PXP

Plains Exploration & Production Company

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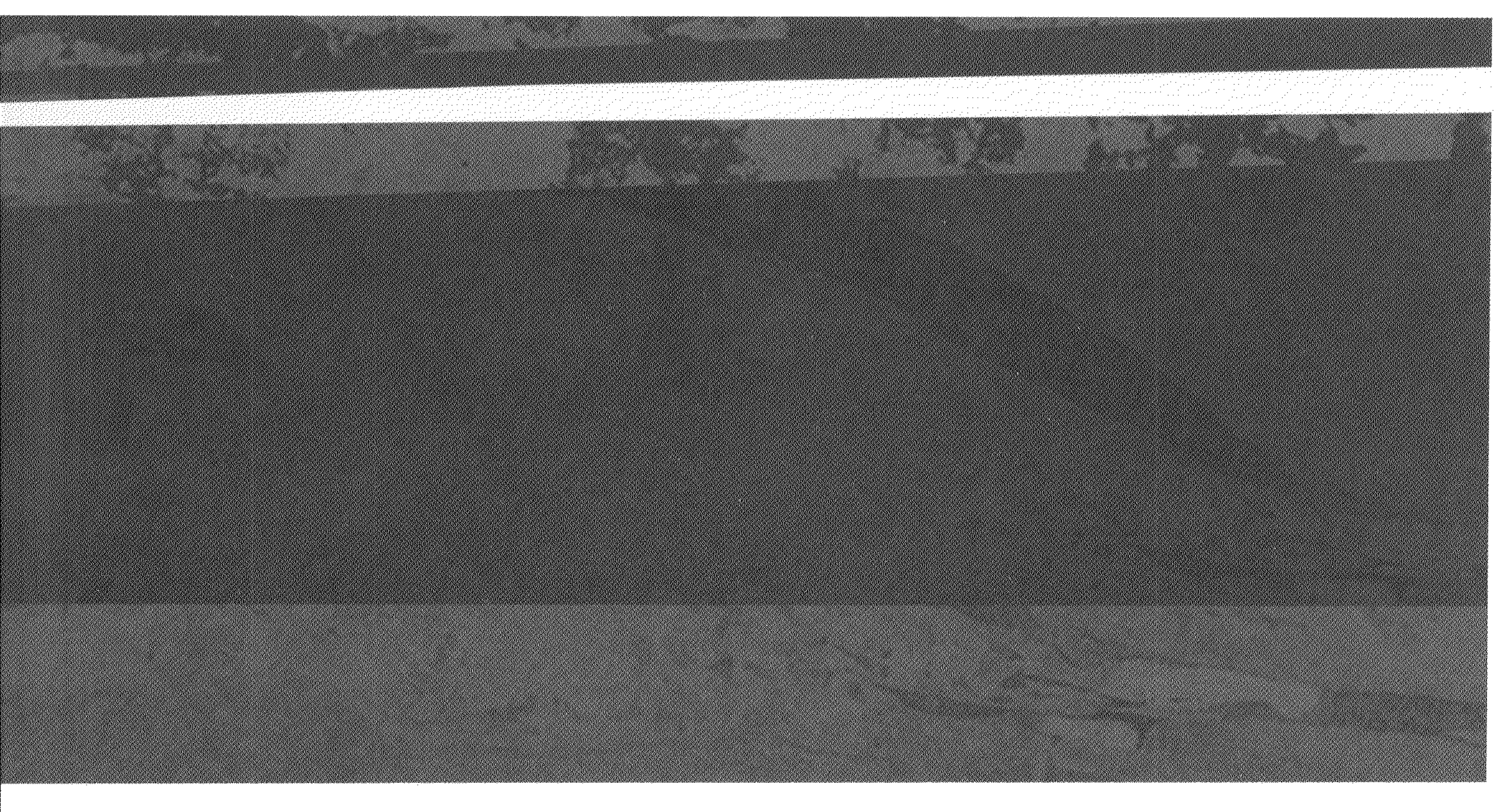
2008 annual report

OUR COMPANY

We are an independent oil and gas company primarily engaged in the activities of acquiring, developing, exploring and producing oil and gas properties primarily in the United States. We own oil and gas properties with principal operations in:

- the Los Angeles and San Joaquin Basins onshore California;
- the Santa Maria Basin offshore California;
- the Gulf of Mexico, including coastal onshore and offshore areas of Texas and Louisiana;
- the Gulf Coast region, including the Haynesville Shale and South and East Texas;
- the Mid-Continent region in Texas and Oklahoma; and
- the Wind River Basin in the Rocky Mountains.

Assets in our principal focus areas include mature properties with long-lived reserves and significant development opportunities as well as newer properties with development and exploration potential. In addition to the assets in our principal focus areas listed above, we also have interest in an exploration prospect offshore Vietnam.



FINANCIAL HIGHLIGHTS

(in thousands, except per share and percentage information)

	2008[1]	2007[2]	2006	2005	2004[3]
Reserve Data:					
Total oil reserves (barrels)	177,707	436,533	333,217	356,333	351,403
Total gas reserves (Mcf)	686,357	1,519,976	110,922	267,921	407,400
Total barrels of oil equivalent (BOE)	292,100	689,862	351,704	400,987	419,303
Percentage proved developed volume	72%	51%	52%	67%	68%
Estimated future net cash flows	$ 2,489,612	$ 18,042,121	$ 5,652,412	$ 6,772,811	$ 4,651,720
Standardized measure	$ 1,136,374	$ 7,623,323	$ 2,510,663	$ 3,082,166	$ 2,236,719
Percentage proved developed present value	96%	67%	68%	77%	79%
Operating Data:					
Oil production (barrels)	20,294	18,124	18,975	18,671	16,441
Average oil price (per barrel)[4]	$ 87.05	$ 61.60	$ 55.62	$ 46.76	$ 36.12
Gas production (Mcf)	79,254	29,312	20,629	29,359	38,590
Average gas price (per Mcf)[4]	$ 8.05	$ 5.68	$ 6.73	$ 7.15	$ 5.90
BOE production	33,503	23,010	22,413	23,564	22,872
Average BOE price[4]	$ 72.03	$ 56.12	$ 53.76	$ 45.96	$ 35.92
Production expense per BOE	$ 18.91	$ 18.25	$ 14.49	$ 12.10	$ 9.76
Selected Financial Data:					
Total revenue	$ 2,403,471	$ 1,272,840	$ 1,018,503	$ 944,420	$ 671,706
Income (loss) from operations[5]	$ (2,627,413)	$ 419,634	$ 1,348,450	$ 343,700	$ 208,599
Income (loss) before cumulative effect of accounting change	$ (709,094)	$ 158,751	$ 599,710	$ (214,012)	$ 8,840
Cumulative effect of accounting change, net of income tax	–	–	$ (2,182)	–	–
Net income (loss)	$ (709,094)	$ 158,751	$ 597,528	$ (214,012)	$ 8,840
Income (loss) per share					
Before cumulative effect of accounting change	$ (6.52)	$ 1.99	$ 7.67	$ (2.75)	$ 0.14
Cumulative effect of accounting change	–	–	$ (0.03)	–	–
Net income (loss) per share	$ (6.52)	$ 1.99	$ 7.64	$ (2.75)	$ 0.14
Weighted average shares outstanding					
Basic	108,828	78,627	77,273	77,726	63,542
Diluted	108,828	79,808	78,234	77,726	64,014
Total assets	$ 7,111,915	$ 9,693,351	$ 2,463,228	$ 2,741,942	$ 2,633,245
Long-term debt	$ 2,805,000	$ 3,305,000	$ 235,500	$ 797,375	$ 635,468
Total shareholders' equity	$ 2,377,280	$ 3,338,247	$ 1,130,683	$ 718,337	$ 870,375

(1) Reflects the February 2008 divestiture of 50% of our working interest in oil and gas properties in the Permian and Piceance Basins and all of our working interests in oil and gas properties in the San Juan Basin and Barnett Shale and the December 2008 divestiture of our remaining interests in oil and gas properties in the Permian and Piceance Basins.

(2) Reflects the acquisition of Pogo Producing Company effective November 6, 2007 and Piceance Basin properties effective May 31, 2007.

(3) Reflects the acquisition of Nuevo Energy Company effective May 14, 2004.

(4) Average realized sales price before derivative transactions.

(5) We are required to perform a full cost ceiling test each quarter. At December 31, 2008, our capitalized costs of proved oil and gas properties exceeded the ceiling, and we recorded a pre-tax non-cash impairment of oil and gas properties of $3.6 billion.

TO OUR SHAREHOLDERS

2008 was another remarkable year for PXP. Throughout unprecedented commodity price volatility, the financial credit crisis and the global impacts these had on economies and companies, PXP continued its strategy of acquiring oil and gas properties with meaningful production and cash flow potential, successfully completed its asset rotation into a large, high potential/lower risk portfolio with top-tier returns, and ended the year with a strong balance sheet. We applied experience and innovation, remained focused, and took swift action to ensure PXP's long-term growth platform remains sound.

We began 2008 focused on integrating assets acquired in late 2007, developing our California, Texas and Flatrock assets, and participating in a number of Gulf of Mexico deepwater exploration projects. We ended the year successfully integrating assets, completing a significant acquisition in the Haynesville Shale and strengthening our South Texas operation with a tax efficient asset acquisition, realizing positive drilling results in the Gulf of Mexico, South Texas and Texas Panhandle areas, delivering meaningful production increases, improving our employee safety record over 2007, closing $3 billion in asset divestments, reducing long-term debt, and repurchasing 5.8 million outstanding PXP common shares.

PXP entered the high-growth Haynesville Shale play in North Louisiana and East Texas and exited the Piceance, Permian, San Juan, and New Albany Basins. Rotation from the Piceance to the Haynesville gas producing properties greatly increased the growth and economic strength of our gas portfolio. We believe the Haynesville Shale is a remarkable opportunity to add substantial asset value through years of growth and cash flow generating potential and is rapidly developing into a world class field. Drilling operations began in July and production net to PXP commenced in September. A significant portion of PXP's resources are planned for its emerging prolific position in the Haynesville Shale where finding and development and full-cycle costs are some of the most attractive in the industry. Drilling results have been encouraging and with over 7,300 potential well locations after risk weighting, this asset area is expected to be a significant driver of future production and reserve growth.

In the Gulf of Mexico, our Flatrock development continued to yield successful drilling results, significant production growth in 2008 with double-digit increases expected in 2009, and three additional Flatrock area step-out prospects. Each of these prospects has several hundred billion cubic feet equivalent potential and is now drilling with results expected throughout the first quarter 2009. Our Gulf of Mexico exploration activities during 2008 yielded a discovery at the Blackbeard prospect. PXP and its partners are waiting on design and procurement of long lead time completion equipment for a high pressure test of this discovery. In early 2009, PXP announced a second significant discovery at the Friesian project and a plan to deepen the Friesian #2 well beginning in March 2009.

In our California base business, PXP maintained an active development program onshore and made substantial progress on several important permitting issues, which laid the groundwork for future production, reserves, and cash flow. With over a 10 year inventory identified in the San Joaquin Valley, the Arroyo Grande Field, and the Los Angeles Basin, these asset areas will sustain multi-year drilling programs providing future reserves and production.

PXP produced a Company-record 33.5 million barrels of oil equivalent (BOE) in 2008, while adding 47 million BOE of reserves through the discoveries, extensions, technical revisions and acquisitions, and reported year-end proved reserves of 292 million BOE. Total proved reserves include negative price revisions totaling 204 million BOE. The majority of the realized price related revisions occurred on our long-life California oil reserves. The dramatic decline in the price of oil and gas and substantially wider than average spot sales differentials were the primary contributors to the revisions.

PXP reported a net loss for the year of $709 million, or $6.52 per diluted share, compared to net income of $159 million, or $1.99 per diluted share, in 2007. The loss was in large part due to a $3.6 billion pre-tax non-cash impairment of oil and gas properties caused by significantly lower year-end 2008 commodity prices compared to year-end 2007. The charge was partially offset by a $1.6 billion pre-tax gain on mark-to-market derivatives.

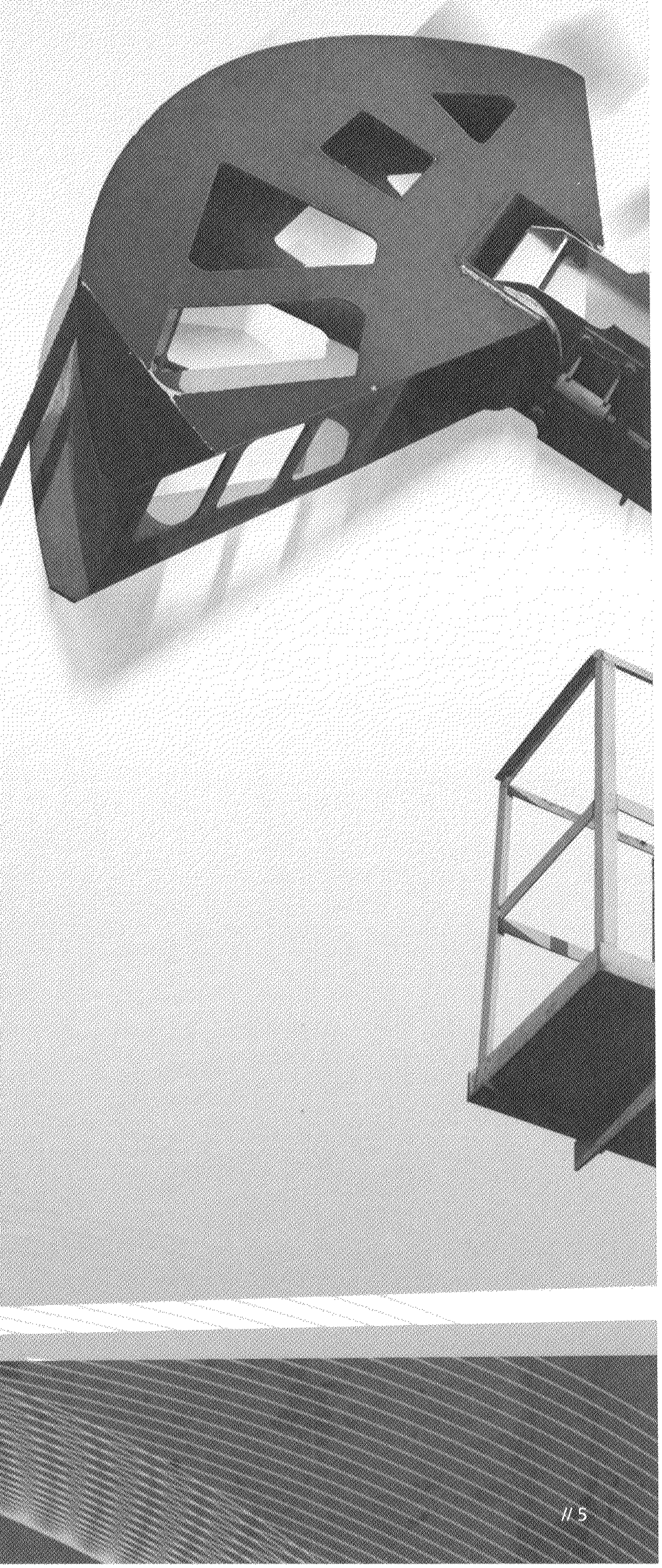
Despite the net loss, net cash flow provided by operating activities more than doubled to $1.4 billion from $588 million in 2007 due to the benefits of higher production volumes and stronger commodity prices in which PXP fully participated as a result of its conservative derivative strategy. PXP ended the year with a strong derivative position protecting its 2009 and 2010 cash flows, $2.5 billion in net long-term debt, a substantial reduction from $3.3 billion at year-end 2007, no near-term debt maturities, nearly $1.0 billion available under its revolving credit facility, and $1.48 billion of estimated value on mark-to-market derivative positions. Early 2009, PXP monetized $1.125 billion in commodity derivative gains, entered into 2010 crude oil derivative positions, and acquired natural gas collars for 2010. The net effect was to accelerate cash receipts and increase liquidity while maintaining the Company's strong derivative position against further declines in oil and natural gas prices during 2009 and 2010.

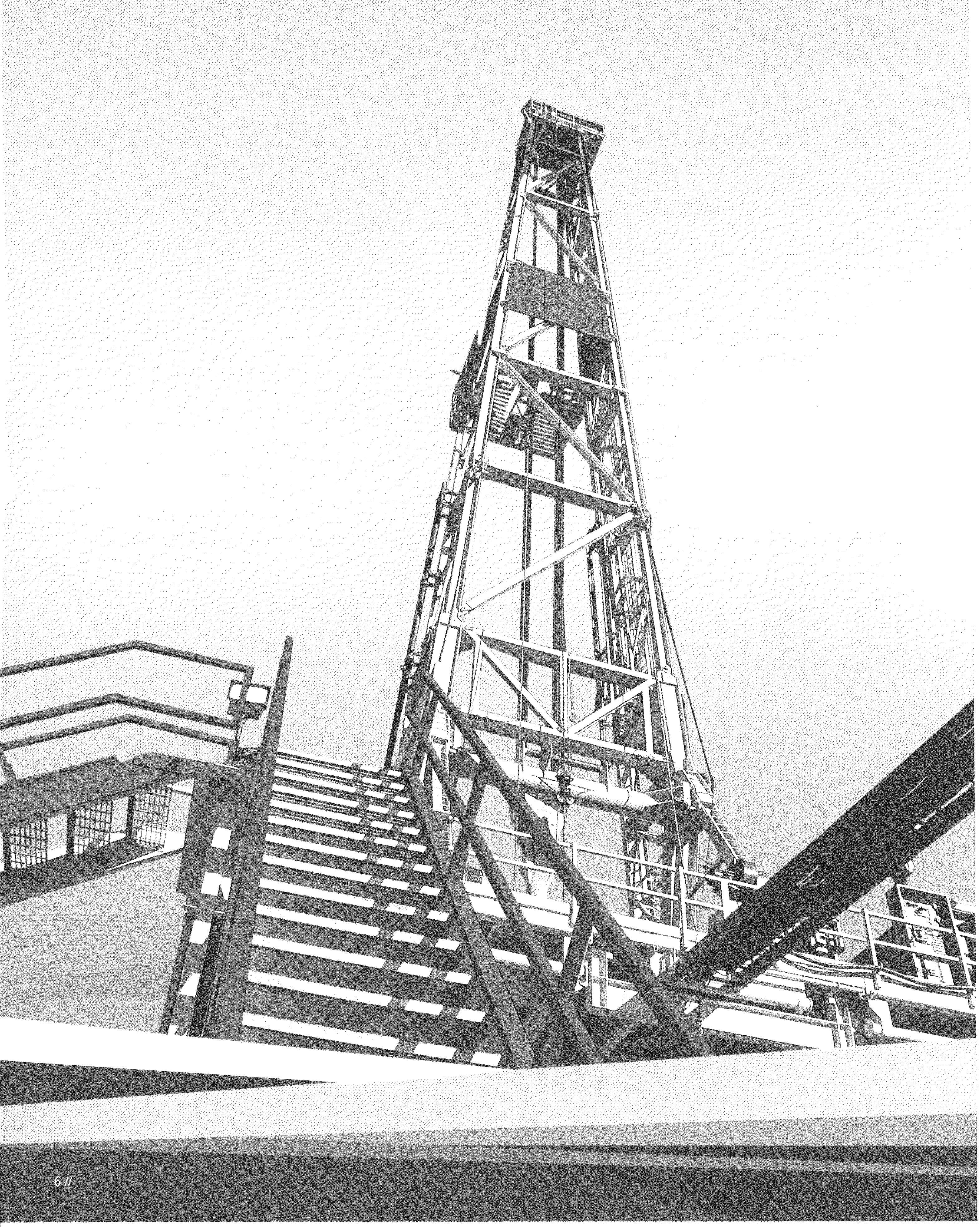
PXP's 2009 capital budget is estimated to be $1.050 billion with flexibility to adjust spending as market conditions warrant. Capital is prudently allocated, based on the current economic conditions, and focused primarily on PXP's major development areas, which management believes present the most efficient use of capital resources for its shareholders. The Company's resources will be primarily directed to the Haynesville Shale, the Friesian, Flatrock and Salida Gulf of Mexico projects, the California long-life oil resource base, and the remaining high-impact exploration projects. To maximize economic returns, we plan to reduce operating expenses in all of our field locations and reduce general and administrative costs throughout 2009. We will continue to aggressively manage our project inventory, our cost structure, and our financial flexibility.

Today, PXP is in an enviable position both operationally and financially. We have a strong derivative position; we have the largest project inventory in our Company's history supporting our long-term growth strategy; and we have financial strength. In 2009, we expect measured progress in all areas of our business while remaining focused on protecting our cash flow and pursuing our internal opportunities. Finally, we continue to retain and develop our highly competent, hard-working employees who continue to engineer the Company's successes.

The Board of Directors and I want to thank each of our shareholders, partners, and employees for their continued confidence and support.

JAMES C. FLORES
Chairman, President and
Chief Executive Officer





PXP

Form 10-k

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

SEC Mail Processing
Section

APR 01 2009

Washington, DC
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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, 2008

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, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer ✓ Accelerated filer __ Non-accelerated filer __ Smaller reporting company __

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

The aggregate market value of the Common Stock held by non-affiliates of the registrant (treating all executive officers and directors of the registrant, for this purpose, as if they may be affiliates of the registrant) was approximately $7.7 billion on June 30, 2008 (based on $72.97 per share, the last sale price of the Common Stock as reported on the New York Stock Exchange on such date). On January 30, 2009, there were 107.6 million shares of the registrant's Common Stock outstanding.

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 2009 Annual Meeting of Stockholders.

PLAINS EXPLORATION & PRODUCTION COMPANY
2008 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 difficulties in integrating our operations as a result of any significant acquisitions;
- unexpected future capital expenditures (including the amount and nature thereof);
- the impact of oil and gas price fluctuations, including the impact on our reserve volumes and values and on our earnings;
- 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;
- the effects of competition;
- the availability (or lack thereof) of acquisition, disposition or combination opportunities;
- the availability (or lack thereof) of capital to fund our business strategy and/or operations;
- the impact of current and future laws and governmental regulations;
- environmental liabilities that are not covered by an effective indemnity or insurance;
- the ability and willingness of our current or potential counterparties to fulfill their obligations to us or to enter into transactions with us in the future; 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 Securities and Exchange Commission. 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.PXP.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.

Bcf. One billion cubic feet of gas.

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.

BOPD. Barrels of oil per day.

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.

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 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 interest. 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, 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 "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, exploring and producing oil and gas properties primarily in the United States. We own oil and gas properties with principal operations in:

- Onshore California;
- Offshore California;
- the Gulf of Mexico;
- the Gulf Coast Region;
- the Mid-Continent Region; and
- the Rocky Mountains.

Assets in our principal focus areas include mature properties with long-lived reserves and significant development opportunities as well as newer properties with development and exploration potential. In addition to the assets in our principal focus areas listed above, we also have an interest in an exploration prospect offshore Vietnam.

Oil and Gas Reserves

As of December 31, 2008, we had estimated proved reserves of 292.1 million barrels of oil equivalent, of which 61% was comprised of oil and 72% was proved developed. We have a total proved reserve life of approximately 10 years and a proved developed reserve life of approximately 7 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, 2008, and based on year-end 2008 reference prices as adjusted for location and quality differentials, our reserves had a standardized measure of $1.1 billion.

The following table sets forth certain information with respect to our reserves that for 2008 are based upon (1) reserve reports prepared by the independent petroleum consulting firms of Netherland, Sewell & Associates, Inc. and Ryder Scott Company L.P. ("Ryder Scott") (95% of reserve volumes) and (2) reserve volumes prepared by us, which were not audited by an independent petroleum consulting firm (5% of reserve volumes). In 2007, our reserves were based upon (1) reserve reports prepared by Netherland, Sewell & Associates, Inc. and Ryder Scott (80% of reserve volumes), (2) reserve volumes prepared by us and audited by Ryder Scott and Miller and Lents, Ltd. (19% of reserve volumes) and (3) reserve volumes prepared by us which were not audited by an independent petroleum consulting firm (1% of reserve volumes). In 2006, 100% of our reserves were based on reserve reports prepared by 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,			
	2008		2007	2006
	(dollars in thousands)			
Oil and Gas Reserves				
Oil (MBbls)				
Proved developed	123,522		227,915	171,646
Proved undeveloped	54,185		208,618	161,571
	177,707		436,533	333,217
Gas (MMcf)				
Proved developed	515,180		757,736	62,021
Proved undeveloped	171,177		762,240	48,901
	686,357		1,519,976	110,922
MBOE	292,100		689,862	351,704
Standardized Measure	$ 1,136,374	(1)	$ 7,623,323	$ 2,510,663
Average year-end realized prices (2)				
Oil (per Bbl)	$ 31.75		$ 85.50	$ 50.71
Gas (per Mcf)	$ 5.50		$ 6.28	$ 6.14
Year-end NYMEX prices				
Oil (per Bbl)	$ 44.60		$ 95.98	$ 61.05
Gas (per MMbtu)	$ 5.71		$ 7.48	$ 6.30
Reserve life (years) (3)	9.9		18.0	17.3

(1) Our year-end 2008 standardized measure includes future development costs related to proved undeveloped reserves of \$81 million in 2009, \$107 million in 2010 and \$115 million in 2011.

(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 transportation and refining costs of heavy crude. Differentials for our California oil production increased significantly at the end of 2008 which reduced our realized price.

(3) 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.

In 2008, we had discoveries and extensions of 42 MMBOE, including the Haynesville Shale (15 MMBOE) and the Gulf of Mexico (12 MMBOE), primarily attributable to the continued success in the Flatrock area. We also acquired 16 MMBOE of reserves, primarily in our South Texas properties. We had a total of 215 MMBOE of negative revisions, 204 MMBOE which was due to significantly lower average year-end prices for oil and gas, including the widening of differentials impacting our California properties and development and production costs, which were reflective of the higher oil and gas prices during the first nine months of the year. We had 207 MMBOE of divestments consisting of primarily all of our Permian Basin, Piceance Basin and San Juan Basin oil and gas properties.

The increase in proved reserves in 2007 was primarily due to the acquisitions of Pogo Producing Company ("Pogo") and the Piceance Basin properties, which accounted for 237 MMBOE. Additionally, we had positive revisions of 93 MMBOE in onshore California, Piceance Basin and Permian Basin, primarily as a result of the significantly higher average year-end realized prices.

Approximately 32% of our proved undeveloped reserves are scheduled for development beyond five years and 37%, or $367 million, of our future estimated capital to develop proved undeveloped reserves is associated with those reserves. Our development pace takes into consideration economic conditions, industry factors and the characteristics and location of each field, while emphasizing minimal impact on the surrounding communities as well as high safety standards. We believe that our historical and forecasted pace of development strikes an appropriate balance between developing our proved reserves and our low risk unproved reserve potential in order to generate steady growth for both production and proved reserves while maximizing the value of our entire portfolio.

The following table sets forth certain information with respect to the total proved undeveloped reserves that were converted to proved developed status over the last five years.

Year	Beginning of Year Proved Undeveloped Reserves (MBOE)	Proved Undeveloped Reserves Converted to Proved Developed (MBOE)	Percentage of Proved Undeveloped Reserves Coverted to Proved Developed	Capital Related to Development of Proved Undeveloped Reserves (millions of dollars)
2008	335,658	29,608	9%	206
2007	169,722	9,853	6%	109
2006	134,031	16,025	12%	128
2005	134,761	26,976	20%	114
2004	116,924	4,150	4%	31

During the three-year period ended December 31, 2008, we participated in 123 exploratory wells, of which 102 were successful, and 660 development wells, of which 652 were successful. During this period, we incurred aggregate oil and gas acquisition, exploration and development costs of $10.4 billion, approximately 88% of which was for acquisition and development activities. During this period, proved reserve additions from acquisitions, extensions, discoveries and improved recovery totaled 346 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 related reserve additions being recognized. Costs include expenditures related to these discoveries. See "Divestments". Approximately 72% of our reserves at December 31, 2008 are classified as proved developed compared to 51% at December 31, 2007.

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.

The reserve documentation and calculations for substantially all of our reserves are reviewed both by our internal engineers and independent third party engineers each year. During this process all performance projections are updated and revised where appropriate, all new well control and petrophysical data acquired is incorporated into our estimated ultimate recovery and remaining reserve calculations, and the remaining proved reserves are redistributed among proved developed and proved undeveloped categories where appropriate. This ensures forecasts of proved undeveloped reserves represent incremental capture and not acceleration. Our drilling activity includes a significant number of wells that were not classified as proved undeveloped in the previous year's reserve report, and we forecast this trend to continue as we have a substantial inventory of low risk unproved locations in addition to proved drilling locations.

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, 2007, 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 July 2008, we acquired from a subsidiary of Chesapeake Energy Corporation ("Chesapeake") a 20% interest in Chesapeake's Haynesville Shale leasehold for approximately $1.65 billion in cash. We funded the acquisition with borrowings under our senior revolving credit facility. In connection with the acquisition, we also agreed, over a multi-year period, to fund 50% of Chesapeake's drilling and completion costs associated with future Haynesville Shale wells, up to an additional $1.65 billion. In addition, we have the option to participate for 20% of any additional leasehold that Chesapeake, or its affiliates, acquires in the Haynesville Shale within a designated area of mutual interest. We currently hold 111,000 net acres in the Haynesville Shale. At the acquisition date there were no material proved reserves associated with the leasehold interests acquired.

In February 2009, PXP and Chesapeake entered into certain amended agreements which, among other matters, provides us without additional monetary consideration by us a one time option, exercisable on or before June 30, 2010, to reduce our obligation to pay 50% of Chesapeake's drilling and completion costs by $800 million in exchange for an assignment to Chesapeake, effective December 31, 2010, of 50% of all of our interest in the Haynesville properties.

In April 2008, we completed the acquisition of oil and gas producing properties in South Texas from a private company. After the exercise of third party preferential rights, we paid approximately $282 million in cash. We funded the acquisition primarily with proceeds from recently completed divestments through the use of a tax deferred like-kind exchange. The effective date of the transaction was January 1, 2008.

In November 2007, we acquired Pogo for approximately 40 million shares of common stock valued at approximately $2.0 billion and approximately $1.5 billion in cash. Pogo was engaged in oil and gas exploration, development, acquisition and production activities on its properties primarily located in the onshore United States and offshore Vietnam and New Zealand. We accounted for the transaction under purchase accounting rules effective November 6, 2007.

In May 2007, we acquired certain properties in the Piceance Basin from a private company for $975 million in cash and one million shares of common stock valued at approximately $45 million. The Piceance Basin properties include interests in oil and gas producing properties in the Mesaverde geologic section of the Piceance Basin in Colorado, plus associated midstream assets, including a 25% interest in Collbran Valley Gas Gathering, LLC, or CVGG. We sold these properties in 2008. See "Divestments".

Other acquisitions of oil and gas properties totaled approximately $20.2 million in 2008.

Divestments

In December 2008, we closed the sale of certain oil and gas properties to a subsidiary of Occidental Petroleum Corporation ("Oxy") and certain other companies with contractual preferential purchase rights, with an effective date of December 1, 2008, and received approximately $1.25 billion in gross cash proceeds or $1.24 billion after preliminary closing adjustments. We sold the remaining 50% of our working interests in oil and gas properties located in the Permian Basin, West Texas and New Mexico, which we acquired in the Pogo acquisition in November 2007. We also sold the remaining 50% of our working interests in oil and gas properties located in the Piceance Basin in Colorado, including our remaining 50% interest in the entity that held our interest in CVGG. We acquired these properties in May 2007. The sale also included our interest in approximately 11,500 net undeveloped acres adjacent to our Piceance Basin assets that we and Oxy jointly acquired from a third party in June 2008.

In February 2008, we closed the sale of certain oil and gas properties to a subsidiary of Oxy and certain other companies with contractual preferential purchase rights, with an effective date of January 1, 2008, and received approximately $1.53 billion in cash proceeds. We sold 50% of our working interests in oil and gas properties located in the Permian Basin, West Texas and New Mexico, which we acquired in the Pogo acquisition in November 2007. We also sold 50% of our working interests in oil and gas properties located in the Piceance Basin in Colorado, including a 50% interest in the entity that held our interest in CVGG. We acquired these properties in May 2007.

In February 2008, we closed the sale to XTO Energy Inc. ("XTO") of certain oil and gas properties located in the San Juan Basin in New Mexico and in the Barnett Shale in Texas. This transaction had an effective date of January 1, 2008, and we received $199.0 million in cash proceeds.

Other divestments totaled approximately $26.4 million in 2008.

In November 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 and one deepwater exploration prospect. We received approximately $706 million in cash proceeds.

In September 2006, we closed the sale of certain oil and gas properties located primarily in California and Texas to subsidiaries of Oxy for net proceeds of approximately $864 million.

Development and Exploration

We expect to continue our long-term reserve and production growth through the development of our existing inventory of projects in each of our primary operating areas. To complement the 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, Gulf Coast Region and offshore Vietnam. To implement the plans, we will focus on:

- allocating investment capital prudently after rigorous evaluation;
- optimizing production practices;
- reducing drilling and production costs;
- 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 development and exploration plan, we seek to add to and enhance our proved reserves and thereby increase cash flows and enhance the value of our asset base. During the three-year period ended December 31, 2008, our additions to proved reserves from extensions, discoveries and improved recovery totaled 92 MMBOE. During this period we incurred aggregate oil and gas development and exploration costs of $2.5 billion.

Our $1.05 billion 2009 capital budget is focused on our major development areas. Approximately 37% of the capital investment is allocated to development activities, 43% to the Haynesville Shale project and 20% for exploration projects. Our resources will be primarily directed to the Haynesville Shale, the Freisian, Flatrock and Salida Gulf of Mexico projects, the California long-life oil resource base, and our remaining high-impact exploration projects. To maximize economic returns, we plan to reduce operating expenses in all of our field locations and reduce general and administrative costs throughout 2009. We continue to aggressively manage our inventory, our cost structure, and our financial flexibility.

Description of Properties

Our oil and gas operations are concentrated onshore California, offshore California, the Gulf of Mexico, the Gulf Coast Region, the Mid-Continent Region and the Rocky Mountains. We also have an interest in an exploration prospect offshore Vietnam. Assets in our principal focus areas include mature properties with long-lived reserves and significant development opportunities, as well as newer properties with development and exploration potential.

We designed our capital investments with the intent of increasing the value of our oil and gas assets through a diversified growth strategy with sustained development of our base properties in California, the Gulf of Mexico, Gulf Coast Region and our Texas asset areas as well as continued exploration primarily in the Gulf of Mexico, onshore Gulf Coast Region and offshore Vietnam. Capital additions to our oil and gas properties were $1.1 billion in 2008, excluding acquisitions, and are currently budgeted to be $1.05 billion in 2009.

The following table sets forth information with respect to our proved oil and gas reserves as of December 31, 2008:

	Proved Reserves at December 31, 2008		
	Proved Developed	Proved Undeveloped	Total Proved
		(MMBOE)	
Onshore California	116.7	53.4	170.1
Offshore California	4.3	-	4.3
Gulf of Mexico	12.8	1.5	14.3
Gulf Coast Region	30.0	13.3	43.3
Mid-Continent Region	13.2	13.8	27.0
Rocky Mountains	30.4	0.7	31.1
All other areas	2.0	-	2.0
Total	209.4	82.7	292.1

Onshore California

Los Angeles Basin

We hold a 100% working interest in the majority of our Los Angeles Basin ("LA Basin") properties, including Inglewood, Las Cienegas, Montebello, Packard, and San Vicente. The LA Basin properties are characterized by light crude (18 to 29 degree API gravity), have well depths ranging from 2,000 feet to over 10,000 feet and include both primary production and mature waterfloods where producing wells have high water cuts.

In 2008, we spent $58.3 million on capital projects in the LA Basin. Our net average daily sales volume from our LA Basin properties in the fourth quarter of 2008 was 13.0 MBOE per day. In 2009 we plan to continue developing these long-lived reserve properties focusing on capital investment projects that provide the best returns under the current low commodity price and high service cost environment, as well as targeting production cost reductions.

San Joaquin Basin

Our San Joaquin Basin properties are primarily in the Cymric, Midway Sunset and South Belridge Fields. These are long-lived fields that have heavier oil (12 to 16 degree API gravity) and shallow wells (generally less than 2,000 feet) that require enhanced oil recovery techniques, including steam injection, and produce with high water cuts.

We spent $76.5 million in 2008 on capital projects in the San Joaquin Basin and drilled 83 wells, including injection wells. Drilling was concentrated in the Cymric Field, where we spent $30.5 million and drilled 22 wells and in the Midway Sunset Field, where we spent $25.4 million and drilled 20 wells. Our net average daily sales volume from our San Joaquin Basin properties in the fourth quarter of 2008 was 20.8 MBOE per day. During 2009, we plan to continue developing these long-lived reserve properties focusing on capital investment projects that provide the best returns under the current low commodity price and high service cost environment as well as targeting production cost reductions.

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. This is a long-lived field that has heavier oil (12 to 16 degree API gravity), well depths averaging 1,700 feet and requires continuous steam injection. In 2008, we spent $13.4 million on capital projects in this field and drilled 18 wells, including injection wells. Our net average daily sales volume from the Arroyo Grande Field in the fourth quarter of 2008 was 1.1 MBOE per day.

We recently obtained permits to construct a water reclamation and treatment facility to improve operating efficiencies for oil recovery activities. The new facility will accelerate field development and production growth. We have elected to delay construction as a result of the current low commodity price and high service cost environment and plan to focus our capital on higher return projects. We plan to continue our drilling efforts within the Arroyo Grande Field in 2009 to increase the efficiency of the recovery process, but at a reduced rate.

Offshore California

Point Arguello. We hold a 69.3% working interest (58% net revenue interest) in the Point Arguello Unit and the various partnerships owning the related transportation, processing and marketing infrastructure. Capital projects in 2008 totaled $4.5 million and our net average daily sales volume in the fourth quarter of 2008 was 3.8 MBOE per day. Much of the activity on this property in 2009 will concentrate on maintaining production.

Point Pedernales. We hold a 100% working interest (83% net revenue interest) in the Pt. Pedernales Field, which includes one platform that is utilized to exploit the Federal OCS Monterey Reservoir by extended reach directional wells, and support facilities which lie within the onshore Lompoc Field. In 2008 we spent $31.2 million on capital projects in this property. Our combined net average daily sales volume from our Pt. Pedernales and Lompoc Fields averaged 7.3 MBOE per day in the fourth quarter of 2008. Much of the activity on this property in 2009 will concentrate on maintaining production.

Gulf of Mexico

We invested $427.2 million in 2008 on exploration and development projects in the Gulf of Mexico asset area which includes coastal onshore and offshore areas of Texas and Louisiana and the Gulf of Mexico.

We entered into an exploration agreement with McMoRan Exploration Co. in November 2006 to participate in several of their Miocene exploratory prospects. During 2008, we participated in 10 wells of which five were successful, one was unsuccessful and four were in progress at year end, located in the Flatrock, Louisiana State Lease 340, South Marsh Island Block 251 and South Timbalier Block 168 areas.

- Production commenced at Flatrock in the first quarter of 2008, and currently four wells are producing. Our net average sales volume for Flatrock was 6.4 MBOE per day in the fourth quarter 2008. A fifth well was being completed at December 31, 2008, and one is in progress. We own a 30% working interest.
- Two wells are currently in progress on Louisiana State Lease 340 and one on South Marsh Island Block 251 at December 31, 2008, where we own working interests ranging from 24% to 44%.
- At December 31, 2008, a well drilled on South Timbalier Block 168, where we own a 35% working interest, was temporarily abandoned awaiting completion.

In the deepwater area of the Gulf of Mexico, we participated in three exploration wells in 2008, of which one was in progress at year end, one was a discovery and one was unsuccessful. On Green Canyon Block 599 we have a 50% working interest in the Friesian discovery well announced in

November 2006. In January 2009, we announced a successful confirmation well, the Friesian #2. The Friesian #2, which we operate, was drilled to a total depth of 28,989 feet and encountered approximately 389 net feet of oil saturated Miocene-aged sands. We and our partner decided to deepen the Friesian #2 an additional 3,500 feet to 32,500 feet true vertical depth to test additional sands. Additionally, early stage commercialization initiatives for Freisian production are under study with multiple parties to target initial production by 2012.

During 2009, we plan to participate in development wells and select exploration wells in the Gulf of Mexico including drilling an exploration well on the Salida prospect with Shell Offshore Inc.

Gulf Coast Region, including Haynesville Shale and South and East Texas

Haynesville Shale

In July 2008, we acquired a 20% interest in Chesapeake's Haynesville Shale leasehold. The Haynesville Shale is characterized by gas production from the Jurassic-aged Haynesville shale formation, and typical well depth is 10,500 feet. The area is currently being developed with approximately 4,000 foot horizontal wells at a measured total depth of 16,000 feet. We have rights to approximately 685,000 gross acres (111,000 net acres). Based on the potential of 80 acre well spacing, we anticipate that there could be over 7,300 potential drilling locations after applying a risk weighting. Drilling operations began in July 2008 and production commenced during the third quarter of 2008. We spent $111.9 million from July 2008 through December 31, 2008 and drilled 26 wells and 19 were in progress. As of December 31, 2008 Chesapeake was operating 20 rigs and anticipates operating an average of approximately 26 rigs during 2009. For 2009, we allocated 43% of our 2009 capital budget, or approximately $450 million, to Haynesville activity.

South Texas

We own interests in oil and gas properties on 94,448 gross acres (62,846 net acres) with 321 square miles of 3-D seismic located in South Texas including 52,648 gross acres (29,453 net acres) that we acquired in April 2008 from a private company.

Development activities are primarily for gas reserves concentrated in the Los Mogotes, Lopez Ranch and Mills Bennett fields. The fields produce from the Eocene Yegua and Wilcox formations, found at depths generally ranging from 7,000 to 14,000 feet.

We spent $79.7 million on exploration and development projects, excluding acquisition costs, in this area in 2008. Our net average daily sales volume from our South Texas properties for the fourth quarter 2008 was 11.1 MBOE per day. In 2009, we plan to continue focusing on development in the Los Mogotes, Lopez Ranch and Mills Bennett Fields but at a reduced rate.

Onshore and Offshore Areas of Texas and Louisiana

Jefferson County, Texas. We hold a 100% working interest in approximately 72,233 gross acres, including the Oligocene, Frio and Vicksburg reservoirs in the Big Mac prospect area. We own over 275 square miles of 3-D seismic data, and interpretation of that data has yielded a number of exploratory prospects.

Polk and Tyler Counties, Texas. We hold approximately 63,186 gross acres, including the Cretaceous Woodbine and Austin Chalk Formations. We own approximately 125 square miles of new, proprietary 3-D seismic data, and interpretation of that data has yielded a number of exploratory prospects, which are generally 100% owned and operated by us.

South Louisiana. We have approximately 39,027 gross acres in central South Louisiana on which to explore for Oligocene and deeper Eocene targets. We own over 165 square miles of new 3-D seismic data in central South Louisiana and hold 100% working interest. We plan to drill a well on this acreage in 2009.

Mid-Continent Region

We have interests in oil and gas properties on approximately 532,292 gross leasehold acres with 715 square miles of 3-D seismic located in Texas and Oklahoma.

Development activities are concentrated in the Courson Ranch area located primarily in Roberts and Hutchinson Counties in Texas as well as in the Wheeler and Marvin Lake Prospects in Wheeler and Hemphill Counties in Texas. The structural and stratigraphic objectives include Cleveland Sands, Mississippian carbonates, Granite and Atoka Wash, found at varying depths.

Exploration opportunities of various stratigraphic and structural plays have been identified in the Mid-Continent Region on a concentration of ranches principally located in Roberts and Hutchinson Counties.

We spent $102.8 million on exploration and development projects in this region in 2008. Our net average daily sales volume from our Mid-Continent Region properties in the fourth quarter 2008 was 5.4 MBOE per day. In 2009, we plan to concentrate our development drilling on the Wheeler and Marvin Lake Prospects as well as additional exploration drilling at the Courson and Turkey Track Ranches at a reduced rate and have targeted production cost reductions.

Rocky Mountains

Wind River Basin

We own a 14% working interest in the Madden Unit and Lost Cabin Gas Plant located in central Wyoming. The Madden Unit is a federal unit operated by a third party and consists of approximately 64,104 gross acres in the Wind River Basin. The Madden Unit is characterized by gas production from multiple stratigraphic horizons of the Lower Fort Union, Lance, Mesaverde and Cody sands and the Madison Dolomite. Production from the Madden Unit is typically found at depths ranging from 5,500 to 25,000 feet. Some of the gas produced from the Madden Unit requires processing at the Lost Cabin Gas Plant to remove high concentrations of carbon dioxide and sulfur.

In 2008, we spent $15.6 million on capital projects in the Madden Unit. Our net average daily sales volume for the fourth quarter 2008 was 4.6 MBOE per day. We will continue to target, among other objectives, the Lower Fort Union Sands in 2009.

International

Vietnam

In November 2007, we acquired Pogo, which had entered into a Production Sharing Contract with PetroVietnam, the state oil company of Vietnam. Our interest in Block 124 covers approximately 1,480,000 gross acres offshore central Vietnam. We have completed the interpretation of approximately 850 square kilometers of 3-D seismic data, and in 2009, we plan to drill two exploratory wells. The first well is expected to commence during the first half of 2009.

Acquisition, Exploration and Development Expenditures

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

	Year Ended December 31,		
	2008	2007	2006
	(In thousands of dollars)		
Property acquisition costs:			
Unproved properties	$ 1,878,842	$ 1,822,312	$ 48,315
Proved properties	267,161	3,883,607	7,175
Exploration costs	520,612	465,246	272,352
Development costs	576,753	357,345	319,730
	$ 3,243,368	$ 6,528,510	$ 647,572

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, 2008, 2007 and 2006.

	Year Ended December 31,		
	2008	2007	2006
Daily Average Volumes			
Oil and liquids sales (Bbls)	55,449	49,655	51,985
Gas (Mcf)			
Production	216,540	80,307	56,519
Used as fuel	6,073	6,307	13,214
Sales	210,467	74,000	43,305
BOE			
Production	91,539	63,041	61,405
Sales	90,527	61,986	59,202
Unit Economics (in dollars)			
Average NYMEX Prices			
Oil	$ 99.75	$ 72.36	$ 66.23
Gas	9.06	6.86	7.21
Average Realized Sales Price Before Derivative Transactions			
Oil (per Bbl)	$ 87.05	$ 61.60	$ 55.62
Gas (per Mcf)	8.05	5.68	6.73
Per BOE	72.03	56.12	53.76
Costs and Expenses per BOE			
Production costs			
Lease operating expenses	$ 9.88	$ 9.98	$ 8.32
Steam gas costs	3.96	4.57	2.95
Electricity	1.59	1.76	1.76
Production and ad valorem taxes	2.84	1.44	1.15
Gathering and transportation	0.64	0.50	0.31
DD&A (oil and gas properties)	17.69	12.92	8.96

See Item 7 – "Management's 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 sales revenue streams if prices decline below the prices at which the derivatives are set. However, ceiling prices in derivatives may result in us 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, crude oil swaps and gas price collar contracts entered into with financial institutions.

A substantial portion of our oil and gas reserves are located in California and approximately 52% 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, and the current percentage rates were renegotiated at the end of 2007. During 2008, we received approximately 88% of the NYMEX index price for crude oil sold under the ConocoPhillips contract, representing approximately 45% of our total crude oil production.

Approximately 28% of our crude oil production is sold through Plains Marketing, L.P. ("PMLP"), which is a subsidiary of Plains All American Pipeline, L.P., with 51% sold under contracts that provide for NYMEX less a fixed price differential (as of December 31, 2008 averaging NYMEX less $9.76 per barrel) and the remainder sold under contracts that provide for monthly field posted prices. 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. This contract is set to expire in November 2009.

Prices received for our gas are subject to seasonal variations and other fluctuations. Approximately 50% 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 2008, 2007 and 2006, sales to ConocoPhillips accounted for 36%, 45% and 54%, respectively, of our total revenues and sales to PMLP accounted for 23%, 31% and 41%, 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, 2008, we had working interests in 2,916 gross (2,817 net) active producing oil wells and 1,362 gross (783 net) active producing gas wells. The following table sets forth information with respect to our developed and undeveloped acreage as of December 31, 2008:

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Domestic (1)				
California				
Onshore	91,125	65,013	103,705	72,101
Offshore	41,588	34,328	125,330	21,503
Louisiana				
Onshore	20,101	7,024	536,117	125,219
Offshore	15,235	5,034	378,518	146,292
Oklahoma	17,445	4,306	39,123	26,040
Texas	223,156	134,192	669,396	419,387
Utah	-	-	71,487	34,335
Wyoming	31,525	4,243	214,055	161,513
Other states (2) ...	11,409	7,442	31,390	27,400
	451,584	261,582	2,169,121	1,033,790
Vietnam (3)	-	-	1,480,000	1,480,000
	451,584	261,582	3,649,121	2,513,790

(1) Approximately 49% of domestic total net undeveloped acres is covered by leases that expire from 2009 through 2011. We added a significant number of new leases in 2008 in the Haynesville Shale, with lease terms generally ranging from two to three years; however, we are actively participating in the drilling of wells in the area to establish production in order to hold a majority of the acreage beyond lease expiration.

(2) Other states include Arkansas, Kansas, Mississippi, Montana, Nevada and North Dakota.

(3) Pursuant to our contract with PetroVietnam, we will be required to designate 20% of this acreage for relinquishment during 2009.

Drilling Activities

Information with regard to our drilling activities during the years ended December 31, 2008, 2007 and 2006 is set forth below:

	Year Ended December 31,					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Oil	7.0	2.7	-	-	1.0	1.0
Gas	52.0	18.1	36.0	32.1	6.0	4.7
Dry	5.0	3.6	8.0	4.9	8.0	6.0
	64.0	24.4	44.0	37.0	15.0	11.7
Development Wells						
Oil	125.0	90.2	140.0	139.1	186.0	185.8
Gas	159.0	80.0	37.0	35.0	5.0	4.4
Dry	1.0	1.0	3.0	3.0	4.0	4.0
	285.0	171.2	180.0	177.1	195.0	194.2
	349.0	195.6	224.0	214.1	210.0	205.9

At December 31, 2008, there were 22 gross exploratory (including 19 gross wells in the Haynesville Shale project) and 13 gross development wells (5.2 net exploratory and 9.9 net development wells) in progress.

Real Estate

During 2008, we pursued 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 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 properties and are engaged in pre-entitlement activities in Lompoc and 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 2008, we spent approximately $14.8 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 emergency planning and 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 these 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 regulatory requirements 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 transportation allowances for offshore production. Delays in the approval or refusal 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.

We acquired the now-dormant Nuevo Energy 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, which has promulgated comparable regulations. 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, FERC exercises regulation over wholesale sales of gas in interstate commerce through the issuance of blanket marketing certificates and the imposition of a code of conduct on blanket marketing certificate holders. The Energy Policy Act of 2005 granted FERC additional regulatory authority over natural gas markets, including the ability to facilitate price transparency and to prevent market manipulation. In furtherance of this new authority, FERC recently imposed an annual reporting requirement on all industry participants, including otherwise non-jurisdictional entities, engaged in wholesale physical natural gas sales and purchases in excess of a de minimus level. 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 and other federal agencies, the United States Congress or state legislative bodies and 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 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, Oil Pollution 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, 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 limit or prohibit construction, drilling and other activities, particularly on lands lying within wilderness or wetlands and other protected areas; and impose substantial liabilities for pollution resulting from or related to 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 or if such is found to exist on properties we own or operated (regardless of who caused it), 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.

Recent and future environmental regulations, including additional federal and state restrictions on greenhouse gas emissions that may be passed in response to climate change concerns, may increase our operating costs and also reduce the demand for the oil and natural gas we produce. On September 27, 2006, California's governor signed into law the "California Global Warming Solutions Act of 2006" Assembly Bill ("AB 32"), which establishes a statewide cap on greenhouse gases ("GHG") that will reduce the state's GHG emission to 1990 levels by 2020. The California Air Resources Board has been designated as the lead agency to establish and adopt regulations to implement AB 32 by January 1, 2012. We will continue to monitor the establishment of these regulations through industry trade groups and other organizations in which we are a member. Similar regulations may be adopted by other states in which we operate or by the federal government.

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 laws and 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, usually increasingly stringent 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.

Permits. Our operations are subject to various federal, state and local laws and regulations that include requiring permits for the drilling and operation 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 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 enforcement for noncompliance as well as 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 well bores, remove tanks, production equipment and flow lines and restore the well site. 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 from previous owners 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 related to environmental remediation and restoration. In connection with the purchase of certain of our onshore California properties, we received a limited indemnity for certain conditions if they violate or are otherwise subject to liability under 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 2009 cash expenditures related to plugging, abandonment and remediation will be approximately $10.3 million. At the Point 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 related onshore facilities. We are responsible for 69.3% of other abandonment costs which primarily consist of wellbore abandonments, conductor removals and site cleanup and preparation.

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, $41 million ($84 million undiscounted), is 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 $66 million). To secure its abandonment obligations the purchaser of the properties is required to periodically deposit funds into an escrow account. At December 31, 2008, the escrow account had a balance of $10.7 million. The fair value of our guarantee, $0.6 million, considers the payment/performance risk and is included in Other Long-Term Liabilities in the Consolidated Balance Sheet.

Employees

As of January 31, 2009, we had 806 full-time employees, three of whom were employed in our international operations and 331 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 are 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. Oil prices decreased substantially during the fourth quarter of 2008, and the price decreases had an adverse effect on our results of operations during the quarter. Any further 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 OPEC and other major producing companies;
- 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 including the value of the U.S. Dollar relative to other major currencies; 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.

Our asset carrying values have been impaired based on oil and natural gas prices as of December 31, 2008 and they may be further impaired if oil and gas prices continue to decline.

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 oil and gas properties (net of accumulated depreciation, depletion and amortization and related deferred income taxes) may not exceed a "ceiling" equal to:

- the present value discounted at 10% of estimated future net cash flows from proved oil and gas reserves, net of estimated future income taxes (including, for this test only, the effect of any related hedging activities); plus
- the lower of cost or estimated 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 an impairment if our capitalized costs exceed this "ceiling," even if prices declined for only a short period of time. 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. Impairments required by these rules do not directly impact our cash flows from operating activities.

The substantial decline in oil and gas prices at December 31, 2008 combined with California oil price differentials, which widened significantly at the end of 2008, impacted our proved reserves as of December 31, 2008, resulting in downward revisions of 204 MMBOE. Based on our year-end proved reserves, we recorded a non-cash pre-tax impairment charge of $3.6 billion in the fourth quarter of 2008 as a result of full cost ceiling limitations. We may be required to recognize additional non-cash pre-tax impairment charges in future reporting periods if market prices for oil or natural gas continue to decline.

Adverse capital and credit market conditions may significantly affect our ability to meet liquidity needs, access to capital and cost of capital.

The capital and credit markets have been experiencing extreme volatility and disruption over the last year. During the second half of 2008 and first quarter of 2009, the volatility and disruption reached unprecedented levels. In some cases, the markets produced downward pressure on stock prices and credit capacity for certain issuers without regard to those issuers' underlying financial strength. If these levels of market disruption and volatility continue, worsen or abate and then arise at a later date, our business, financial condition and results of operations as well as our ability to access capital may all be negatively impacted.

The impairment of financial institutions could adversely affect us.

We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies, other investment funds and other institutions. These transactions expose us to credit risk in the event of default of our counterparties. Continued deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We have exposure to these financial institutions in the form of oil and gas derivative contracts, which protect our cash flows when commodity prices decline. During periods of low oil and gas prices, we may have significant exposure to our derivative counterparties and the value of our derivative positions may provide a significant amount of cash flow. We also maintain insurance policies with insurance companies to protect us against certain risks inherent in our business. In addition, if any lender under our credit facility is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender's commitment under our credit facility. Currently, no single lender in our credit facility has commitments representing more than 11% of our total commitments. However, if banks continue to consolidate, we may experience a more concentrated credit risk.

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 us and 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, transportation 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.

The recent worldwide economic recession has caused a slowdown in economic activity and, as a result, reduced demand for energy and contributed to significantly lower oil and natural gas prices. Oil prices declined from record levels in early July 2008 of over $140 per Bbl to below $45 per Bbl in December 2008, while natural gas prices declined from over $13 per Mcf to below $6 per Mcf over the same period. Forecasted 2009 prices for oil and natural gas have also declined. Our net realized oil and natural gas prices were $88.91 and $6.94 at September 30, 2008, respectively and $31.75 and $5.50 at December 31, 2008, respectively.

Lower oil and natural gas prices not only decrease our revenues on a per Bbl or Mcf basis, but also may reduce the amount of hydrocarbons that we can produce economically and therefore potentially reduce the amount of our proved reserves. Reductions in the amount of our proved reserves, in turn, may reduce the borrowing base under our senior revolving credit facility. The borrowing base is determined at the discretion of our lenders based on, among other things, the collateral value of our proved reserves and is subject to regular redeterminations on May 1 of each year, as well as unscheduled redeterminations as set forth in the credit agreement.

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 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 production.

A substantial portion of our oil and gas reserves are located in California. 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 and the margin (sales price minus production costs) is generally less than that of lighter oil sales due to the processes required to refine this type of oil and the transportation requirements. As such, 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 and gas production, which exposes us to the risk of financial loss and may result in our making cash payments or prevent us from receiving the full benefit of increases in prices for oil and gas 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 and gas prices above the maximum fixed amount specified in the derivative agreement. The derivative instruments also expose us to the risks of financial loss in a variety of circumstances, including when:

- a counterparty to the derivative contract is unable to satisfy its obligations. The fair value of our derivatives as of December 31, 2008 was approximately $1.5 billion or 21% of total assets. The largest exposure to any one counterparty is $512.8 million. The fair value of our derivative instruments as of December 31, 2008 categorized by Standard and Poor's rating is disclosed in Item 7A – "Quantitative and Qualitative Disclosures About Market Risk". In the first quarter of 2009, we monetized a portion of our crude oil put option contracts for a total consideration of $1.1 billion to be received in March 2009;

- production is delayed or less than expected; or

- there is an adverse change in the expected differential between the underlying price in the derivative instrument and actual prices received for our production.

The level of derivative activity depends on our view of market conditions, available derivative prices and our operating strategy.

Since all of our derivative contracts are accounted for under mark-to-market accounting, we expect continued volatility in derivative gains or losses on our income statement as changes occur in the NYMEX price indexes.

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, Louisiana, Texas and Vietnam. 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. 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' 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 and Vietnam operations are susceptible to hurricanes or typhoons. 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, developing or exploring for oil and gas properties.

The successful acquisition 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 development and exploration operations may not result in any increases in reserves. Our operations may be curtailed, delayed or canceled as a result of:

- increases in the costs of, or inadequate access, to 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, 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 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 and processing for our production. Substantially all of our oil and gas production is transported by pipelines and trucks and/or processed in facilities owned by third parties. The inability or unwillingness of these parties to provide transportation and processing services to us for a reasonable fee could result in our having to find transportation and processing alternatives, increased transportation and processing 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 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.

Potential regulations regarding climate change could alter the way we conduct our business.

Governments around the world are beginning to address climate change issues. This may result in new environmental regulations that may unfavorably impact us, our suppliers and our customers. The cost of meeting these requirements may have an adverse impact on our financial condition, results of operations and cash flows.

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 176 acres of our 497 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 foreign operations subject us to additional risks.

Our ownership and operations in Vietnam are subject to the various risks inherent in foreign operations. These risks may include the following:

- currency restrictions and exchange rate fluctuations;
- risks of increases in taxes and governmental royalties and renegotiation of contracts with governmental entities; and
- changes in laws and policies governing operations of foreign-based companies.

United States laws and policies on foreign trade, taxation and investment may also adversely affect our international operations. In addition, if a dispute arises from foreign operations, foreign courts may have exclusive jurisdiction over the dispute, or we may not be able to subject foreign persons to the jurisdiction of United States courts.

Local laws and customs in many countries differ significantly from those in the United States. In many foreign countries, particularly in those with developing economies like Vietnam, it is common to engage in business practices that are prohibited by United States regulations applicable to us. The U.S. Foreign Corrupt Practices Act prohibits corporations and individuals, including us and our employees, from engaging in certain activities to obtain or retain business or to influence a person working in an official capacity. Although we have implemented policies and procedures designed to ensure compliance with these laws, there can be no assurance that all of our employees, contractors and agents, including those based in or from countries where practices which violate such United States laws may be customary, will not take actions in violation of our policies. Any such violation, even if prohibited by our policies, could have a material adverse effect on our business. In addition, our foreign competitors that are not subject to the U.S. Foreign Corrupt Practices Act or similar laws may be able to secure business or other preferential treatment in such countries by means that such laws prohibit with respect to us.

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 stock appreciation rights 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 $50 million, $52 million and $55 million of stock based compensation expense for the years ended December 31, 2008, 2007 and 2006, 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, 2008 goodwill totaled $535 million and represented 8% of our total assets.

Goodwill is not amortized; instead it must be tested at least annually for impairment by applying a fair-value based test. Goodwill is deemed to be 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.

See Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Factors that May Affect Future Results—Goodwill".

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 regulatory approvals.

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.

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. Plaintiffs filed a motion for final judgment on November 29, 2006 and the court granted such motion on January 11, 2007. Judgment on the $1 billion on 35 leases was filed January 12, 2007. The United States has filed an appeal and Plaintiffs filed a cross-appeal concerning the Court's October 31, 2006 decision. The United States Court of Appeals for the Federal Circuit affirmed on August 25, 2008 the trial courts' judgment in all respects concluding that the lessees may recover $1 billion in lease bonuses paid. The United States filed combined petitions for rehearing and rehearing en banc in October 2008, but the United States Court of Appeals for the Federal Circuit denied the Government's combined petitions on December 5, 2008. On December 24, 2008, the United States Court of Appeals for the Federal Circuit agreed to stay the mandate for 90 days pending consideration of the Government's possible filing of a petition for writ of certiorari. 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 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
2008		
1st Quarter	$ 57.00	$ 40.72
2nd Quarter ...	79.86	52.30
3rd Quarter	76.53	30.64
4th Quarter	35.05	15.52
2007		
1st Quarter	$ 49.42	$ 43.00
2nd Quarter ...	54.30	42.38
3rd Quarter	51.76	35.31
4th Quarter	57.08	43.91

At January 30, 2009, we had approximately 2,391 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 – "Management's Discussion and Analysis of Financial Condition and Results of Operations – Financing Activities" and Note 8 to the consolidated financial statements, our credit facility and indentures restrict our ability to pay cash dividends.

Issuer Purchases of Equity Securities

Our Board of Directors has authorized the repurchase of up to $1.0 billion 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. During the year ended December 31, 2008, we repurchased approximately 5.8 million common shares at a cost of approximately $304.2 million. We may expend an additional $695.8 million under the program.

Item 6. *Selected Financial Data*

The following selected financial information was derived from our consolidated financial statements, including the consolidated balance sheets at December 31, 2008 and 2007 and the related consolidated statements of income and cash flows for each of the three years in the period ended December 31, 2008 and 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,				
	2008 (1)	**2007 (2)**	**2006**	**2005**	**2004 (3)**
	(In thousands, except per share amounts)				
Revenues	$ 2,403,471	$ 1,272,840	$ 1,018,503	$ 944,420	$ 671,706
Costs and Expenses					
Production costs	626,428	413,122	313,125	285,292	223,080
General and administrative	153,306	124,006	123,134	127,513	92,042
Depreciation, depletion, amortization and accretion	621,484	316,078	216,782	187,915	147,985
Impairment of oil and gas properties (4)	3,629,666	-	-	-	-
Gain on sale of oil and gas properties (5)	-	-	(982,988)	-	-
	5,030,884	853,206	(329,947)	600,720	463,107
Income (Loss) from Operations	(2,627,413)	419,634	1,348,450	343,700	208,599
Other Income (Expense)					
Gain on sale of assets (6)	65,689	-	-	-	-
Interest expense	(116,991)	(68,908)	(64,675)	(55,421)	(37,294)
Debt extinguishment costs (7)	(18,256)	-	(45,063)	-	(19,691)
Gain (loss) on mark-to-market derivative contracts (8)	1,555,917	(88,549)	(297,503)	(636,473)	(150,314)
Gain on termination of merger agreement (9)	-	-	37,902	-	-
Other income (expense)	(12,575)	6,322	5,496	3,324	723
Income (Loss) Before Income Taxes and Cumulative Effect of Accounting Change	(1,153,629)	268,499	984,607	(344,870)	2,023
Income tax (expense) benefit					
Current	(230,815)	4,677	(142,378)	229	(375)
Deferred	675,350	(114,425)	(242,519)	130,629	7,192
Income (Loss) Before Cumulative Effect of Accounting Change	(709,094)	158,751	599,710	(214,012)	8,840
Cumulative effect of accounting change, net of tax (expense)/benefit (10)	-	-	(2,182)	-	-
Net Income (Loss)	$ (709,094)	$ 158,751	$ 597,528	$ (214,012)	$ 8,840
Earnings (Loss) Per Share					
Basic					
Income (loss) before cumulative effect of accounting change	$ (6.52)	$ 2.02	$ 7.76	$ (2.75)	$ 0.14
Cumulative effect of accounting change	-	-	(0.03)	-	-
Net income (loss)	$ (6.52)	$ 2.02	$ 7.73	$ (2.75)	$ 0.14
Diluted					
Income (loss) before cumulative effect of accounting change	$ (6.52)	$ 1.99	$ 7.67	$ (2.75)	$ 0.14
Cumulative effect of accounting change	-	-	(0.03)	-	-
Net income (loss)	$ (6.52)	$ 1.99	$ 7.64	$ (2.75)	$ 0.14
Weighted Average Common Shares Outstanding					
Basic	108,828	78,627	77,273	77,726	63,542
Diluted	108,828	79,808	78,234	77,726	64,014

Table continued on following page

	Year Ended December 31,				
	2008 (1)	2007 (2)	2006	2005	2004 (3)
	(In thousands of dollars)				
Cash Flow Data					
Net cash provided by operating activities	$ 1,371,409	$ 588,112	$ 674,981	$ 463,334	$ 363,219
Net cash provided by (used in) investing activities	(227,790)	(2,243,137)	811,999	(168,420)	5,414
Net cash provided by (used in) financing activities	(857,190)	1,679,572	(1,487,633)	(294,907)	(368,465)

	As of December 31,				
	2008 (1)	2007 (2)	2006	2005	2004 (3)
	(In thousands of dollars)				
Balance Sheet Data					
Assets					
Cash and cash equivalents	$ 311,875	$ 25,446	$ 899	$ 1,552	$ 1,545
Other current assets	1,164,566	649,474	183,897	291,780	256,622
Property and equipment, net	4,513,396	8,377,227	2,107,524	2,251,887	2,184,962
Goodwill	535,265	536,822	158,515	173,858	170,467
Other assets	586,813	104,382	12,393	22,865	19,649
	$ 7,111,915	$ 9,693,351	$ 2,463,228	$ 2,741,942	$ 2,633,245
Liabilities and Stockholders' Equity					
Current liabilities	$ 993,645	$ 818,046	$ 460,192	$ 363,998	$ 426,395
Long-term debt	2,805,000	3,305,000	235,500	797,375	635,468
Other long-term liabilities	191,534	272,627	170,574	603,422	381,524
Deferred income taxes	744,456	1,959,431	466,279	258,810	319,483
Stockholders' equity	2,377,280	3,338,247	1,130,683	718,337	870,375
	$ 7,111,915	$ 9,693,351	$ 2,463,228	$ 2,741,942	$ 2,633,245

(1) Reflects the February 2008 divestiture of 50% of our working interest in the Piceance and Permian Basins and the Barnett Shale, the April 2008 acquisition of the South Texas properties and the December 2008 divestiture of the remainder of our interests in the Piceance and Permian Basins.
(2) Reflects the acquisition of Pogo effective November 6, 2007 and Piceance Basin properties effective May 31, 2007.
(3) Reflects the acquisition of Nuevo effective May 14, 2004.
(4) We are required to perform a full cost ceiling test each quarter. At December 31, 2008, our capitalized costs of proved oil and gas properties exceeded the ceiling and we recorded an impairment of oil and gas properties.
(5) Represents gain on the sale of oil and gas properties to subsidiaries of Oxy of $345 million and gain on the sale of non-producing oil and gas properties to Statoil of $638 million. Gain on the sale of these oil and gas properties was recognized because the sale caused a significant change in the relationship between capitalized costs and proved reserves.
(6) Represents the gain on the sale of our investment in CVGG.
(7) In connection with the reduction in our senior revolving credit facility commitments and borrowing base due to divestitures and the offering of 7 5/8% Senior Notes, we recorded $18.3 million of debt extinguishment costs in 2008. In connection with the retirement of our 7 1/8% Senior Notes and 8 3/4% 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.
(8) We do not use hedge accounting for our derivative instruments. 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.
(9) Represents the fee received by us, net of expense, in connection with a terminated merger in 2006.
(10) Cumulative effect of adopting SFAS 123R—"Share-Based Payment" in 2006.

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 primarily in the United States. We own oil and gas properties with principal operations in:

- Onshore California;
- Offshore California;
- the Gulf of Mexico;
- the Gulf Coast Region;
- the Mid-Continent Region; and
- the Rocky Mountains.

We also have an interest in an exploration prospect offshore Vietnam.

Our cash flows depend on many factors, including the price of oil and gas, which declined significantly during the fourth quarter of 2008, 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 and subjects us to the credit risk of the counterparties to such agreements. Since all of our derivative contracts are accounted for under mark-to-market accounting, we expect continued volatility in gains and losses on derivative contracts on our income statement as changes occur in the NYMEX price indices. The level of derivative activity depends on our view of market conditions, available derivative prices and our operating strategy. See Item 7A "Quantitative and Qualitative Disclosures About Market Risk".

Assets in our principal focus areas include mature properties with long-lived reserves and significant development opportunities as well as newer properties with development and exploration potential. Our primary sources of liquidity are cash generated from our operations, our cash balances, projected cash settlements from our derivative contracts, our senior revolving credit facility and periodic public offerings of debt. At December 31, 2008, we had approximately $994 million of availability under our senior revolving credit facility. We believe that we have sufficient liquidity through our forecasted cash flow from operations, cash balances, projected cash settlements from our derivatives 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 and anticipated capital expenditures. In addition, we could curtail the portion of our capital expenditures which is discretionary if our cash flows declined from expected levels.

Capital and Credit Markets

During 2008, there has been extreme volatility and disruption in the capital and credit markets. During the second half of 2008 and first quarter of 2009, the volatility and disruption have created conditions that may adversely affect the financial condition of the lenders in our senior revolving credit facility, the counterparties to our commodity price risk management agreements, our insurers and our oil and gas purchasers. See "Liquidity and Capital Resources".

Acquisitions

In July 2008, we acquired from a subsidiary of Chesapeake a 20% interest in Chesapeake's Haynesville Shale leasehold for approximately $1.65 billion in cash. We funded the acquisition with borrowings under our senior revolving credit facility. In connection with the acquisition, we also agreed, over a multi-year period, to fund 50% of Chesapeake's drilling and completion costs associated with future Haynesville Shale wells, up to an additional $1.65 billion. In addition, we will have the option to participate for 20% of any additional leasehold that Chesapeake, or its affiliates, acquires in the Haynesville Shale within a designated area of mutual interest. We currently hold 111,000 net acres in the Haynesville Shale. At the acquisition date, there were no material proved reserves associated with the leasehold interests acquired.

In April 2008, we completed the acquisition of oil and gas producing properties in South Texas from a private company. After the exercise of third party preferential rights, we paid approximately $282 million in cash. We funded the acquisition primarily with proceeds from recently completed divestments through the use of a tax deferred like-kind exchange. We estimate that proved reserves were approximately 93 billion cubic feet of natural gas equivalent as of December 31, 2007. The effective date of the transaction was January 1, 2008.

Divestments

In December 2008, we closed the sale of certain oil and gas properties to a subsidiary of Oxy and certain other companies with contractual preferential purchase rights, with an effective date of December 1, 2008, and received approximately $1.25 billion in gross cash proceeds, and $1.24 billion after preliminary closing adjustments. We sold the remaining 50% of our working interests in oil and gas properties located in the Permian Basin, West Texas and New Mexico, which we acquired in the Pogo acquisition in November 2007. We also sold the remaining 50% of our working interests in oil and gas properties located in the Piceance Basin in Colorado, including a 50% interest in the entity that held our interest in CVGG. We acquired these properties in May 2007. The sale also included our interest in approximately 11,500 net undeveloped acres adjacent to the Piceance Basin assets that we and Oxy jointly acquired from a third party in June 2008.

In February 2008, we closed the sale of certain oil and gas properties to a subsidiary of Oxy and certain other companies with contractual preferential purchase rights, with an effective date of January 1, 2008, and received approximately $1.53 billion in cash proceeds. We sold 50% of our working interests in oil and gas properties located in the Permian Basin, West Texas and New Mexico, which we acquired in the Pogo acquisition in November 2007. We also sold 50% of our working interests in oil and gas properties located in the Piceance Basin in Colorado, including a 50% interest in the entity that held our interest in CVGG. We acquired these properties in May 2007.

In February 2008, we closed the sale to XTO of certain oil and gas properties located in the San Juan Basin in New Mexico and in the Barnett Shale in Texas. This transaction had an effective date of January 1, 2008, and we received $199.0 million in cash proceeds.

Derivatives

In the first quarter of 2009, we monetized our 2009 and 2010 crude oil put option contracts on 40,000 BOPD. As a result, we received $389 million in net proceeds on February 20, 2009 and will receive approximately $711 million in net proceeds in March 2009, which we will use to reduce the outstanding balance on our senior revolving credit facility. We currently are party to crude oil put option contracts on 32,500 BOPD in 2009 and 40,000 BOPD in 2010. These put options have a strike price of $55 per barrel. Additionally, we are party to natural gas $10 by $20 collars on 150,000 MMbtu in 2009 and natural gas three way collars on 40,000 million British thermal units (MMbtu) per day for 2010. Under the later arrangement, if the index price is below the floor price of $6.25 per MMbtu, we receive the difference between $6.25 and the index price up to a maximum of $1.45 per MMbtu. If the index price is greater than the ceiling price of $8.00 per MMbtu, we pay the difference between the index price and $8.00 per MMbtu.

General

We follow the full cost method of accounting whereby all costs associated with property acquisition, exploration 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 an impairment if our capitalized costs exceed the allowed "ceiling." 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. During the fourth quarter of 2008, oil and gas prices declined significantly and we recorded a $3.6 billion non-cash pre-tax impairment charge of our oil and gas properties related to our year-end ceiling test. If prices continue to decline, additional impairment of our oil and gas properties could occur. Impairment charges 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 (including stock based compensation), steam gas costs, electricity 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

In addition to fluctuations as a result of operating in the oil and gas industry, 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"), which are accounted for as liability awards under SFAS 123R and are remeasured to fair value each reporting period. The fair value of SARs is related to the market price of our common stock and will fluctuate with movements in our stock price.

In 2008, we reported a net loss of $709.1 million, or $6.52 per share. The net loss for the period includes a $1.6 billion non-cash pre-tax derivative mark-to-market gain and a $3.6 billion non-cash pre-tax impairment of our oil and gas properties. Our results reflect (1) the divestment of 50% of our working interest in the Piceance and Permian Basin properties to Oxy, on February 29, 2008, and all of our working interest in the San Juan Basin and Barnett Shale to XTO on February 15, 2008, (2) the acquisition of the South Texas oil and gas properties on April 17, 2008 and (3) the divestment of our remaining interest in the Piceance and Permian Basin properties to Oxy on December 1, 2008.

In 2007, we reported net income of $158.8 million, or $1.99 per diluted share. Net income for the period includes an $88.5 million pre-tax derivative mark-to-market loss. Our results reflect the acquisitions of the Piceance Basin properties effective May 31, 2007 and Pogo effective November 6, 2007.

In 2006, we reported net income of $597.5 million, or $7.64 per diluted share. Net income for the period includes a $983.0 million pre-tax gain on sales of oil and gas properties, a $297.5 million pre-tax derivative mark-to-market loss, debt extinguishment costs of $45.1 million, a $37.9 million gain on the termination of a merger agreement, and a non-cash, after-tax expense related to the adoption of SFAS 123R of $2.2 million, or $0.03 per share.

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,		
	2008 (1)	2007 (2)	2006 (3)
Sales Volumes			
Oil and liquids sales (MBbls)	20,294	18,124	18,975
Gas (MMcf)			
Production	79,254	29,312	20,629
Used as fuel	2,223	2,302	4,823
Sales	77,031	27,010	15,806
MBOE			
Production	33,503	23,010	22,413
Sales	33,133	22,625	21,609
Daily Average Volumes			
Oil and liquids sales (Bbls)	55,449	49,655	51,985
Gas (Mcf)			
Production	216,540	80,307	56,519
Used as fuel	6,073	6,307	13,214
Sales	210,467	74,000	43,305
BOE			
Production	91,539	63,041	61,405
Sales	90,527	61,986	59,202
Unit Economics (in dollars)			
Average NYMEX Prices			
Oil	$ 99.75	$ 72.36	$ 66.23
Gas	9.06	6.86	7.21
Average Realized Sales Price Before Derivative Transactions			
Oil (per Bbl)	$ 87.05	$ 61.60	$ 55.62
Gas (per Mcf)	8.05	5.68	6.73
Per BOE	72.03	56.12	53.76
Costs and Expenses per BOE			
Production costs			
Lease operating expenses	$ 9.88	$ 9.98	$ 8.32
Steam gas costs	3.96	4.57	2.95
Electricity	1.59	1.76	1.76
Production and ad valorem taxes	2.84	1.44	1.15
Gathering and transportation	0.64	0.50	0.31
DD&A (oil and gas properties)	17.69	12.92	8.96

(1) Reflects the February 2008 divestiture of 50% of our working interest in the Piceance and Permian Basins to Oxy and the San Juan Basin and Barnett Shale to XTO, the April 2008 acquisition of the South Texas properties and the divestiture of the remainder of our interest in the Piceance and Permian Basins effective December 1, 2008.

(2) Reflects the acquisition of Pogo effective November 6, 2007 and the Piceance Basin properties effective May 31, 2007.

(3) Reflects the sale of oil and gas properties to subsidiaries of Oxy effective October 1, 2006.

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

	Year Ended December 31,		
	2008	2007	2006
Mark-to-market contracts			
Oil sales	$ (81,447)	$ (103,784)	$ (89,596)
Gas sales	47,163	235	-
Gas purchases	-	-	(11,425)
Elimination of crude oil collars	-	-	(593,283)

Comparison of Year Ended December 31, 2008 to Year Ended December 31, 2007

Oil and gas revenues. Oil and gas revenues increased $1.1 billion, or 88%, to $2.4 billion for 2008 from $1.3 billion for 2007 primarily due to a 46% increase in sales volumes and a $15.91 per BOE increase in average realized prices. Oil and gas prices declined significantly during the fourth quarter of 2008. Based on our forecasted production, if oil and gas prices remain at current levels or decline our revenues in 2009 will be significantly lower than the amounts reported in 2008.

Oil revenues increased $650.3 million to $1.8 billion for 2008 from $1.1 billion for 2007 reflecting higher average realized prices ($461.4 million) and higher sales volumes ($188.9 million). Our average realized price for oil increased $25.45 to $87.05 per Bbl for 2008 from $61.60 per Bbl for 2007. The increase is primarily attributable to an improvement in the NYMEX oil price, which averaged $99.75 per Bbl in 2008 versus $72.36 per Bbl in 2007. Oil sales volumes increased 5.7 MBbls per day to 55.4 MBbls per day in 2008 from 49.7 MBbls per day in 2007 due to production from the properties acquired in the Pogo acquisition (6.6 incremental MBbls per day), partially offset by a decrease in our onshore and offshore California properties. Oil production for 2008 includes 6.1 MBbls per day for properties sold during 2008.

Gas revenues increased $466.5 million to $619.9 million in 2008 from $153.4 million in 2007 due to increased sales volumes ($402.6 million) and higher average realized prices ($63.9 million). Our average realized price for gas was $8.05 per Mcf in 2008 compared to $5.68 per Mcf in 2007. Our realized price for gas increased primarily due to an increase in the index price for natural gas ($2.20 per Mcf). Gas sales volumes increased from 74.0 MMcf per day in 2007 to 210.5 MMcf per day in 2008, primarily reflecting sales from the properties acquired in the Pogo acquisition in November 2007 (119.9 MMcf per day), the Piceance Basin properties (5.9 MMcf per day) and the Flatrock project in the Gulf of Mexico (16.4 MMcf per day), partially offset by a reduction in the California onshore gas sales. Gas production for 2008 includes 50.9 MMcf per day for properties sold during 2008.

Lease operating expenses. Lease operating expenses increased $101.6 million, to $327.4 million in 2008 from $225.8 million in 2007. Lease operating expenses for 2008 includes $85.7 million incremental lease operating expense attributable to the Pogo and Piceance Basin acquisitions. Excluding these incremental costs, lease operating expenses increased $15.9 million due primarily to higher expenditures for well workovers, repairs and maintenance and increases from service providers. On a per unit basis, lease operating expenses decreased to $9.88 per BOE in 2008 versus $9.98 per BOE in 2007 due to increased volumes. Increased service costs were reflective of the higher oil and gas prices during the first nine months of the year; however, due to the significant decrease in oil and gas prices in the fourth quarter of 2008 and the expected reduced spending in the industry in 2009, we expect that service costs will decline in 2009. In addition, due to the significant oil and gas price decline we have implemented a program under which we expect to reduce lease operating expense during 2009.

Steam gas costs. Steam gas costs increased $27.7 million, to $131.2 million in 2008 from $103.5 million in 2007, primarily reflecting the higher cost of gas used in steam generation. In 2008 we burned approximately 16.9 Bcf of natural gas at a cost of approximately $7.78 per MMbtu compared to 16.8 Bcf at a cost of approximately $6.17 per MMbtu in 2007. Our average cost to purchase natural gas used in steam operations was approximately $5.27 per MMbtu at December 31, 2008. If gas prices remain at current levels, our steam costs are expected to decline in 2009.

Electricity. Electricity increased $12.9 million, to $52.7 million in 2008 from $39.8 million in 2007, primarily reflecting higher cost for purchased electricity and an increase in usage. On a per unit basis, electricity was $1.59 per BOE in 2008 and $1.76 per BOE in 2007.

Production and ad valorem taxes. Production and ad valorem taxes increased $61.4 million, to $94.0 million in 2008 from $32.6 million in 2007 primarily reflecting increased volumes from the Pogo and Piceance Basin acquisitions and increased tax basis due to higher commodity prices during the first half of 2008.

Gathering and transportation expenses. Gathering and transportation expenses increased $9.7 million, to $21.1 million in 2008 from $11.4 million in 2007, primarily reflecting the Pogo and Piceance Basin acquisitions.

General and administrative expense. G&A expense increased $29.3 million, to $153.3 million in 2008 from $124.0 million in 2007. The increase is primarily due to increased personnel and other costs due to the acquisitions in 2007 ($41.1 million). These expenses were partially offset by an increase in amounts capitalized as part of our acquisition, exploration and development activities. Capitalized costs were $60.6 million in 2008 compared to $44.6 million in 2007, primarily reflecting increased costs and our acquisition, exploration and development activities.

Depreciation, depletion and amortization, or DD&A. DD&A expense increased $302.2 million, to $608.4 million in 2008 from $306.3 million in 2007. The increase was attributable to our oil and gas DD&A, primarily due to a higher per unit rate ($185.6 million) and increased production ($109.8 million). Our 2008 DD&A rate was $17.69 compared to $12.92 in 2007. The increase primarily reflects the reduction in our oil and gas reserves due to lower oil and gas prices, our acquisitions, higher cost reserve additions and exploration costs. Our oil and gas DD&A rate for 2009 after the effect of the impairment of oil and gas properties is expected to be $11.49 per BOE.

Impairment of oil and gas properties. Due to the significant decrease in oil prices in the fourth quarter 2008, the carrying value of our oil and gas properties exceeded our ceiling, equal to the present value of estimated future net cash flows from proved oil and gas reserves, net of estimated future income taxes plus the lower of cost or estimated fair value of unproved properties not included in the costs being amortized. As a result, we recorded a non-cash pre-tax impairment charge of $3.6 billion. The net realized oil and gas prices used in the ceiling tests were $31.75 and $5.50, respectively, at December 31, 2008 compared to $88.91 and $6.94 respectively, at September 30, 2008. If oil and gas prices decline further in 2009, additional impairments of our oil and gas properties could occur.

Accretion expense. Accretion expense increased $3.2 million, to $13.0 million in 2008 from $9.8 million in 2007. Accretion expense for 2008 included $2.6 million attributable to an increase in our asset retirement obligation associated with the Pogo and Piceance Basin properties acquired in November and May 2007, respectively.

Gain on the sale of assets. We completed sales to Oxy of the entity which held our investment in CVGG and recorded gains totaling $65.7 million.

Interest expense. Interest expense increased $48.1 million, to $117.0 million in 2008 from $68.9 million in 2007 primarily due to higher outstanding debt related to the Pogo and Haynesville Shale acquisitions. Interest expense does not include interest capitalized on oil and gas properties not subject to amortization. We capitalized $71.8 million and $34.6 million of interest in 2008 and 2007, respectively. The increase in capitalized interest is primarily due to a higher unevaluated property balance related to the Pogo and Haynesville Shale acquisitions.

Debt extinguishment costs. In connection with our asset divestments, reductions of the commitments under our senior revolving credit facility occurred in February and December 2008, and we recorded $18.3 million of debt extinguishment costs.

Gain (loss) on mark-to-market derivative contracts. We do not use hedge accounting for our derivative instruments. 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 decrease in oil prices in the third and fourth quarters of 2008, we recognized gains related to mark-to-market derivative contracts of $1.6 billion in 2008 as compared to a loss of $88.5 million in 2007.

Income tax (benefit) expense. Our 2008 income tax benefit was $444.5 million, reflecting an annual effective tax rate of 39%, as compared with income tax expense of $109.7 million and an effective tax rate of 41% for 2007. Variances in our annual effective tax rate from the 35% federal statutory rate primarily result from the effect of state income taxes and permanent differences which include (1) the special deduction for domestic production activities and (2) expenses that are not deductible because of Internal Revenue Service limitations.

Our 2008 current tax expense of $230.8 million primarily results from the recognition of tax in excess of book gains attributable to our 2008 asset sales plus the non-deductibility for tax purposes of the 2008 oil and gas properties impairment. Our 2007 current benefit primarily reflects the effect of tax refunds received in 2007.

Comparison of Year Ended December 31, 2007 to Year Ended December 31, 2006

Oil and gas revenues. Oil and gas revenues increased $253.7 million, or 25%, to $1.3 billion for 2007 from $1.0 billion for 2006 primarily due to the absence of an oil revenue hedging loss in 2007 and higher realized prices.

Oil revenues, excluding the effects of hedging, increased $60.9 million to $1.1 billion for 2007 from $1.0 billion for 2006 reflecting higher realized prices ($113.3 million) partially offset by lower sales volumes ($52.4 million). Our average realized price for oil increased $5.98 to $61.60 per Bbl for 2007 from $55.62 per Bbl for 2006. The increase is primarily attributable to an improvement in the NYMEX oil price, which averaged $72.36 per Bbl in 2007 versus $66.23 per Bbl in 2006. Oil sales volumes decreased 2.3 MBbls per day to 49.7 MBbls per day in 2007 from 52.0 MBbls per day in 2006 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. Hedging had no impact on oil revenues in 2007.

Gas revenues increased $47.1 million to $153.4 million in 2007 from $106.3 million in 2006 due to increased sales volumes ($63.6 million) partially offset by lower realized prices ($16.5 million). Our average realized price for gas was $5.68 per Mcf in 2007 compared to $6.73 per Mcf in 2006. Our realized price for gas decreased due to a decrease in the index price for natural gas ($0.35 per Mcf) and the higher differentials for the Piceance Basin properties that we acquired in 2007. Our average differential for gas sold in the Piceance Basin was $3.33 per Mcf during 2007. Gas sales volumes increased from 43.3 MMcf per day in 2006 to 74.0 MMcf per day in 2007, primarily reflecting the impact of the acquisition of the Pogo and Piceance Basin acquisitions, partially offset by the 2006 property sale.

Lease operating expenses. Lease operating expenses increased $46.1 million, to $225.8 million in 2007 from $179.7 million in 2006. The increase is primarily attributable to higher expenditures for well workovers, repairs and maintenance, labor costs, general cost increases from service providers and the impact of our acquisition and divestment activity. On a per unit basis, lease operating expenses increased to $9.98 per BOE in 2007 versus $8.32 per BOE in 2006 due to increased costs.

Steam gas costs. Steam gas costs increased $39.7 million, to $103.5 million in 2007 from $63.8 million in 2006, primarily reflecting higher steam volumes and higher cost of gas used in steam generation. In 2007 we burned approximately 16.8 Bcf of natural gas at a cost of approximately $6.17 per Mcf compared to 14.6 Bcf at a cost of approximately $4.36 per Mcf in 2006. The higher cost per Mcf in 2007 reflects that substantially all of the gas burned in 2007 was purchased while in 2006 approximately 20% of the gas burned was produced from the Company's properties and costs for these volumes consisted only of transportation costs.

Electricity. Electricity increased $1.8 million, to $39.8 million in 2007 from $38.0 million in 2006, primarily reflecting higher cost for purchased electricity and an increase in usage. On a per unit basis, electricity was $1.76 per BOE in 2007 and 2006.

Production and ad valorem taxes. Production and ad valorem taxes increased $7.8 million, to $32.6 million in 2007 from $24.8 million in 2006 primarily reflecting increased volumes from the Pogo acquisition and the effect of increased oil prices.

Gathering and transportation expenses. Gathering and transportation expenses increased $4.6 million, to $11.4 million in 2007 from $6.8 million in 2006, primarily reflecting the Pogo and Piceance Basin acquisitions.

General and administrative expense. G&A expense increased $0.9 million, to $124.0 million in 2007 from $123.1 million in 2006 due to an increase in other G&A expense of $5.0 million ($75.9 million in 2007 versus $70.9 million in 2006) as a result of increased personnel costs due to the acquisitions in 2007, offset by a decrease in stock based compensation in 2007 ($48.1 million in 2007 versus $52.2 million in 2006). The decrease in stock based compensation in 2007 primarily reflects lower expense for SARs, which fluctuates with changes in our stock price and other factors that impact fair value.

G&A expense does not include amounts capitalized as part of our acquisition, exploration and development activities. Capitalized costs were $44.6 million in 2007 compared to $34.8 million in 2006, primarily reflecting increased costs and our acquisition, exploration and development activities.

Depreciation, depletion and amortization, or DD&A. DD&A expense increased $99.1 million, to $306.3 million in 2007 from $207.2 million in 2006. Approximately $97.4 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 $12.92 per BOE in 2007 compared to $8.96 per BOE in 2006. The increase primarily reflects the effect of our acquisitions, increased future development costs, higher cost reserve additions and exploration costs.

Accretion expense. Accretion expense increased $0.2 million, to $9.8 million in 2007 from $9.6 million in 2006.

Interest expense. Interest expense increased $4.2 million, to $68.9 million in 2007 from $64.7 million in 2006 primarily due to higher outstanding debt related to the Piceance Basin and Pogo acquisitions. Interest expense does not include interest capitalized on oil and gas properties not subject to amortization. We capitalized $34.6 million and $7.9 million of interest in 2007 and 2006, respectively. The increase in capitalized interest is due to a higher unevaluated property balance related to the Piceance Basin and Pogo acquisitions.

Gain (loss) on mark-to-market derivative contracts. We do not currently use hedge accounting for our derivative instruments. 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 $88.5 million and $297.5 million in 2007 and 2006, respectively.

Income tax expense. Our 2007 income tax expense was $109.7 million, reflecting an annual effective tax rate of 41%, as compared with income tax expense of $384.9 million and an effective tax rate of 39% for 2006. Variances in our annual effective tax rate from the 35% federal statutory rate primarily result from the effect of state income taxes and permanent differences primarily related to expenses that are not deductible because of Internal Revenue Service limitations. The current benefit for 2007 primarily reflects the effect of tax refunds received in 2007.

Liquidity and Capital Resources

Liquidity is important to our operations. Our liquidity may be affected by declines in oil and gas prices, an inability to access the capital and credit markets and the success of our commodity price risk management activities, which may subject us to the credit risk of the counterparties to such agreements. This situation may arise due to circumstances beyond our control, such as a general disruption of the financial markets and adverse economic conditions that cause substantial or extended declines in oil and gas prices.

During 2008, there was extreme volatility and disruption in the capital and credit markets. During the second half of 2008 and the first quarter of 2009, the volatility and disruption reached unprecedented levels that may adversely affect the financial condition of lenders in our senior revolving credit facility and the counterparties to our commodity price risk management agreements, as well as our insurers and our oil and natural gas purchasers. While these market conditions persist, our liquidity may be adversely affected by limitations on our ability to access the capital and credit markets.

Our primary sources of liquidity are cash generated from our operations, our senior revolving credit facility and periodic public offerings of debt. At December 31, 2008, we had approximately $994 million available under our senior revolving credit facility, which had aggregate commitments of $2.3 billion and a borrowing base of $2.7 billion. Under the terms of the senior revolving credit facility, the borrowing base will be redetermined on an annual basis, with PXP and the lenders each having the right to one annual interim unscheduled redetermination. Since our last interim redetermination in the fourth quarter of 2008, which was a result of the sale of oil and gas properties on December 1, 2008, oil and gas prices have declined substantially. As a result of these declines, which impacted our year-end 2008 reserves, the monetization of our crude positions, and other relevant factors, our borrowing base may be decreased, which would adversely affect our liquidity position.

The commitments of each lender to make loans to us are several and not joint under our senior revolving credit facility. Accordingly, if any lender fails to make loans to us, our available liquidity could be reduced by an amount up to the aggregate amount of such lender's commitments under the credit facility. The commitments are from a diverse syndicate of 22 lenders with no single lender's commitment representing more than 11% of the total commitments.

Our cash flows depend on many factors, including the price of oil and gas, the success of our acquisitions 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. Further, we become subject to the credit risk of the counterparties to such agreements when the price of oil and natural gas decreases below the floor specified in the derivative agreement. We consider the credit quality of our counterparties when we value our commodity derivatives. See Item 7A – "Quantitative and Qualitative Disclosures About Market Risk". The level of derivative activity depends on our view of market conditions, available derivative prices and our operating strategy.

In response to market conditions and as part of our regular contingency planning and portfolio optimization, we took a number of actions to improve our liquidity position. In December 2008, we closed on the sale of certain properties to Oxy for $1.25 billion, and $1.0 billion was used to pay down our senior revolving credit facility. As a result of the sale, our senior revolving credit facility commitments were reduced from $2.7 billion to $2.3 billion. We also changed our cash management activities to maintain larger cash and cash equivalents balances, and the balance in cash and cash equivalents was $311.9 million at December 31, 2008.

In the first quarter of 2009, we continued to strengthen our liquidity and monetized our 2009 and 2010 crude oil put option contracts on 40,000 BOPD with weighted average strike prices of $106.16 per barrel and $111.49 per barrel, respectively. As a result of this monetization, we received $389 million in net proceeds on February 20, 2009 and will receive approximately $711 million in net proceeds in March 2009, which we will use to reduce the outstanding balance on our senior revolving credit facility, further increasing our liquidity and positioning us to capitalize on future opportunities. In connection with this monetization, we entered into crude oil put option on 40,000 BOPD in 2010. These put options have a strike price of $55 per barrel, a $3.86 per barrel upfront payment, which has been deducted from the total proceeds expected to be received from the monetization, and a deferred put premium plus interest of $5 per barrel. We have retained our put options on 32,500 BOPD with a $55 strike price in 2009. Additionally, in a separate transaction, we acquired natural gas three way collars on 40,000 million British thermal units (MMbtu) per day for 2010. Under this arrangement, if the index price is below the floor price of $6.25 per MMbtu, we receive the difference between $6.25 and the index price up to a maximum of $1.45 per MMbtu. If the index price is greater than the ceiling price of $8.00 per MMbtu, we pay the difference between the index price and $8.00 per MMbtu. In addition, we currently are party to natural gas $10 by $20 collars on 150,000 MMbtu in 2009. The monetization and reset arrangements accelerate cash receipts, while maintaining a hedge position that helps protect against further declines in oil and natural gas prices during 2009 and 2010.

Our $1.05 billion 2009 capital budget is focused on our major development areas. Approximately 37% of the capital investment is allocated to development activities, 43% to the Haynesville Shale project and 20% for exploration projects. Our resources will be primarily directed to the Haynesville Shale, the Friesian, Flatrock and Salida Gulf of Mexico projects, the California long-life oil resource base, and our remaining high-impact exploration projects. To maximize economic returns, we plan to reduce operating expenses in all of our field locations and reduce general and administrative costs throughout 2009. We continue to aggressively manage our inventory, our cost structure, and our financial flexibility.

We believe that we have sufficient liquidity through our forecasted cash flow from operations, cash balances, projected cash settlements from our commodity derivative positions 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 and anticipated capital expenditures. In addition, we could curtail the portion of our capital expenditures which is discretionary if our cash flows declined from expected levels. We have no near-term debt maturities. Our senior revolving credit facility matures on November 6, 2012 and the next maturity of our senior notes will occur on June 15, 2015.

Working Capital

At December 31, 2008, we had working capital of approximately $482.8 million, primarily as a result of maintaining greater cash balances and the current portion of the fair value of our derivative instruments. In prior periods, we generally had a working capital deficit because we used excess cash to pay down borrowings under our senior revolving credit facility; however, as a result of the current volatility and disruption in the capital and credit markets we changed our cash management activities to maintain larger cash and cash equivalents balances. Any significant cash balances consisted of highly liquid money market mutual funds that consist of U.S. government securities. Our working capital is affected by fluctuations in the fair value of our commodity derivative instruments and stock appreciation rights.

Financing Activities

7⅝% Senior Notes. In May 2008, we issued $400.0 million of 7⅝% Senior Notes due 2018 (the "7⅝% Senior Notes") at par. We may redeem all or part of the 7⅝% Senior Notes on or after June 1, 2013 at specified redemption prices and prior to such date at a "make-whole" redemption price. In addition, prior to June 1, 2011 we may, at our option, redeem up to 35% of the 7⅝% Senior Notes with the proceeds of certain equity offerings. In the event of a change of control, as defined in the indenture, we will be required to make an offer to repurchase the 7⅝% Senior Notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of repurchase. We used the proceeds of this offering to reduce debt under our senior revolving credit facility.

The 7% Senior Notes due 2017, the 7¾% Senior Notes due 2015 and the 7⅝% Senior Notes (together the "Senior Notes") are our general unsecured senior obligations. The Senior Notes are jointly and severally guaranteed on a full and unconditional basis by certain of our existing domestic subsidiaries. In the future, the guarantees may be released or terminated under certain circumstances. The Senior Notes rank senior in right of payment to all of our existing and future subordinated indebtedness; *pari passu* in right of payment with any of our existing and future unsecured indebtedness that is not by its terms subordinated to the Senior Notes; effectively junior to our existing and future secured indebtedness, including indebtedness under our senior revolving credit facility, to the extent of our assets constituting collateral securing that indebtedness; and effectively subordinate to all existing and future indebtedness and other liabilities (other than indebtedness and liabilities owed to us) of our non-guarantor subsidiaries.

The indentures governing the Senior Notes contain covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to incur additional debt; make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock; sell assets, including capital stock of our restricted subsidiaries; restrict dividends or other payments by restricted subsidiaries; create liens that secure debt; enter into transactions with affiliates; and merge or consolidate with another company.

Senior Revolving Credit Facility. During 2008, the borrowing base and commitments under our senior revolving credit facility were adjusted as a result of oil and gas property acquisitions and divestitures and the completion of the offering of $400 million of 7$^5/_8$% Senior Notes. Additionally, in February 2008, we entered into an amendment to our senior revolving credit facility which allows us to repurchase up to $1.0 billion of our common stock, subject to certain conditions being met. As of December 31, 2008, our senior revolving credit facility provides for a borrowing base of $2.7 billion and aggregate commitments of the lenders of $2.3 billion. The borrowing base will be redetermined on an annual basis, with PXP and the lenders each having the right to one annual interim unscheduled redetermination, and adjusted based on PXP's oil and gas properties, reserves, other indebtedness and other relevant factors. Additionally, our senior revolving credit facility contains a $250 million sub-limit on letters of credit, a $50 million commitment for swingline loans, and matures on November 6, 2012. Collateral consists of 100% of the shares of stock in certain of our domestic and 65% of certain foreign subsidiaries and mortgages covering at least 75% of the total present value of our domestic oil and gas properties. At December 31, 2008, we had $0.7 million in letters of credit outstanding under our senior revolving credit facility.

Amounts borrowed under our senior revolving credit facility 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%; (ii) the greater of (1) the prime rate, as determined by JPMorgan Chase Bank and (2) the federal funds rate, plus ½ of 1%, plus an additional variable amount ranging from 0% to 0.25% for each of (1) and (2); and (iii) the over-night federal funds rate plus an additional variable amount ranging from 1.00% to 1.75% for swingline loans. 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 our senior revolving credit facility to the conforming borrowing base and (2) our long-term debt ratings. Commitment fees and letter of credit fees under our senior revolving credit facility are based on the utilization rate and our long-term debt rating. Commitment fees range from 0.225% to 0.375% of the amount available for borrowing. Letter of credit fees range from 1.0% 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 our senior revolving credit facility was 3.149% at December 31, 2008.

Our senior revolving credit facility, as amended 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 take-or-pay or other prepayment arrangements, merge or consolidate and enter into transactions with affiliates. In addition, we are required to maintain a ratio of debt to EBITDAX (as defined) of no greater than 4.25 to 1.

Short-term Credit Facility. We have an uncommitted short-term unsecured credit facility under the terms of which we may make borrowings from time to time until June 1, 2009, not to exceed at any time the maximum principal amount of $75.0 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 June 1, 2009. Each advance under the short-term facility shall bear interest at a rate per annum mutually agreed on by the bank and PXP. No amounts were outstanding under the short-term credit facility at December 31, 2008.

Cash Flows

	Year Ended December 31,		
	2008	2007	2006
	(in millions of dollars)		
Cash provided by (used in):			
Operating activities	$ 1,371.4	$ 588.1	$ 675.0
Investing activities	(227.8)	(2,243.1)	812.0
Financing activities	(857.2)	1,679.6	(1,487.6)

Net cash provided by operating activities was $1.4 billion in 2008, $588.1 million in 2007 and $675.0 million in 2006. The increase in net cash provided by operating activities in 2008 reflects higher operating income primarily related to the Pogo acquisition and higher commodity prices. The decrease in net cash provided by operating activities in 2007 was a result of income tax payments of $118.9 million in 2007 primarily related to the gain recognized in connection with PXP's 2006 oil and gas property sales.

Net cash used in investing activities of $227.8 million in 2008 primarily reflects the purchase of our Haynesville Shale leasehold for $1.65 billion, additions to oil and gas properties of $1.1 billion and the purchase of our South Texas properties for $282 million, partially offset by the net proceeds from property sales of $3.0 billion. Net cash used in investing activities was $2.2 billion in 2007, reflecting the acquisition of the Piceance properties for $975.4 million, and Pogo for $298.0 million (net of cash acquired), $770.4 million of oil and gas property additions, derivative settlements of $99.9 million and a $59.1 million increase in restricted cash. 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. Derivative settlements related to derivatives that are not accounted for as hedges and do not contain a significant financing element are reflected as investing activities.

Net cash used in financing activities of $857.2 million in 2008 primarily reflects a $900.0 million net decrease in borrowings under our senior revolving credit facility and $304.2 million used for treasury stock purchases, partially offset by $400 million from the issuance of the 7⁵/₈% Senior Notes. Net cash provided by financing activities in 2007 was $1.7 billion, reflecting net borrowings on our senior revolving credit facility of $2.0 billion and proceeds from the issuance of our 7¾% Senior Notes and 7% Senior Notes of $1.1 billion, partially offset by the redemption of the Pogo notes of $1.3 billion. Net cash used in financing activities in 2006 was $1.5 billion, primarily reflecting payments totaling $524.9 million to redeem all $250 million outstanding principal of our 7.125% Senior Notes and purchase $274.9 million of our $275 million outstanding principal of our 8.75% 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. 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.

Capital Requirements

We have made and will continue to make substantial capital expenditures for the acquisition, development, exploration and production of oil and gas. We have a capital budget for 2009, excluding acquisitions, of approximately $1.05 billion. We believe that we have sufficient liquidity through our forecasted cash flow from operations, cash balances, projected cash settlements from our commodity derivative positions 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, contingencies and anticipated capital expenditures. In addition, we could curtail the portion of our capital expenditures which are discretionary if our cash flows declined from expected levels.

Stock Repurchase Program

In December 2007, our Board of Directors authorized the repurchase of up to $1.0 billion 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. During the year ended December 31, 2008, we repurchased approximately 5.8 million common shares at a cost of approximately $304.2 million. We may expend an additional $695.8 million under this program.

Commitments and Contingencies

Contractual obligations. At December 31, 2008, the aggregate amounts of contractually obligated payment commitments for the next five years are as follows (in thousands):

	Total	2009	2010 and 2011	2012 and 2013	Thereafter
Long-term debt	$ 2,805,000	$ -	$ -	$ 1,305,000	$ 1,500,000
Drilling commitments	1,720,699	441,165	932,400	347,134	-
Interest on debt	1,042,281	155,587	311,174	260,935	314,585
Commodity derivative contracts	353,710	177,302	176,408	-	-
Asset retirement obligation	169,809	10,336	22,029	18,640	118,804
Operating leases	122,707	19,658	33,903	25,843	43,303
Tax uncertainties	45,597	26,708	6,136	5,319	7,434
Stock appreciation rights	3,417	2,975	442	-	-
Other	9,827	5,826	1,701	1,140	1,160
	$ 6,273,047	$ 839,557	$ 1,484,193	$ 1,964,011	$ 1,985,286

The long-term debt and interest on debt amounts consist of amounts due under our senior revolving credit facility and Senior Notes and interest payments to maturity. The principal amount under our senior revolving 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, 2008 remains outstanding to maturity with interest and commitment fees calculated at the rates in effect at December 31, 2008.

Drilling commitments include our estimated remaining obligation in connection with our acquisition of a 20% interest in Chesapeake's Haynesville Shale leasehold in July 2008. In connection with the acquisition we also agreed, over a multi-year period, to fund 50% of Chesapeake's drilling and completion costs associated with future Haynesville Shale wells, up to an additional $1.65 billion. The payment of the obligation is dependent upon the volume of drilling activity; however, based upon current development plans, we anticipate completing payment of the obligation by the end of 2012. In February 2009, PXP and Chesapeake entered into certain amended agreements which, among other matters, provides us without additional monetary consideration by us a one time option, exercisable on or before June 30, 2010, to reduce our obligation to pay 50% of Chesapeake's drilling and completion costs by $800 million in exchange for an assignment to Chesapeake, effective December 31, 2010, of 50% of all of our interest in the Haynesville properties. Additionally, the drilling commitments include the estimate of our costs to drill two wells required under our Production Sharing Agreement with PetroVietnam, participation in a Gulf of Mexico prospect and commitments for drilling rigs.

The obligation for commodity derivative contracts represents the deferred premium cost and interest on the crude oil put options and natural gas collars that will be paid when such options are settled.

Asset retirement obligations represent the estimated fair value at December 31, 2008 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 are unknown because they are subject to, among other things, federal, state and local regulation and economic factors. See Note 7 to the consolidated financial statements.

Operating leases relate primarily to obligations associated with aircraft and our office facilities.

Tax uncertainties represent the potential cash payments related to uncertain tax positions taken or expected to be taken in a tax return.

Stock appreciation rights ($3.0 million current and $0.4 million long-term) represent the net liability for the deemed vested portion of SARs. The liability at December 31, 2008 is calculated based on our closing stock price and other factors 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. The current SAR liability represents the vested awards as well as the awards expected to vest during the following year and is reflected in the table in 2009 because the holders have the right to exercise the awards. The awards do not all expire in 2009, so a portion of the amount will potentially be paid in a later year. The long-term SAR liability is deemed to be a contractual obligation in the year the awards vest. At December 31, 2008 we had approximately 2.0 million SARs outstanding of which 0.6 million were vested. If all of the vested SARs were exercised, based on $23.24, the price of our common stock as of December 31, 2008, we would pay $0.3 million to holders of the SARs. In 2008 we made cash payments of $59.1 million for SARs that were exercised during that period. See "Critical Accounting Policies and Factors that May Affect Future Results – Stock based compensation".

Other contractual obligations represent our liability for pipeline repair commitments, environmental remediation obligations, pension obligations and post-retirement benefits.

Environmental matters. As discussed under Items 1 and 2 "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 environmental obligations 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 2009 cash expenditures related to plugging, abandonment and remediation will be approximately $10.3 million. At the Point 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, conductor removals and site cleanup and preparation. Although our offshore California properties have a shorter reserve life, third parties have retained the majority of the obligations for abandoning these properties.

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, $41 million ($84 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 $66 million). To secure its abandonment obligations the purchaser of the properties is required to periodically deposit funds into an escrow account. At December 31, 2008, the escrow account had a balance of $10.7 million. The fair value of our guarantee, $0.6 million, considers the payment/performance risk of the purchaser and is included in Other Long-Term Liabilities in our 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.

In the event we make a claim under our insurance policies, we will be subject to the credit risk of the insurers. During the second half of 2008 and first quarter of 2009, the volatility and disruption in the financial and credit markets reached unprecedented levels which may adversely affect the credit quality of our insurers and impact their ability to pay out claims.

Industry Concentration

Financial instruments that potentially subject us to concentrations of credit risk consist principally of accounts receivable with respect to our oil and gas operations and derivative instruments.

The six financial institutions that are contract counterparties for our derivative commodity contracts all have Standard & Poor's ratings of A/Negative or better as of December 31, 2008. Our counterparties to our derivative agreements or their affiliates are generally also lenders under our senior revolving credit facility. As a result, the counterparties to our derivative agreements share in the collateral supporting our revolving credit facility. Therefore, we are not generally required to post additional collateral under our derivative agreements.

At December 31, 2008, we had the following commodity derivative net asset balances with counterparties rated by Standard & Poor's (in thousands):

S&P Rating	Fair Value(1)	Deferred Premium Liability	Net Asset
AA+ / Watch Negative	$ 630,530	$ 117,730	$ 512,800
A+ / Stable	164,166	18,399	145,767
A / Negative	1,001,146	197,027	804,119
	$ 1,795,842	$ 333,156	$ 1,462,686

(1) The fair value does not include the settlements receivable at December 31, 2008.

There has been consolidation in the banking and finance sector during 2008. At December 31, 2008, we had commitments under our senior revolving credit facility from 22 lenders. Currently, no single lender in our credit facility has commitments representing more than 11% of our total commitments. However, if banks continue to consolidate, we may experience a more concentrated credit risk.

During 2008, 2007 and 2006 sales to ConocoPhillips accounted for 36%, 45% and 54%, respectively, of our total revenues and sales to PMLP accounted for 23%, 31% and 41%, 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.

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.

Impairments of oil and gas properties. 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 oil and gas properties (net of accumulated depreciation, depletion and amortization and related deferred income taxes) may not exceed a "ceiling" equal to:

- the present value discounted at 10% of estimated future net cash flows from proved oil and gas reserves, net of estimated future income taxes; plus

- the lower of cost or estimated 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. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including derivative contracts that qualify and are designated for hedge accounting treatment. None of our derivative contracts were designated as hedges at December 31, 2008. The rules require an impairment if our capitalized costs exceed this "ceiling," even if prices declined for only a short period of time.

The substantial decline in commodity prices at December 31, 2008 combined with California oil price differentials, which widened significantly at the end of 2008, impacted our proved reserves as of December 31, 2008, resulting in downward revisions of 204 MMBOE. Based on the discounted value of our proved reserves at December 31, 2008, we recorded a non-cash pre-tax impairment charge of $3.6 billion in the fourth quarter of 2008 as a result of full cost ceiling limitations. We may be required to recognize additional non-cash pre-tax impairment charges in future reporting periods if market prices for oil and natural gas continue to decline.

Oil and gas reserves. Approximately 95% of our 2008 proved reserve information is based on estimates prepared by outside engineering firms. 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 61% at December 31, 2008) 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 index prices and in differentials from the index price and the corresponding adjustment to the projected economic life of such properties. The substantial decline in commodity prices at December 31, 2008 combined with California oil price differentials, which widened significantly at the end of 2008, impacted our proved reserves as of December 31, 2008 resulting in downward revisions of 204 MMBOE. 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 development costs would affect our DD&A. 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 previously discussed. 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 development program, as well as future economic conditions.

Our oil and gas DD&A rate for 2009 after the effect of the impairment of oil and gas properties is expected to be $11.49 per BOE. Based on our estimated proved reserves and our net oil and gas properties subject to amortization at December 31, 2008: (i) a 5% increase in our costs subject to amortization would increase our DD&A rate by approximately $0.57 per BOE and (ii) a five percent negative revision to proved reserves would increase our DD&A rate by approximately $0.60 per BOE.

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. Any further substantial or extended decline in the price of oil and gas below current levels 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. These contracts also expose us to credit risk of nonperformance by the counterparties.

We do not use hedge accounting for our derivative instruments. These derivative contracts are reflected at fair value on our balance sheet and 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. 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 price quotations, volatilities, interest rates and contract terms. We adjust the valuations from the model for credit quality, using the counterparty's credit quality for asset balances and our credit quality for liability balances. We use the credit default swap value for counterparties, when available, or the spread between the risk-free interest rates and the yield on the counterparty's publicly-traded debt for similar maturities. We consider the impact of netting and offset provisions in the agreements on counterparty credit risk, including whether the position with the counterparty is a net asset or net liability. We determine whether the market for our derivative instruments is active or inactive based on transaction volume for such instruments. We value the instruments using similar instruments and by extrapolating data between data points for the thinly traded instruments. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts and interest rates.

For a further discussion concerning our risks related to oil and gas prices and our derivatives, see Item 7A – "Quantitative and Qualitative Disclosures about Market Risk".

Fair Value. We adopted SFAS No. 157, "Fair Value Measurements" ("SFAS 157") and SFAS No.159, "The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115" ("SFAS 159") effective January 1, 2008, each of which address the fair value measurement of assets and liabilities. We have elected to partially adopt SFAS 157 as provided by FSP SFAS 157-2, which deferred the effective date of SFAS 157 for nonfinancial assets and liabilities that are recognized and disclosed at fair value in the financial statements on a nonrecurring basis. SFAS 159 permits the measurement of financial instruments and certain other items at fair value that were not previously required to be measured at fair value. We have not elected to present assets and liabilities at fair value that were not required to be measured at fair value prior to the adoption of SFAS 159.

As defined in SFAS 157, fair value is the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date ("exit price"). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. SFAS 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities ("Level 1") and the lowest priority to unobservable inputs ("Level 3"). The three levels of fair value under SFAS 157 are as follows:

- Level 1 – Valuations utilizing quoted, unadjusted prices for assets or liabilities in active markets for identical assets or liabilities as of the reporting date. This is the most reliable evidence of fair value and does not require a significant amount of judgment.
- Level 2 – Valuations utilizing market-based inputs that are directly or indirectly observable but not considered Level 1 quoted prices, including quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; or valuation techniques whose inputs are observable. Where observable inputs are available, directly or indirectly, for substantially the full term of the asset or liability.
- Level 3 – Valuations utilizing techniques whose significant inputs are unobservable. This provides the least objective evidence of fair value and requires a significant degree of judgment.

A financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement.

We estimate the fair values of our derivative instruments as described above, in Commodity pricing and risk management activities.

In October 2008, the Financial Accounting Standards Board ("FASB") issued FSP SFAS 157-3, "Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active" ("FSP SFAS 157-3"). This FSP clarifies the application of SFAS No. 157 in a market that is not active and provides for an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. We determined whether the market for our derivative instruments was active or inactive based on transaction volume for such instruments and classified those instruments in inactive markets as Level 3 instruments. We value these Level 3 instruments using similar instruments and extrapolating data between data points for the thinly traded instruments.

Stock based compensation. Under SFAS 123R stock appreciation rights 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 stock appreciation rights 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 judgment with respect to expected life, volatility, expected returns and other factors.

We recognized $50 million, $52 million and $55 million of stock based compensation expense for the years ended December 31, 2008, 2007 and 2006, 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, 2008, goodwill totaled $535 million and represented approximately 8% 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; instead it is tested at least annually for impairment at a level of reporting referred to as a reporting unit. Impairment occurs 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 to be 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 the reporting unit's goodwill with the carrying amount of that goodwill. If the carrying amount of that reporting unit's 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 producing properties 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 fair value measurement, if available. Accordingly, we use the quoted market price of our common stock as a starting point in determining the fair value of our reporting unit.

We perform our goodwill impairment test annually on December 31 and have recorded no impairments to goodwill based on such tests. We also perform an interim impairment test if events occur or circumstances change that would indicate that the fair value of our reporting unit could be below its carrying amount. Due to the adverse market conditions that had a pervasive impact on the U.S. business climate in the third quarter of 2008, we performed an interim goodwill impairment test as of September 30, 2008. In determining the fair value of our reporting unit in the first step of the goodwill impairment test, we applied a control premium to the quoted market price of our common stock at September 30, 2008, and we concluded that our goodwill was not impaired as of that date. We determined the control premium through reference to control premiums in recent acquisition transactions for our industry and other comparable industries.

Market conditions continued to deteriorate and our common stock price continued to decline in the fourth quarter of 2008. The carrying value of our reporting unit, which is equivalent to our book equity, also declined significantly from $3.9 billion at September 30, 2008 to $2.4 billion at December 31, 2008 due primarily to the $3.6 billion non-cash pre-tax impairment charge that we recorded in the fourth quarter of 2008. As a result, we did not have an impairment of goodwill when we performed step one of our annual impairment test as of December 31, 2008. In determining the fair value of our reporting unit in the first step of the goodwill impairment test, we applied a control premium to the quoted market price of our common stock at December 31, 2008. We determined the control premium through reference to control premiums in acquisition transactions for our industry and other comparable industries. If the price of our common stock declines, we could have an impairment of our goodwill in future periods.

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.

Recent Accounting Pronouncements

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* ("SFAS 141R"). SFAS 141R broadens the guidance of SFAS 141, extending its applicability to all transactions and other events in which one entity obtains control over one or more other businesses. It broadens the fair value measurement and recognition of assets acquired, liabilities assumed, and interests transferred as a result of business combinations and requires that acquisition-related costs incurred prior to the acquisition be expensed. SFAS 141R also expands the definition of what qualifies as a business, and this expanded definition could include prospective oil and gas purchases. This could cause us to expense transaction costs for future oil and gas property purchases that we have historically capitalized. Additionally, SFAS 141R expands the required disclosures to improve the statement users' abilities to evaluate the nature and financial effects of business combinations. SFAS 141R is effective for business combinations for which the acquisition date is on or after January 1, 2009, except for certain tax effects related to prior business combinations for which SFAS 141R is now effective.

In December 2008, the SEC issued a final rule, Modernization of Oil and Gas Reporting which is effective January 1, 2010 for reporting 2009 reserve information. The new disclosure requirements permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. The new disclosure requirements also require companies to include nontraditional resources such as oil sands, shale, coalbeds or other nonrenewable natural resources in reserves if they are intended to be upgraded to synthetic oil and gas. Currently the SEC requires that reserve volumes are determined using prices on the last day of the reporting period; however, the new disclosure requirements provide for reporting oil and gas reserves using an average price based upon the prior twelve month period rather than year-end prices. The new requirements also will allow companies to disclose their probable and possible reserves to investors. The new disclosure requirements also require companies to report the independence and qualifications of a reserve preparer or auditor. We will adopt the provisions of the final rule in connection with our December 31, 2009 Form 10-K filing. We are currently evaluating the impact of the final rule.

Item 7A. *Quantitative and Qualitative 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 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. We do not currently use hedge accounting for our derivative instruments.

See Note 5 to the Consolidated Financial Statements – "Derivative Instruments" for a discussion of our derivative activities. In the fourth quarter of 2008, certain of our derivatives classified as Level 2 under SFAS 157 were reclassified to Level 3 as significant inputs in determining the fair value were unobservable. See Note 6 to the Consolidated Financial Statements – "Fair Value Measurements of Assets and Liabilities."

As of December 31, 2008, we had the following outstanding commodity derivative contracts that were not designated as hedging instruments:

Period	Instrument Type	Daily Volumes	Average Price (1)	Deferred Premium	Index	Settlement
Sales of Crude Oil Production						
2009						
Jan -Dec	Put options	32,500 Bbls	$55.00 Strike price	$3.38 per Bbl	WTI	Monthly
Jan -Dec	Put options	40,000 Bbls	$106.16 Strike price	$8.10 per Bbl	WTI	Monthly
Jan -Dec	Swap contracts	20,000 Bbls	Pay: $53.71 (fixed price)	none	WTI	Monthly
			Receive: Average monthly settlement price (floating)		WTI	
2010						
Jan -Dec	Put options	40,000 Bbls	$111.49 Strike price	$12.08 per Bbl	WTI	Annual
Sales of Natural Gas Production						
2009						
Jan -Dec	Collar	150,000 MMBtu	$10.00 Floor - $20.00 Ceiling	$0.346 per MMBtu	Henry Hub	Monthly

(1) The average strike prices do not reflect the cost to purchase the put options or collars.

As a result of the transactions since December 31, 2008, we have the following outstanding commodity derivative contracts as of February 25, 2009:

Period	Instrument Type	Daily Volumes	Average Price	Deferred Premium	Index	Settlement
Sales of Crude Oil Production						
2009						
Jan -Dec	Put options	32,500 Bbls	$55.00 Strike price	$3.38 per Bbl	WTI	Monthly
2010						
Jan -Dec	Put options (1)	40,000 Bbls	$55.00 Strike price	$5.00 per Bbl	WTI	Monthly
Sales of Natural Gas Production						
2009						
Jan -Dec	Collar	150,000 MMBtu	$10.00 Floor - $20.00 Ceiling	$0.346 per MMBtu	Henry Hub	Monthly
2010						
Jan -Dec	Put/Call (2)	40,000 MMBtu	$6.25 Floor - $4.80 Floor by $8.00 Ceiling	No premium	Henry Hub	Monthly

(1) An upfront payment of $3.86 per barrel was paid upon entering into this derivative contract.

(2) We receive the difference between the floor of $6.25 per MMBtu less NYMEX up to a maximum of $1.45 per MMBtu. We pay if NYMEX is greater than the $8.00 ceiling.

For put options, we pay a premium to the counterparty in exchange for the sale of a put option. If the index price is below the strike price of the put option, we receive the difference between the strike price and the index price less the premium and interest. If the index price settles at or above the strike price of the put option, we pay only the option premium and interest.

In a typical collar transaction, if the floating price based on a market index is below the floor price in the derivative agreement, we receive from the counterparty this difference, multiplied by the specified quantity. If the floating price exceeds the floor price and is less than the ceiling price, no payment is required by either party. If the floating price exceeds the ceiling price, we must pay the counterparty this difference multiplied by the specified quantity. If we have less production than the volumes we have specified under the collar transaction when the floating price exceeds the ceiling price, we must make payments against which there is no offsetting revenue from production.

The fair value of outstanding crude oil and gas commodity derivative instruments at December 31, 2008 and the change in fair value that would be expected from a 10% price increase or decrease is shown below (in millions). The fair value does not include the deferred premiums on the purchased put options and natural gas collars:

	Fair Value Asset (Liability)	Effect of 10% Price Increase	Effect of 10% Price Decrease
Crude oil put options	$ 1,575	$ (155)	$ 168
Crude oil swap contracts	5	39	(39)
Natural gas collars	216	(28)	31
	$ 1,796	$ (144)	$ 160

None of our offsetting physical positions are included in the above table. Price risk sensitivities were calculated by assuming an across-the-board 10% increase or decrease in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price.

We estimate the fair value of our derivatives using an option-pricing model. The option-pricing model uses various factors, including NYMEX price quotations, volatilities, interest rates and contract terms. We adjust the valuations from the model for credit quality, using the counterparty's credit quality for asset balances and our credit quality for liability balances. We use the credit default swap value for counterparties, when available, or the spread between the risk-free interest rates and the yield on the counterparty's publicly-traded debt for similar maturities. We consider the impact of netting and offset provisions in the agreements on counterparty credit risk, including whether the position with the counterparty is a net asset or net liability. We determined whether the market for our derivative instruments is active or inactive based on transaction volume for such instruments. We value the instruments using similar instruments and by extrapolating data between data points for the thinly traded instruments.

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 revenue 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 50% 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, 2008, $1.3 billion was outstanding under our senior revolving credit facility at an effective interest rate of 3.149%. The carrying value of our senior revolving credit facility is approximately $0.2 million greater than its fair value, based on rates currently available for debt instruments with similar terms and average maturities from companies with similar credit ratings in our industry. Based on the $1.3 billion outstanding under our senior revolving credit facility at December 31, 2008, on an annualized basis a 1% change in the effective interest rate would result in a $13.0 million change in our interest costs.

Foreign Currency Risk

As a result of the Pogo acquisition, we acquired an operation in Vietnam which exposes us to foreign currency exchange risk on cash flows for expenses and investing transactions. We expect foreign currency risk to be minimal due to the size of our operation and the use of U.S. dollar denominated contracts.

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, 2008 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, 2008.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2008 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Changes in Internal Controls

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2008 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, executive officers and certain corporate governance items will be included in an amendment to this Form 10-K or in the proxy statement for the 2009 annual meeting of stockholders, in either case, to be filed within 120 days after December 31, 2008, 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, 2009 and their business experience for the last five years.

Directors

James C. Flores, age 49, Chairman of the Board, President and Chief Executive Officer and a Director since September 2002. He has been Chairman of the Board and Chief Executive Officer of PXP 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 73, Director since May 2004. He also was a director of Nuevo Energy Company from 1990 to May 2004. 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 62, 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, BCM Technologies, Inc., the Texas Medical Center and Greater Houston Area Red Cross and is Vice Chairman of Torch Securities LLC. He sits on the Audit Committee and is Chairman of the Compensation Committee for Service Corporation International.

Jerry L. Dees, age 69, 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 68, 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 a director for three privately owned companies. Previously, he has served as President and CEO for Magna Corporation, (now Baker Petrolite, a unit of Baker Hughes). Mr. Delimitros currently serves on two Development Committees for the College of Engineering at the University of Washington in Seattle and is a member of the University of Washington Foundation Board.

Thomas A. Fry, III, age 64, Director since November 2007. He was also a director of Pogo from 2004 to November 2007. He has been the President of National Ocean Industries Association ("NOIA") since December 2000. Before joining NOIA, Mr. Fry served as the Director of the Department of Interior's Bureau of Land Management and has also served as the Director of the Minerals Management Service.

Robert L. Gerry III, age 71, Director since May 2004. He was also a director of Nuevo from 1990 to May 2004. Mr. Gerry currently serves as a director of Integrity Bank. 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 PXP, 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.

Charles G. Groat, age 68, Director since November 2007. He was also a director of Pogo from 2005 to November 2007. Dr. Groat currently serves as the Director of the Center for International Energy and Environment Policy and as the Director of the Energy and Earth Resources Graduate Program at the University of Texas at Austin. Before joining the University of Texas at Austin, Dr. Groat served for more than six years as Director of the U.S. Geological Survey, having been appointed by President Clinton and retained by President Bush.

John H. Lollar, age 70, 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 49, Chairman of the Board, President and Chief Executive Officer and a Director since September 2002. He has been Chairman of the Board and Chief Executive Officer of PXP 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 51, Executive Vice President—Exploration and Production since June 2006. He was PXP's Vice President of Development from April 2006 to June 2006. He was also PXP's 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 46, Executive Vice President and Chief Financial Officer since June 2006. He joined PXP in May 2003 as Vice President Finance & Investor Relations and in May 2004, Mr. Talbert became Vice President Finance & Treasurer. Prior to joining PXP, 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 47, Executive Vice President, General Counsel and Secretary since September 2003. He has served as Executive Vice President and General Counsel of PXP since 2003. He was also Plains Resources' Executive Vice President, General Counsel, and Secretary from September 2003 to June 2004. He was previously 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 and a senior executive officer with two New York Stock Exchange traded companies.

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 2009 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 2009 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 and director independence will be included in an amendment to this Form 10-K or in the proxy statement for the 2009 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 2009 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
2.1	Purchase and Sale Agreement between Plains Exploration & Production Company, PXP Louisiana L.L.C., PXP Louisiana Operations LLC and Chesapeake Louisiana, L.P., dated July 1, 2008 (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed July 8, 2008, File No. 1-31470 (the "July 8, 2008 Form 8-K")).
2.2	Participation Agreement between Plains Exploration & Production Company, PXP Louisiana L.L.C., PXP Louisiana Operations LLC and Chesapeake Louisiana, L.P., dated July 7, 2008,(incorporated by reference to Exhibit 2.2 to the July 8, 2008 Form 8-K).
2.3*	First Amendment to the Participation Agreement between Plains Exploration & Production Company, PXP Louisiana L.L.C., PXP Louisiana Operations LLC and Chesapeake Louisiana, L.P., dated February 20, 2009.
2.4	Purchase and Sale Agreement dated September 24, 2008, by and among Plains Exploration & Production Company, Plains Resources Inc., PXP Hell's Gulch LLC, PXP East Plateau LLC, PXP Brush Creek LLC, PXP Piceance LLC, Pogo Producing Company LLC, Pogo Panhandle 2004 LP and Latigo Petroleum Texas, LP and OXY USA Inc. (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed September 25, 2008, File No. 1-31470).
2.5	Agreement and Plan of Merger, dated July 17, 2007, by and among Plains Exploration & Production Company, PXP Acquisition LLC and Pogo Producing Company (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed July 18, 2007, File No. 1-31470).
2.6	Purchase and Sale Agreement dated December 14, 2007, by and among Plains Exploration & Production Company, Plains Resources Inc., PXP Hell's Gulch LLC, PXP East Plateau LLC, PXP Brush Creek LLC, PXP Piceance LLC, Pogo Producing Company LLC, Pogo Panhandle 2004 LP and Latigo Petroleum Texas LP, and OXY USA Inc. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed December 17, 2007, File No. 1-31470 (the "December 17, 2007 Form 8-K")).
2.7	Asset Purchase & Sale Agreement between Plains Exploration & Production Company and Laramie Energy, LLC, dated April 18, 2007 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed April 24, 2007, File No. 1-31470 (the "April 24, 2007 Form 8-K")).
2.8	Membership Interests Purchase & Sale Agreement between Plains Exploration & Production Company and Laramie Energy, LLC, dated as of April 18, 2007 (incorporated by reference to Exhibit 10.2 to the April 24, 2007 Form 8-K).
2.9	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 Company's Current Report on Form 8-K filed October 4, 2006, File No. 1-31470).

2.10 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, File No. 1-31470).

2.11 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, File No. 1-31470).

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 Quarterly Report on Form 10-Q for the period ending June 30, 2004, File No. 1-31470).

3.3 Certificate of Amendment to the Certificate of Incorporation of Plains Exploration & Production Company dated November 6, 2007 (incorporated by reference to Exhibit 3.3 to the Company's Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-31470 (the "2007 10-K")).

3.4 Bylaws of Plains Exploration & Production Company (incorporated by reference to Exhibit 3.2 to the Amendment No. 2 to Form S-1).

4.1 Indenture, dated as of March 13, 2007, among Plains Exploration & Production Company, the Subsidiary Guarantors parties thereto, and Wells Fargo Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed March 13, 2007, File No. 1-31470 (the "March 13, 2007 Form 8-K")).

4.2 First Supplemental Indenture, dated March 13, 2007, to the Indenture dated as of March 13, 2007, among Plains Exploration & Production Company, the Subsidiary Guarantors parties thereto, and Wells Fargo Bank, N.A., as Trustee (including form of 7% Senior Note) (incorporated by reference to Exhibit 4.2 to the March 13, 2007 Form 8-K).

4.3 Second Supplemental Indenture dated as of June 5, 2007, to the Indenture dated as of March 13, 2007, among Plains Exploration & Production Company, Plains Resources Inc., PXP East Plateau LLC, PXP Brush Creek LLC, PXP CV Pipeline LLC, PXP Hell's Gulch LLC, PXP Piceance LLC, the Subsidiary Guarantors parties thereto, and Wells Fargo Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.3 to the Company's 2007 10-K).

4.4 Third Supplemental Indenture dated as of June 19, 2007, to Indenture dated as of March 13, 2007, among Plains Exploration & Production Company, the Subsidiary Guarantors parties thereto, and Wells Fargo Bank, N.A., as Trustee (including form of 7¾% Senior Note) (incorporated by reference to Exhibit 4.2 to the Company's current Report on Form 8-K filed June 19, 2007, File No. 1-31470).

4.5 Fourth Supplemental Indenture, dated as of November 14, 2007, to the Indenture dated as of March 13, 2007, among Plains Exploration & Production Company, Laramie Land & Cattle Company, LLC, the Subsidiary Guarantors parties thereto and Wells Fargo Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.5 to the Company's 2007 10-K).

4.6 Fifth Supplemental Indenture, dated as of January 29, 2008, to the Indenture dated as of March 13, 2007, among Plains Exploration & Production Company, Latigo Gas Group, LLC, Latigo Gas Holdings, LLC, Latigo Gas Services, LP, Latigo Holding (Texas), LLC, Latigo Investments, LLC, Latigo Petroleum, Inc., Latigo Petroleum Texas LP, Pogo Energy, Inc., Pogo Panhandle 2004, L.P., Pogo Producing Company LLC, Pogo Producing (Texas Panhandle) Company, PXP Aircraft LLC, the Subsidiary Guarantors parties thereto and Wells Fargo Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.6 to the Company's 2007 10-K).

4.7 Sixth Supplemental Indenture, dated as of February 13, 2008, to the Indenture dated as of March 13, 2007, among Plains Exploration & Production Company, Pogo Partners, Inc., Pogo Producing (San Juan) Company, the Subsidiary Guarantors parties thereto and Wells Fargo Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.5 to the Company's 2007 10-K).

4.8 Seventh Supplemental Indenture, dated as of May 23, 2008 to the indenture dated as of March 13, 2007, among Plains Exploration & Production Company, the Subsidiary Guarantors parties thereto and Wells Fargo Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K file on May 23, 2008, File No. 1-31470).

4.9 Eighth Supplemental Indenture, dated July 10, 2008, to indenture dated as of March 13, 2007, among Plains Exploration & Production Company, PXP Louisiana Operations LLC, the Subsidiary Guarantors parties thereto and Wells Fargo Bank, N.A. as Trustees (incorporated by reference to Exhibit 4.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, File No. 1-31470).

4.10 Amended and Restated Credit Agreement, dated as of November 6, 2007, among Plains Exploration & Production Company, as borrower, each of the lenders that is a signatory thereto, and JPMorgan Chase Bank, N.A., as administrative agent (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed November 6, 2007, File No. 1-31470).

4.11 Amendment No. 1 to Amended and Restated Credit Agreement, dated as of February 13, 2008, among Plains Exploration & Production Company, as borrower, each of the lenders that is a signatory thereto, and JPMorgan Chase Bank, N.A., as administrative agent (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed February 20, 2008, File No. 1-31470).

4.12 Amendment No. 3 to Amended and Restated Credit Amendment, dated as of July 23, 2008, among Plains Exploration & Production Company, as borrower, each of the lenders that is a signature thereto and JPMorgan Chase Bank, N.A., as administrative agent (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed July 23, 2008, File No. 1-31470).

10.1 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, File No. 1-31470 (the "2005 10-K").

10.2 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).

10.3 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).

10.4	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 Company's Annual Report on Form 10-K for the year ended December 31, 2004, File 1-31470).
10.5	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 Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2004, File No. 1-31470).
10.6	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).
10.7†	Plains Exploration & Production Company 2002 Stock Incentive Plan (incorporated by reference to Exhibit 10.7 to the Company's 2007 10-K).
10.8†	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, File No. 1-31470).
10.9*†	Form of Restricted Stock Unit Agreement under the 2002 Stock Incentive Plan.
10.10†	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).
10.11†	Amended and Restated Plains Exploration & Production Company 2004 Stock Incentive Plan (incorporated by reference to Exhibit 4.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2007, File No. 1-31470).
10.12†	Form of Plains Restricted Stock Award Agreement under the 2004 Incentive Plan (incorporated by reference to Exhibit 10.36 to the Company's Form 10-K for the year ended December 31, 2006, File No. 1-31470).
10.13†*	Form of Restricted Stock Unit Agreement under the 2004 Stock Incentive Plan.
10.14†	Form of Plains Stock Appreciation Rights Agreement under the 2004 Incentive Plan (incorporated by reference to Exhibit 10.9 to the September 30, 2006 Form 10-Q).
10.15†	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 10.15 to the Company's 2007 10-K).
10.16†	Amended and Restated Plains Exploration & Production Company Long-Term Retention and Deferral Agreement for James C. Flores (incorporated by reference to Exhibit 10.16 to the Company's 2007 10-K).
10.17†	Amended and Restated Plains Exploration & Production Company Long-Term Retention and Deferral Agreement for John F. Wombwell (incorporated by reference to Exhibit 10.17 to the Company's 2007 10-K).
10.18†	Amended and Restated Employment Agreement, effective as of June 9, 2004, between Plains Exploration & Production Company and James C. Flores (incorporated by reference to Exhibit 10.18 to the Company's 2007 10-K).
10.19†	Amendment to Plains Exploration & Production Company Amended and Restated Employment Agreement, effective as of March 12, 2008, by and between Plains Exploration & Production Company and James C. Flores (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed March 12, 2008, File No. 1-31470).

10.20†	Amended and Restated Employment Agreement, effective as of June 9, 2004, between Plains Exploration & Production Company and John F. Wombwell (incorporated by reference to Exhibit 10.19 to the Company's 2007 10-K).
10.21†	Amended and Restated Employment Agreement, effective as of November 8, 2006, between Plains Exploration & Production Company and Winston M. Talbert (incorporated by reference to Exhibit 10.20 to the Company's 2007 10-K).
10.22†	Amended and Restated Employment Agreement, effective as of November 8, 2006, between Plains Exploration & Production Company and Doss R. Bourgeois (incorporated by reference to Exhibit 10.21 to the Company's 2007 10-K).
10.23*	Form of Election for Director Deferral of Restricted Stock Awards.
10.24	Summary of Director Compensation Program (incorporated by reference to Exhibit 10.5 to the March 31, 2006 Form 10-Q).
21.1*	List of Subsidiaries of Plains Exploration & Production Company.
23.1*	Consent of PricewaterhouseCoopers LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
23.3*	Consent of Ryder Scott Company, L.P.
23.4*	Consent of Miller and Lents, Ltd.
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.
† Management contracts or compensatory plans or arrangements.

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 25, 2009	/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 25, 2009	/s/ James C. Flores
	James C. Flores, Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)
Date: February 25, 2009	/s/ Isaac Arnold, Jr.
	Isaac Arnold, Jr., Director
Date: February 25, 2009	/s/ Alan R. Buckwalter, III
	Alan R. Buckwalter, III, Director
Date: February 25, 2009	/s/ Jerry L. Dees
	Jerry L. Dees, Director
Date: February 25, 2009	/s/ Tom H. Delimitros
	Tom H. Delimitros, Director
Date: February 25, 2009	/s/ Thomas A. Fry, III
	Thomas A. Fry, III, Director
Date: February 25, 2009	/s/ Robert L. Gerry, III
	Robert L. Gerry, III, Director
Date: February 25, 2009	/s/ Charles G. Groat
	Charles G. Groat, Director
Date: February 25, 2009	/s/ John H. Lollar
	John H. Lollar, Director
Date: February 25, 2009	/s/ Winston M. Talbert
	Winston M. Talbert, Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: February 25, 2009	/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:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income and comprehensive income, of stockholders' equity and of cash flows present fairly, in all material respects, the financial position of Plains Exploration & Production Company and its subsidiaries (the Company) at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Annual Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we consider necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Notes 6 and 11 to the consolidated financial statements, the Company changed its method of accounting and disclosure for fair values of financial assets and liabilities effective January 1, 2008 and its method of accounting for uncertain tax positions effective January 1, 2007.

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 25, 2009

PLAINS EXPLORATION & PRODUCTION COMPANY
CONSOLIDATED BALANCE SHEETS
(in thousands of dollars)

	December 31, 2008	December 31, 2007
ASSETS		
Current Assets		
Cash and cash equivalents	$ 311,875	$ 25,446
Restricted cash	-	59,092
Accounts receivable	175,896	304,972
Commodity derivative contracts	945,838	2,186
Inventories	23,368	18,394
Deferred income taxes	-	229,893
Other current assets	19,464	34,937
	1,476,441	674,920
Property and Equipment, at cost		
Oil and natural gas properties—full cost method		
Subject to amortization	7,106,785	7,340,238
Not subject to amortization	2,513,424	1,951,783
Other property and equipment	110,990	85,928
	9,731,199	9,377,949
Less allowance for depreciation, depletion, amortization and impairment	(5,217,803)	(1,000,722)
	4,513,396	8,377,227
Goodwill	535,265	536,822
Commodity Derivative Contracts	530,181	-
Other Assets	56,632	104,382
	$ 7,111,915	$ 9,693,351
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 363,713	$ 319,583
Commodity derivative contracts	-	79,938
Royalties and revenues payable	87,874	132,919
Stock appreciation rights	2,975	63,106
Interest payable	20,843	25,330
Income taxes payable	102,948	3,492
Deferred income taxes	285,426	-
Accrued merger expenses	-	77,980
Other current liabilities	129,866	115,698
	993,645	818,046
Long-Term Debt	2,805,000	3,305,000
Other Long-Term Liabilities		
Asset retirement obligation	159,473	184,080
Commodity derivative contracts	-	33,821
Other	32,061	54,726
	191,534	272,627
Deferred Income Taxes	744,456	1,959,431
Commitments and Contingencies (Note 12)		
Stockholders' Equity		
Common stock, $0.01 par value, 250.0 million shares authorized, 112.9 million and 112.8 million shares issued at December 31, 2008 and 2007, respectively	1,129	1,128
Additional paid-in capital	2,739,625	2,711,617
Retained earnings (deficit)	(85,101)	623,993
Accumulated other comprehensive income	(684)	1,566
Treasury stock, at cost, 5.3 million shares and 1,042 shares at December 31, 2008 and 2007, respectively	(277,689)	(57)
	2,377,280	3,338,247
	$ 7,111,915	$ 9,693,351

See notes to consolidated financial statements.

PLAINS EXPLORATION & PRODUCTION COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(in thousands, except per share data)

	Year Ended December 31,		
	2008	**2007**	**2006**
Revenues			
Oil sales	$ 1,766,677	$ 1,116,376	$ 1,055,482
Oil hedging	-	-	(145,755)
Gas sales	619,886	153,416	106,319
Other operating revenues	16,908	3,048	2,457
	2,403,471	1,272,840	1,018,503
Costs and Expenses			
Production costs			
Lease operating expenses	327,412	225,845	179,741
Steam gas costs	131,156	103,464	63,811
Electricity	52,735	39,767	38,011
Production and ad valorem taxes	93,988	32,636	24,777
Gathering and transportation expenses	21,137	11,410	6,785
General and administrative	153,306	124,006	123,134
Depreciation, depletion and amortization	608,448	306,278	207,173
Impairment of oil and gas properties	3,629,666	-	-
Accretion	13,036	9,800	9,609
Gain on sale of oil and gas properties	-	-	(982,988)
	5,030,884	853,206	(329,947)
Income (Loss) from Operations	(2,627,413)	419,634	1,348,450
Other Income (Expense)			
Gain on sale of assets	65,689	-	-
Interest expense	(116,991)	(68,908)	(64,675)
Debt extinguishment costs	(18,256)	-	(45,063)
Gain (loss) on mark-to-market derivative contracts	1,555,917	(88,549)	(297,503)
Gain on termination of merger agreement	-	-	37,902
Other income (expense)	(12,575)	6,322	5,496
Income (Loss) Before Income Taxes and Cumulative Effect of Accounting Change	(1,153,629)	268,499	984,607
Income tax (expense) benefit			
Current	(230,815)	4,677	(142,378)
Deferred	675,350	(114,425)	(242,519)
Income (Loss) Before Cumulative Effect of Accounting Change	(709,094)	158,751	599,710
Cumulative effect of accounting change (net of income tax benefit of $1,363)	-	-	(2,182)
Net Income (Loss)	$ (709,094)	$ 158,751	$ 597,528
Earnings (loss) per share			
Basic			
Income (loss) before cumulative effect of accounting change	$ (6.52)	$ 2.02	$ 7.76
Cumulative effect of accounting change	-	-	(0.03)
Net income (loss)	$ (6.52)	$ 2.02	$ 7.73
Diluted			
Income (loss) before cumulative effect of accounting change	$ (6.52)	$ 1.99	$ 7.67
Cumulative effect of accounting change	-	-	(0.03)
Net income (loss)	$ (6.52)	$ 1.99	$ 7.64
Weighted Average Shares Outstanding			
Basic	108,828	78,627	77,273
Diluted	108,828	79,808	78,234

See notes to consolidated financial statements.

PLAINS EXPLORATION & PRODUCTION COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands of dollars)

	Year Ended December 31,		
	2008	2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$ (709,094)	$ 158,751	$ 597,528
Items not affecting cash flows from operating activities			
Gain on sale of assets	(65,689)	-	(982,988)
Depreciation, depletion, amortization and accretion	621,484	316,078	216,782
Impairment of oil and gas properties	3,629,666	-	-
Deferred income tax expense (benefit)	(675,350)	114,425	242,519
Debt extinguishment costs	18,256	-	9,289
Cumulative effect of adoption of accounting change	-	-	2,182
Commodity derivative contracts	(1,555,917)	88,549	443,258
Noncash compensation	50,401	52,019	55,486
Other noncash items	6,546	707	(268)
Change in assets and liabilities from operating activities, net of effect of acquisitions			
Accounts receivable and other assets	120,761	(65,694)	29,739
Inventories	(4,782)	(530)	(1,277)
Accounts payable and other liabilities	(109,182)	53,351	(13,821)
Stock appreciation rights	(59,078)	(8,322)	(17,720)
Income taxes payable/receivable	103,387	(121,222)	94,272
Net cash provided by operating activities	1,371,409	588,112	674,981
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to oil and gas properties	(1,116,715)	(770,409)	(634,330)
Acquisition of oil and gas properties	(2,006,127)	(975,407)	-
Acquisition of Pogo Producing Company, net of cash acquired	(77,686)	(298,031)	-
Decrease (increase) in restricted cash	59,092	(59,092)	-
Proceeds from sales of oil and gas properties and related assets, net of costs and expenses	2,969,945	-	1,550,663
Derivative settlements	(8,606)	(99,861)	(93,411)
Additions to other property and equipment	(44,436)	(36,176)	(10,923)
Other, net	(3,257)	(4,161)	-
Net cash (used in) provided by investing activities	(227,790)	(2,243,137)	811,999
CASH FLOWS FROM FINANCING ACTIVITIES			
Revolving credit facilities			
Borrowings	14,331,046	4,745,100	1,618,900
Repayments	(15,231,046)	(2,775,600)	(1,655,400)
Proceeds from issuance of Senior Notes	400,000	1,100,000	-
Redemption of long-term debt	-	(1,291,926)	(524,863)
Costs incurred in connection with financing arrangements	(27,527)	(47,333)	-
Derivative settlements	(25,678)	(3,688)	(621,862)
Purchase of treasury stock	(304,192)	(47,485)	(298,445)
Other	207	504	(5,963)
Net cash (used in) provided by financing activities	(857,190)	1,679,572	(1,487,633)
Net increase (decrease) in cash and cash equivalents	286,429	24,547	(653)
Cash and cash equivalents, beginning of period	25,446	899	1,552
Cash and cash equivalents, end of period	$ 311,875	$ 25,446	$ 899

See notes to consolidated financial statements.

PLAINS EXPLORATION & PRODUCTION COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands of dollars)

	Year Ended December 31,		
	2008	**2007**	**2006**
Net Income (Loss)	$ (709,094)	$ 158,751	$ 597,528
Other Comprehensive Income (Loss)			
Commodity hedging contracts			
Reclassification adjustment for terminated contracts	-	-	145,755
Related tax expense	-	-	(56,189)
Pension			
Pension liability adjustment	(3,616)	2,522	-
Related tax expense	1,366	(956)	-
	(2,250)	1,566	89,566
Comprehensive Income (Loss)	$ (711,344)	$ 160,317	$ 687,094

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, 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
Net income	-	-	-	158,751	-	-	-	158,751
Issuance of common stock in connection with property acquisition	1,000	10	44,530	-	-	-	-	44,540
Issuance of common stock in connection with acquisition of Pogo Producing Company	32,308	323	1,649,320	-	-	7,755	345,873	1,995,516
Restricted stock awards	357	3	53,234	-	-		-	53,237
Treasury stock transactions	-	-	-	-	-	(1,026)	(47,485)	(47,485)
Cumulative effect of accounting change (Note 9)	-	-	-	1,378	-	-	-	1,378
Other comprehensive income	-	-	-	-	1,566	-	-	1,566
Exercise of stock options and other	4	-	61	-	-	-	-	61
Balance at December 31, 2007	112,841	1,128	2,711,617	623,993	1,566	(1)	(57)	3,338,247
Net loss	-	-	-	(709,094)	-	-	-	(709,094)
Restricted stock awards	19	-	54,293	-	-	-	-	54,293
Treasury stock purchases	-	-	-	-	-	(5,771)	(304,192)	(304,192)
Issuance of treasury stock for restricted stock awards	-	-	(26,560)	-	-	489	26,560	-
Other comprehensive loss	-	-	-	-	(2,250)	-	-	(2,250)
Exercise of stock options and other	14	1	275	-	-	-	-	276
Balance at December 31, 2008	112,874	$ 1,129	$ 2,739,625	$ (85,101)	$ (684)	(5,283)	$(277,689)	$ 2,377,280

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", the "Company", "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, develops, explores for and produces oil and gas. Our upstream activities are primarily located in the United States. We also have interests in an exploration prospect offshore Vietnam.

Significant Accounting Policies

Oil and Gas Properties. We follow the full cost method of accounting whereby all costs associated with property acquisition, exploration 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 and development activities. General and administrative costs associated with production, operations, marketing and general corporate activities are expensed as incurred. Capitalized costs, along with our estimated future costs to develop proved reserves and asset retirement costs which are not already included in oil and gas properties, net of related salvage value, 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 cause a significant change in the relationship between costs and the estimated value of proved reserves, in which case a gain or loss is recognized.

We review the carrying value of our proved oil and gas properties quarterly under the SEC's full cost accounting rules. Under these rules, capitalized costs of oil and gas properties (net of accumulated depreciation, depletion and amortization and related deferred income taxes) are subject to a ceiling, on a country-by-country basis, which limits such costs to the present value of estimated future net revenues from proved oil and natural gas reserves of such properties (including the effect of any related hedging activities) reduced by estimated future operating expenses, development expenditures, abandonment costs (net of salvage values) to the extent not included in oil and gas properties pursuant to Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143") and estimated future income taxes thereon plus the lower of cost or estimated fair value of unproved properties not included in the costs being amortized. 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. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including derivative contracts that qualify and are designated for hedge accounting treatment. None of our derivative contracts were designated as hedges at December 31, 2008. The rules require an impairment if our capitalized costs exceed the ceiling, even if prices declined only for a short period of time. See Note 2.

Asset Retirement Obligation. We account for our asset retirement obligation 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. For oil and gas properties, this is the period in which the well is drilled or acquired. 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.

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, land and real estate development costs. 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 twenty 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) allocating purchase price in connection with business combinations and determining fair value, including goodwill; (4) income taxes; (5) accrued assets and liabilities; (6) stock based compensation; (7) asset retirement obligations and (8) valuation of derivative instruments. The current volatility in the economic factors used to calculate these estimates have increased the degree of uncertainty in these estimates. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Cash and Cash Equivalents. Cash and cash equivalents at December 31, 2008 consisted primarily of highly liquid money market mutual funds that consist of U.S. government securities and demand deposits with financial institutions. The mutual funds are available to us upon demand and have insignificant interest rate risk. The majority of cash and cash equivalents was concentrated in four mutual funds at four different institutions at December 31, 2008. Accounts payable at December 31, 2008 and 2007 includes $19.1 million and $5.8 million, respectively, representing outstanding checks that had not been presented for payment.

Restricted Cash. Restricted cash at December 31, 2007 consists of certain amounts payable to former Pogo Producing Company ("Pogo") executives, which were paid in 2008.

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, 2008	December 31, 2007
Oil	$ 6,689	$ 6,066
Materials and supplies	16,679	12,328
	$ 23,368	$ 18,394

Federal and State Income Taxes. Income taxes are accounted for in accordance with SFAS 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.

We also account for income taxes in accordance with Financial Accounting Standards Board ("FASB") Interpretation No. 48 "Accounting for Uncertainty in Income Taxes (an interpretation of FASB Statement No. 109)" ("FIN 48"). This interpretation clarifies the accounting for uncertainty in income taxes recognized in the financial statements by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. Under FIN 48, the tax benefit from an uncertain tax position is to be recognized when it is more likely than not, based on the technical merits of the position, that the position will be sustained on examination by the taxing authorities. Additionally, the amount of the tax benefit to be recognized is the largest amount of benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods, and financial statement disclosures. We recognize potential penalties and interest related to unrecognized tax benefits as a component of income tax expense. See Note 11.

Revenue Recognition. Oil and gas revenue from our interests in producing wells is recognized when the production is delivered and the title transfers. We follow the sales method of accounting for gas imbalances. If our sales of production volumes for a well exceed our portion of the estimated remaining recoverable reserves of the well, a liability is recorded. No receivables are recorded for those wells on which we have taken less than our ownership share of production.

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, 2008, our derivative instruments consisted of crude oil put option contracts and swaps and natural gas collars 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"). The Company presents the fair value of its derivatives on a net basis in accordance with FASB Interpretation No. 39 "Offsetting of Amounts Related to Certain Contracts an interpretation of APB Opinion No. 10 and FASB Statement No. 105" ("FIN 39"). See Note 5.

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. At December 31, 2008, goodwill totaled $535 million and represented approximately 8% 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; instead it is tested at least annually for impairment at a level of reporting referred to as a reporting unit. Impairment occurs 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 goodwill impairment loss to be recognized, if any. The first step of the goodwill impairment test compares the fair value of the reporting unit with its carrying amount, including goodwill. If the fair value of the reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not to be 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 the reporting unit's goodwill with the carrying amount of that goodwill. If the carrying amount of that reporting unit's 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 producing properties 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 should be used as the basis for the fair value measurement, if available. Accordingly, we use the quoted market price of our common stock as a starting point in determining the fair value of our reporting unit.

We perform our goodwill impairment test annually on December 31 and have recorded no impairments to goodwill based on such tests. We also perform interim impairment tests if events occur or circumstances change that would indicate that the fair value of our reporting unit could be below its carrying amount. Due to the adverse market conditions that had a pervasive impact on the U.S. business climate in the third quarter of 2008, we performed an interim goodwill impairment test as of September 30, 2008. In determining the fair value of our reporting unit in the first step of the goodwill impairment test, we applied a control premium to the quoted market price of our common stock at September 30, 2008, and we concluded that our goodwill was not impaired as of that date. We determined the control premium through reference to control premiums in acquisition transactions for our industry and other comparable industries.

Market conditions continued to deteriorate and our common stock price continued to decline in the fourth quarter of 2008. The carrying value of our reporting unit, which is equivalent to our book equity, also declined significantly from $3.9 billion at September 30, 2008 to $2.4 billion at December 31, 2008 due primarily to the $3.6 billion non-cash pre-tax impairment charge that we recorded in the fourth quarter of 2008. See Note 2. As a result, we did not have an impairment of goodwill when we performed step one of our annual impairment test as of December 31, 2008. In determining the fair value of our reporting unit in the first step of the goodwill impairment test, we applied a control premium to the quoted market price of our common stock at December 31, 2008. We determined the control premium through reference to control premiums in recent acquisition transactions for our industry and other comparable industries. If the price of our common stock declines, we could have an impairment of our goodwill in future periods.

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.

In 2007, we recorded $383.7 million of goodwill in connection with our acquisition of Pogo, which was decreased by $1.5 million during 2008 when the purchase accounting was finalized. In 2007, goodwill decreased by $4.6 million, as a result of a change in the tax basis related to our 2004 acquisition of Nuevo Energy Company ("Nuevo").

Business Segment Information. SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information" ("SFAS 131") establishes standards for reporting information about operating segments. We acquire, develop, explore for and produce oil and gas primarily in the United States. Our corporate management team administers all properties as a whole rather than as discrete operating segments. We allocate capital resources on a project-by-project basis across our entire asset base to maximize profitability and measure financial performance as a single enterprise and not on an area-by-area basis. Accordingly, we have one operating segment, our oil and gas operations. Our international activities currently consist of an exploration prospect offshore Vietnam that has no proved reserves, oil and gas production or sales. Capitalized costs consisted of $15.4 million of costs not subject to amortization as of December 31, 2008. Accordingly, no geographic data is presented for our international operations.

Stock Based Compensation. Our stock based compensation is accounted for under SFAS No. 123R, "Share-Based Payment" ("SFAS 123R"), which requires that the compensation cost relating to share-based payment transactions be recognized in the financial statements. That cost is measured based on the fair value of the equity and liability awards issued. See Note 9.

Pension and Other Post-Retirement Benefits. As a result of our acquisition of Pogo, we recorded assets and liabilities for a defined benefit pension plan and other post-retirement benefits. We account for the pension plan under SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an Amendment of FASB Statements No. 87, 88, 106 and 132(R)" ("SFAS 158"). Under SFAS 158, we record an asset or liability for pension and other postretirement benefit plans based on their overfunded or underfunded status. Any deferred amounts related to unrealized gains and losses or changes in actuarial assumptions are recorded in accumulated other comprehensive income (loss), a component of stockholders' equity, until those gains and losses are recognized in the income statement. See Note 10.

Recent Accounting Pronouncements. In December 2007, the FASB issued SFAS No. 141 (revised 2007), "Business Combinations" ("SFAS 141R"). SFAS 141R broadens the guidance of SFAS 141, extending its applicability to all transactions and other events in which one entity obtains control over one or more other businesses. It broadens the fair value measurement and recognition of assets acquired, liabilities assumed, and interests transferred as a result of business combinations and requires that acquisition-related costs incurred prior to the acquisition be expensed. SFAS 141R also expands the definition of what qualifies as a business, and this expanded definition could include prospective oil and gas property acquisitions. This could require us to expense transaction costs for future oil and natural gas property purchases that we have historically capitalized. Additionally, SFAS 141R expands the required disclosures to improve the statement users' abilities to evaluate the nature and financial effects of business combinations. SFAS 141R is effective for business combinations for which the acquisition date is on or after January 1, 2009, except for certain income tax effects related to prior business combinations for which FAS 141R is now effective.

In December 2008, the SEC issued a final rule, Modernization of Oil and Gas Reporting which is effective January 1, 2010 for reporting 2009 reserve information. The new disclosure requirements permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. The new disclosure requirements also require companies to include nontraditional resources such as oil sands, shale, coalbeds or other nonrenewable natural resources in reserves if they are intended to be upgraded to synthetic oil and gas. Currently the SEC requires that reserve volumes are determined using prices on the last day of the reporting period; however, the new disclosure requirements provide for reporting oil and gas reserves using an average price based upon the prior twelve month period rather than year-end prices. The new requirements also will allow companies to disclose their probable and possible reserves to investors. The new disclosure requirements also require companies to report the independence and qualifications of a reserves preparer or auditor. We will adopt the provisions of the final rule in connection with our December 31, 2009 Form 10-K filing. We are currently evaluating the impact of the final rule.

Note 2 — Impairment of Oil and Gas Properties

At December 31, 2008 the capitalized costs of our proved oil and gas properties, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceeded the ceiling under the full cost method of accounting for our oil and gas properties.

The reduction in proved reserves in 2008 is primarily due to the reduction in average year-end realized prices for oil and gas. Differentials for our California oil production increased significantly at the end of the 2008, which reduced our realized price. At December 31, 2008, our capitalized costs of proved oil and gas properties exceeded the ceiling and we recorded a non-cash pre-tax impairment charge of $3.6 billion. We may be required to recognize additional non-cash pre-tax impairment charges in future reporting periods if market prices for oil and natural gas continue to decline.

Note 3 — Acquisitions

Chesapeake Joint Venture

In July 2008, we acquired from a subsidiary of Chesapeake Energy Corporation ("Chesapeake") a 20% interest in Chesapeake's Haynesville Shale leasehold for approximately $1.65 billion in cash. We funded the acquisition with borrowings under our senior revolving credit facility. In connection with the acquisition, we also agreed, over a multi-year period, to fund 50% of Chesapeake's drilling and completion costs associated with future Haynesville Shale wells, up to an additional $1.65 billion. In addition, we will have the option to participate for 20% of any additional leasehold that Chesapeake, or its affiliates, acquires in the Haynesville Shale within a designated area of mutual interest. We currently hold 111,000 net acres in the Haynesville Shale. At the acquisition date, there were no material proved reserves associated with the leasehold interests acquired.

In February 2009, PXP and Chesapeake entered into certain amended agreements which, among other matters, provides us without additional monetary consideration by us a one time option, exercisable on or before June 30, 2010, to reduce our obligation to pay 50% of Chesapeake's drilling and completion costs by $800 million in exchange for an assignment to Chesapeake, effective December 31, 2010, of 50% of all of our interest in the Haynesville properties.

South Texas Properties

In April 2008, we completed the acquisition of oil and gas producing properties in South Texas from a private company. After the exercise of third party preferential rights, we paid approximately $282 million in cash. We funded the acquisition primarily with proceeds from recently completed divestments through the use of a tax deferred like-kind exchange. See Note 4. The effective date of the transaction was January 1, 2008.

Pogo Producing Company

In November 2007, we acquired Pogo in a stock and cash transaction (the "Pogo acquisition"). We paid cash consideration of approximately $1.5 billion and issued approximately 40 million common shares valued at approximately $2.0 billion. In addition, we paid cash consideration of $35.4 million to redeem outstanding stock options. The total purchase price includes $154.2 million of merger costs. These costs include Pogo executive management severance, investment banking fees, legal and accounting fees, seismic transfer fees, printing expenses and other merger-related costs. The cash portion of the purchase price was funded by borrowings under our senior revolving credit facility.

The acquisition was accounted for under the purchase method of accounting and Pogo's results of operations were included in our consolidated statement of income effective November 6, 2007. The assets and liabilities of Pogo were recorded at their fair values. The calculation of the purchase price and the allocation to assets and liabilities as of November 6, 2007 is shown below. The purchase price allocation was finalized in the second quarter 2008. The average PXP common stock price is based on the average closing price of PXP common stock during the five business days commencing two days before the merger was announced.

		(thousands except shares and share price)
Shares of PXP common stock issued		40,062,560
Average PXP stock price	$	49.81
Fair value of PXP common stock to be issued	$	1,995,516
Cash payment to stockholders		1,461,604
Cash payment to option holders		35,382
Merger expenses		154,157
Total estimated purchase price before liabilities assumed		3,646,659
Fair value of liabilities:		
Current liabilities		258,044
Long-term debt		1,291,977
Asset retirement obligation		49,974
Deferred income tax liabilities, net		1,222,649
Other noncurrent liabilities		33,388
Total estimated purchase price plus liabilities assumed	$	6,502,691
Fair value of assets acquired:		
Cash and cash equivalents	$	1,276,699
Other current assets		146,573
Oil and gas properties		
Subject to amortization		3,361,710
Not subject to amortization		1,333,130
Other non-current assets		2,376
Goodwill		382,203
Total assets	$	6,502,691

The significant factors contributing to the recognition of goodwill included, but were not limited to, providing the Company with greater financial flexibility with access to lower cost of capital and higher returns from cost synergies, having increased opportunities from a broader and more diversified reserve base and the ability to acquire an established business with an assembled workforce. In addition, we recorded goodwill due to the application of purchase accounting rules that require deferred taxes be recorded at undiscounted amounts. Goodwill is not deductible for income tax purposes.

Piceance Basin Properties

Piceance Acquisition. In May 2007, we acquired certain properties located in the Piceance Basin (the "Piceance acquisition") for $975 million in cash, including $10 million in related acquisition costs and $65 million for net cash outflows from the effective date to the closing date (primarily related to capital expenditures for drilling and acreage acquisitions) and issued one million shares of common stock with a fair value of approximately $45 million to the seller. The Piceance acquisition included interests in oil and gas producing properties in the Mesaverde geologic section of the Piceance Basin in Colorado, plus associated midstream assets, including a 25% interest in Collbran Valley Gas Gathering LLC ("CVGG"). We allocated the purchase price as follows: $518 million to oil and gas properties subject to amortization, $448 million to oil and gas properties not subject to amortization, $40 million to our investment in CVGG and the remainder to inventory and other properties and equipment. We financed the acquisition using our senior revolving credit facility.

Piceance Basin Expansion. In June 2008, PXP and a subsidiary of Occidental Petroleum Corporation ("Oxy") acquired equal shares of working interests in acreage immediately adjacent to our existing Piceance Basin assets from a third party. PXP and Oxy agreed to pay an aggregate of $158.6 million for a 95% working interest in approximately 11,500 net acres. Under the terms of the acquisition agreement, PXP paid approximately $20.3 million on June 27, 2008, with the remaining balance payable in equal amounts of approximately $20.3 million on July 1, 2009 and July 1, 2010 and approximately $18.5 million on July 1, 2011.

In February 2008, we sold 50% of our interest in the oil and gas properties acquired in the Piceance acquisition in May 2007 and in December 2008, we sold our remaining interest in the oil and gas properties acquired in the Piceance Basin acquisition in May 2007 and our interest in the Piceance Basin expansion. See Note 4. Oxy assumed our obligation for the unpaid consideration for the Piceance Basin expansion in connection with the sale.

Unaudited Pro Forma Information

The following unaudited pro forma information shows the pro forma effect of the Pogo acquisition, the Piceance acquisition, the issuance by PXP of $500 million of 7% Senior Notes due 2017, the issuance by PXP of $600 million of 7.75% Senior Notes due 2015, $2.0 billion of borrowings under the revolving credit facility, and the retirement of Pogo's $450 million 7.875% Senior Subordinated Notes due 2013, $300 million 6.625% Senior Subordinated Notes due 2015, and $500 million 6.875% Senior Subordinated Notes. We believe the assumptions used provide a reasonable basis for presenting the pro forma significant effects directly attributable to the Pogo and Piceance Basin properties acquisitions. This unaudited pro forma information assumes such transactions occurred on January 1 of the years presented. 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 dates.

	Year Ended December 31,	
	2007	**2006**
	(in thousands, except per share data) (unaudited)	
Revenues	$ 2,022,599	$ 1,664,017
Income from operations	396,841	1,397,500
Income from continuing operations	74,422	702,118
Net income	74,422	702,118
Basic and diluted earnings per share		
Basic		
Income from continuing operations	$ 0.66	$ 5.94
Net income	0.66	5.94
Diluted		
Income from continuing operations	0.65	5.89
Net income	0.65	5.89
Weighted average shares outstanding		
Basic	113,066	118,273
Diluted	114,247	119,234

Pro forma results for 2006 include the $983.0 million gain on the sale of oil and gas properties, the $45.1 million charge for debt extinguishment and the $37.9 million gain on termination of merger agreement.

Note 4 — Divestments

In December 2008, we closed the sale of certain oil and gas properties to a subsidiary of Oxy and certain other companies with contractual preferential purchase rights, with an effective date of

December 1, 2008, and received approximately $1.25 billion in gross cash proceeds, or $1.24 billion after preliminary closing adjustments. We sold the remaining 50% of our working interests in oil and gas properties located in the Permian Basin, West Texas and New Mexico, which we acquired in the Pogo acquisition in November 2007. (See Note 3 – "Acquisitions, Pogo Producing Company"). We also sold the remaining 50% of our working interests in oil and gas properties located in the Piceance Basin in Colorado, including a 50% interest in the entity that held our interest in CVGG. We acquired these properties in May 2007. The sale also included our interest in approximately 11,500 net undeveloped acres adjacent to our Piceance Basin assets that we and Oxy jointly acquired from a third party in June 2008. (See Note 3 – "Acquisitions, Piceance Basin Properties, Piceance Basin Expansion"). We recorded a $35.1 million pretax gain on the sale of the 50% interest in the entity that held our interest in CVGG.

In February 2008, we closed the sale of certain oil and gas properties to a subsidiary of Oxy and certain other companies with contractual preferential purchase rights, with an effective date of January 1, 2008, and received approximately $1.53 billion in cash proceeds. We sold 50% of our working interests in oil and gas properties located in the Permian Basin, West Texas and New Mexico. We acquired the above referenced properties in the Pogo acquisition in November 2007 (See Note 3 – "Acquisitions, Pogo Producing Company"). We also sold 50% of our working interests in oil and gas properties located in the Piceance Basin in Colorado, including a 50% interest in the entity that held our interest in CVGG. We acquired these properties in May 2007 (See Note 3 – "Acquisitions, Piceance Basin Properties, Piceance Basin Acquisition"). We recorded a $34.7 million pretax gain on the sale of the 50% interest in the entity that held our interest in CVGG.

In February 2008, we closed the sale to XTO Energy Inc. ("XTO") of certain oil and gas properties located in the San Juan Basin in New Mexico and in the Barnett Shale in Texas. This transaction had an effective date of January 1, 2008, and we received $199.0 million in cash proceeds.

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 result in a significant change in the relationship between capitalized costs and proved reserves, in which case a gain or loss is recognized. The proceeds from the 2008 sales of oil and gas properties were recorded as reductions to capitalized costs because the sales did not cause a significant change in the relationship between capitalized costs and estimated proved reserves.

In November 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 caused a significant change in the relationship between capitalized costs and proved reserves. With respect to the sale of properties to Statoil, capitalized costs consisted of the costs of the prospects that were classified as costs not subject to amortization.

In September 2006, we closed the sale of oil and gas properties located primarily in California and Texas to subsidiaries of Oxy. 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 resulted in a significant change in the relationship between capitalized costs and proved reserves. 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 September 29, 2006 sale of properties to Oxy, 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.

Note 5 — Derivative Instruments

General

We are exposed to various market risks, including volatility in oil and gas commodity prices, interest rates and foreign currency. The level of derivative activity depends on our view of market conditions, available derivative prices and operating strategy. We use various derivative instruments to manage our exposure to commodity price risk on sales of oil and gas production. Currently, we do not use derivatives to manage our interest rate or foreign currency risk. The interest rate on our senior revolving credit facility is variable, while our senior notes are at fixed interest rates, thereby mitigating our interest rate risk exposure. Our foreign currency risk in Vietnam has been minimal due to the size of our operations.

A variety of derivative instruments may be utilized to manage our exposure to the volatility of oil and gas commodity prices such as swaps, collars, puts, calls and various combinations of these. The type of instrument we select is a function of market conditions, available derivative prices and our operating strategy.

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. We do not currently use hedge accounting for our derivative instruments.

Under SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" ("SFAS 149"), certain of our derivatives were deemed to contain a significant financing element. 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 not accounted for under hedge accounting and do not have a significant financing element are reflected as investing activities in the Statement of Cash Flows.

For put options, we pay a premium to the counterparty in exchange for the sale of a put option. If the index price is below the strike price of the put option, we receive the difference between the strike price and the index price less the premium and interest. If the market price settles at or above the strike price of the put option, we pay only the option premium and interest.

In a typical collar transaction, if the floating price based on a market index is below the floor price in the derivative agreement, we receive from the counterparty this difference multiplied by the specified quantity. If the floating price exceeds the floor price and is less than the ceiling price, no payment is required by either party. If the floating price exceeds the ceiling price, we must pay the counterparty the difference multiplied by the specified quantity. If we have less production than the volumes we have specified under the collar transaction when the floating price exceeds the ceiling price, we must make payments against which there is no offsetting revenues from production.

As of December 31, 2008, we had the following outstanding commodity derivative contracts that were not designated as hedging instruments:

Period	Instrument Type	Daily Volumes	Average Price(1)	Deferred Premium	Index	Settlement
Sales of Crude Oil Production						
2009						
Jan - Dec	Put options	32,500 Bbls	\$55.00 Strike price	\$3.38 per Bbl	WTI	Monthly
Jan - Dec	Put options	40,000 Bbls	\$106.16 Strike price	\$8.10 per Bbl	WTI	Monthly
Jan - Dec	Swap contracts	20,000 Bbls	Pay: \$53.71 (fixed price)	none	WTI	Monthly
			Receive: Average monthly settlement price (floating)		WTI	
2010						
Jan - Dec	Put options	40,000 Bbls	\$111.49 Strike price	\$12.08 per Bbl	WTI	Annual
Sales of Natural Gas Production						
2009						
Jan - Dec	Collar	150,000 MMBtu	\$10.00 Floor - \$20.00 Ceiling	\$0.346 per MMBtu	Henry Hub	Monthly

(1) The average strike prices do not reflect the cost to purchase the put options or collars.

In the fourth quarter of 2008, we locked in approximately \$324 million in value on half (20,000 barrels) of our 2009 \$106.16 crude oil puts (40,000 BOPD), regardless of the average NYMEX West Texas Intermediate ("WTI") crude oil monthly settlement price in 2009. This was accomplished by entering into crude oil swap contracts for 20,000 BOPD. Under the swap contracts, we agreed to pay a weighted average fixed price of \$53.71 per barrel of oil, and the counterparties agreed to pay a floating price per barrel based on the average NYMEX WTI crude oil monthly settlement price. In addition, we accelerated the cash flow due to us by converting the annual settlement of the \$106.16 crude oil puts, which would have settled in January of 2010, to a monthly settlement during 2009. In return for the conversion, we agreed to a weighted average increase in deferred premiums plus interest of \$1.91 per barrel or a total of \$8.10 per barrel.

In the first quarter of 2009, we monetized our 2009 and 2010 crude oil put option contracts on 40,000 BOPD with weighted average strike prices of \$106.16 per barrel and \$111.49 per barrel, respectively. In addition, we also terminated our crude oil swaps for 20,000 BOPD in 2009. As a result of this monetization, we received \$389 million in net proceeds on February 20, 2009 and will receive approximately \$711 million in net proceeds in March 2009, which we will use to reduce the outstanding balance on our senior revolving credit facility. In 2009 we have also entered into crude oil put option contracts on 40,000 BOPD in 2010. These put options have a strike price of \$55 per barrel, a \$3.86 per barrel upfront payment, which has been deducted from the total proceeds expected to be received from the monetization, and a deferred put premium plus interest of \$5 per barrel. We have retained our put options on 32,500 BOPD with a \$55 strike price in 2009. Additionally, in a separate transaction, we acquired natural gas three way collars on 40,000 million British thermal units (MMbtu) per day for 2010. Under this arrangement, if the index price is below the floor price of \$6.25 per MMbtu, we receive the difference between \$6.25 and the index price up to a maximum of \$1.45 per MMbtu. If the index price is greater than the ceiling price of \$8.00 per MMbtu, we pay the difference between the index price and \$8.00 per MMbtu.

Balance Sheet

At December 31, 2008 and 2007, the fair value of our commodity derivatives consisted of the following (in thousands):

	December 31, 2008	December 31, 2007
Commodity derivative assets:		
Crude oil puts	$ 1,575,327	$ 3,786
Crude oil swaps	5,124	-
Natural gas collars	215,391	4,378
Commodity derivative liabilities:		
Natural gas collars	-	(13,314)
Net derivative fair value asset (liability)	$ 1,795,842	$ (5,150)

At December 31, 2008 and 2007, commodity derivative assets and liabilities consisted of the following (in thousands):

	December 31, 2008	December 31, 2007
Net fair value asset (liability)	$ 1,795,842	$ (5,150)
Deferred premium and accrued interest on puts and collars	(333,156)	(93,902)
Settlement receivable (payable)	13,333	(12,521)
Net commodity derivative asset (liability)	$ 1,476,019	$ (111,573)
Short-term commodity derivative asset	$ 945,838	$ 2,186
Long-term commodity derivative asset	530,181	-
Short-term commodity derivative liability	-	(79,938)
Long-term commodity derivative liability	-	(33,821)
	$ 1,476,019	$ (111,573)

The counterparties for our commodity derivative contracts consist of six financial institutions. Our counterparties to our derivative agreements or their affiliates are generally also lenders under our senior revolving credit facility. As a result, the counterparties to our derivative agreements share in the collateral supporting our revolving credit facility. Therefore, we are not generally required to post additional collateral under our derivative agreements.

Income Statement

During the years ended December 31, 2008, 2007 and 2006, pre-tax amounts recognized in our income statement for derivatives were as follows (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Gain (loss) on mark-to-market derivative contracts	$ 1,555,917	$ (88,549)	$ (297,503)
Gain (loss) reclassified from OCI and recognized in:			
Oil revenues	-	-	(145,755)

Cash Payments and Receipts

During the years ended December 31, 2008, 2007 and 2006, cash receipts (payments) for derivatives were as follows (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Mark-to-market contracts			
Oil sales	$ (81,447)	$(103,784)	$(89,596)
Gas sales	47,163	235	-
Gas purchases	-	-	(11,425)
Elimination of crude oil collars	-	-	(593,283)

Elimination of 2006, 2007 and 2008 Swap and Collar Positions

During 2006, we paid $593.3 million to eliminate 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 were recognized in our income statement in 2006 and $423 million in prior periods.

Contingent Features

Certain of our derivative counterparty agreements contain provisions that require cross defaults and acceleration of those instruments to any material debt. If we were to default on any of our material debt agreements, it would be a violation of these provisions, and the counterparties to the derivative instruments could request immediate payment on derivative instruments that are in a net liability position on December 31, 2008. As of December 31, 2008 we are in a net asset position with all of the counterparties to our derivative instruments.

Note 6 — Fair Value Measurements of Assets and Liabilities

Effective January 1, 2008, we adopted SFAS No. 157 "Fair Value Measurements" ("SFAS 157"). SFAS 157 defines fair value, establishes a framework for measuring fair value and expands the related disclosure requirements. SFAS 157 does not require any new fair value measurements but may require some entities to change their measurement practices. Pursuant to SFAS 157, we have revised our fair value calculations to consider our credit quality and the credit quality of our counterparties.

As defined in SFAS 157, fair value is the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date ("exit price"). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. SFAS 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities ("Level 1") and the lowest priority to unobservable inputs ("Level 3"). The three levels of fair value under SFAS 157 are as follows:

- Level 1 – Quoted, unadjusted prices for assets or liabilities in active markets for identical assets or liabilities as of the reporting date.

- Level 2 – Market-based inputs that are directly or indirectly observable but not considered Level 1 quoted prices, including quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; or valuation techniques whose inputs are observable. Where observable inputs are available, directly or indirectly, for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

- Level 3 – Valuation techniques whose significant inputs are unobservable.

A financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement.

We estimate the fair values of our derivative instruments, including crude oil put options, crude oil swaps and natural gas collars using an option-pricing model. The option-pricing model uses various inputs including NYMEX price quotations, volatilities, interest rates and contract terms. We adjust the valuations from the model for credit quality, using the counterparty's credit quality for asset balances and our credit quality for liability balances. We use the credit default swap value for counterparties, when available, or the spread between the risk-free interest rates and the yield on the counterparty's publicly-traded debt for similar maturities. We consider the impact of netting agreements on counterparty credit risk, including whether the position with the counterparty is a net asset or net liability.

We classify our derivatives as Level 2 if the inputs used in the valuation model are directly or indirectly observable as described above; however, if the significant inputs are not observable, we classify those derivatives as Level 3. For our derivatives classified as Level 3, certain inputs that were significant to the overall fair value measurement were not observable for substantially the full term of the instrument. For these inputs, we utilize pricing and volatility information from other instruments with similar characteristics. Our crude oil put options and our natural gas collars are classified as Level 3 instruments.

The following table presents, for each fair value hierarchy level, our commodity derivative assets related to continuing operations which are measured at fair value on a recurring basis as of December 31, 2008 (in thousands):

		Fair Value Measurements at Reporting Date Using:		
	Fair Value (1)	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Commodity derivative assets	$ 1,795,842	$ -	$ 5,124	$ 1,790,718

(1) Option premium, interest and settlement receivable are not included in the fair value of derivatives.

The following table presents a reconciliation of changes in fair value of financial assets and liabilities classified as Level 3 (in thousands):

	Commodity Derivative Contracts (1)
Fair value at January 1, 2008	$ -
Realized and unrealized gains included in earnings	1,544,873
Purchases and settlements	242,416
Transfers (2)	3,429
Fair value at December 31, 2008	$ 1,790,718
Realized and unrealized gains included in earnings related to financial assets and liabilities on the Consolidated Balance Sheet as of December 31, 2008 (3)	$ 1,544,873
Change in unrealized gains and losses relating to assets and liabilities still held as of December 31, 2008 (3)	$ 1,499,370

(1) Deferred option premiums and interest are not included in the fair value of derivatives.

(2) Our $55 crude put options were classified as Level 2 through the first three quarters of 2008 because the inputs used to value such instruments were directly or indirectly observable. In the fourth quarter of 2008, certain inputs that were significant to the overall fair value were not observable for substantially the full term of the instrument.

(3) Realized and unrealized gains and losses included in earnings for the period are reported as gain (loss) on mark-to-market derivative contracts in our Consolidated Statements of Income.

In November 2007, the FASB agreed to a one-year deferral of SFAS 157 fair value measurement requirements for nonfinancial assets and liabilities that are not required or permitted to be measured at fair value on a recurring basis. In February 2008, the FASB issued FASB Staff Position ("FSP") SFAS 157-2 "Effective date of SFAS 157." This FSP defers the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 and interim periods within those fiscal years for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). We have elected to utilize this deferral and have only partially applied SFAS 157 (to financial assets and liabilities measured at fair value on a recurring basis, as described above). Accordingly, we will apply SFAS 157 to our nonfinancial assets and liabilities, which we disclose or recognize at fair value on a nonrecurring basis, such as asset retirement obligations, goodwill impairment and other assets and liabilities, in the first quarter of 2009. We do not expect that the application of SFAS 157 to our nonfinancial assets and liabilities, which we disclose or recognize at fair value on a nonrecurring basis will have a significant impact on our consolidated financial position, results of operations or cash flows.

In October 2008, the FASB issued FSP SFAS 157-3. This FSP clarifies the application of SFAS 157 in a market that is not active and provides for an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. We determined whether the market for our derivative instruments was active or inactive based on transaction volume for such instruments and classified those instruments that we determined were not actively traded as Level 3 instruments. We value these Level 3 instruments using similar instruments and extrapolating data between data points for thinly traded instruments. This FSP was effective upon issuance, including prior periods for which financial statements have not been issued. The adoption of FSP SFAS 157-3 did not have a significant impact on our consolidated financial position, results of operations or cash flows.

We adopted SFAS No. 159 "The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of SFAS No. 115" ("SFAS 159") on January 1, 2008. SFAS 159 permits companies to choose to measure financial instruments and certain other items at fair value that were not previously required to be measured at fair value. We have elected not to present assets and liabilities at fair value that were not required to be measured at fair value prior to the adoption of SFAS 159.

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of SFAS 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; however certain of our derivative financial instruments have a deferred premium, including our crude oil puts and natural gas collars. We offset the fair value of the derivative financial instrument by the amount of deferred premium in accordance with FIN 39. The carrying amounts and fair values of our other financial instruments are as follows (in thousands):

	December 31, 2008		December 31, 2007	
	Carrying Amount	Fair Value (1)	Carrying Amount	Fair Value
Current Liability				
Deferred premium on derivative contracts	$ 170,189	$ 170,189	$ 56,652	$ 56,652
Non-Current Liability				
Deferred premium on derivative contracts	162,967	162,967	37,250	37,250
Long-Term Debt				
Senior revolving credit facility	1,305,000	1,125,945	2,205,000	2,205,000
7% Senior Notes	500,000	342,500	500,000	478,150
7¾% Senior Notes	600,000	453,000	600,000	600,000
7⅝% Senior Notes	400,000	274,000	-	-

(1) The fair value disclosure at December 31, 2008 was prepared under the provisions of FAS 157.

The fair value of our senior revolving credit facility at December 31, 2008 is based on rates currently available for debt instruments with similar terms and average maturities from companies with similar credit ratings in our industry. The fair value of the Senior Notes is based on quoted market prices based on trades of such debt.

Note 7 — Asset Retirement Obligation

The following table reflects the changes in our asset retirement obligation during the years ended December 31, 2008, 2007 and 2006 (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Asset retirement obligation - beginning of period	$ 195,408	$ 137,311	$ 160,955
Liabilities incurred in acquisitions	1,697	54,349	-
Property dispositions and other	(29,236)	-	(30,506)
Settlements	(6,907)	(2,396)	(2,886)
Change in estimate	(7,571)	(6,900)	(3,134)
Accretion expense	13,036	9,800	9,609
Asset retirement additions	3,382	3,244	3,273
Asset retirement obligation - end of period (1)	$ 169,809	$ 195,408	$ 137,311

(1) $10.3 million and $11.3 million included in other current liabilities at December 31, 2008 and 2007, respectively.

Note 8 — Long-Term Debt

At December 31, 2008 and 2007, long-term debt consisted of (in thousands):

	December 31,	
	2008	2007
Senior revolving credit facility . . .	$ 1,305,000	$ 2,205,000
7¾% Senior Notes	600,000	600,000
7% Senior Notes	500,000	500,000
7⅝% Senior Notes	400,000	-
	$ 2,805,000	$ 3,305,000

Aggregate total maturities of long-term debt in the next five years are $1.3 billion in 2012.

Senior Revolving Credit Facility. During 2008, the borrowing base and commitments under our senior revolving credit facility were adjusted as a result of oil and gas property acquisitions and divestitures and the completion of the offering of $400 million of 7⅝% senior notes due 2018 (the "7⅝% Senior Notes"). Additionally, in February 2008, we entered into an amendment to our senior revolving credit facility which allows us to repurchase up to $1.0 billion of our common stock, subject to certain conditions being met. As of December 31, 2008, our senior revolving credit facility provides for a borrowing base of $2.7 billion and aggregate commitments of the lenders of $2.3 billion. The borrowing base will be redetermined on an annual basis, with PXP and the lenders each having the right to one annual interim unscheduled redetermination, and adjusted based on PXP's oil and gas properties, reserves, other indebtedness and other relevant factors. Additionally, our senior revolving credit facility contains a $250 million sub-limit on letters of credit, a $50 million commitment for swingline loans, and matures on November 6, 2012. Collateral consists of 100% of the shares of stock in certain of our domestic and 65% of certain foreign subsidiaries and mortgages covering at least 75% of the total present value of our domestic oil and gas properties. At December 31, 2008, we had $0.7 million in letters of credit outstanding under our senior revolving credit facility.

Amounts borrowed under our senior revolving credit facility 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%; (ii) the greater of (1) the prime rate, as determined by JPMorgan Chase Bank and (2) the federal funds rate, plus ½ of 1%, plus an additional variable amount ranging from 0% to 0.25% for each of (1) and (2) above; and (iii) the over-night federal funds rate plus an additional variable amount ranging from 1.00% to 1.75% for swingline loans. 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 our senior revolving credit facility to the conforming borrowing base and (2) our long-term debt ratings. Commitment fees and letter of credit fees under our senior revolving credit facility are based on the utilization rate and our long-term debt rating. Commitment fees range from 0.225% to 0.375% of the amount available for borrowing. Letter of credit fees range from 1.0% 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 our senior revolving credit facility was 3.149% at December 31, 2008.

Our senior revolving credit facility, as amended, contains negative covenants that limit our ability, as well as the ability of our restricted subsidiaries to, among other things, 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 take-or-pay or other prepayment arrangements, merge or consolidate and enter into transactions with affiliates. In addition, we are required to maintain a ratio of debt to EBITDAX (as defined) of no greater than 4.25 to 1.

Short-term Credit Facility. We have an uncommitted short-term unsecured credit facility under the terms of which we may make borrowings from time to time until June 1, 2009, not to exceed at any time the maximum principal amount of $75.0 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 June 1, 2009. Each advance under the short-term facility shall bear interest at a rate per annum mutually agreed on by the bank and PXP. No amounts were outstanding under the short-term credit facility at December 31, 2008.

7⅝% Senior Notes. In May 2008, we issued $400.0 million of 7⅝% Senior Notes due 2018 at par. We may redeem all or part of the 7⅝% Senior Notes on or after June 1, 2013 at specified redemption prices and prior to such date at a "make-whole" redemption price. In addition, prior to June 1, 2011 we may, at our option, redeem up to 35% of the 7⅝% Senior Notes with the proceeds of certain equity offerings. In the event of a change of control, as defined in the indenture, we will be required to make an offer to repurchase the 7⅝% Senior Notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of repurchase. We used the proceeds of this offering to reduce debt under our senior revolving credit facility.

7¾% Senior Notes. In June 2007, we issued $600.0 million principal amount of 7¾% Senior Notes due 2015 (the "7¾% Senior Notes") at par. We may redeem all or part of the 7¾% Senior Notes on or after June 15, 2011 at specified redemption prices and prior to such date at a "make-whole" redemption price. In addition, prior to June 15, 2010 we may, at our option, redeem up to 35% of the 7¾% Senior Notes with the proceeds from certain equity offerings. In the event of a change of control, as defined in the indenture, we will be required to make an offer to repurchase the 7¾% Senior Notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of the repurchase.

7% Senior Notes. In March 2007, we issued $500.0 million principal amount of 7% Senior Notes due 2017 (the "7% Senior Notes") at par. We may redeem all or part of the 7% Senior Notes on or after March 15, 2012 at specified redemption prices and prior to such date at a "make-whole" redemption price. In addition, prior to March 15, 2010 we may, at our option, redeem up to 35% of the 7% Senior Notes with the proceeds from certain equity offerings. In the event of a change of control, as defined in the indenture, we will be required to make an offer to repurchase the 7% Senior Notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of the repurchase.

The 7¾% Senior Notes, the 7% Senior Notes and the 7⅝% Senior Notes (together, the "Senior Notes") are our general unsecured senior obligations. The Senior Notes are jointly and severally guaranteed on a full and unconditional basis by certain of our existing domestic subsidiaries. In the future, the guarantees may be released or terminated under certain circumstances. The Senior Notes rank senior in right of payment to all of our existing and future subordinated indebtedness; *pari passu* in right of payment with any of our existing and future unsecured indebtedness that is not by its terms subordinated to the Senior Notes; effectively junior to our existing and future secured indebtedness, including indebtedness under our senior revolving credit facility, to the extent of our assets constituting collateral securing that indebtedness; and effectively subordinate to all existing and future indebtedness and other liabilities (other than indebtedness and liabilities owed to us) of our non-guarantor subsidiaries.

The indentures governing the Senior Notes contain covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to incur additional debt; make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock; sell assets, including capital stock of our restricted subsidiaries; restrict dividends or other payments by restricted subsidiaries; create liens that secure debt; enter into transactions with affiliates; and merge or consolidate with another company.

$7^1/_8$% Senior Notes. On November 3, 2006, we made payments totaling $268.6 million to retire all $250 million outstanding principal amount of our $7^1/_8$% Senior Notes due 2014. 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.

$8^3/_4$% 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 $8^3/_4$% Senior Subordinated Notes due 2012 (the "Senior Subordinated Notes"). In October 2007, we made the final payment to retire the remaining $0.1 million principal amount.

Debt Extinguishment Costs. During 2008, we recorded $18.3 million of debt extinguishment costs related to the changes in our commitments under our senior revolving credit facility. In connection with the retirement of the $7^1/_8$% Senior Notes due 2014 and the $8^3/_4$% Senior Subordinated Notes due 2012, we recorded $45.1 million of debt extinguishment costs in 2006.

Pogo Tender Offers and Consent Solicitations for Senior Subordinated Notes of Pogo Producing Company LLC. Prior to the acquisition by PXP, Pogo initiated a tender offer of 104% for the $450 million of its outstanding 7.875% Senior Subordinated Notes due 2013 (the "7.875% Senior Subordinated Notes"), of 103% for the $300 million of its outstanding 6.625% Senior Subordinated Notes due 2015 (the "6.625% Senior Subordinated Notes") and of 103% for the $500 million of its outstanding 6.875% Senior Subordinated Notes due 2017 (the "6.875% Senior Subordinated Notes"). In November and December 2007, we completed the redemption of all $450 million of outstanding 7.875% Senior Subordinated Notes, over 99% of all $500 million of outstanding 6.875% Senior Subordinated Notes and all $300 million of outstanding 6.625% Senior Subordinated Notes. The Notes were redeemed for approximately $1.3 billion, which included the tender offer purchase price and consent payments of $42.0 million plus accrued interest to November 19, 2007 of $10.4 million. The cash redemption payment was funded using available cash on hand. The remaining $0.1 million of the 6.875% Senior Subordinated Notes principal outstanding was redeemed in October 2008.

Note 9 — Stock Based and Other Compensation Plans

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 was 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 three stock incentive plans: the 2002 Stock Incentive Plan (the "2002 Plan"), which provides for a maximum of 1.5 million shares available for awards, the 2004 Stock Incentive Plan (the "2004 Plan"), which provides for a maximum of 8.4 million shares available for awards, and the 2006 Incentive Plan (the "2006 Incentive Plan"), which provides for a maximum of approximately 3.5 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, restricted stock units ("RSUs") and stock appreciation rights ("SARs")), to our directors, officers, employees, consultants and advisors. Our 2006 Plan provides for the grant of cash-only SARs and RSUs to non-officer employees. 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 SAR may be exercised more than 10 years after its grant date, 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 decide in its discretion.

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 is expensed or capitalized based on the nature of the employee's activities, and for the years ended December 31, 2008, 2007 and 2006 was (in thousands):

	Year Ended December 31,		
	2008	**2007**	**2006**
Stock based compensation included in:			
General and administrative expense	$ 51,262	$ 48,123	$ 52,196
Lease operating expenses	(861)	3,896	3,289
Oil and natural gas properties under full cost method	11,465	11,010	8,378
Total stock based compensation	$ 61,866	$ 63,029	$ 63,863

Stock based compensation charged to earnings for the years ended December 31, 2008, 2007 and 2006 was (in thousands):

	Year Ended December 31,		
	2008	**2007**	**2006**
Charged to earnings	$ 50,401	$ 52,019	$ 55,485
Tax benefit	(18,933)	(19,728)	(22,111)
	$ 31,468	$ 32,291	$ 33,374

At December 31, 2008, there is $208.8 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 5.1 years. Stock based compensation for the year ended December 31, 2006 includes $8.4 million resulting from the accelerated vesting of 0.5 million RSUs.

Estimates of fair value are not intended to predict actual future events or 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

SAR grants generally vest ratably over three years or 100% at the end of three years and expire within five 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 is based on the number of SARs ultimately expected to vest and has been reduced for estimated forfeitures.

The following table summarizes the status of our SARs at December 31, 2008 and the changes during the year then ended:

	Outstanding (thousands)	Weighted Average Exercise Price	Aggregate Intrinsic Value ($ thousands)	Weighted Average Remaining Contractural Life (Years)
Outstanding at January 1, 2008	2,767	$ 28.90		
Granted	817	49.56		
Exercised	(1,375)	13.75		
Forfeited or expired	(178)	49.30		
Outstanding at December 31, 2008	2,031	45.66	$ 410	3.1
Exercisable at December 31, 2008	587	38.69	$ 317	1.8

The total intrinsic value of SARs exercised during the years ended December 31, 2008, 2007 and 2006 was $59.1 million, $8.3 million and $17.7 million, respectively. The weighted average grant date fair value per share for SARs granted in 2008, 2007 and 2006 was $13.48, $12.42 and $10.45, respectively.

We estimate the fair value of SARs granted using the Black-Scholes valuation model. The following assumptions are as of December 31, 2008, 2007 and 2006:

	2008	2007	2006
Expected life (in years)	1 - 4	1 - 4	1 - 4
Volatility	36.5%-90.9%	27.6%-30.8%	26.8%-37.3%
Risk-free interest rate	0.4%-1.3%	3.1% - 3.5%	4.7%-5.0%
Dividend yield	0%	0%	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 expected life of the SARs granted. The expected life represents the period of time that SARs granted are expected to be outstanding. The risk-free interest 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 five 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 of our restricted stock and RSUs at December 31, 2008 and the changes during the year then ended:

	Equity Instruments (thousands)	Weighted Average Grant Date Fair Value	Aggregate Intrinsic Value ($ thousands)	Weighted Average Remaining Contractural Life (Years)
Nonvested at January 1, 2008	4,843	$ 44.73		
Granted	2,176	52.31		
Vested	(802)	42.76		
Forfeited	(53)	47.85		
Reclassified to liability instruments	(805)	53.58		
Nonvested at December 31, 2008	5,359	$ 46.73	$ 124,537	3.9

	Liability Instruments (thousands)	Weighted Average Grant Date Fair Value	Aggregate Intrinsic Value ($ thousands)	Average Remaining Contractural Life (Years)
Nonvested at January 1, 2008	-	$ -		
Reclassified from equity instruments	805	53.58		
Nonvested at December 31, 2008	805	$ 53.58	$ 18,720	12.0

The total intrinsic value of restricted stock and RSUs vested in 2008, 2007 and 2006 was $42.7 million, $26.3 million and $35.0 million, respectively. The intrinsic value was based upon the closing price of PXP'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, 2007 and 2006 was $48.43 per share and $41.40 per share, respectively.

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

The non-vested shares in the tables above include 2.3 million shares that were deemed granted in 2005 for accounting purposes 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 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 December 31, 2008, 0.9 million shares had been granted and 1.4 million shares will be granted in 2009 through 2014.

In addition, under the terms of our Long-Term Retention and Deferred Compensation Plan, annual grants may be increased if certain common stock price based performance targets are achieved. We 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 with respect to the Monte Carlo simulation model:

Expected annual return	9.80%
Expected daily return	0.04%
Daily standard deviation	2.09%

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 $46.61 per unit, an aggregate fair value of $18.7 million and a weighted average remaining contractual life of six years.

The tables above also include 1.0 million RSUs considered granted in 2008 for accounting purposes. An executive has been granted the right to receive five annual grants of 200,000 RSUs beginning in September 2015 and continuing until 2019. Each annual grant is subject to continued service by the executive. The first three annual grants will each vest in full in 2020 and the fourth and fifth annual grants will each vest ratably over a three year period from the date of the grant. Under the provisions of SFAS 123R, the grant date for accounting purposes for all 1.0 million RSUs to be granted in the future is March 2008.

At certain times a sufficient number of shares were not available for issuance under our stock compensation plans to satisfy all awards deemed granted for accounting purposes. At such times, we reclassified and account for as liability awards the number of shares deemed granted in excess of available shares.

Stock Options

At December 31, 2008, there were 38,999 stock options outstanding with an average exercise price of $8.98 per share and an average remaining life of 2.2 years. The intrinsic value of options exercised in the years ended December 31, 2008, 2007 and 2006 was $0.5 million, $0.3 million and $1.5 million, respectively, and the Company received $0.3 million, $0.1 million and $0.9 million, respectively, upon the exercise of such options.

Other

We 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 2008, 2007 and 2006 we made contributions totaling $7.0 million, $5.5 million and $4.9 million, respectively, to the 401(k) plan.

The Company has certain awards which have vested, but, at the election of the award recipients, the issuance of those common shares has been deferred. During 2008, 2007 and 2006, approximately 123,000, 63,000 and 30,000 common shares, respectively, vested and were deferred resulting in total deferred common shares of approximately 216,000 common shares at December 31, 2008. These common shares will be issued upon the earliest of the deferral date designated by the recipient, their retirement from the Company or death.

Note 10 — Pension and Post-retirement Benefits

Pension Plan

As a result of our acquisition of Pogo, we assumed responsibility for a defined benefit pension plan for former employees of Pogo ("Pogo Pension Plan"). Benefits under the plan are based on years of service and the employees' average compensation for five consecutive years within the final ten years of service which produced the highest average compensation. Upon closing the Pogo acquisition, PXP notified all employees that the Pogo Pension Plan would be frozen 45 days following notice to employees and that PXP would terminate the plan. At December 31, 2008 and 2007, the benefit obligation, fair value of the plan assets and amount the plan is over or underfunded (in thousands):

	December 31,	
	2008	2007
Benefit obligation	$ 7,105	$ 8,959
Fair value of the plan assets	5,066	10,256
Amount plan is over (under) funded	(2,039)	1,297

Expected benefit payments for 2009, the year in which the plan is expected to be terminated, are $7.1 million.

Other post-retirement benefits

As a result of the Pogo acquisition, PXP is currently providing medical coverage to an eligible group of retired Pogo U.S. employees and their eligible dependents, although the Company has no obligation to do so. The portion of the cost of this coverage being paid by PXP will be reduced over the next year with the retirees paying the full cost of their coverage at the beginning of 2010. The post-retirement medical plan has no assets, and the Company is funding it on a pay-as-you-go basis. The post-retirement benefit obligation at December 31, 2008 was $0.1 million.

Note 11 — Income Taxes

For the years ended December 31, 2008, 2007 and 2006 our income tax expense (benefit) consisted of (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Current			
U.S. Federal	$ 195,154	$ (2,158)	$ 118,659
State	35,661	(2,519)	23,719
	230,815	(4,677)	142,378
Deferred			
U.S. Federal	(613,768)	110,080	216,117
State	(61,582)	4,345	26,402
	(675,350)	114,425	242,519
	$ (444,535)	$ 109,748	$ 384,897

Our deferred income tax assets and liabilities at December 31, 2008 and 2007 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,	
	2008	2007
Deferred tax assets:		
Net operating loss	$ 38,355	$ 205,372
Tax credits	32,654	36,774
Commodity derivative contracts and other	49,391	111,296
	120,400	353,442
Deferred tax liabilities:		
Commodity derivative contracts	(551,217)	-
Net oil & gas acquisition, exploration and development costs and other	(599,065)	(2,082,980)
Net deferred tax liability	$ (1,029,882)	$(1,729,538)
Current (liability) asset	$ (285,426)	$ 229,893
Long-term liability	(744,456)	(1,959,431)
	$ (1,029,882)	$(1,729,538)

Tax carryforwards at December 31, 2008, which are available for future utilization on income tax returns, are as follows (in thousands):

FEDERAL	Amount	Expiration
Alternative minimum tax (AMT) credit	$ 3,268	-
Enhanced oil recovery credit	20,747	2025
Net operating loss - regular tax	43,056	2027
STATE		
Alternative minimum tax (AMT) credit	$ 521	-
Enhanced oil recovery credit	26,765	2016-2020
Net operating loss - regular tax	402,188	2019-2023

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 (benefit) in the accompanying consolidated statements of income (in thousands):

	Year Ended December 31,		
	2008	2007	2006
U.S. federal income tax (benefit) provision at statutory rate	$ (403,770)	$ 93,975	$ 344,613
State income taxes, net of federal benefit/expense	(59,516)	1,826	33,754
Non-deductible expenses	14,066	9,882	7,947
Uncertain tax positions	21,403	(452)	-
Other	(16,718)	4,517	(1,417)
Income tax (benefit) expense on (loss) income before income taxes and cumulative effect of accounting change	$ (444,535)	$ 109,748	$ 384,897

Tax Loss Carryovers. Certain of our U.S. tax loss carryovers obtained as a result of the acquisitions of Nuevo and Pogo are subject to Internal Revenue Code limitations as to the amount that can be used each year. We do not expect these limitations to materially impact our ability to utilize these losses.

Other Tax Matters. The Company did not record a tax benefit related to non-cash employee compensation for 2008 and 2007 since the Company generated a net operating loss for tax purposes in 2007 and did not utilize all of this net operating loss carry forward in 2008. As the Company utilizes this net operating loss in future periods, a tax benefit of $3.8 million will be credited to additional paid in capital as a result of the noncash employee compensation that vested in 2008 and 2007. A deferred tax benefit related to noncash employee compensation of approximately $2.9 million was credited to additional paid in capital in 2006.

FIN 48. Effective January 1, 2007, we adopted FIN 48. This interpretation clarified 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. At adoption, we recorded the cumulative effect of the change in accounting principle as a $1.4 million increase in the opening balance of retained earnings, a $0.8 million decrease in goodwill and a $2.2 million reduction in our existing reserves for uncertain tax positions. The adjustment to goodwill relates to tax positions taken with respect to Nuevo and 3TEC Energy Corporation ("3TEC") in periods prior to our acquisition of these companies in 2004 and 2003, respectively. In the fourth quarter of 2007, we recorded additional uncertain tax positions related to our acquisition of Pogo. We recorded these effects as a $4.6 million increase in goodwill and a $4.6 million increase in our reserves for uncertain tax positions.

During 2008, we recorded additional reserves for uncertain tax positions of $25.5 million primarily related to tax credits and future tax deductions.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (dollars in thousands):

	2008	2007
Balance at January 1	$ 24,370	$ 19,732
Additions for tax positions in prior years	20,929	395
Reductions for tax positions of prior years	(538)	(556)
Additions based on tax positions related to the current year	2,402	4,799
Adjustments for audit settlements in the current year	-	-
Adjustments due to any expiration of a statute of limitations	-	-
Balance at December 31	$ 47,163	$ 24,370

Included in the balance at December 31, 2008 is approximately $47.4 million that would affect our effective tax rate if recognized.

In addition, included in the December 31, 2008 balance is a benefit of approximately $0.3 million and included in the December 31, 2007 balance is an expense of approximately $2.7 million representing tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deduction. Due to the impact of deferred tax accounting, other than interest and penalties, any changes in the period in which items are deducted would not affect the annual effective tax rate but would affect the timing of the payment of cash to the taxing authority.

We recognize interest and penalties related to unrecognized tax positions in income tax expense. Included in the balance of uncertain tax positions at December 31, 2008 and 2007 are interest and penalties of approximately $2.4 million and $0.5 million, respectively.

We file income tax returns in the U.S. federal and various state and foreign jurisdictions. For the previously filed PXP, Nuevo and 3TEC tax returns, we are no longer subject to U.S. federal and state income tax examinations by tax authorities for years before 1996. The Internal Revenue Service is examining of the PXP and Nuevo U.S. income tax returns for 2003 and 2004, the field audit work for which is anticipated to be completed in the first quarter of 2009. Based on discussions with the IRS as of December 31, 2008, we anticipate that the balance of our unrecognized tax benefits could be reduced during the next 12 months as the IRS finalizes its examination and we seek any appropriate administrative appeals. We estimate this reduction could be in a range of between $20 to $23 million.

For the previously filed Pogo tax returns, we are no longer subject to U.S. federal and state income tax examinations by tax authorities for years prior to 2005. During 2008, the IRS began an examination of Pogo's federal tax return for 2006 and has subsequently expanded the examination to include Pogo's return for 2007. We do not anticipate any significant IRS audit adjustments for Pogo tax years subsequent to 2005 that would result in a material change to our financial position.

Note 12 — Commitments, Contingencies and Industry Concentration

Commitments and Contingencies

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

2009	$ 19,658
2010	16,991
2011	16,912
2012	13,066
2013	12,777
Thereafter	43,303
	$ 122,707

Total expenses related to such leases were $10.8 million, $7.9 million and $6.2 million in 2008, 2007 and 2006, 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, $41 million ($84 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 $66 million). To secure its abandonment obligations the purchaser of the properties is required to periodically deposit funds into an escrow account. At December 31, 2008, the escrow account had a balance of $10.7 million. The fair value of our guarantee, $0.6 million, considers the payment/performance risk of the purchaser and 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.

In the event we make a claim under our insurance policies, we will be subject to the credit risk of the insurers. During the second half of 2008 and first quarter of 2009, the volatility and disruption in the financial and credit markets reached unprecedented levels which may adversely affect the credit quality of our insurers and impact their ability to pay out claims.

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 July 7, 2008, we acquired from a subsidiary of Chesapeake a 20% interest in Chesapeake's Haynesville Shale leasehold for approximately $1.65 billion in cash. In connection with the acquisition we also agreed, over a multi-year period, to fund 50% of Chesapeake's drilling and completion costs associated with future Haynesville Shale wells, up to an additional $1.65 billion. As of December 31, 2008, approximately $1.58 billion of this commitment remains. In February 2009, PXP and Chesapeake entered into certain amended agreements which, among other matters, provides us without additional monetary consideration by us a one time option, exercisable on or before June 30, 2010, to reduce our obligation to pay 50% of Chesapeake's drilling and completion costs by $800 million in exchange for an assignment to Chesapeake, effective December 31, 2010, of 50% of all of our interest in the Haynesville properties.

We have a participation agreement with one of our partners in the Gulf of Mexico, and we are drilling two wells offshore Vietnam under our Production Sharing Contract with PetroVietnam. Both of these projects are expected to be completed in 2009, and our commitments are approximately $134.5 million. Additionally, we have two drilling rig commitments under which the minimum commitment would be the day rate for the rig. One contract ends in the first quarter 2009 and the second contract on December 31, 2009. Our commitment for the two rigs is approximately $10.2 million.

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. Plaintiffs filed a motion for final judgment on November 29, 2006 and the court granted such motion on January 11, 2007. Judgment on the $1 billion on 35 leases was filed January 12, 2007. The United States has filed an appeal and Plaintiffs filed a cross-appeal concerning the Court's October 31, 2006 decision. The United States Court of Appeals for the Federal Circuit affirmed on August 25, 2008 the trial courts' judgment in all respects concluding that the lessees may recover $1 billion in lease bonuses paid. The United States filed combined petitions for rehearing and rehearing en banc in October 2008, but the United States Court of Appeals for the Federal Circuit denied the Government's combined petitions on December 5, 2008. On December 24, 2008, the United States Court of Appeals for the Federal Circuit agreed to stay the mandate for 90 days pending consideration of the Government's possible filing of a petition for writ of certiorari. No payments will be made until all appeals have either been waived or exhausted. We are among the current lessees of the 35 leases. Our share of the $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. During 2008, 2007 and 2006, sales to ConocoPhillips accounted for approximately 36%, 45% and 54%, respectively, of our total revenues and sales to Plains Marketing, L.P. ("PMLP") accounted for approximately 23%, 31% and 41%, 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.

At December 31, 2008 we had the following commodity derivative net asset (liability) balances with counterparties rated by Standard & Poor's ("S&P"). The ratings are as of December 31, 2008 (in thousands):

S&P Rating	Fair Value (1)	Deferred Premium Liability	Net Asset
AA+ / Watch Negative	$ 630,530	$ 117,730	$ 512,800
A+ / Stable	164,166	18,399	145,767
A / Negative	1,001,146	197,027	804,119
	$ 1,795,842	$ 333,156	$ 1,462,686

(1) The fair value does not include the settlements receivable at December 31, 2008.

The maximum amount of loss due to credit risk that we would incur if the counterparties to our derivative contracts failed completely to perform according to the term of the contracts at December 31, 2008 is $1.5 billion.

We do not require collateral or other security to support the derivative instruments subject to credit risk. However, the agreements with each of the counterparties to our derivative instruments have netting provisions within the agreements. If a default event occurs, the non-defaulting party can offset the amount payable to the defaulting party with the amount due from the defaulting party. As a result of the offset provisions, our maximum amount of loss due to credit risk is limited to the net amounts of the payables and receivables due from the counterparties. The netting agreements would reduce our maximum amount of loss by the premiums and interest associated with the derivative, approximately $358.6 million at December 31, 2008.

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 13 — Supplemental Cash Flow Information

Cash payments for interest and income taxes were as follows (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Cash payments for interest (net of capitalized interest)	$ 117,278	$ 44,193	$ 72,046
Cash payments for income taxes	$ 145,674	$ 118,876	$ 44,863

At December 31, 2008 and 2007 accrued capital expenditures included in Accounts Payable in the Consolidated Balance Sheet were $245 million and $187 million, respectively.

Common stock and treasury shares issued for no cash payment in connection with our compensation plans were as follows (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Shares	509	362	901
Amount	$ 27,512	$ 15,175	$ 25,959

Non-cash oil and gas property additions included:

- Acquisition of acreage adjacent to our Piceance Basin properties in 2008 for $20.3 million in cash and installments payable in equal amounts of approximately $20.3 million on July 1, 2009 and July 1, 2010 and approximately $18.5 million on July 1, 2011, a total of $59.1 million payable. This liability was assumed by the purchaser of our Piceance Basin properties in December 2008.
- The issuance of one million shares of common stock with a fair value of approximately $45 million in connection with the 2007 Piceance Basin property acquisition to the seller.
- We recorded noncash reductions to oil and gas properties of $18.7 million in 2008 and $20.8 million in 2006 and additions to oil and gas properties of $60.5 million in 2007, respectively for the asset retirement obligation.

The 2007 Pogo acquisition included non-cash consideration as follows (in thousands):

Common stock issued	$ 1,995,516
Senior Subordinated Notes	1,291,977
Current liabilities	258,044
Other noncurrent liabilities	33,388
Deferred income tax liabilities	1,222,649
Asset retirement obligation	49,974
	$ 4,851,548

In the second quarter of 2008 we entered into crude oil puts and natural gas collars which included deferred premiums to be paid to the counterparty to the derivative contract. The deferred premiums and interest on these derivative contracts totaled $285.7 million. In the fourth quarter we modified certain of our crude oil put contracts and agreed to pay additional premium and interest. The additional deferred premium and interest related to these derivative contracts totaled $27.9 million. In 2007 and 2006, we entered into crude puts which included deferred premiums and interest of $40.1 million and $58.2 million, respectively.

Note 14 — Stockholders' Equity

Earnings Per Share

Weighted average shares outstanding for computing basic and diluted earnings for the years ended December 31, 2008, 2007 and 2006 were (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Common shares outstanding- basic	108,828	78,627	77,273
Unvested restricted stock, restricted stock units and stock options	-	1,181	961
Common shares outstanding - diluted	108,828	79,808	78,234

Because we recognized a net loss for the year ended December 31, 2008, no unvested restricted stock, unvested restricted stock units or stock options were included in computing earnings per share because the effect was antidilutive. In 2007 and 2006, no unvested restricted stock, restricted stock units and stock options were excluded in computing earnings per share. In computing earnings per share, no adjustments were made to reported net income.

Authorized Shares

In November 2007, our stockholders approved an amendment to our certificate of incorporation to increase the number of authorized common shares from 150 million to 250 million.

The number of authorized preferred shares at December 31, 2008 is 5,000,000 with a par value of $0.01. No preferred shares are issued or outstanding at December 31, 2008.

Stock Repurchase Program

In December 2007, our Board of Directors authorized a stock repurchase program permitting us to repurchase up to $1.0 billion 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. During the year ended December 31, 2008, we repurchased approximately 5.8 million common shares at a cost of approximately $304.2 million. We may expend an additional $695.8 million under the program.

Note 15 — Consolidating Financial Statements

We are the issuer of \$600 million of 7¾% Senior Notes, \$500 million of 7% Senior Notes and \$400 million of 7⅝% Senior Notes, which are jointly and severally guaranteed on a full and unconditional basis by certain of our existing domestic subsidiaries (referred to as "Guarantor Subsidiaries"). Certain of our subsidiaries do not guarantee the Senior Notes (referred to as "Non-Guarantor Subsidiaries").

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.

During 2008, we completed a restructuring of our subsidiaries, which caused a subsidiary which was previously reported as a Guarantor Subsidiary to be merged into PXP. We restated the Issuer and Guarantor Subsidiaries columns of the condensed consolidating balance sheet at December 31, 2007 and the condensed consolidating statement of income and cash flows for the years ended December 31, 2007 and 2006 to reflect the restructuring.

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2008
(in thousands)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS					
Current Assets					
Cash and cash equivalents	$ 309,362	$ 285	$ 2,228	$ -	$ 311,875
Accounts receivable and other current assets	1,045,947	161,469	1,765	(44,615)	1,164,566
	1,355,309	161,754	3,993	(44,615)	1,476,441
Property and Equipment, at cost					
Oil and natural gas properties — full cost method	3,465,656	6,139,111	15,442	-	9,620,209
Other property and equipment	45,689	35,048	30,253	-	110,990
	3,511,345	6,174,159	45,695	-	9,731,199
Less allowance for depreciation, depletion, amortization and impairment	(2,011,763)	(3,481,169)	(24)	275,153	(5,217,803)
	1,499,582	2,692,990	45,671	275,153	4,513,396
Investment in and Advances to Subsidiaries	3,130,150	(152,601)	(40,606)	(2,936,943)	-
Other Assets	552,498	569,580	-	-	1,122,078
	$ 6,537,539	$ 3,271,723	$ 9,058	$ (2,706,405)	$ 7,111,915
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities	$ 758,476	$ 278,375	$ 1,409	$ (44,615)	$ 993,645
Long-Term Debt	2,805,000	-	-	-	2,805,000
Other Long-Term Liabilities	132,621	58,913	-	-	191,534
Deferred Income Taxes	464,162	174,991	2,527	102,776	744,456
Stockholders' Equity	2,377,280	2,759,444	5,122	(2,764,566)	2,377,280
	$ 6,537,539	$ 3,271,723	$ 9,058	$ (2,706,405)	$ 7,111,915

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2007
(in thousands)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS					
Current Assets					
Cash and cash equivalents	$ 15,897	$ 2,261	$ 7,288	$ -	$ 25,446
Accounts receivable and other current assets	258,951	381,818	8,705	-	649,474
	274,848	384,079	15,993	-	674,920
Property and Equipment, at cost					
Oil and natural gas properties — full cost method	2,866,470	6,410,094	15,457	-	9,292,021
Other property and equipment	57,384	11,903	16,641	-	85,928
	2,923,854	6,421,997	32,098	-	9,377,949
Less allowance for depreciation, depletion, amortization and impairment	(551,166)	(1,059,424)	(21)	609,889	(1,000,722)
	2,372,688	5,362,573	32,077	609,889	8,377,227
Investment in and Advances to Subsidiaries	5,094,294	(825,491)	(26,292)	(4,242,511)	-
Other Assets	24,504	613,264	3,436	-	641,204
	$ 7,766,334	$ 5,534,425	$ 25,214	$ (3,632,622)	$ 9,693,351
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities	$ 392,830	$ 413,959	$ 11,257	$ -	$ 818,046
Long-Term Debt	3,305,000	-	-	-	3,305,000
Other Long-Term Liabilities	171,626	101,001	-	-	272,627
Deferred Income Taxes	558,631	1,162,062	2,262	236,476	1,959,431
Stockholders' Equity	3,338,247	3,857,403	11,695	(3,869,098)	3,338,247
	$ 7,766,334	$ 5,534,425	$ 25,214	$ (3,632,622)	$ 9,693,351

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2008
(in thousands)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues					
Oil sales	$ 1,298,465	$ 468,212	$ -	$ -	$ 1,766,677
Gas sales	79,118	540,768	-	-	619,886
Other operating revenues	1,919	14,989	-	-	16,908
	1,379,502	1,023,969	-	-	2,403,471
Costs and Expenses					
Production costs	370,800	255,627	1	-	626,428
General and administrative	100,590	52,414	302	-	153,306
Depreciation, depletion, amortization and accretion	248,771	359,942	7	12,764	621,484
Impairment of oil and gas properties	1,234,814	2,066,982	5,898	321,972	3,629,666
	1,954,975	2,734,965	6,208	334,736	5,030,884
Income (Loss) from Operations	(575,473)	(1,710,996)	(6,208)	(334,736)	(2,627,413)
Other Income (Expense)					
Equity in earnings of subsidiaries	(1,288,070)	(4,573)	-	1,292,643	-
Interest expense	(52,147)	(86,809)	-	21,965	(116,991)
Debt extinguishment costs	(18,256)	-	-	-	(18,256)
Gain (loss) on mark-to-market derivative contracts	1,566,513	(10,596)	-	-	1,555,917
Other income (expense)	24,197	49,106	1,776	(21,965)	53,114
Income (Loss) Before Income Taxes	(343,236)	(1,763,868)	(4,432)	957,907	(1,153,629)
Income tax (expense) benefit	(365,858)	676,879	(186)	133,700	444,535
Net Income (Loss)	$ (709,094)	$ (1,086,989)	$ (4,618)	$ 1,091,607	$ (709,094)

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2007
(in thousands)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues					
Oil sales	$ 921,530	$ 194,846	$ -	$ -	$ 1,116,376
Gas sales	25,565	127,851	-	-	153,416
Other operating revenues	2,569	478	1	-	3,048
	949,664	323,175	1	-	1,272,840
Costs and Expenses					
Production costs	306,289	106,766	67	-	413,122
General and administrative	104,640	18,859	507	-	124,006
Depreciation, depletion, amortization and accretion	159,545	156,510	23	-	316,078
Impairment of oil and gas properties	-	609,889	-	(609,889)	-
	570,474	892,024	597	(609,889)	853,206
Income (Loss) from Operations	379,190	(568,849)	(596)	609,889	419,634
Other Income (Expense)					
Equity in earnings of subsidiaries	(10,407)	(282)	-	10,689	-
Interest expense	(39,323)	(68,692)	-	39,107	(68,908)
Debt extinguishment costs	-	-	-	-	-
(Loss) gain on mark-to-market derivative contracts	(88,993)	444	-	-	(88,549)
Other income (expense)	39,181	6,105	143	(39,107)	6,322
Income (Loss) Before Income Taxes	279,648	(631,274)	(453)	620,578	268,499
Income tax (expense) benefit	(120,897)	247,454	171	(236,476)	(109,748)
Net Income (Loss)	$ 158,751	$ (383,820)	$ (282)	$ 384,102	$ 158,751

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2006
(in thousands)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues					
Oil sales	$ 832,521	$ 77,206	$ -	$ -	$ 909,727
Gas sales	33,741	72,578	-	-	106,319
Other operating revenues	1,816	641	-	-	2,457
	868,078	150,425	-	-	1,018,503
Costs and Expenses					
Production costs	250,407	62,718	-	-	313,125
General and administrative	115,479	7,655	-	-	123,134
Depreciation, depletion, amortization and accretion	106,921	109,861	-	-	216,782
Gain on sale of oil and gas properties	(915,841)	(67,147)	-	-	(982,988)
	(443,034)	113,087	-	-	(329,947)
Income from Operations	1,311,112	37,338	-	-	1,348,450
Other Income (Expense)					
Equity in earnings of subsidiaries	(19,925)	-	-	19,925	-
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)
Other income	43,398	-	-	-	43,398
Income Before Income Taxes and Cumulative Effect of Accounting Change	941,725	22,957	-	19,925	984,607
Income tax expense	(342,015)	(42,882)	-	-	(384,897)
Income (Loss) Before Cumulative Effect of Accounting Change	599,710	(19,925)	-	19,925	599,710
Cumulative effect of accounting change, net of tax benefit	(2,182)	-	-	-	(2,182)
Net Income (Loss)	$ 597,528	$ (19,925)	$ -	$ 19,925	$ 597,528

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2008
(in thousands)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income (loss)	$ (709,094)	$(1,086,989)	$ (4,618)	$ 1,091,607	$ (709,094)
Items not affecting cash flows from operating activities					
Gain on sale of assets	-	(65,689)	-	-	(65,689)
Depreciation, depletion, amortization, accretion and impairment	1,483,585	2,426,924	5,905	334,736	4,251,150
Equity in earnings of subsidiaries	1,288,070	4,573	-	(1,292,643)	-
Deferred income tax expense (benefit)	348,279	(890,194)	265	(133,700)	(675,350)
Debt extinguishment costs	18,256	-	-	-	18,256
Commodity derivative contracts	(1,566,513)	10,596	-	-	(1,555,917)
Noncash compensation	43,240	7,197	(36)	-	50,401
Other noncash items	3,506	2,232	808	-	6,546
Change in assets and liabilities from operating activities, net of effect of acquisitions					
Accounts receivable and other assets	45,165	68,547	2,267	-	115,979
Accounts payable and other liabilities	(45,438)	(62,357)	(1,387)	-	(109,182)
Stock appreciation rights	(59,078)	-	-	-	(59,078)
Income taxes payable/receivable	103,387	-	-	-	103,387
Net cash provided by operating activities	953,365	414,840	3,204	-	1,371,409
CASH FLOWS FROM INVESTING ACTIVITIES					
Additions to oil and gas properties	(530,738)	(577,878)	(8,099)	-	(1,116,715)
Acquisition of oil and gas properties	-	(2,006,127)	-	-	(2,006,127)
Acquisition of Pogo Producing Company	-	(77,686)	-	-	(77,686)
Decrease in restricted cash	-	59,092	-	-	59,092
Proceeds from sales of oil and gas properties and related assets, net of costs and expenses	2,969,945	-	-	-	2,969,945
Derivative settlements	(8,606)	-	-	-	(8,606)
Other, net	(28,274)	(2,550)	(16,869)	-	(47,693)
Net cash provided by (used in) investing activities	2,402,327	(2,605,149)	(24,968)	-	(227,790)
CASH FLOWS FROM FINANCING ACTIVITIES					
Revolving credit facilities					
Borrowings	14,331,046	-	-	-	14,331,046
Repayments	(15,231,046)	-	-	-	(15,231,046)
Proceeds from issuance of Senior Notes	400,000	-	-	-	400,000
Costs incurred in connection with financing arrangements	(27,527)	-	-	-	(27,527)
Derivative settlements	(25,678)	-	-	-	(25,678)
Purchase of treasury stock	(304,192)	-	-	-	(304,192)
Investment in and advances to affiliates	(2,205,088)	2,188,384	16,704	-	-
Other	258	(51)	-	-	207
Net cash (used in) provided by financing activities	(3,062,227)	2,188,333	16,704	-	(857,190)
Net increase (decrease) in cash and cash equivalents	293,465	(1,976)	(5,060)	-	286,429
Cash and cash equivalents, beginning of period	15,897	2,261	7,288	-	25,446
Cash and cash equivalents, end of period	$ 309,362	$ 285	$ 2,228	$ -	$ 311,875

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2007
(in thousands)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income (loss)	$ 158,751	$ (383,820)	$ (282)	$ 384,102	$ 158,751
Items not affecting cash flows from operating activities					
Depreciation, depletion, amortization, accretion and impairment	159,545	766,399	23	(609,889)	316,078
Equity in earnings of subsidiaries	10,407	282	-	(10,689)	-
Deferred income tax expense (benefit)	121,065	(243,016)	(100)	236,476	114,425
Commodity derivative contracts	88,993	(444)	-	-	88,549
Noncash compensation	47,435	4,584	-	-	52,019
Other noncash items	1,157	(450)	-	-	707
Change in assets and liabilities from operating activities, net of effect of acquisitions					
Accounts receivable and other assets	(27,571)	(26,603)	(12,050)	-	(66,224)
Accounts payable and other liabilities	50,993	(6,223)	8,581	-	53,351
Stock appreciation rights	(8,322)	-	-	-	(8,322)
Income taxes payable/receivable	(121,222)	-	-	-	(121,222)
Net cash provided by (used by) operating activities	481,231	110,709	(3,828)	-	588,112
CASH FLOWS FROM INVESTING ACTIVITIES					
Additions to oil and gas properties	(541,621)	(228,788)	-	-	(770,409)
Acquisition of oil and gas properties	(975,407)	-	-	-	(975,407)
Acquisition of Pogo Producing Company, net of cash acquired	-	(304,676)	6,645	-	(298,031)
Increase in restricted cash	-	(59,092)	-	-	(59,092)
Derivative settlements	(99,861)	-	-	-	(99,861)
Other, net	(26,065)	(6,221)	(8,051)	-	(40,337)
Net cash used in investing activities	(1,642,954)	(598,777)	(1,406)	-	(2,243,137)
CASH FLOWS FROM FINANCING ACTIVITIES					
Revolving credit facilities					
Borrowings	4,745,100	-	-	-	4,745,100
Repayments	(2,775,600)	-	-	-	(2,775,600)
Proceeds from issuance of Senior Notes	1,100,000	-	-	-	1,100,000
Redemption of long-term debt	-	(1,291,926)	-	-	(1,291,926)
Costs incurred in connection with financing arrangements	(47,333)	-	-	-	(47,333)
Derivative settlements	(3,688)	-	-	-	(3,688)
Purchase of treasury stock	(47,485)	-	-	-	(47,485)
Investment in and advances to affiliates	(1,794,280)	1,781,758	12,522	-	-
Other	10	494	-	-	504
Net cash provided by financing activities	1,176,724	490,326	12,522	-	1,679,572
Net increase in cash and cash equivalents	15,001	2,258	7,288	-	24,547
Cash and cash equivalents, beginning of period	896	3	-	-	899
Cash and cash equivalents, end of period	$ 15,897	$ 2,261	$ 7,288	$ -	$ 25,446

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2006
(in thousands)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income (loss)	$ 597,528	$ (19,925)	$ -	$ 19,925	$ 597,528
Items not affecting cash flows from operating activities					
Gain on sale of oil and gas properties	(915,841)	(67,147)	-	-	(982,988)
Depreciation, depletion, amortization and accretion	106,921	109,861	-	-	216,782
Equity in earnings of subsidiaries	19,925	-	-	(19,925)	-
Deferred income tax expense (benefit)	298,103	(55,584)	-	-	242,519
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	55,486	-	-	-	55,486
Other noncash items	(268)	-	-	-	(268)
Change in assets and liabilities from operating activities					
Accounts receivable and other assets	23,365	5,097	-	-	28,462
Accounts payable and other liabilities	(4,965)	(8,856)	-	-	(13,821)
Stock appreciation rights	(17,720)	-	-	-	(17,720)
Income taxes payable/receivable	94,272	-	-	-	94,272
Net cash provided by operating activities	661,460	13,521	-	-	674,981
CASH FLOWS FROM INVESTING ACTIVITIES					
Additions to oil and gas properties	(501,044)	(133,286)	-	-	(634,330)
Proceeds from sales of oil and gas properties	1,453,650	97,013	-	-	1,550,663
Derivative settlements	(93,411)	-	-	-	(93,411)
Other, net	(4,301)	(1,034)	(5,588)	-	(10,923)
Net cash provided by (used in) investing activities	854,894	(37,307)	(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)
Purchase of treasury stock	(298,445)	-	-	-	(298,445)
Investment in and advances to affiliates	(29,373)	23,785	5,588	-	-
Other	(5,963)	-	-	-	(5,963)
Net cash (used in) provided by financing activities	(1,517,006)	23,785	5,588	-	(1,487,633)
Net 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

Note 16 — Quarterly Financial Data (Unaudited)

The following table shows summary financial data for 2008 and 2007 (in thousands, except per share data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2008 (1)					
Revenues	$ 623,077	$ 732,703	$ 719,537	$ 328,154	$ 2,403,471
Income (loss) from operations	285,889	390,377	386,468	(3,690,147)	(2,627,413)
Net income (loss)	163,501	202,918	493,145	(1,568,658)	(709,094)
Basic earnings (loss) per share	1.46	1.88	4.58	(14.56)	(6.52)
Diluted earnings (loss) per share	1.43	1.84	4.50	(14.56)	(6.52)
2007 (2)					
Revenues	$ 224,693	$ 255,547	$ 298,969	$ 493,631	$ 1,272,840
Income from operations	62,024	71,040	110,548	176,022	419,634
Net income	20,570	25,318	32,860	80,003	158,751
Basic earnings per share	0.28	0.35	0.45	0.83	2.02
Diluted earnings per share	0.28	0.35	0.45	0.81	1.99

(1) Reflects the February 2008 divestments of 50% of our working interest in the Piceance and Permian Basins to Oxy and the San Juan Basin and Barnett Shale to XTO, the April 2008 acquisition of the South Texas properties and the December 2008 divestment of the remainder of our interests in the Piceance and Permian Basins. Additionally at December 31, 2008, our capitalized costs of proved oil and gas properties exceeded the ceiling, and we recorded a $3.6 billion non-cash pre-tax impairment of our oil and gas properties in the fourth quarter.

(2) Reflects the acquisition of Pogo effective November 6, 2007 and Piceance Basin properties effective May 31, 2007.

Note 17 — Oil and Natural Gas Activities

Costs incurred

Our oil and natural gas acquisition, exploration and development activities are primarily conducted in the United States. Our international activities currently consist of an exploration project offshore Vietnam that was obtained in our Pogo acquisition. The following table summarizes the costs incurred during the last three years (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Property acquisitions costs			
Unproved properties	$ 1,878,842	$ 1,822,312	$ 48,315
Proved properties	267,161	3,883,607	7,175
Exploration costs	520,612	465,246	272,352
Development costs	576,753	357,345	319,730
	$ 3,243,368	$ 6,528,510	$ 647,572

Amounts presented include capitalized general and administrative expense of $60.6 million, $44.6 million and $34.8 million in 2008, 2007 and 2006, respectively, and capitalized interest expense of $70.5 million, $34.6 million and $7.9 million in 2008, 2007 and 2006, respectively.

Capitalized costs

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

	December 31,	
	2008	2007
Property subject to amortization	$ 7,106,785	$ 7,340,238
Accumulated DD&A and impairment	(5,207,600)	(991,319)
	$ 1,899,185	$ 6,348,919

The average DD&A rate per equivalent unit of production was $17.69, $12.92 and $8.96 in 2008, 2007 and 2006, respectively.

Costs not subject to amortization

The following table summarizes the categories of costs comprising the amount of unproved properties not subject to amortization by the year in which such costs were incurred (in thousands):

	December 31,				
	Total	2008 (1)	2007	2006	Prior
Onshore					
Acquisition costs	$ 2,019,060	$ 1,668,760	$ 335,663	$ 2,547	$ 12,090
Exploration costs	36,313	35,399	2	511	401
Capitalized interest	37,183	31,706	2,056	945	2,476
Offshore					
Acquisition costs	29,117	7,435	4,192	9,385	8,105
Exploration costs	358,973	233,256	65,986	59,662	69
Capitalized interest	17,336	8,844	6,327	1,131	1,034
International					
Acquisition costs	14,874	3,623	11,251	-	-
Capitalized interest	568	458	110	-	-
	$ 2,513,424	$ 1,989,481	$ 425,587	$ 74,181	$ 24,175

(1) Includes $1.65 billion attributable to the Chesapeake acquisition. See Note 3.

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 are established or impairment is 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 60% of the costs not subject to amortization at December 31, 2008 will be transferred to the amortization base over the next five years and the remainder in the next seven to ten years. Approximately 49% of our domestic total net undeveloped acreage is covered by leases that will expire from 2009 through 2011. We added a significant number of new leases in 2008 in the Haynesville Shale, with lease terms generally ranging from two to three years; however, we are participating in the drilling of wells in the area to establish production in order to hold a majority of the acreage beyond lease expiration.

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 and interest income. Income tax expense was determined by applying the statutory rates to pretax operating results (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Revenues from oil and gas producing activities	$ 2,403,471	$ 1,272,840	$ 1,018,503
Production costs	(626,428)	(413,122)	(313,125)
Depreciation, depletion, amortization and accretion	(605,440)	(306,713)	(209,108)
Impairment of oil and gas properties	(3,629,666)	-	-
Income tax benefit (expense)	923,003	(209,589)	(197,764)
Results of operations from producing activities (excluding general and administrative and interest costs)	$ (1,535,060)	$ 343,416	$ 298,506

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, 2008. The following reserve information in 2008 is based upon (1) reserve reports prepared by the independent petroleum consulting firms of Netherland, Sewell & Associates, Inc. and Ryder Scott Company L.P. ("Ryder Scott") (95% of reserve volumes) and (2) reserve volumes prepared by us (5% of reserve volumes). In 2007, our reserves were based upon (1) reserve reports prepared by the independent petroleum consulting firms of Netherland, Sewell & Associates, Inc. and Ryder Scott (80% of reserve volumes), (2) reserve volumes prepared by us and audited by Ryder Scott and Miller and Lents, Ltd. (19% of reserve volumes) and (3) reserve volumes prepared by us, which were not audited by an independent petroleum consulting firm (1% of reserve volumes). In 2006, 100% of our reserves were based on reserve reports prepared by 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 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. The market price for California crude oil differs from the established market indices due primarily to transportation, refining costs and quality adjustments. Approximately 60% of our 2008 reserve volumes is attributable to properties in California where differentials to the NYMEX reference prices have been volatile due to these factors.

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, 2008.

	As of or for the Year Ended December 31,					
	2008		2007		2006	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
Proved Reserves						
Beginning balance	436,533	1,519,976	333,217	110,922	356,333	267,921
Revision of previous estimates	(172,359)	(256,390)	40,726	310,858	(2,045)	(3,949)
Extensions, discoveries and other additions	5,424	218,967	6,074	151,346	7,688	3,765
Improved recovery	-	-	-	-	10,095	2,438
Purchase of reserves in-place	2,513	82,651	74,646	976,395	-	-
Sale of reserves in-place	(74,110)	(799,593)	-	-	(19,879)	(138,624)
Production	(20,294)	(79,254)	(18,130)	(29,545)	(18,975)	(20,629)
Ending balance	177,707	686,357	436,533	1,519,976	333,217	110,922
Proved Developed Reserves						
Beginning balance	227,915	757,736	171,646	62,021	234,638	193,904
Ending balance	123,522	515,180	227,915	757,736	171,646	62,021

Revisions of Previous Estimates

In 2008 we had a total of 215 MMBOE of negative revisions. Approximately 204 MMBOE of these revisions were related to the significant decline in oil prices at December 31, 2008 and a widening of the basis differentials from our recent historical average at December 31, 2008. This most significantly impacted our California properties which accounted for 171 MMBOE, or 84%, of the total revisions due to price. The balance of 33 MMBOE of negative revisions due to price was primarily in the Mid-Continent Region. The remaining 11 MMBOE of total negative revisions were based on updated technical evaluations and performance projections.

In 2007 we had a total of 93 MMBOE of positive revisions. These positive results were a result of both successful development activities as well as economic life extension resulting from significantly higher oil prices at year-end 2007. Onshore California properties account for 27 MMBOE, primarily in the Inglewood, Las Cienegas, Cymric and Midway Sunset fields which totaled 19 MMBOE of revisions. We also had 52 MMBOE of positive revisions in the Piceance Basin. Revisions of 45 MMBOE were due to higher gas price realizations at December 31, 2007. These reserves were evaluated as technically proven at the time of the May 2007 acquisition but were not classified as proven because the reserves were not commercial due to high gas price location differentials in the Rocky Mountains at the time. The balance of 14 MMBOE of positive revisions were primarily in offshore California and the Permian Basin.

In 2006 we had a total of 3 MMBOE of downward revisions primarily related to performance of our Inglewood Deep development.

Improved Recovery

In 2006 we had a total of 11 MMBOE of proved reserve additions related to expansion of improved recovery projects in several of our onshore California fields.

Purchases of Minerals in Place

In 2008 we had a total of 16 MMBOE of proved reserve additions related to acquisitions. Interests acquired in South Texas properties accounted for 15 MMBOE and the remainder related to interests acquired in the Piceance Basin properties.

In 2007 we had a total of 237 MMBOE of proved reserve additions related to acquisitions resulting from two transactions. The first, occurring in May 2007, was the acquisition of the Piceance Basin properties representing 19 MMBOE of additions to proved reserves. The second transaction, occurring in November 2007, was the acquisition of Pogo, representing 218 MMBOE of additions to proved reserves.

Extensions and Discoveries

In 2008 we had a total of 42 MMBOE of extensions and discoveries, including (1) 15 MMBOE of discoveries and extension in the Haynesville trend resulting from successful drilling during 2008 that developed and extended the proved acreage, (2) 12 MMBOE of extensions in the Gulf of Mexico primarily attributable to continued success in the Flatrock area, (3) 8 MMBOE of extensions in the Piceance Basin resulting from continued successful drilling during 2008 that extended the proved acreage, prior to our divestment later in 2008 and (4) 7 MMBOE of extensions in the Mid-Continent Region resulting from successful drilling during 2008 primarily in the Wheeler and Courson Ranch areas.

In 2007 we had a total of 31 MMBOE of extensions and discoveries, including (1) 19 MMBOE of extensions in the Piceance Basin resulting from successful drilling during 2007 that extended the proved acreage, (2) 3 MMBOE attributable to new discoveries made in the Gulf of Mexico on the Hurricane Deep and Flatrock prospects, and (3) 9 MMBOE of extensions primarily attributable to the extension of proved acreage in Cymric and Midway Sunset Diatomite, East Texas Austin Chalk and South Texas.

In 2006 we had a total of 8 MMBOE of extensions and discoveries, the majority of which were related to the extension of proved acreage in several of our onshore California fields.

Sales of Minerals in Place

In 2008 we had a total of 207 MMBOE of divestments, including 96 MMBOE representing our entire interest in the Piceance Basin, 95 MMBOE representing our entire working interest in the Permian Basin and 12 MMBOE representing our entire interest in the San Juan Basin. The remaining 4 MMBOE of divestments represented a portion of our interests in Austin Chalk trend and all of our working interests in the Barnett Shale and New Albany Shale trends.

In 2006 we had a total of 43 MMBOE of divestments, including 30 MMBOE representing our entire interest in several fields in onshore California and 3 MMBOE representing in our entire interest in fields located in West Texas.

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,		
	2008	2007	2006
Future cash inflows	$ 9,311,501	$ 46,466,516	$ 17,318,297
Future development costs	(1,704,350)	(4,919,564)	(1,979,251)
Future production expense	(4,345,314)	(14,408,460)	(6,623,201)
Future income tax expense	(772,225)	(9,096,371)	(3,063,433)
Future net cash flows	2,489,612	18,042,121	5,652,412
Discounted at 10% per year	(1,353,238)	(10,418,798)	(3,141,749)
Standardized measure of discounted future net cash flows	$ 1,136,374	$ 7,623,323	$ 2,510,663

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 use various derivative instruments to manage our exposure to commodity prices. Arrangements in effect at December 31, 2008 are discussed in Note 5. 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, 2008, 2007 and 2006 were $31.75, $85.50 and $50.71 per barrel of oil, respectively, and $5.50, $6.28 and $6.14 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 in effect at December 31 of the year presented and held constant throughout the life of the properties.

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, 2008, are as follows (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Balance, beginning of year	$ 7,623,323	$ 2,510,663	$ 3,082,166
Sales, net of production expenses	(1,760,135)	(856,670)	(848,676)
Net change in sales and transfer prices, net of production expenses	(7,161,276)	4,250,363	240,127
Extensions, discoveries and improved recovery, net of costs	389,719	348,785	194,904
Changes in estimated future development costs	1,013,179	(219,710)	(322,294)
Previously estimated development costs incurred during the year	369,693	184,268	196,482
Purchase of reserves in-place	201,771	3,856,043	-
Sale of reserves in-place	(2,503,747)	-	(508,692)
Revision of quantity estimates	(1,800,309)	3,435	52,478
Accretion of discount	812,356	393,743	445,583
Net change in income taxes	3,951,800	(2,847,597)	(21,415)
Balance, end of year	$ 1,136,374	$ 7,623,323	$ 2,510,663

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NYSE CORPORATE GOVERNANCE COMPLIANCE

As required by the rules of the New York Stock Exchange, following our 2008 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 2008 Annual Report on Form 10-K as Exhibits 31.1 and 31.2.

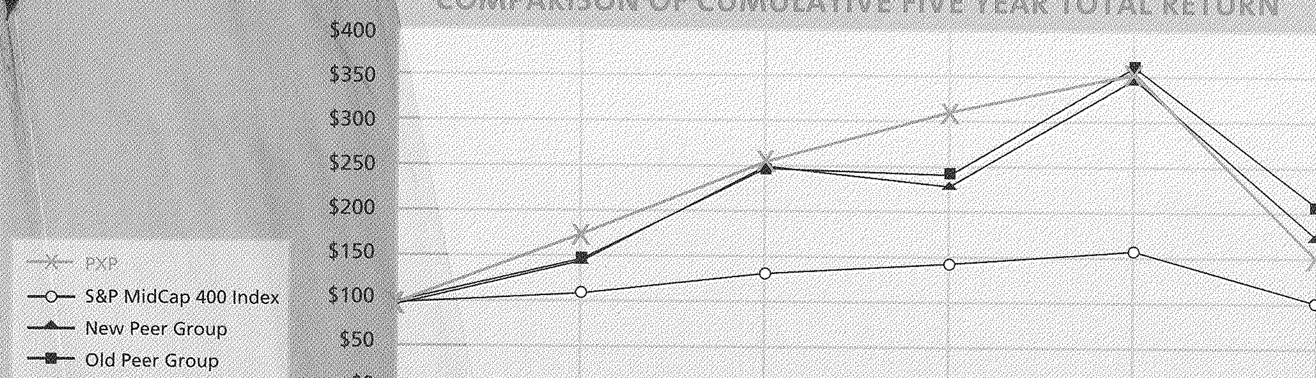
COMPARISON OF SHAREHOLDER RETURN

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 Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, Cimarex Energy Co., Denbury Resources Inc., EOG Resources, Inc., Forest Oil Corporation, Newfield Exploration Company, Noble Energy, Inc., Petrohawk Energy Corporation, Pioneer Natural Resources Company, Range Resources Corporation, Sandridge Energy, Inc. and Ultra Petroleum Corp. and (iii) a peer group used by PXP last year consisting of Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, Cimarex Energy Co., Denbury Resources Inc., EOG Resources, Inc., Forest Oil Corporation, Newfield Exploration Company, Noble Energy, Inc., Pioneer Natural Resources Company, Range Resources Corporation, Ultra Petroleum Corp. and XTO Energy Inc.

The graph covers the period from December 31, 2003, through December 31, 2008, and assumes that $100 was invested on December 31, 2003 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 CUMULATIVE FIVE YEAR TOTAL RETURN



Directors

TOP LEFT: Alan R. Buckwalter, III, Tom H. Delimitros, Robert L. Gerry, III
MIDDLE LEFT: John H. Lollar, Thomas A. Fry, III
BOTTOM LEFT: Jerry L. Dees, James C. Flores, Charles G. Groat, Isaac Arnold, Jr.

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.
President of The Arnold Corporation
and Former Chairman of Quintana
Petroleum Corporation

Alan R. Buckwalter, III
Retired, Chairman and Chief Executive Officer
JPMorgan 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

Thomas A. Fry, III
President
National Ocean Industries Association

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

Charles G. Groat
Interim Dean
Jackson School of Geosciences
Director, Center for International Energy
and Environmental Policy
The University of Texas at Austin

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

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, 2008, is available free of charge on request to:

Investor Relations
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713.579.6000 or 1.800.934.6083

Independent Registered Public Accounting Firm

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

Transfer Agent

American Stock Transfer & Trust
59 Maiden Lane, Plaza Level
New York, New York 10038
1.800.937.5449

CORPORATE HEADQUARTERS

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PXP
NYSE

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 difficulties in integrating our operations as a result of any significant acquisitions;
- unexpected future capital expenditures (including the amount and nature thereof);
- the impact of oil and gas price fluctuations, including the impact on our reserve volumes and values and on our earnings;
- 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;
- the effects of competition;
- the availability (or lack thereof) of acquisition, disposition or combination opportunities;
- the availability (or lack thereof) of Capital to fund our business strategy and/or operations;
- the impact of current and future laws and governmental regulations;
- environmental liabilities that are not covered by an effective indemnity or insurance;
- the ability and willingness of our current or potential counterparties to fulfill their obligations to us or to enter into transactions with us in the future; 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 Securities and Exchange Commission. 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. Our website is www.pxp.com. No information from the SEC's or our website is incorporated by reference herein. 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. 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. 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.

Designed by: Origin, Houston, Texas
www.origindesign.com

PXP

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