Capitalized costs

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

	December 31,	
	2006	2005
Proved properties	$2,624,277	$2,604,892
Accumulated DD&A	(694,126)	(493,835)
	$1,930,151	$2,111,057

The average DD&A rate per equivalent unit of production was $8.96, $7.39 and $5.93 in 2006, 2005 and 2004, respectively.

Costs not subject to amortization

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

	December 31,		
	2006	2005	2004
Onshore			
Acquisition costs	$ 19,031	$ 43,503	$29,894
Exploration costs	1,848	5,061	6,331
Capitalized interest	3,227	3,819	3,388
Offshore			
Acquisition costs	13,669	37,486	37,486
Exploration costs	100,276	18,306	394
Capitalized interest	4,045	4,029	1,912
	$142,096	$112,204	$79,405

Unproved property costs not subject to amortization consist of acquisition costs related to unproved areas, exploration costs and capitalized interest. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves established or impairment determined. We will continue to evaluate these properties and costs will be transferred into the amortization base as the undeveloped areas are tested. Due to the nature of the reserves, the ultimate evaluation of the properties will occur over a period of several years. We expect that 93% of the costs not subject to amortization at December 31, 2006 will be transferred to the amortization base over the next three years and the remainder within the next seven years. The majority of the leases covering the properties are held by production and will not limit the time period for evaluation. Approximately 52%, 13%, 19% and 16% of the balance in unproved properties at December 31, 2006, related to additions made in 2006, 2005, 2004 and prior periods, respectively.

Results of operations for oil and gas producing activities

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

	Year Ended December 31,		
	2006	2005	2004
Revenues from oil and gas producing activities	$1,018,503	$ 944,420	$ 671,706
Production costs	(313,125)	(285,292)	(223,080)
Depreciation, depletion, amortization and accretion	(209,108)	(181,609)	(144,093)
Income tax expense	(197,764)	(187,210)	(120,106)
Results of operations from producing activities (excluding general and administrative and interest costs)	$ 298,506	$ 290,309	$ 184,427

Supplemental reserve information (unaudited)

The following information summarizes our net proved reserves of oil (including condensate and natural gas liquids) and gas and the present values thereof for the three years ended December 31, 2006. The following reserve information is based upon reports of the independent petroleum consulting firm of Netherland, Sewell & Associates, Inc. The estimates are in accordance with SEC regulations.

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

Decreases in the prices of oil and natural gas have had, and could have in the future, an adverse effect on the carrying value of our proved reserves, reserve volumes and our revenues, profitability and cash flow. A significant portion of our reserve base (approximately 95% of year-end 2006 reserve volumes) is comprised of oil properties that are sensitive to crude oil price volatility.

Estimated quantities of oil and natural gas reserves (unaudited)

The following table sets forth certain data pertaining to our proved and proved developed reserves for the three years ended December 31, 2006 (in thousands).

	As of or for the Year Ended December 31,					
	2006		2005		2004	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
Proved Reserves						
Beginning balance	356,333	267,921	351,403	407,400	227,728	319,177
Revision of previous estimates	(2,045)	(3,949)	(13,002)	3,518	(138)	(27,773)
Extensions, discoveries and other additions	7,688	3,765	747	21,530	20,980	47,677
Improved recovery	10,095	2,438	20,134	752	10,225	2,617
Purchase of reserves in-place	—	—	17,314	12,038	161,068	162,527
Sale of reserves in-place	(19,879)	(138,624)	(1,592)	(147,958)	(52,019)	(58,235)
Production	(18,975)	(20,629)	(18,671)	(29,359)	(16,441)	(38,590)
Ending balance	333,217	110,922	356,333	267,921	351,403	407,400
Proved Developed Reserves						
Beginning balance	234,638	193,904	233,707	305,009	124,822	235,070
Ending balance	171,646	62,021	234,638	193,904	233,707	305,009

Standardized measure of discounted future net cash flows (unaudited)

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

	December 31,		
	2006	2005	2004
Future cash inflows	$17,318,297	$20,133,050	$13,106,450
Future development costs	(1,979,251)	(1,536,196)	(1,205,386)
Future production expense	(6,623,201)	(8,314,665)	(4,991,280)
Future income tax expense	(3,063,433)	(3,509,378)	(2,258,064)
Future net cash flows	5,652,412	6,772,811	4,651,720
Discounted at 10% per year	(3,141,749)	(3,690,645)	(2,415,001)
Standardized measure of discounted future net cash flows	$ 2,510,663	$ 3,082,166	$ 2,236,719

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

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

2. In accordance with SEC guidelines, the engineers' estimates of future net revenues from our proved properties and the present value thereof are made using oil and gas sales prices in effect at December 31 of the year presented and are held constant throughout the life of the properties, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. We have entered into certain arrangements to fix a floor on prices for a portion of our oil production. Arrangements in effect at December 31, 2006 are

discussed in Note 4. Such arrangements are not reflected in the reserve reports. The overall average year-end sale prices used in the reserve reports as of December 31, 2006, 2005 and 2004 were $50.81, $51.40 and $30.91 per barrel of oil, respectively, and $6.14, $8.02 and $5.93 per Mcf of gas, respectively.

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

4. Future income taxes were calculated by applying the statutory federal and state income tax rate to pre-tax future net cash flows, net of the tax basis of the properties involved and utilization of available tax carryforwards related to oil and gas operations.

The principal sources of changes in the Standardized Measure of the future net cash flows for the three years ended December 31, 2006, are as follows (in thousands):

	Year Ended December 31,		
	2006	2005	2004
Balance, beginning of year	$3,082,166	$2,236,719	$1,256,803
Sales, net of production expenses	(848,676)	(797,622)	(598,197)
Net change in sales and transfer prices, net of production expenses	240,127	2,284,096	258,819
Extensions, discoveries and improved recovery, net of costs	194,904	283,222	414,055
Changes in estimated future development costs	(322,294)	(304,045)	(39,759)
Previously estimated development costs incurred during the year	196,482	224,338	49,823
Purchase of reserves in-place	—	240,725	1,481,958
Sale of reserves in-place	(508,692)	(276,255)	(370,620)
Revision of quantity estimates	52,478	(558,470)	(13,020)
Accretion of discount	445,583	266,113	189,590
Net change in income taxes	(21,415)	(516,655)	(392,733)
Balance, end of year	$2,510,663	$3,082,166	$2,236,719

Note 14—Quarterly Financial Data (Unaudited)

The following table shows summary financial data for 2006 and 2005 (in thousands, except per share data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2006					
Revenues	$ 251,619	$278,386	$280,907	$207,591	$1,018,503
Gain on sale of oil and gas properties	—	—	345,480	637,508	982,988
Income from operations	105,289	110,284	456,151	676,726	1,348,450
Income (loss) before cumulative effect of accounting change	(49,470)	(7,127)	272,693	383,614	599,710
Cumulative effect of accounting change, net of tax expense	(2,182)	—	—	—	(2,182)
Net income (loss)	(51,652)	(7,127)	272,693	383,614	597,528
Basic earnings (loss) per share					
Income (loss) before cumulative effect of accounting change	(0.63)	(0.09)	3.56	5.09	7.76
Cumulative effect of accounting change	(0.03)	—	—	—	(0.03)
Net income (loss)	(0.66)	(0.09)	3.56	5.09	7.73
Diluted earnings (loss) per share					
Income (loss) before cumulative effect of accounting change	(0.63)	(0.09)	3.50	5.02	7.67
Cumulative effect of accounting change	(0.03)	—	—	—	(0.03)
Net income (loss)	(0.66)	(0.09)	3.50	5.02	7.64
2005					
Revenues	$ 190,075	$217,308	$262,619	$274,418	$ 944,420
Income from operations	40,744	81,449	96,592	124,915	343,700
Net income (loss)	(205,618)	(47,330)	(31,849)	70,785	(214,012)
Basic earnings (loss) per share	(2.66)	(0.61)	(0.41)	0.90	(2.75)
Diluted earnings (loss) per share	(2.66)	(0.61)	(0.41)	0.90	(2.75)

Note 15—Consolidating Financial Statements

We are the issuer of the Senior Subordinated Notes which are jointly and severally guaranteed on a full and unconditional basis by certain of our domestic wholly owned restricted subsidiaries (referred to as "Guarantor Subsidiaries"). Certain of our subsidiaries do not guarantee the Senior Notes and the Senior Subordinated Notes (referred to as "Non-Guarantor Subsidiaries"). As discussed in Note 6, in 2006 we made payments to retire $274.9 million of the $275.0 million outstanding principal amount of the Senior Subordinated Notes.

In 2006 we recognized a gain on the sale of oil and gas properties to Occidental (see Note 2). A portion of the gain was allocated to certain of our subsidiaries based on the relative reserve volumes sold.

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

- PXP (the "Issuer" or "Parent");
- the Guarantor Subsidiaries on a combined basis;
- the Non-Guarantor Subsidiaries on a combined basis;
- elimination entries necessary to consolidate the Issuer, Guarantor Subsidiaries and Non-Guarantor Subsidiaries; and
- PXP on a consolidated basis.

PLAINS EXPLORATION & PRODUCTION COMPANY

CONDENSED CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2006
(in thousands)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercomany Eliminations	Consolidated
ASSETS					
Current Assets					
Cash and cash equivalents	$ 896	$ 3	$ —	$ —	$ 899
Accounts receivable and other current assets	156,242	27,655	—	—	183,897
	157,138	27,658	—	—	184,796
Property and Equipment, at cost					
Oil and natural gas properties—full cost method					
Subject to amortization	2,131,959	492,318	—	—	2,624,277
Not subject to amortization	124,830	17,266	—	—	142,096
Other property and equipment	31,237	1,564	8,591	—	41,392
	2,288,026	511,148	8,591	—	2,807,765
Less allowance for depreciation, depletion and amortization	(390,931)	(309,310)	—	—	(700,241)
	1,897,095	201,838	8,591	—	2,107,524
Investment in and Advances to Subsidiaries	352,667	—	—	(352,667)	—
Other Assets	(1,674)	172,582	—	—	170,908
	$2,405,226	$ 402,078	$8,591	$(352,667)	$2,463,228
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Accounts payable and other current liabilities	$ 320,899	$ 44,131	$ —	$ —	$ 365,030
Commodity derivative contracts	95,162	—	—	—	95,162
	416,061	44,131	—	—	460,192
Long-Term Debt	235,500	—	—	—	235,500
Other Long-Term Liabilities	151,365	19,209	—	—	170,574
Payable to Parent	—	(101,526)	5,585	95,941	—
Deferred Income Taxes	471,617	(5,338)	—	—	466,279
Stockholders' Equity	1,130,683	445,602	3,006	(448,608)	1,130,683
	$2,405,226	$ 402,078	$8,591	$(352,667)	$2,463,228

PLAINS EXPLORATION & PRODUCTION COMPANY

CONDENSED CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2005
(in thousands)

	Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS				
Current Assets				
Cash and cash equivalents	$ 1,548	$ 4	$ —	$ 1,552
Accounts receivable and other current assets	247,721	44,059	—	291,780
	249,269	44,063	—	293,332
Property and Equipment, at cost				
Oil and natural gas properties—full cost method				
Subject to amortization	2,126,960	477,932	—	2,604,892
Not subject to amortization	73,987	38,217	—	112,204
Other property and equipment	31,959	907	—	32,866
	2,232,906	517,056	—	2,749,962
Less allowance for depreciation, depletion and amortization	(305,510)	(192,565)	—	(498,075)
	1,927,396	324,491	—	2,251,887
Investment in and Advances to Subsidiaries	458,984	—	(458,984)	—
Other Assets	33,828	162,895	—	196,723
	$2,669,477	$ 531,449	$(458,984)	$2,741,942
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current Liabilities				
Accounts payable and other current liabilities	$ 199,508	$ 78,894	$ —	$ 278,402
Commodity derivative contracts	85,596	—	—	85,596
	285,104	78,894	—	363,998
Long-Term Debt	797,375	—	—	797,375
Other Long-Term Liabilities	573,848	29,574	—	603,422
Payable to Parent	—	103,526	(103,526)	—
Deferred Income Taxes	294,813	(36,003)	—	258,810
Stockholders' Equity				
Stockholders' equity	807,903	386,229	(386,229)	807,903
Accumulated other comprehensive income	(89,566)	(30,771)	30,771	(89,566)
	718,337	355,458	(355,458)	718,337
	$2,669,477	$ 531,449	$(458,984)	$2,741,942

PLAINS EXPLORATION & PRODUCTION COMPANY

CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2006
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues					
Oil sales	$ 798,802	$ 110,925	$ —	$ —	$ 909,727
Gas sales	32,110	74,209	—	—	106,319
Other operating revenues	1,579	878	—	—	2,457
	832,491	186,012	—	—	1,018,503
Costs and Expenses					
Production costs	236,346	76,779	—	—	313,125
General and administrative	115,463	7,671	—	—	123,134
Depreciation, depletion, amortization and accretion	98,225	118,557	—	—	216,782
Gain on sale of oil and gas properties	(856,602)	(126,386)	—	—	(982,988)
	(406,568)	76,621	—	—	(329,947)
Income from Operations	1,239,059	109,391	—	—	1,348,450
Other Income (Expense)					
Equity in earnings of subsidiaries	59,371	—	—	(59,371)	—
Interest expense	(50,294)	(14,381)	—	—	(64,675)
Debt extinguishment costs	(45,063)				(45,063)
Loss on mark-to-market derivative contracts	(297,503)	—	—	—	(297,503)
Interest and other income	43,398	—	—	—	43,398
Income Before Income Taxes and Cumulative Effect of Accounting Change	948,968	95,010	—	(59,371)	984,607
Income tax expense					
Current	(118,100)	(24,278)	—	—	(142,378)
Deferred	(231,158)	(11,361)	—	—	(242,519)
Income Before Cumulative Effect of Accounting Change	599,710	59,371	—	(59,371)	599,710
Cumulative effect of accounting change, net of tax benefit	(2,182)	—	—	—	(2,182)
Net Income	$ 597,528	$ 59,371	$ —	$(59,371)	$ 597,528

PLAINS EXPLORATION & PRODUCTION COMPANY

CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2005
(in thousands)

	Parent	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues				
Oil sales	$ 651,689	$ 82,343	$ —	$ 734,032
Gas sales	56,292	150,444	—	206,736
Other operating revenues	2,854	798	—	3,652
	710,835	233,585	—	944,420
Costs and Expenses				
Production costs	213,594	71,698	—	285,292
General and administrative	121,586	5,927	—	127,513
Depreciation, depletion, amortization and accretion	107,789	80,126	—	187,915
	442,969	157,751	—	600,720
Income from Operations	267,866	75,834	—	343,700
Other Income (Expense)				
Equity in earnings of subsidiaries	32,600	—	(32,600)	—
Interest expense	(40,690)	(14,731)	—	(55,421)
Loss on mark-to-market derivative contracts	(636,473)	—	—	(636,473)
Interest and other income (expense)	3,324	—	—	3,324
Income (Loss) Before Income Taxes	(373,373)	61,103	(32,600)	(344,870)
Income tax benefit (expense)				
Current	80,104	(79,875)	—	229
Deferred	79,257	51,372	—	130,629
Net Income (Loss)	$(214,012)	$ 32,600	$(32,600)	$(214,012)

PLAINS EXPLORATION & PRODUCTION COMPANY

CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2004
(in thousands)

	Parent	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues				
Oil sales	$ 386,060	$ 61,996	$ —	$ 448,056
Gas sales	41,908	179,452	—	221,360
Other operating revenues	1,211	1,079	—	2,290
	429,179	242,527	—	671,706
Costs and Expenses				
Production costs	159,129	63,951	—	223,080
General and administrative	80,452	4,745	—	85,197
Provision for legal and regulatory settlements	1,520	5,325	—	6,845
Depreciation, depletion, amortization and accretion	74,951	73,034	—	147,985
	316,052	147,055	—	463,107
Income from Operations	113,127	95,472	—	208,599
Other Income (Expense)				
Equity in earnings of subsidiaries	46,774	—	(46,774)	—
Interest expense	(22,854)	(14,440)	—	(37,294)
Loss on mark-to-market derivative contracts	(148,043)	(2,271)	—	(150,314)
Debt extinguishment costs	(19,691)	—	—	(19,691)
Interest and other income (expense)	797	(74)	—	723
Income (Loss) Before Income Taxes	(29,890)	78,687	(46,774)	2,023
Income tax benefit (expense)				
Current	19,032	(19,407)	—	(375)
Deferred	19,698	(12,506)	—	7,192
Net Income	$ 8,840	$ 46,774	$(46,774)	$ 8,840

PLAINS EXPLORATION & PRODUCTION COMPANY

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2006
(in thousands of dollars)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income (loss)	$ 597,528	$ 59,371	$ —	$(59,371)	$ 597,528
Items not affecting cash flows from operating activities					
Gain on sale of oil and gas properties	(856,602)	(126,386)	—	—	(982,988)
Depreciation, depletion, amortization and accretion	98,225	118,557	—	—	216,782
Equity in earnings of subsidiaries	(59,371)	—	—	59,371	—
Deferred income taxes	231,158	11,361	—	—	242,519
Noncash portion of debt extinguishment costs	9,289	—	—	—	9,289
Cumulative effect of adoption of accounting change	2,182	—	—	—	2,182
Commodity derivative contracts	393,183	50,075	—	—	443,258
Noncash compensation	37,766	—	—	—	37,766
Other noncash items	(268)	—	—	—	(268)
Change in assets and liabilities from operating activities					
Accounts receivable and other assets	21,290	7,172	—	—	28,462
Accounts payable and other liabilities	(4,662)	(9,159)	—	—	(13,821)
Income taxes payable	94,272	—	—	—	94,272
Net cash provided by operating activities	563,990	110,991	—	—	674,981
CASH FLOWS FROM INVESTING ACTIVITIES					
Additions to oil and gas properties	(484,296)	(150,034)	—	—	(634,330)
Proceeds from property sales, net	1,305,536	245,127	—	—	1,550,663
Derivative settlements	(93,411)	—	—	—	(93,411)
Other	(4,300)	(1,035)	(5,588)		(10,923)
Net cash provided by (used in) investing activities	723,529	94,058	(5,588)	—	811,999
CASH FLOWS FROM FINANCING ACTIVITIES					
Revolving credit facilities					
Borrowings	1,618,900	—	—	—	1,618,900
Repayments	(1,655,400)	—	—	—	(1,655,400)
Redemption of long-term debt	(524,863)	—	—	—	(524,863)
Derivative settlements	(621,862)	—	—	—	(621,862)
Investment in and advances to affiliates	199,462	(205,050)	5,588	—	—
Treasury stock purchases	(298,445)	—	—	—	(298,445)
Excess tax benefit from stock-based compensation	2,899	—	—	—	2,899
Other	(8,862)	—	—	—	(8,862)
Net cash provided by (used in) financing activities	(1,288,171)	(205,050)	5,588	—	(1,487,633)
Net increase (decrease) in cash and cash equivalents	(652)	(1)	—	—	(653)
Cash and cash equivalents, beginning of period	1,548	4	—	—	1,552
Cash and cash equivalents, end of period	$ 896	$ 3	$ —	$ —	$ 899

PLAINS EXPLORATION & PRODUCTION COMPANY

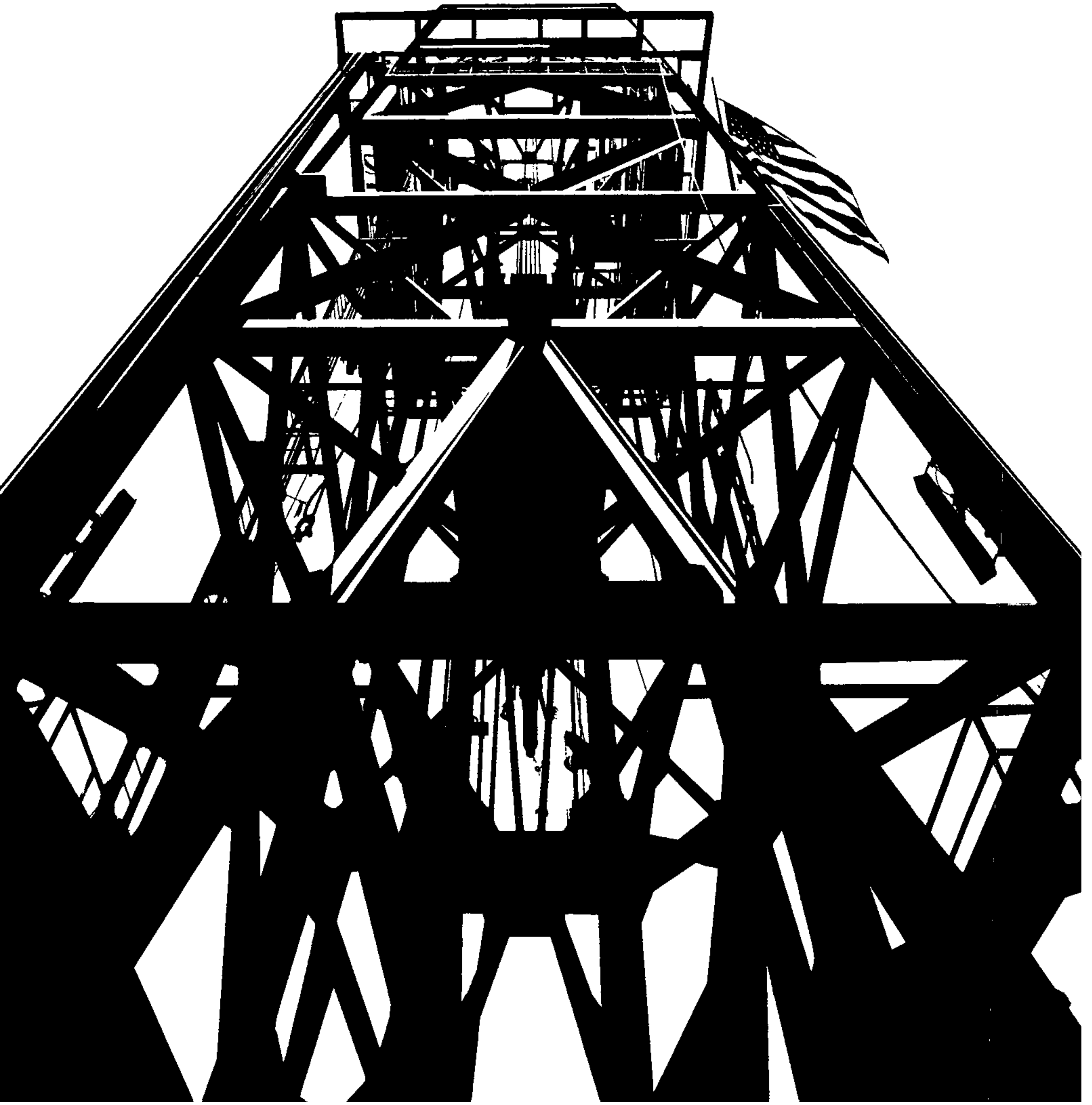
CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2005
(in thousands)

	Parent	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income (loss)	$ (214,012)	$ 32,600	$(32,600)	$ (214,012)
Items not affecting cash flows from operating activities				
Depreciation, depletion, amortization and accretion	107,789	80,126	—	187,915
Equity in earnings of subsidiaries	(32,600)	—	32,600	—
Deferred income taxes	(79,257)	(51,372)	—	(130,629)
Commodity derivative contracts	563,873	56,691	—	620,564
Noncash compensation	55,271	—	—	55,271
Other noncash items	(93)	—	—	(93)
Change in assets and liabilities from operating activities, net of effect of acquisitions				
Accounts receivable and other assets	(16,636)	(14,777)	—	(31,413)
Accounts payable and other liabilities	(20,275)	(3,994)	—	(24,269)
Net cash provided by operating activities	364,060	99,274	—	463,334
CASH FLOWS FROM INVESTING ACTIVITIES				
Additions to oil and gas properties	(295,730)	(213,397)	—	(509,127)
Proceeds from sales of properties	9,345	337,105	—	346,450
Other property and equipment	(5,419)	(324)	—	(5,743)
Net cash (used in) provided by investing activities	(291,804)	123,384	—	(168,420)
CASH FLOWS FROM FINANCING ACTIVITIES				
Revolving credit facilities				
Borrowings	1,504,200	—	—	1,504,200
Repayments	(1,342,200)	—	—	(1,342,200)
Costs incurred in connection with financing arrangements	(1,600)	—	—	(1,600)
Derivative settlements	(453,443)	(6,007)	—	(459,450)
Investment in and advances to affiliates	217,316	(217,316)	—	—
Other	4,143	—	—	4,143
Net cash (used in) provided by financing activities	(71,584)	(223,323)	—	(294,907)
Net increase (decrease) in cash and cash equivalents	672	(665)	—	7
Cash and cash equivalents, beginning of period	876	669	—	1,545
Cash and cash equivalents, end of period	$ 1,548	$ 4	$ —	$ 1,552

PLAINS EXPLORATION & PRODUCTION COMPANY

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2004
(in thousands)

	Parent	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	$ 8,840	$ 46,774	$(46,774)	$ 8,840
Items not affecting cash flows from operating activities				
Depreciation, depletion, amortization and accretion	74,951	73,034	—	147,985
Equity in earnings of subsidiaries	(46,774)	—	46,774	—
Deferred income taxes	(19,698)	12,506	—	(7,192)
Noncash portion of debt extinguishment costs	(4,453)	—	—	(4,453)
Commodity derivative contracts	187,584	(14,554)	—	173,030
Noncash compensation	28,360	—	—	28,360
Other noncash items	(144)	—	—	(144)
Change in assets and liabilities from operating activities, net of effect of acquisitions				
Accounts receivable and other assets	804	(18,733)	—	(17,929)
Accounts payable and other liabilities	12,731	21,991	—	34,722
Net cash provided by operating activities	242,201	121,018	—	363,219
CASH FLOWS FROM INVESTING ACTIVITIES				
Additions to oil and gas properties	(99,522)	(111,865)	—	(211,387)
Acquisition of Nuevo Energy Company, net of cash acquired	(14,156)	—	—	(14,156)
Proceeds from sales of properties	211,173	27,816	—	238,989
Other property and equipment	(7,633)	(399)	—	(8,032)
Net cash (used in) provided by investing activities	89,862	(84,448)	—	5,414
CASH FLOWS FROM FINANCING ACTIVITIES				
Revolving credit facilities				
Borrowings	1,044,850	—	—	1,044,850
Repayments	(1,145,850)	—	—	(1,145,850)
Proceeds from issuance of 7.125% Senior Notes	248,695	—	—	248,695
Retirement of debt assumed in acquisition of Nuevo Energy Company	(405,000)	—	—	(405,000)
Costs incurred in connection with financing arrangements	(9,325)	—	—	(9,325)
Derivative settlements	(103,521)	—	—	(103,521)
Investment in and advances to affiliates	36,875	(36,875)	—	—
Other	1,686	—	—	1,686
Net cash (used in) provided by financing activities	(331,590)	(36,875)	—	(368,465)
Net increase (decrease) in cash and cash equivalents	473	(305)	—	168
Cash and cash equivalents, beginning of period	403	974	—	1,377
Cash and cash equivalents, end of period	$ 876	$ 669	$ —	$ 1,545



PXP BOARD MEMBERS

(standing from left to right) Jerry L. Dees, Tom H. Delimitros, Alan R. Buckwalter, III
(sitting from left to right) Isaac Arnold, Jr., James C. Flores, Robert L. Gerry, III, John H. Lollar

NYSE CORPORATE GOVERNANCE COMPLIANCE

As required by the rules of the New York Stock Exchange, following our 2006 Annual Meeting of Shareholders we submitted the annual CEO Certification regarding NYSE corporate governance listing standards to the NYSE. In addition, we have filed the certifications required by Section 302 of the Sarbanes-Oxley Act of 2002 with our 2006 Annual Report on Form 10-K as Exhibits 31.1 and 31.2.

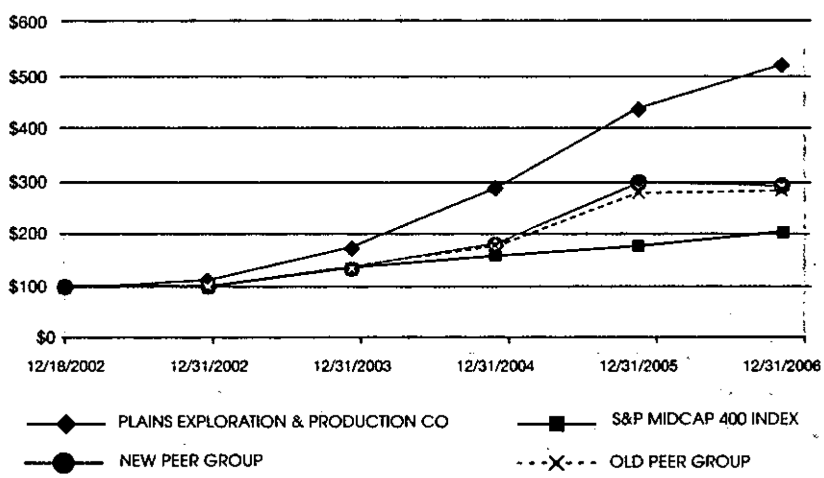
COMPARISON OF SHAREHOLDER RETURN

The following graph compares the cumulative total shareholder return on our common stock with the cumulative return of (i) the S&P MidCap 400, (ii) a peer group consisting of Chesapeake Energy Corp., Cimarex Energy Co., Denbury Resources Inc., EOG Resources, Inc., Newfield Exploration Company, Noble Energy, Inc., Pioneer Natural Resources Company, Pogo Producing Company and XTO Energy Inc. and (iii) a peer group used by PXP last year consisting of Cabot Oil & Gas Corp., Chesapeake Energy Corp., Denbury Resources Inc., EOG Resources, Inc., Forest Oil Corporation, The Houston Exploration Company, Newfield Exploration Company, Noble Energy, Inc., Pioneer Natural Resources Company, Pogo Producing Company, Stone Energy Corp., Vintage Petroleum, Inc. and XTO Energy Inc.

The graph covers the period from December 18, 2002, the date PXP's common stock started trading, through December 31, 2006, and assumes that $100 was invested on December 18, 2002 and that any dividends were reinvested. No dividends have been declared or paid on PXP's common stock. Shareholder returns over the period indicated should not be considered indicative of future shareholder returns.

The information contained in the Performance Graph shall not be deemed "soliciting material" or to be "filed" with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act or the Exchange Act, except to the extent that PXP specifically incorporates it by reference into such filing.

COMPARISON OF SHAREHOLDER RETURN



COMPANY INFORMATION

EXECUTIVE OFFICERS

James C. Flores
Chairman, President and Chief Executive Officer

Doss R. Bourgeois
Executive Vice President — Exploration & Production

Winston M. Talbert
Executive Vice President and Chief Financial Officer

John F. Wombwell
Executive Vice President and General Counsel

DIRECTORS

James C. Flores
Chairman, President and Chief Executive Officer
Plains Exploration & Production Company

Isaac Arnold, Jr.
Chairman of Quintana Petroleum

Alan R. Buckwalter, III
Retired, Chairman and Chief Executive Officer
Chase Bank of Texas

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

Tom H. Delimitros
General Partner
AMT Venture Funds

Robert L. Gerry, III
Chairman and Chief Executive Officer
VAALCO Energy, Inc.

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

TRANSFER AGENT

American Stock Transfer & Trust
59 Maiden Lane, Plaza Level
New York, New York 10038

FORM 10-K

A copy of the Company's annual report on Form 10-K to the Securities and Exchange Commission for the year ended December 31, 2006, is available free of charge on request to:

Investor Relations
Plains Exploration & Production Company
700 Milam, Suite 3100
Houston, Texas 77002
713.579.6000 or 800.934.6083

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

PricewaterhouseCoopers LLP
1201 Louisiana Street, Suite 2900
Houston, Texas 77002-5678

CORPORATE HEADQUARTERS

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PXP LISTED NYSE

STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

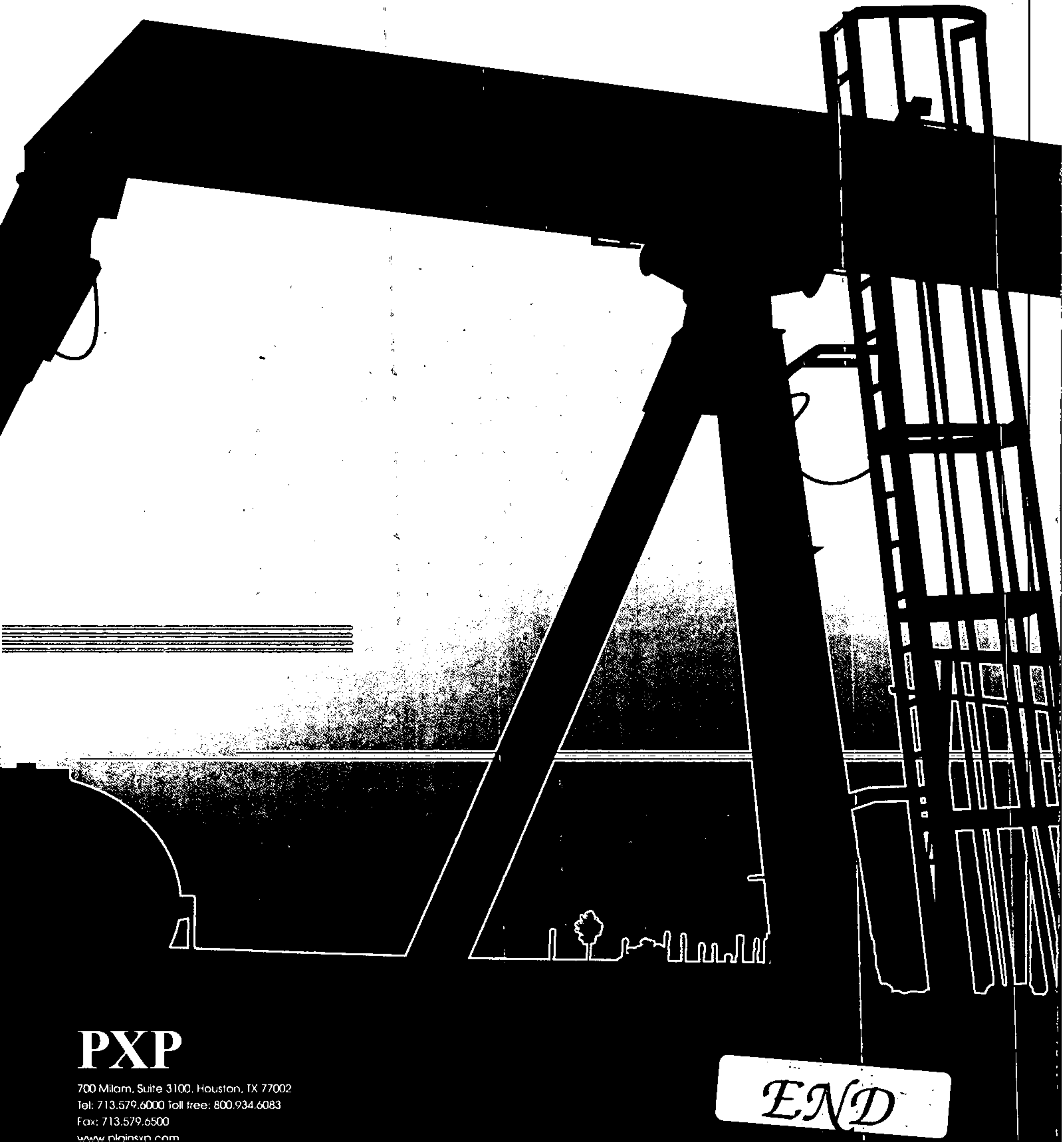
This annual Report on Form 10-K includes forward-looking information regarding PXP that is intended to be covered by the safe harbor for "forward-looking statements" provided by the Private Securities Litigation Reform Act of 1995. Statements that are predictive in nature, that depend upon or refer to future events or conditions, or that include words such as "will," "would," "should," "plans," "likely," "expects," "anticipates," "intends," "believes," "estimates," "thinks," "may," and similar expressions, are forward-looking statements. Although we believe that our expectations are based on reasonable assumptions, there are risks, uncertainties and other factors that could cause actual results to be materially different from those in the forward-looking statements. These factors include, among other things:

- 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, including the impact on our reserve volumes and values and our earnings as a result of our derivative positions;
- 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;
- the success of our derivative activities;
- the success of our risk-management activities;
- unexpected difficulties in integrating our operations as a result of any significant acquisitions;
- the effects of competition;
- 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 reliance on these statements without also considering the risks and uncertainties associated with these statements and our business that are discussed in this report and our other filings with the SEC. Moreover, 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 for any obligation to disclose material information under the Federal securities laws, we do not intend to update these forward-looking statements and information. See Item 1A – "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 100 F Street, N.E. Room 1580, 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 website at www.sec.gov. No information from the SEC's website is incorporated by reference herein. Our website is www.plainsxp.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 website. These documents are posted to our website as soon as reasonably practicable after we have filed or furnished these documents with the SEC. We have placed on our website copies of our Corporate Governance Guidelines, charters of our Audit, Organization & Compensation and Nominating & Corporate Governance Committees and our Policy Concerning Corporate Ethics and Conflicts of Interest. Shareholders may request a printed copy of these governance materials by writing to the Corporate Secretary, Plains Exploration & Production Company, 700 Milam, Suite 3100, Houston, TX 77002.



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